BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

In the Matter of the Transmission Permit for the Big Stone South to Ellendale Project

EL13-028

DIRECT TESTIMONY OF JASON WEIERS

BACKGROUND OF WITNESS

Q. State your name, your employer, and your business address.

A. My name is Jason Weiers. I work for Otter Tail Power Company ("OTP"), and my business address is 215 South Cascade Street, Fergus Falls, MN 56537.

Q. What is your current position with OTP?

A. Manager, Delivery Planning.

Q. What are your duties and responsibilities in that position?

A. I am responsible for managing an employee group involved in administering various transmission contracts with neighboring utilities, supporting regulatory related activities, transmission planning responsibilities, transmission project development, and capital budget development for OTP.

Q. What is your educational background?

A. I received a Bachelor of Science degree in electrical engineering with an emphasis in power from North Dakota State University in May of 2000. I have also taken courses and attended conferences throughout my career related to engineering practices, project management, public speaking, finance, and managing people.

Q. Have you been employed by OTP since you graduated in May of 2000?

A. Yes.

Q. What other positions have you held at OTP, and what were you duties and responsibilities in those positions?

A. Before being promoted to manager in 2013, I held the title of Supervisor, Delivery Studies. I was in that position from 2008 until 2013. In that position, I supervised an employee group involved in the traditional transmission planning processes of a transmission owning utility. My activities included: overseeing the building of transmission system models; performing transmission studies, coordinating with neighboring utilities; ensuring compliance with North American Electric Reliability Corporation (NERC) reliability standards related to transmission planning; and various other activities.

Before 2008, I worked as a Transmission and Distribution Studies Engineer at OTP. In that position, I engaged in technical studies resulting in several high voltage transmission and generation projects that have been built or are still being developed, including large scale transmission projects currently being pursued through the CapX 2020 initiative. The CapX 2020 initiative is a joint effort of 11 transmission owning utilities in Minnesota and the surrounding region to expand the electric transmission grid to ensure continued reliable and affordable service.

Q. Do you hold any professional designations?

A. I am a registered professional engineer in the State of Minnesota and a member of the Red River Valley chapter of the Institute of Electrical and Electronic Engineers (IEEE).

Q. Have you worked on any groups relating to electrical power planning and transmission?

A. Through my career at OTP, I have served on the Mid-Continent Area Power Pool (MAPP) Planning Standards Development Working Group (PSDWG) and as a MAPP representative on the North American Electric Reliability Corporation (NERC) Interconnection Dynamics Working Group (IDWG). I am currently the chair of the Midwest Reliability Organization (MRO) Transmission Assessment Subcommittee (TAS) and one of three Midcontinent Independent System Operator (MISO) elected representatives on the Transmission Owner (TO) / Transmission Developer (TD) sector of the Eastern Interconnection Planning

Collaborative (EIPC). I also serve as a member of the Technical Review Committee (TRC) involved in the Minnesota Renewable Integration Transmission Study (MRITS).

Q. Do you have any prior experience as an expert witness?

A. Yes. In 2006, I served as an expert witness for the Big Stone II project in Minnesota docket number CN-05-619 (Certificate of Need Application) and Minnesota docket number TR-05-1275 (Route Permit Application). These dockets were related to adding transmission in Minnesota to support a second coal-fired generator at the existing Big Stone Plant near Big Stone, South Dakota. The purpose of my involvement in these dockets was to describe the need for the transmission project, outline the study requirements under the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff ("MISO Tariff"), and explain the results of various transmission studies performed for the project.

I also was an expert witness for the Bemidji to Grand Rapids 230 kV project through Minnesota docket number CN-07-1222 (Certificate of Need Application) and Minnesota docket number TL-07-1327 (Route Permit Application). These dockets were related to adding a new, 70-mile 230 kV line from Bemidji, MN to Grand Rapids, MN to maintain reliability in the Red River Valley, which is an expansive area centered along the North Dakota/Minnesota state border. My involvement in these dockets was again to establish the need for the transmission project, which was identified through various local and regional transmission studies and confirmed by MISO as being needed for reliability purposes.

Q. What is the purpose of your testimony in this matter?

A. The purpose of my testimony is to discuss and demonstrate that the Big Stone South to Ellendale 345 kV Transmission Project ("Project") is necessary to serve a public use. I will also discuss why the Project represents a reasonable relationship to an overall plan of transmitting electricity in the public interest.

As the primary OTP representative participating in the MISO transmission studies leading to MISO's recommendation and approval of the Multi-Value Project (MVP) portfolio in December of 2011, my testimony describes the studies that show the need for the Project. In addition, I will also explain the consequences of not building this Project or delaying the in-service date of the Project. Through the course of describing these aspects, I will also provide some background information about MISO and its responsibilities within the Midwest.

Q. What experience do you have in determining need and demand for electric transmission projects?

A. I have approximately 14 years of experience in performing or overseeing transmission planning activities at OTP. Through the course of my experience, I have been involved in several transmission studies leading to the recommendation, approval, and construction of numerous transmission projects. These projects ensure adherence with applicable NERC Reliability Standards, Federal Energy Regulatory Commission (FERC) orders, and applicable state mandates. Through the course of my activities related to planning for new transmission projects, extensive coordination occurs across several neighboring utilities and MISO.

BACKGROUND OF MISO

Q. What is MISO?

A. MISO is a not-for-profit, member-based regional transmission organization (RTO) operating across 15 U.S. states and the Canadian province of Manitoba (see Figure 1). As a Regional Transmission Organization, MISO, among several other duties, assures consumers of nondiscriminatory, open access to the transmission facilities of its members.

Q. What is Figure 1 below?

A. This is a map showing the MISO area, which includes the Midwest region and most of South Dakota.

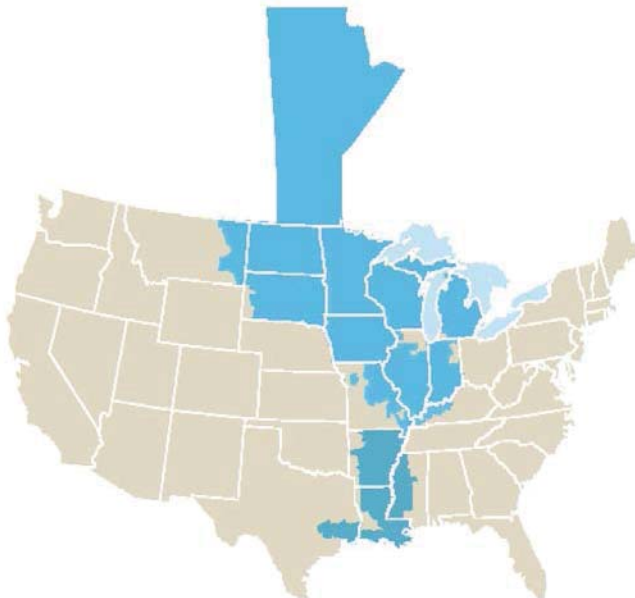

Figure 1 – MISO Region

Q. What are MISO's responsibilities?

A. As an RTO, MISO is responsible for planning the transmission systems of its member Transmission Owners (TOs). Each year, MISO undertakes the development of the MISO Transmission Expansion Plan (MTEP) in collaboration with Transmission Owners and multiple other stakeholders.

Furthermore, MISO is the NERC registered Planning Coordinator for its member Transmission Owners, which includes portions of South Dakota, and performs planning functions collaboratively with stakeholders while also providing an independent assessment and perspective of the needs of the transmission system overall.

Lastly, MISO is responsible for approving transmission service, new generation interconnections, and new transmission interconnections to and within the MISO footprint, and for ensuring that the system is planned to reliably and efficiently provide for existing and forecasted usage of the transmission system.

Q. What experience do you have in working with MISO?

A. Before my current position, I was the primary planning contact for OTP with MISO for a period of over 10 years. I participated in MISO's planning efforts each year and provided feedback and suggestions pertaining to the planning of the OTP transmission system.

Specific to the Project, I have participated directly in the planning of the MVP portfolio that was approved by MISO in December 2011.

Q. Are MDU and OTP members of MISO?

A. Yes. MDU and OTP are both transmission-owning members of MISO. Since both OTP and MDU own transmission that is planned and operated by MISO, they are classified as Transmission Owners within MISO.

Q. What is the significance of being a Transmission Owner within MISO?

A. As Transmission Owners within MISO, both OTP and MDU are signatories to the Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc., a Delaware Non-Stock Corporation ("Transmission Owners Agreement" or "TOA"). The Transmission Owners Agreement is the foundational agreement that founded MISO and, among other things, provides for TOs to transfer functional control of their transmission facilities to the independent Transmission Provider (MISO) and obligates TOs to construct specific transmission projects that MISO has identified as needed to address a specific transmission issue(s), which the MISO Board of Directors has approved in the MTEP.

Q. How is MISO governed?

A. MISO is governed by an independent, eight-member Board of Directors. The Board of Directors is comprised of seven independent directors elected by the membership, plus MISO's president.

Q. Who are members of MISO?

A. Members of MISO include 48 Transmission Owners with $20 billion in transmission assets under MISO's functional control plus 96 non-transmission owning members.

Members across MISO are classified into a broad list of stakeholder groups called sectors. Members join one of nine sectors for representation and voting purposes at various stakeholder meetings conducted by MISO. The sectors present within MISO include:

1. Transmission Owners
2. Independent Power Producers and Exempt Wholesale Generators
3. Power Marketers and Brokers
4. Municipals, Cooperatives, and Transmission Dependent Utilities
5. Public Consumers
6. State Regulatory Authorities
7. Environmental and Other stakeholder group
8. Eligible End Use Customers
9. Coordination Members

Q. Is this a voluntary organization?

A. Yes, although OTP and MDU joined MISO as a result of FERC Order No. 2000 issued in 1999, which strongly encouraged all regulated utilities to join a Regional Transmission Organization.

Q. Other than performing studies, what does MISO do?

A. Among many other responsibilities, MISO is the NERC registered Reliability Coordinator for its footprint, providing real-time operational monitoring and control of the transmission system of its member TOs.

MISO also operates a real-time and day-ahead locational marginal price based energy and ancillary services market in which each market participant's offer to supply energy is matched to demand and is cleared to be dispatched in the market based on a security constrained economic dispatch process.

Q. Are you familiar with how MISO conducts studies of projects authorized by MISO?

A. Yes. MISO's transmission planning process is based on an annual cycle that is referred to as the MTEP process. The MTEP process adheres to the nine planning principles outlined in FERC Order No. 890.[1] These planning principles result in an open and transparent regional planning process which results in recommendations for transmission expansion that are included in the MTEP report. Recent FERC Order No. 1000 furthered the planning principles outlined in FERC Order No. 890 and included requirements to plan for public policy requirements and for coordinated inter-regional planning and cost allocation.[2]

Consistent with these planning principles, the objectives of the MTEP process are (i) to identify transmission system expansions that will ensure the reliability of the transmission system that is under the operational and planning control of MISO, (ii) to identify transmission

[1] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).
[2] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 66,051 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012), *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012).

expansion that is critically needed to support the reliable and competitive supply of electric power, and (iii) to identify transmission expansion that is necessary to support energy policy mandates in effect within the MISO footprint.

The MTEP process is performed in a manner that ensures that the regional planning process is open, transparent, and coordinated. Once a project is deemed necessary for a public use and thoroughly evaluated against available alternatives through MISO's MTEP process, it is submitted for approval to the MISO Board of Directors.

Q. Is the process MISO uses to conduct its studies available in publicly filed documents?

A. Yes it is. Attachment FF to the MISO Tariff describes the process in which MISO conducts studies.

Q. What is Exhibit 10?

A. Attachment FF to the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff I described above.

Q. Is this document publicly available?

A. Yes, The MISO Tariff can be accessed from the following internet link: https://www.misoenergy.org/Library/Tariff/Pages/Tariff.aspx.

Q. What is the planning process employed by MISO to develop the MTEP?

A. MISO uses a "bottom-up, top down" approach in developing the MTEP. The "bottom-up" portion relies on the ongoing responsibilities of the individual TOs to continuously review and plan to reliably and efficiently meet the needs of their local transmission systems. MISO then reviews these local planning activities with stakeholders and performs a "top down" review of the adequacy of, and appropriateness of, the local plans in a coordinated fashion with all other local plans to most efficiently ensure that all of the needs are cost effectively met. In addition, MISO considers, together with stakeholders, opportunities for improvements and expansions that would reduce consumer costs by providing access to low cost resources that are consistent with and required by evolving legislative energy policies.

Q. What factors does MISO study when planning a new transmission project during the MTEP?

A. There are numerous factors evaluated when planning a transmission project, however, two considerations are crucial. First, the security of the transmission system must be maintained. That is, the transmission system must be able to withstand contingencies (generation and/or transmission facility outages) without interruption of service to load. This is achieved, in part, by assuring that contingencies do not lead to cascading loss of other generator or transmission facilities. Second, the transmission system must be adequately planned to be able to accommodate load growth and/or changes in load and load growth patterns, as well as changes in generation and generation dispatch patterns without causing equipment to operate outside of its design capability. Additional factors include addressing transmission constraints that limit market efficiency and provide transmission expansions that enable public policy mandates to be achieved.

Q. What must be considered in planning, operating and maintaining an adequate, efficient and reliable transmission system?

A. A transmission system must have capacity sufficient to meet projected power flow patterns while maintaining adequate voltage levels, loading levels, and system stability. This requires an engineering evaluation of the system as a whole, as well as an evaluation of critical individual system components (transformers, lines), under both normal and contingency conditions (conditions where one or more system components are out of service). Power system simulation models are developed for use in these analyses. Projected peak power flows for each major component are checked to ensure that rated capacities are not exceeded. Voltage levels are also checked to ensure that voltage levels are maintained above the minimum level required for safe operation of the system.

Q. Why is it necessary to provide adequate capacity to meet projected power flows?

A. Overloaded equipment threatens the system's ability to continue to provide adequate and reliable service to its customers. Overloaded equipment can fail and cause brownouts and blackouts (which, for major transmission components, can be widespread and extended) as well as potentially dangerous conditions. In addition, overloads reduce the service life of equipment and tend to increase the probability of component failure in the future.

Q. Why is it necessary to ensure that voltage levels are maintained?

A. Transmission voltages must be maintained within specified criteria both to ensure that adequate customer voltage is maintained and to ensure that voltage-sensitive equipment operates properly, such as motors and compressors.

Q. Why is it necessary to ensure that system stability is maintained?

A. Certain conditions could cause a generating unit to lose synchronism with the rest of the system or cause system voltages to decline rapidly in an uncontrolled manner. These severe contingencies, while unlikely, must be tested to ensure that the transmission system is strong enough to prevent their occurrence, or that in such instances protective systems act to regain control of the system, either by rapid tripping of the out-of-step generator, or by controlled shedding of load to arrest voltage decline. Without these measures in place, such disturbances could affect the secure operation of wide areas of the interconnected transmission systems of the state or of the nation, depending on the severity of the disturbance.

Q. Why are contingency conditions as well as normal operating conditions studied?

A. Generating units and major transmission system components cannot be assumed to be in operation all of the time. In addition to scheduled maintenance outages, unscheduled outages can occur. Therefore, reliability must be maintained for an appropriate range of possible system failures. For example, the transmission system must, at a minimum, continue to operate adequately with any single line or transformer in an area out of service.

Q. What are the standards that govern planning practices used by MISO and TOs to ensure reliable transmission performance?

A. The transmission system is planned in compliance with NERC, regional entity, and the transmission owning members' local planning standards. In addition, planning practices are dictated by FERC Order Nos. 890 and 1000. MISO implements these practices through its governing and informational documents, including Attachment FF to MISO's Tariff, the TOA, and MISO's Transmission Planning Business Practices Manual (BPM).

Q. Can you briefly summarize the scope of the FERC planning practices?

As mentioned earlier, FERC Order No. 890 is primarily concerned with ensuring that transmission planning takes place in an open and transparent manner where stakeholders to the planning process are engaged in, and have opportunities to provide input and comment on the development of local transmission plans as well as regional transmission plans. The planning process also addresses economic and regulatory policy considerations in addition to the NERC standards for reliability. There are also requirements aimed at ensuring coordination with neighboring planning regions and proper cost allocation through FERC Order No. 1000.

Q. What is the NERC transmission planning standard and what does it require?

A. The NERC transmission planning standard (TPL) is applicable to transmission planning and governs planning requirements to ensure reliable transmission system performance. The standard addresses system performance under normal (no contingency) conditions; following events resulting in the loss of a single transmission element (single contingency); following events resulting in loss of multiple elements (multiple contingency); and following more extreme events that result in loss of many transmission elements, such as entire generating stations or substations or multiple transmission lines in a common right-of-way.

Q. What are the associated system performance requirements for contingency events prescribed under the NERC transmission planning standard?

A. For all but the extreme events, the NERC transmission planning standard requires that system stability be maintained and that no cascading outages occur for the prescribed contingency events. Furthermore, facilities must remain at all times within applicable loading and voltage criteria during normal conditions, following single contingency events and following multiple contingency events.

DEMAND FOR THE PROJECT

Q. Are you familiar with the facility sought to be constructed in the Application?

A. Yes. The Project involves approximately 160-170 miles of new single circuit 345 kV transmission line from a new 345 kV substation located near Ellendale, North Dakota to a new Big Stone South substation located near Big Stone City, South Dakota.

Q. Did you assist in drafting any sections in the Application?

A. Yes. I assisted in drafting various sections of the Application primarily related to demand and purpose of the Project, which are addressed in Sections 4 and 6 of the Application.

Q. Did MISO approve the Project described in the Application?

A. Yes.

Q. When?

A. The Project was approved by the MISO Board of Directors on December 8, 2011 as part of the 2011 MISO Transmission Expansion Plan.

Q. What is the significance of MISO's approval?

In accordance with the Transmission Owners Agreement (TOA), approval of the MTEP by the MISO Board of Directors certifies the MTEP as MISO's transmission expansion plan for meeting the transmission needs of the MISO footprint. As such, OTP and MDU have been directed to timely construct the Project by MISO based on portions of the TOA.

Q. Is the Project part of MISO's MVP portfolio?

A. Yes.

Q. What is MISO's MVP portfolio?

A. The MVP portfolio is a group of seventeen transmission projects distributed across the MISO footprint that enables the reliable delivery of the aggregate of current state Renewable Portfolio Standards (RPS) within MISO and provides for economic benefits in excess of the portfolio costs primarily by reducing production costs. Each project within the MVP portfolio approved by the MISO Board of Directors was evaluated as part of the portfolio of MVPs and determined to be a necessary component of the portfolio that provides benefits that span broadly across the MISO footprint.

Q. What is an MVP under the MISO Tariff and what criteria must be met for a transmission project to be classified as an MVP?

A. An MVP is a type of transmission project developed by MISO and stakeholders and accepted by the Federal Energy Regulatory Commission (FERC). An MVP is a transmission project that must be: i) evaluated as part of a portfolio of MVPs whose benefits are spread broadly across the MISO footprint and ii) meets at least one of the following criteria:

- Criterion 1: A Multi-Value Project must be developed through the transmission expansion planning process for the purpose of enabling the Transmission System to reliably and economically deliver energy in support of documented energy policy mandates or laws that have been enacted or adopted through state or federal legislation or regulatory requirements that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation. The MVP must be shown to enable the transmission system to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade.

- Criterion 2: A Multi-Value Project must provide multiple types of economic value across multiple pricing zones with a Total MVP Benefit-to-Cost ratio of 1.0 or higher where the Total MVP Benefit-to-Cost ratio is described in Section II.C.7 of Attachment FF to the MISO tariff, which is Exhibit 10. The reduction of production costs and the associated reduction of LMPs resulting from a transmission congestion relief project are not additive and are considered a single type of economic value.

- Criterion 3: A Multi Value Project must address at least one Transmission Issue associated with a projected violation of a NERC or Regional Entity standard and at least one economic-based Transmission Issue that provides economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs based on the definition of financial benefits and Project Costs provided in Section II.C.7 of Attachment FF, which is Exhibit 10.

Q. What projects have been approved as part of the MTEP11 MVP Portfolio and where are they located?

A. The facilities associated with this Project are an integral part of a larger set of Multi-Value Project (MVP) transmission line expansions across MISO. The 2011 MVP Portfolio and its 17 projects are shown in Figure 2 and listed in Table 1. As shown below, the Big Stone South to Ellendale 345 kV Project is referred to as MVP-6.

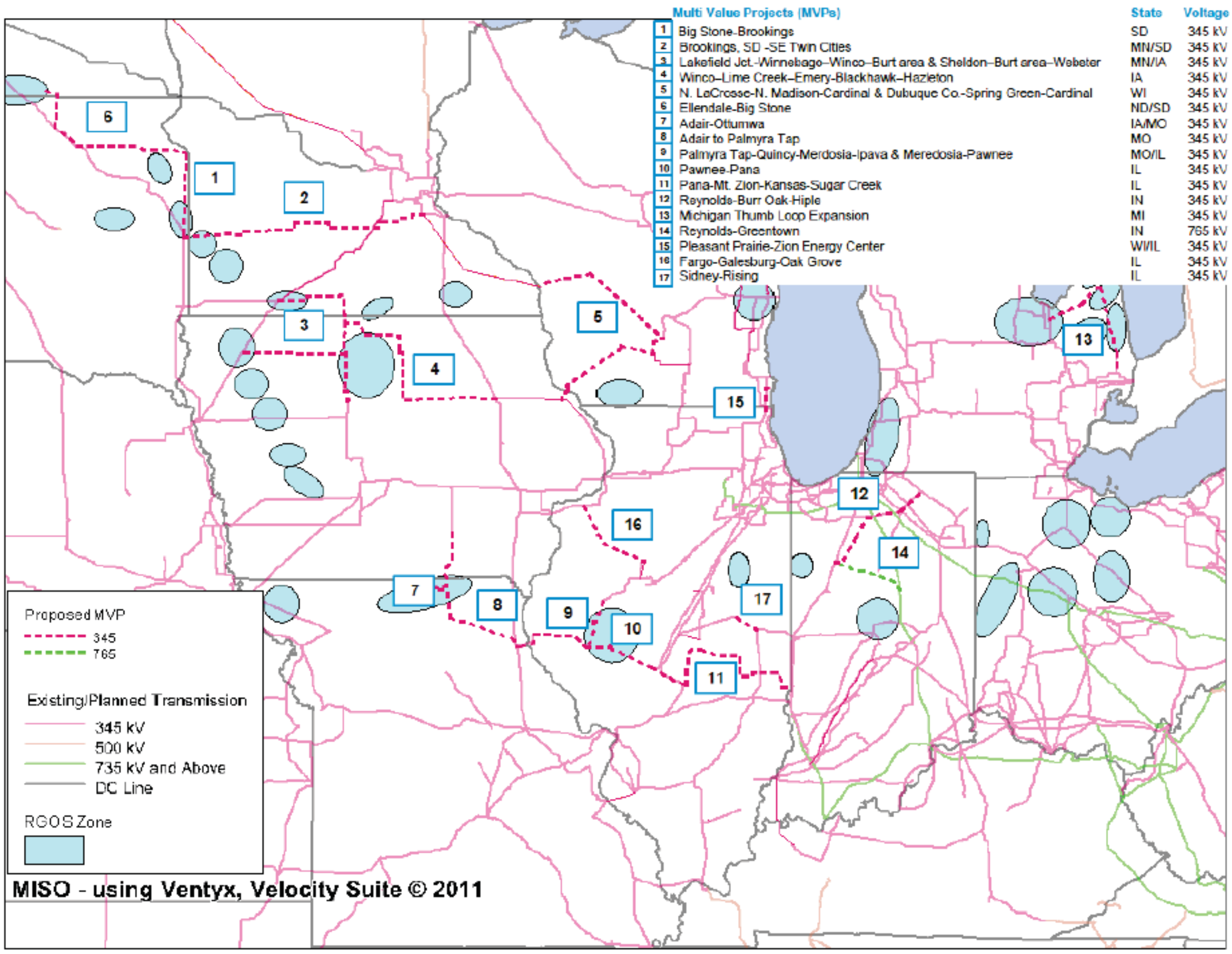

Figure 2 – MISO 2011 MVP Portfolio from MVP Report

The 17 projects comprising the MISO 2011 MVP Portfolio are listed below in Table 1.

	Project	State	Voltage (kV)
1	Big Stone – Brookings	SD	345
2	Brookings, SD – SE Twin Cities	MN/SD	345
3	Lakefield Jct. – Winnebago – Winco – Burt area & Sheldon – Burt area – Webster	MN/IA	345
4	Winco – Lime Creek – Emery – Black Hawk – Hazleton	IA	345
5	N. LaCrosse – N. Madison – Cardinal & Dubuque Co. – Spring Green – Cardinal	WI	345
6	Ellendale – Big Stone	ND/SD	345
7	Adair – Ottumwa	IA/MO	345
8	Adair – Palmyra Tap	MO/IL	345
9	Palmyra – Quincy – Meredosia – Ipava & Meredosia – Pawnee	IL	345
10	Pawnee – Pana	IL	345
11	Pana – Mt. Zion – Kansas – Sugar Creek	IL/IN	345
12	Reynolds – Burr Oak – Hiple	IN	345
13	Michigan Thumb Loop Expansion	MI	345
14	Reynolds – Greentown	IN	765
15	Pleasant Prairie – Zion Energy Center	WI/IL	345
16	Fargo – Galesburg – Oak Grove	IL	345
17	Sidney – Rising	IL	345

Table 1 – MISO 2011 MVP Portfolio Projects

References to the Big Stone Substation throughout the MISO MVP study material are synonymous with the Big Stone South Substation. The Big Stone South Substation is actually being constructed as part of MVP-1 (Big Stone – Brookings 345 kV) and is a new substation being constructed near Big Stone City, South Dakota to allow for 345 kV connections into the existing 230 kV transmission system in the Big Stone area. The Big Stone to Brookings 345 kV project, with the associated Big Stone South substation, has been approved by the South Dakota Public Utilities Commission in dockets EL06-002 (which was recertified through docket EL12-063) and EL13-020. The facilities approved through these dockets have been accurately reflected in studies performed by MISO in support of the 2011 MVP portfolio.

Q. Please discuss the relationship of the Project to the MISO 2011 MVP portfolio.

A. The Project not only provides benefits on its own, it also works together with MVP-1 (Big Stone to Brookings 345 kV project) to provide benefits to the MISO region. These two projects work together to transmit renewable energy from South Dakota and North Dakota to major 345 kV transmission substations and load centers. Together, these two projects also address congestion on the transmission system by providing additional pathways for energy to flow in order to avoid local area congestion.

Q. How did the Project become part of the MVP portfolio of projects?

A. In addressing its RTO planning responsibilities, MISO undertook a multi-year planning process aimed at addressing the regional transmission plans necessary to enable state renewable mandates and objectives to be met at the lowest delivered wholesale energy cost. This effort was known as the Regional Generation Outlet Study (RGOS) and was conducted between 2008 and 2010. The RGOS identified indicative transmission options that would provide sufficient transmission capacity and connectivity needed for the efficient and reliable delivery of new generation capacity to meet the combined renewable portfolio standards and objectives of the MISO region, while providing value across the footprint.

These indicative transmission plans were further consolidated into a proposed MVP portfolio in collaboration with transmission owning MISO members and their representatives, including OTP and MDU, and evaluated for effectiveness during the MVP analysis undertaken by MISO.

Q. What was the overall goal of the MVP analysis undertaken by MISO?

A. The overall goal of the MVP portfolio analysis was to design a transmission portfolio which takes advantage of the linkages between local and regional reliability and economic benefits to promote a competitive and efficient electric market within MISO. To achieve this goal, a Technical Studies Task Force (TSTF), comprised of state regulators, wind power developers, TOs, and participants in MISO's wholesale markets, met with MISO study engineers to guide the MVP study process. The MVP portfolio was designed using reliability and economic analyses, applying several future scenarios to determine the robustness of the designed portfolio under a number of different assumptions.

Q. When was this study and analysis done that supported inclusion of the Project in the MISO 2011 MVP Portfolio?

A. The RGOS study was initiated in 2008 and was concluded in 2010. The MVP study started during 2010 and wrapped up near the end of 2011.

Q. Is the analysis and study contained in the Application?

A. Yes.

Q. Where?

A. Both the RGOS and the MVP study are included within the Application in Appendix B, specifically Appendix B.1 is the MVP study report and Appendix B.3 is the RGOS report.

Additionally, included within Appendix B is Appendix B.2, which is the 2005 MISO Transmission Expansion Plan, and Appendix B.4, which is the 2011 MISO Transmission Expansion Plan. These study reports also include details of all or portions of the Project that have been identified through past MTEP planning cycles.

Q. What did the MISO analysis and study of the Project show as to the demand for this Project?

A. The MVP portfolio analyses evaluated the expected future conditions on the MISO regional transmission grid. The analysis found that the Project will be needed in order to ensure the continued reliable operation of the OTP and MDU transmission systems into the future. In addition, the MVP analyses also show that the MVP portfolio of projects provide additional connectivity across the grid, reducing transmission congestion and enabling access to a broader array of resources for customers across MISO. The transmission projects included in the MISO 2011 MVP portfolio increase market efficiency, competitive generation supply, and provide opportunity for economic benefits to ratepayers well in excess of the MVP portfolio costs. The MVP portfolio, including the Project, represents the best overall solution for delivering these benefits based on the expected future conditions.

Q. Why must this Project be constructed?

A. The construction of the Project will enable OTP and MDU to reliably deliver the energy this area needs today and into the future. The Project improves the reliability of the bulk electric system in the area. Reliability studies performed by MISO for the Project have identified the following transmission issues are mitigated as a result of the Project during contingencies prescribed in the NERC transmission planning standards:

- Oakes – Ellendale 230 kV Line
- Aberdeen – Ellendale 115 kV Line
- Oakes – Forman 230 kV Line
- Forman 230/115 kV Transformer
- Aberdeen Jct. – Aberdeen 115 kV Line
- Forman 230 kV Bus Tie
- Ellendale 230/115 kV Transformer
- Heskett 230/115 kV Transformer

The construction of the Project will address these loading issues by providing an alternative transmission path for energy to flow during contingencies.

Q. Were alternatives to the Big Stone South to Ellendale 345 kV Project considered in the development of the MVP portfolio?

A. Yes. The Owner's considered both overbuilding and reconductoring existing transmission lines that are located in the siting area.

Q. What does it mean to "overbuild" an existing transmission line?

A. "Overbuilding" an existing transmission line involves constructing a new project along an existing transmission corridor using new structures that accommodate two circuits, the new circuit and the existing circuit, on a common structure.

Q. What does it mean to "reconductor" an existing transmission line?

A. "Reconductoring" an existing transmission line involves replacing the existing conductor along a transmission line with a different conductor, usually larger, to increase the capability of the existing circuit.

Q. Why were the alternatives of overbuilding and reconductoring not pursued for this Project?

A. These alternatives were rejected for the reasons stated in response to data request 2-3 of the Staff's Second Set of Data Requests, which are attached as Exhibit 3 to the direct testimony of Henry Ford.

Q. Does the MISO MVP analyses consider future wind generation?

A. Yes. With the focus of the MVP study being to develop a transmission plan to meet Renewable Portfolio Standards (RPS) and clean energy goals across the MISO footprint, assumptions surrounding the amount and location of future wind generation were a fundamental building block of this study. Through an extensive stakeholder process, locations were identified as future energy zones that represented the best method to meet renewable energy requirements at the lowest overall system cost. To determine the amount of additional wind generation needed to meet state renewable portfolio standards, data was gathered by entities across MISO to identify the incremental wind generation needed. As a result of this investigation, incremental renewable generation was modeled across the MISO footprint in the identified energy zones. More specifically, approximately 900 MW of additional wind was located in South Dakota in the 2021 timeframe and approximately 1400 MW in the 2026 timeframe within energy zones located in eastern South Dakota.

Q. How were the renewable energy zones used in the MVP studies developed?

A. Energy zone development began during the RGOS referenced previously in my testimony. MISO staff evaluated multiple energy zone configurations possible to meet renewable energy requirements and objectives. Zone selection was based on a number of potential locations developed by MISO utilizing wind data supplied by the National Renewable Energy Laboratory (NREL) of the US Department of Energy. Zone selection involved a great deal of stakeholder interaction, including the involvement of regulatory bodies such as the Upper Midwest Transmission Development Initiative (UMTDI) and various state agencies within the MISO footprint, including the Midwest Governors Association (MGA).

Q. What were the final set of energy zones selected for use in the MISO MVP studies and what amount of incremental renewable energy was assumed in energy zones located in the South Dakota and North Dakota?

A. The final set of energy zones selected for use in the MISO MVP planning studies represented a balance between meeting renewable energy needs locally while also taking advantage of higher wind potential areas within the MISO market footprint. The analyses and selection process located wind zones distributed across the region. The renewable energy zone locations used in the MISO 2011 MVP studies are shown in Figure 3.

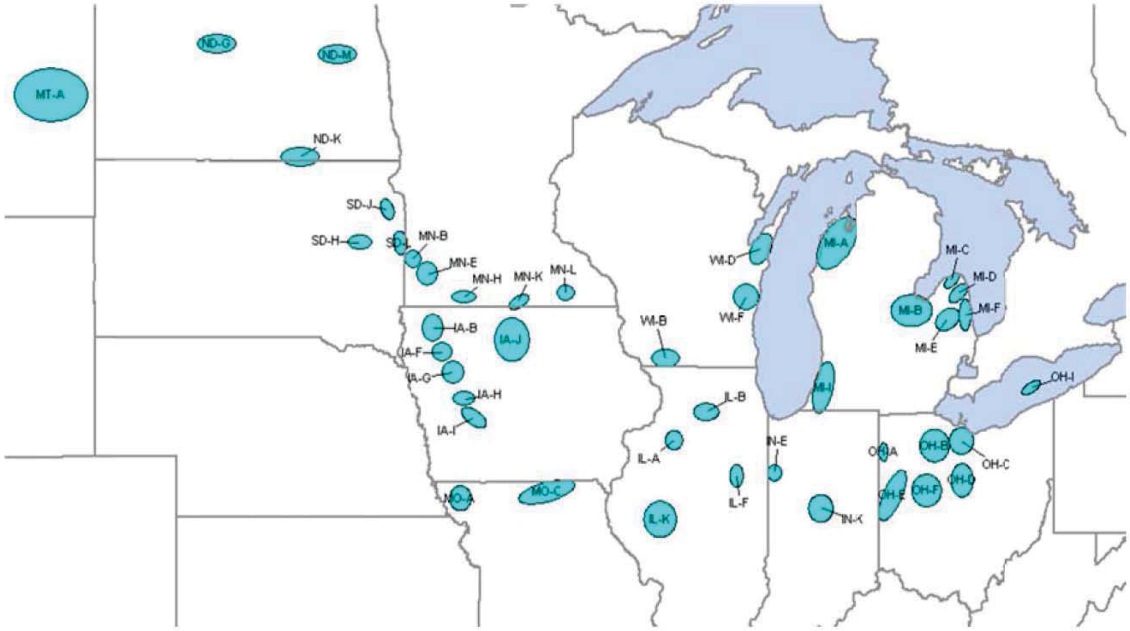

Figure 3 – Renewable Energy Zones in MISO MVP Studies

The amount of incremental renewable energy included in the South Dakota and North Dakota during the MVP studies was approximately 1300 MW in the 2021 timeframe and approximately 2100 MW in the 2026 timeframe, as shown in Table 2, with approximately 900 MW assumed in South Dakota in 2021 and 1400 MW in 2026.

Wind Zone	2021 Incremental Wind (MW)	2026 Incremental Wind (MW)
ND-G	199	313
ND-K	164	259
ND-M	59	94
SD-H	300	474

SD-J	292	461
SD-L	300	474

Table 2 – Incremental Wind Generation in the Dakotas

Q. Do you expect future renewable energy generation development in the South Dakota and North Dakota as a result of this Project?

A. Yes. As mentioned previously, the Project will mitigate transmission issues on the system and increase the capability of the transmission system thereby allowing future opportunities for transmitting energy generated from renewable resource. The Project will be located in the general vicinity of several proposed generation projects that reside in the MISO Generator Interconnection Queue and closely align with the MVP incremental energy zones.

Figure 4 shows the locations of the proposed generation projects that were active in the MISO Generator Interconnection Queue in the South Dakota and North Dakota as well as western Minnesota as of March 17, 2014, the location of MVP Energy Zones (shown as shaded blue ovals on Figure 4), and the approximate location of the Project.

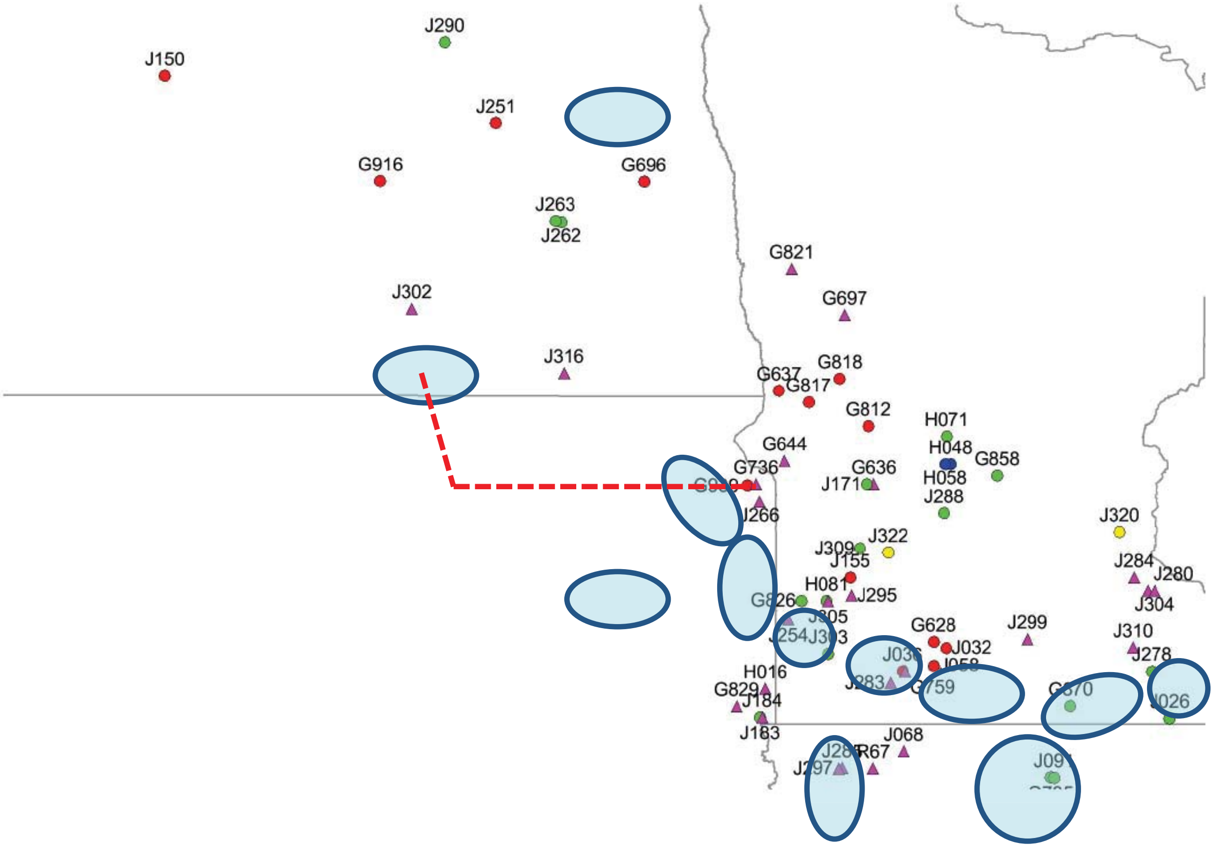

Figure 4 – Big Stone South to Ellendale and Active MISO Generator Interconnection Queue Projects

As shown in Figure 4, several proposed generation projects in the MISO interconnection queue are aligned with the MVP energy zones and are poised to leverage the additional transmission system capability enabled by the Project.

Q. What will be the benefits to South Dakota and the region if the Project is constructed?

A. The MVP portfolio allows for a more efficient dispatch of generating resources, opening wholesale markets to competition and spreading the benefits of low cost generation to South Dakota and throughout the MISO footprint. These benefits were outlined through a series of production cost analyses that captured the economic benefits of the low cost generation resources that can be reliably delivered with the addition of the MVP transmission. These benefits reflect the savings achieved through the reduction of transmission congestion and through more efficient use of generation resources. The analysis found that the MVP portfolio will produce an estimated $12.4 to $40.9 billion in present value adjusted production cost benefits to the aggregate MISO footprint under existing energy policies, depending on the period over which benefits are calculated, discount rates applied, and assumptions about growth rates of energy and demand. Under additional possible Future Scenarios representing sensitivities to variations in energy policies, this benefit increases to a maximum present value of $91.7 billion.

While congestion-driven production cost benefits were by far the single greatest benefit identified, additional benefits from the new transmission facilities were also identified. These additional benefits included reductions in operating reserve requirements, reduced planning reserve margin requirements, reduced transmission system losses, lower capital costs of renewable resources, and deferrals of transmission investments that would be required for the reliability of the system in the absence of the MVPs. These additional factors contribute between $3.1 billion and $8.2 billion in additional present value benefits above the production cost savings.

When compared to the present value of the revenue requirements for the MVP portfolio, the portfolio produces total benefits of between 1.8 to 3.0 times the costs on a present value basis, under existing policies. When these system-wide benefits were evaluated for their distribution within the MISO footprint, benefits to Local Resource Zone 1 amounted to between 1.6 and 2.9 times the overall portfolio costs to Local Resource Zone 1. Zone 1 is comprised of MISO member companies within Minnesota, South Dakota, North Dakota, and parts of Wisconsin and Montana. (see Figure 5)

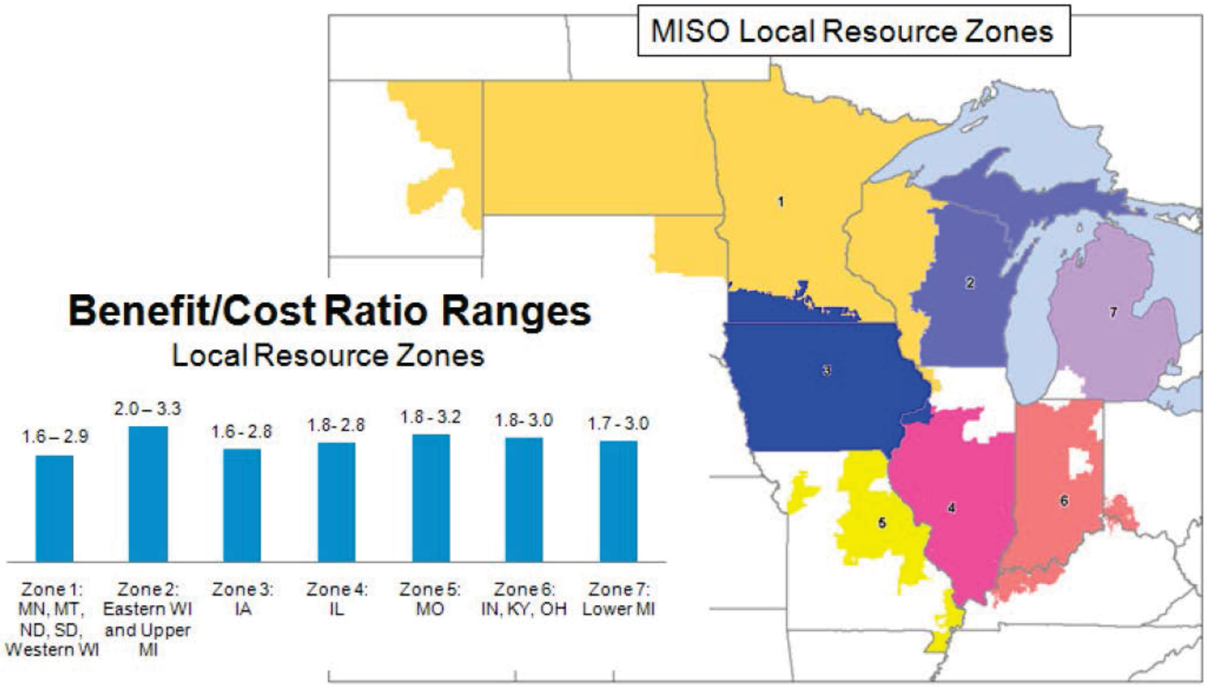

Figure 5 – Benefit-Cost Ratios to Local Resource Zones Across MISO

Q. Were the benefits quantified?

A. Yes.

Q. Where in the studies were the benefits quantified?

A. Included as Appendix B.1 of the Application is the "Multi-Value Project Portfolio – Results and Analysis" report (MVP report). The benefits are discussed on pages 49 through 69 of this report in Section 8, which discusses "Portfolio economic benefits analyses" and Section 9, which includes a description of "Qualitative and Social Benefits" (pages 70 – 79) that are also realized by the MVP portfolio. Benefit-to-Cost ratios calculated for each of the local resource zones across MISO are found in Section 1, which is the Executive Summary (Page 6).

Q. What is the relationship of the Big Stone South to Ellendale 345 kV Project to the present and future economic development of the area?

A. The addition of the Big Stone South to Ellendale 345 kV Project will better enable OTP and MDU to reliably deliver the energy this area needs today and into the future. If approved, the Project will improve the ability to serve present and future economic development in the area. The construction of this Project improves the transmission grid's ability to meet the energy demands of South Dakota residents and businesses now and into the future. Electricity is the foundation of ongoing economic development and prosperity in the country; OTP and MDU are maintaining the strength of that foundation through the proposed construction of this Project.

In addition to the direct benefits of the recommended MVP portfolio, studies have shown the indirect economic benefits of the transmission investment. These indirect benefits result from the impact of investment and jobs in the local economy. The MVP portfolio will enable approximately 900 MW of incremental wind generation resources in South Dakota by the year 2021 and approximately 1,400 MW by the year 2026 according to the MVP studies. This incremental generation will encourage the development of new generation projects in the Dakotas, resulting in the creation of new jobs and associated benefits resulting from the new projects.

Q. Are there other benefits to South Dakota from the Big Stone South to Ellendale 345 kV Project?

A. Yes. In the event that legislation or environmental regulation leads to the retirement of some coal-fired plants, transmission investment through the Big Stone South to Ellendale 345 kV Project provides a robust transmission path that will be available to provide needed support to maintain reliable service regardless of fuel-types for future generation resources.

Q. What assumptions were used in projecting the expected future conditions upon which the MISO need and benefit analyses were based?

A. MISO employed multiple models to project future system conditions and performance. Models were developed representing the transmission system for the year 2021 to evaluate transmission system reliability. The representation of the transmission system in this timeframe was developed by adding transmission upgrades identified in previously approved MISO MTEP regional planning processes to the existing transmission system. Additionally, load forecasts applied in the models were supplied by MISO transmission owners through an annual model building process. Reliability analysis of the transmission system focused on both peak (100%) load and off-peak (70%) load conditions. Lastly, generation included in the MVP modeling efforts were existing generation, committed generation from the MISO generation interconnection process, and generation in renewable energy zones sufficient to meet regional renewable energy mandates.

In addition to reliability analysis, production cost modeling was also performed to analyze production cost savings enabled by the MVP portfolio under several different future scenarios. Production cost models were developed for the years 2021, 2026, and 2031. In arriving at the range of production cost benefits, a variety of assumptions were used for applying discount rates, demand and energy growth rates, and natural gas prices.

Q. Is the construction, operation, and maintenance of the Big Stone South to Ellendale 345 kV Project necessary to serve a public use?

A. Yes. The Big Stone South to Ellendale 345 kV Project is an integral part of the MISO 2011 MVP portfolio. As a result, it facilitates the numerous 2011 MVP portfolio benefits, including meeting energy policy requirements consisting of widespread implementation of renewable portfolio standards across the MISO footprint. The MISO 2011 MVP Portfolio of seventeen 345 kV and 765 kV projects is designed to meet this need that was defined based on the input from many stakeholders which included participation by the Midwest Governor's Association (MGA), the Upper Midwest Transmission Development Initiative, and the Organization of MISO States (OMS) Cost Allocation and Regional Planning (CARP).

Q, What if the Project is not built as currently designed?

A. When a project is redesigned after the extensive regional planning process, MISO must ensure that the redesigned project will continue to meet the initial needs of the project. This review process should involve engaging MISO stakeholders (and MISO's Board of Directors) to ensure continued transparency surrounding project development and cost allocation. In the worst case scenario, such re-engagement could lead to delays in the completion of an urgently needed project that may take years to construct. In addition, after a project is approved for the regional plan, that project is assumed to be part of the base transmission plan, and incremental system needs are identified relying upon that base transmission plan. While modifications may occur to approved plans, such changes have ripple effects on the identification of necessary projects in subsequent planning studies. These ripple effects can contribute to delays in addressing other transmission system needs leading to increased costs to consumers. For these reasons, modifications to transmission projects subsequent to the collaborative regional planning process should be minimized to the extent possible.

Q. Do current MISO planning studies assume the existence of the Big Stone South to Ellendale 345 kV Project?

A. Yes. The project was approved by MISO in December of 2011. Since that time, regional planning studies conducted by MISO include this project in the base transmission plan.

Q. Is there a time frame that the Project must be constructed?

A. Yes. The expected time frame in which the Project must be constructed is included within the MISO approval by the Board of Directors.

Q. What is the time frame in which the Project must be constructed?

A. The Project was approved by the MISO Board of Directors with an in-service date of December 31, 2019. Therefore, the Project must be energized by the end of 2019.

Q. What are the consequences specific to a delay of building the Big Stone South to Ellendale 345 kV Project?

A. In the context of this Project, if the Project was not constructed as planned, it would result in the inability of the existing transmission system owned by OTP and MDU in southern North Dakota and eastern South Dakota to continue to provide reliable service. The MISO analyses of this Project had identified several 230 kV and 115 kV transmission facilities that will be loaded above safe operating levels in the future without this Project. In addition, the MISO analyses identified economic benefits that would not be able to be adequately realized or distributed without the Project.

In addition, future wind resources in North Dakota and South Dakota could not be successfully or reliably integrated into the MISO transmission system.

Q. Are there benefits to the construction of the Project other than to the transmission system?

A. Yes.

Q. Did someone else testify about those benefits?

A. Yes, Mr. Ford testified about those benefits.

PAYMENT FOR THE PROJECT

Q. Who is going to be paying for the Project?

A. MVP project costs are recovered from MISO transmission customers on an equitable basis based on their pro-rata usage of energy. The methodology is described in Attachment MM of the MISO Tariff.

Q. How will the Project be financed?

A. OTP and MDU will use private financing to obtain the necessary capital to construct the Project. The revenues received from other MISO customers, as well as MDU and OTP customers, will be used to meet OTP and MDU's respective revenue requirements associated with this new transmission investment.

Q. Based upon the results of MISO planning studies as well as Otter Tail and MDU's review outlined in your testimony above, how would you summarize your assessment of the Big Stone South – Ellendale 345 kV Project?

A. The Big Stone South to Ellendale 345 kV Project is a critical component of the MISO 2011 MVP portfolio that is needed for the continued development of a reliable and efficient regional transmission system in the Dakotas and across MISO. It is a part of the MISO 2011 MVP portfolio of projects that involves multiple utilities developing a joint transmission plan to meet the backbone transmission infrastructure needs of a large region for most of the next decade, not just the incremental needs over the next few years. Therefore, the Project is necessary to serve a public use and represents a reasonable relationship to an overall plan of transmitting electricity in the public interest.

Q. Does this complete your direct testimony?

A. Yes, it does.

ATTACHMENT FF

TRANSMISSION EXPANSION PLANNING PROTOCOL

I. Transmission Expansion Plan - Purpose and Scope, Definition and Role of OMS Committee: This Attachment FF describes the process to be used by the Transmission Provider to develop the MISO Transmission Expansion Plan ("MTEP"), subject to review and approval by the Transmission Provider Board. The provisions of this Attachment FF are consistent with the applicable provisions of Appendix B of the ISO Agreement and this Tariff. For purposes of this Attachment FF, all references to Transmission Owner(s) will include ITC(s). The costs incurred by the Transmission Provider in the performance of data collection, analyses and review, and in the development of the MTEP report, costs incurred under Section I.C of this Attachment FF, and costs incurred under Section I.D of this Attachment FF shall be recovered from all Transmission Customers under Schedule 10 of the Tariff.

A. Enrollment Process: The MTEP is developed to facilitate the timely and orderly expansion of and/or modification to the Transmission System to maintain reliability, promote efficiency in bulk power markets and facilitate compliance with applicable Federal and state laws, regulatory mandates and regulatory obligations. Any transmission provider that wishes to enroll in the Transmission Provider planning process for purposes of Order No. 1000 compliance must become a Transmission Owner, by signing the ISO Agreement, and by, within a reasonable period of time: (1) turning over functional control of its transmission facilities to the Transmission Provider; and (2) taking service under this Tariff for all its load that is physically located within the geographic area comprising the Transmission System. All Transmission Owners enrolled in the Transmission Provider's transmission planning region are listed in either

EXHIBIT 10

(1) Attachment FF-4 of this Tariff, for Transmission Owners without a separately filed local planning process or (2) Attachment FF-5 of this Tariff, for Transmission Owners with a separately filed local planning process.

B. OMS Committee Input to MTEP Process: To the extent not otherwise specifically addressed in other portions of this Attachment FF, with respect to the MTEP process, the OMS Committee may provide input to the Transmission Provider planning staff and the System Planning Committee of the Transmission Provider Board, as appropriate, regarding the following:

1. At the start of a planning cycle, the OMS Committee may suggest to the Transmission Provider Board modifications to the Transmission Provider’s planning principles and planning objectives for that planning cycle;
2. At the start of a planning cycle, the OMS Committee may suggest additional scope elements in the MTEP;
3. Modeling inputs or assumptions used in the development of the MTEP and related appropriate cost/benefit analyses with respect to certain projects that are not proposed strictly for reliability; and
4. Concerns about general or specific issues with the MTEP process as they arise during the planning year.

Furthermore, at the end of the MTEP development process, but before the MTEP is submitted to the Transmission Provider Board for its review, the OMS Committee may submit a reconsideration request to the Transmission Provider planning staff, which shall respond prior to submitting the final MTEP report to the Transmission Provider Board. This reconsideration request can be made only with respect to Network Upgrades eligible to receive regional cost allocation under Attachment FF if such projects: (1) will be recommended to the Transmission Provider Board for MTEP Appendix A approval, but have not been considered through the complete MTEP process or (2) will have a change in project cost of twenty-five percent (25%) or greater between the final Subregional Planning Meeting in the current planning year and the project being submitted to the Transmission Provider Board for approval. The Transmission Provider shall consider such a reconsideration request only if it is endorsed by the OMS acting by a vote of sixty-six percent (66%) or more of the OMS members.

At the end of each MTEP cycle, the OMS Committee may submit its assessment of the MTEP process to the Planning Advisory Committee, Transmission Provider, and the System Planning Committee of the Transmission Provider Board. Upon receipt of any such assessment from the OMS Committee, the Transmission Provider planning staff shall provide an appropriate response in a reasonably timely manner.

The manner in which the OMS Committee shall provide its assessment shall be set forth in the Transmission Planning Business Practices Manual procedures. The general procedures adopted with respect to the OMS Committee input into the MTEP shall remain unchanged until June 1, 2015, unless otherwise mutually agreed to by the Transmission Provider and the OMS Committee. Changes to the Transmission Planning Business Practices Manual procedures which describe OMS Committee input into the MTEP process may not be adopted with less than sixty

(60) days' notice to the OMS Committee unless the OMS Committee consents to such earlier adoption. At the end of the two year period the Transmission Provider, the OMS, and other stakeholders will assess the success of the input procedures and provide suggestions for improvement.

C. Development of the MTEP: The Transmission Provider, working in collaboration with representatives of the Transmission Owners, OMS, and the Planning Advisory Committee, shall develop the MTEP, consistent with Good Utility Practice and taking into consideration long-range planning horizons, as appropriate. The Transmission Provider shall develop the MTEP for expected use patterns and analyze the performance of the Transmission System in meeting both reliability needs and the needs of the competitive bulk power market, under a wide variety of contingency conditions. The MTEP will give full consideration to the needs of all Market Participants, will include consideration of demand-side options, and will identify expansions or enhancements needed to i) support competition and efficiency in bulk power markets; ii) comply with Applicable Laws and Regulations; and iii) maintain reliability. This analysis and planning process shall integrate into the development of the MTEP among other things:

(i) the Transmission Issues identified from Facilities Studies carried out in connection with specific transmission service requests; (ii) Transmission Issues associated with generator interconnection service; (iii) the Transmission Issues, including proposed transmission projects, identified by the Transmission Owners in connection with their planning analyses in accordance with local planning process described in Section I.D.1.a to this Attachment FF and the coordination processes of Section I.D.1.b., or developed by

Transmission Owners utilizing their own FERC-approved local transmission planning process described in Section I.D.2, as applicable, to provide reliable power supply to their connected load customers and to expand trading opportunities, better integrate the grid and alleviate congestion; (iv) the transmission planning obligations of a Transmission Owner, imposed by federal or state law(s) or regulatory authorities, which can no longer be performed solely by the Transmission Owner following transfer of functional control of its transmission facilities to the Transmission Provider; (v) plans and analyses developed by the Transmission Provider to provide for a reliable Transmission System and to expand trading opportunities, better integrate the grid and alleviate congestion; (vi) the identification, evaluation, and analysis of expansions to enable the Transmission System to fully support the simultaneous feasibility of all Stage 1A ARRs; (vii) the inputs provided by the Planning Advisory Committee; (viii) the inputs, if any, provided by the state and local regulatory authorities having jurisdiction over any of the Transmission Owners; (ix) the inputs of the OMS Committee; and (x) the Transmission Issues identified by stakeholders or the Transmission Provider that are selected by the Transmission Provider, pursuant to Section I.C.1.b, to address applicable transmission needs driven by public policy requirements in accordance with Applicable Laws and Regulations.

1. Planning Cycle and Milestones: The ISO Agreement requires that a regional transmission plan be developed biennially or more frequently. An MTEP planning cycle is established for each calendar year. The development of the MTEP for a planning cycle with a given calendar year designation begins on June 1 of the year prior

to the MTEP calendar year designation and ends with the approval of the final MTEP report by the Transmission Provider Board. This approval typically occurs at the Transmission Provider Board Meeting in December of the MTEP designated year. For example, the development of the MTEP14 transmission plan will commence on June 1 of 2013 and typically end with approval in December 2014. The development of the MTEP will follow specified process steps that are detailed, including process diagrams, in the Transmission Provider's Transmission Planning Business Practices Manual ("TPBPM"). The TPBPM shall be posted on the website of the Transmission Provider.

a. Planning Functions: The planning process includes the following functions which are described in detail in the TPBPM:

i. Model Development;

ii. Generator Interconnection Planning;

iii. Transmission Service Planning;

iv. Cyclical Regional Expansion Planning activities;

v. Interregional coordination with neighboring transmission planning regions;

vi. System Support Resource ("SSR") Studies for unit de-commissioning;

vii. Transmission-to-Transmission Interconnections;

viii. Load Interconnections; and

ix. Focus Studies. These are studies initiated during the cyclical baseline planning process that cannot be delayed until the next planning cycle (for example, NERC/FERC directives, or near-term critical operational issues).

Each of these planning functions may develop system expansions that are taken into consideration in developing the entirety of the MTEP.

b. Planning Cycle: The regional planning process is performed through a continuous series of planning cycles, with each cycle typically addressing Transmission Issues through a rolling planning horizon. Each cycle commences with regional model development, identification of potential Transmission Issues, selection of Transmission Issues to be evaluated, identification of potential expansions from the local planning processes of the Transmission Owners, and identification by stakeholders or the Transmission Provider of potential expansions that address the selected Transmission Issues. Each cycle concludes with recommendations to the Transmission Provider Board of recommended solutions to the Transmission Issues evaluated. Transmission Owner plans developed through local planning processes described in Section I.D.1.a are included in the beginning of each regional planning cycle as potential alternatives to local Transmission Issues identified by the Transmission Owners.

i. Key Planning Cycle Milestones: The regional planning process evaluates, with stakeholder input throughout the cycle, the local plans of the Transmission Owners, as one input to the development of the regional plan. Key milestones in the typical MTEP development process are listed below and requirements and timelines for data submittal, review, and comment at each of these milestone points are described in the TPBPM:

(a). Model development;

(b). Testing models against applicable planning criteria;

(c). Identification of potential Transmission Issues;

(d). Selection of Transmission Issues to evaluate;

(e). Development of possible solutions to identified Transmission Issues;

(f). Selection of preferred solution;

(g). Determination of funding and cost responsibility; and

(h). Monitoring progress on solution implementation.

ii. Selecting Transmission Issues to be evaluated through the MTEP Process: The Transmission Provider will select the Transmission Issues, including but not limited to those involving applicable transmission needs driven by public policy requirements, for which transmission solutions will be evaluated through the MTEP process. The scope of planning studies, development of future scenarios to be modeled and analyzed in long-term transmission planning studies, and the development of suitable models and assumptions to support such transmission planning studies will be driven by the selected Transmission Issues.

a. The process for selecting transmission needs driven by public policy requirements, out of the larger set of transmission needs driven by public policy requirements that stakeholders may propose, to be included in the selected Transmission Issue(s) for which transmission solutions will be evaluated shall be as follows:

1. At the beginning of the MTEP cycle, stakeholders submit to the Transmission Provider, proposals to consider transmission needs driven by public policy requirements, as part of the Transmission Issues they may raise, in accordance with Section I.C.2.b, through Sub-Regional Planning Meetings, the Planning Subcommittee and/or the Planning Advisory Committee. The Transmission Provider may also identify transmission needs driven by public policy requirements to be evaluated.
2. The Transmission Provider will then consolidate all such identified transmission needs driven by public policy requirements that it receives into a list that will be distributed to stakeholders through the Planning Subcommittee and/or the Planning Advisory Committee and to other stakeholder forums as the Transmission Provider deems necessary.
3. Transmission needs driven by public policy requirements will be discussed in the Sub-Regional Planning Meetings, Planning Subcommittee and/or the Planning Advisory Committee in accordance with Section I.C.2.b.

4. The Transmission Provider will assess such identified transmission needs driven by public policy requirements that it receives, considering the feedback received from stakeholders and the Sub-Regional Planning Meetings, Planning Subcommittee and/or the Planning Advisory Committee, and select the public policy requirements that will be further studied in the MTEP process. This selection will be based on:
    a. the effective dates, nature and magnitude of the public policy requirements in the Applicable Laws and Regulations;
    b. the immediacy or other estimated timing, and extent, of the potential impact on the identified transmission needs;
    c. the availability of the resources, and any limitations thereto, that would be required by consideration of such transmission needs driven by public policy requirements;
    d. the relative significance of other Transmission Issues that have been raised for consideration; and
    e. other appropriate factors that can aid the prioritization of Transmission Issues to be

considered by the regional transmission planning process.

iii. The Transmission Provider shall address each of these milestones throughout the planning cycle through Sub-regional Planning Meetings, Planning Subcommittee and Planning Advisory Committee meetings.

2. Stakeholders Input in Planning Process: The Transmission Provider shall facilitate discussions with its Transmission Customers, Transmission Owners, OMS Committee, and other stakeholders about the Transmission Issues and solutions involving both transferred and non-transferred facilities, as described in Section I.D.1 of this Attachment FF.

These discussions will take place at Sub-regional Planning Meetings and at regularly scheduled meetings of the Transmission Provider's Planning Subcommittee, at locations provided by the Transmission Provider and with communication capabilities for those participants unable to have in person representation at these meetings. Once the MTEP report for a specific planning cycle has been completed but prior to recommendation to the Transmission Provider Board for approval, the Transmission Provider shall seek feedback on the proposed MTEP, including Network Upgrades recommended for approval, from the Transmission Provider's stakeholders and the OMS Committee.

a. Planning Advisory Committee ("PAC"): The Planning Advisory Committee is a standing committee reporting to the Transmission Provider's Advisory Committee, and functions subject to the Stakeholder Governance Guide developed by the Stakeholder Governance Working Group, as approved by the

Advisory Committee. The PAC is responsible for addressing planning policy issues of importance to stakeholders and within the responsibilities of the Transmission Provider. The PAC charter is maintained on the Transmission Provider's website.

b. Planning Subcommittee ("PS"): The Planning Subcommittee is a standing stakeholder-chaired subcommittee of the Planning Advisory Committee, and functions subject to the Stakeholder Governance Guide developed by the Stakeholder Governance Working Group, as approved by the Advisory Committee. Planning Subcommittee membership is open to interested parties, including, but not limited to: transmission delivery service and interconnection service customers, marketers, developers, Transmission Owners, state and local regulatory authorities, federal regulatory staff, other Market Participants, and all interested parties. The charter for the committee is developed by stakeholders and is maintained on the Transmission Provider's website. The Transmission Provider will seek guidance from Transmission Owners, state and local regulatory authorities, and other stakeholders through the Planning Subcommittee and/or the Planning Advisory Committee prior to the beginning of each new planning cycle. Guidance will include the scope of planning studies to be undertaken (including which Transmission Issues to consider), the development of future scenarios to be modeled and analyzed in long-term planning studies, and the development of suitable models and assumptions to support such studies. The Transmission Provider will also seek guidance from Transmission Owners, state and local regulatory authorities, and other stakeholders through the Planning Subcommittee and/or the Planning Advisory Committee prior to implementing changes or revisions to the scope, models, and assumptions during the planning cycle. The Planning Subcommittee and/or the Planning Advisory Committee may form working groups at the discretion of stakeholders to perform specific tasks supporting the planning processes, such as model development and detail review of study results and draft plan reports.

c. Sub-regional Planning Meetings ("SPMs"): The Transmission Provider shall utilize SPMs to provide opportunity for Transmission Owners, state and local regulatory authorities, and other stakeholders to provide input to the planning process, and to carry out the tasks of coordinating transmission plans among the Transmission Owners and proposals to address the Transmission Issues identified in the scope of transmission planning studies. Input and planned coordination may occur through the use of existing sub-regional planning groups ("SPGs") where they exist, or through the establishment of new sub-regional meeting forums. One or more SPMs will be used or established for each of the four regional Planning Sub-regions of the Transmission Provider. Planning Sub-regions shall be defined based upon the Transmission Provider Planning Sub-regions: West, Central, South, and East as defined in Attachment FF-3.

i) SPM Participants: Participants at an SPM will consist of representatives of the Transmission Owners operating within the associated Planning Sub-region that integrate their local planning processes with the regional process, representatives from state and local regulatory authorities, and any other parties interested in or impacted by the planning process. For those Transmission Owners engaged in local planning under their own FERC approved local planning processes, such Transmission Owners shall participate in the SPM in order to coordinate their planning activities.

Neighboring transmission-owning utilities and regulatory participants are eligible and encouraged to participate in the SPM to promote joint planning between the Transmission Provider and neighboring transmission systems.

ii) SPM Guidelines. The Sub-regional Planning Meeting participants shall:

(a) Make recommendations for a coordinated sub-regional Plan, after considering sub-regional and regional needs and alternatives, for the ensuing ten years, for all transmission facilities in the sub-region; (b) Review and comment on proposed Transmission Owners plans identified in local planning processes described in Section I.D.1.a. of this Attachment FF, for additions and modifications to the sub-regional transmission system, as potential solutions to identify Transmission Issues and review the transmission plans developed by those Transmission Owners that have their own FERC-approved local planning process (described in Section I.D.2) to ensure coordination of the projects set forth in such plans with the potential regional planning solutions developed in the SPM process consistent with the requirements of Appendix B of the Transmission Owners' Agreement; (c) Form technical study task forces as required to carry out the sub-regional planning responsibilities;

(b) Encourage non-Transmission Provider member participation to improve understanding by the SPM participants, the Planning Subcommittee, and the Transmission Provider staff of facility changes outside the Transmission Provider Region to ensure the impact of such changes are considered in the planning studies;

(c) Promote other stakeholder (i.e., environmental agencies, and load and generation developers) involvement in development of the sub-regional plans.

(d) Recommend to the Planning Subcommittee proposed sub-regional plans to be included in the MTEP. In addition, the transmission projects developed by any Transmission Owner or Owners utilizing the provisions of their own FERC-approved local planning process shall be submitted for inclusion in the regional MTEP after being evaluated by the Transmission Provider in the regional evaluation of SPMs in accordance with Appendix B of the

Transmission Owners' Agreement in determining the Transmission Provider's recommendation for inclusion in the MTEP.

(e) Reflect, as desired, minority opinions to the Transmission Provider or the Planning Subcommittee.

(f) SPM Frequency, Location and Agenda: SPMs should meet at least two times per year or as otherwise provided for in the TPBPM, to provide input in the planning process, review plans and recommend changes, if any, needed to address stakeholder needs and to coordinate proposed plans.

Meetings involving CEII or confidential materials shall be handled under Section I.C.12 of this Attachment FF.

3. Meeting Notifications: Notice shall be provided by way of email exploder lists distribution by the Transmission Provider of all SPMs, Planning Subcommittee, and Planning Advisory Committee meetings. These email exploder lists are established and maintained by the Transmission Provider and it is the responsibility of stakeholders to have registered as described on the Transmission Provider website. Meeting dates, times, locations, and materials will also be posted on the meeting calendar page of the Transmission Provider's website. Meeting notification guidelines are set forth in the stakeholder developed Stakeholder Governance Guidelines.

4. Other Meeting Schedules: Planning Subcommittee meetings are regularly scheduled meetings that occur no less than bimonthly. Annual meeting schedules and

objectives are developed at the December meeting each year for the subsequent year. Planning Advisory Committee meetings are scheduled as per the PAC Charter.

5. Planning Criteria: The Transmission Provider shall evaluate the system to address Transmission Issues in a manner consistent with the ISO Agreement and this Attachment FF. Projects included in the MTEP may be based upon any applicable planning criteria, including accepted NERC reliability standards and reliability standards adopted by Regional Entities, local planning reliability or economic planning criteria of the Transmission Owner, or required by State or local authorities, any economic or other planning criteria or metrics defined in this Attachment FF, and any Applicable Laws and Regulations. Transmission Owners are required to annually provide updated copies of local planning criteria for posting on the Transmission Provider's website.

The Transmission Provider will post on its website an explanation of which transmission needs driven by public policy requirements will be evaluated for potential solutions in the local or regional transmission planning process, as well as an explanation of why other suggested potential transmission needs will not be evaluated.

6. Planning Analysis Methods: Planning analyses performed by the Transmission Provider will test the Transmission System under a wide variety of conditions as described in Section II and using standard industry applications to model steady state power flow, angular and voltage stability, short-circuit, and economic parameters, as determined appropriate by the Transmission Provider to be compliant with applicable criteria and this Tariff.

7. Planning Models: The Transmission Provider shall collaborate with Transmission Owners, other transmission providers, Transmission Customers, and other stakeholders to develop appropriate planning models that reflect expected system conditions for the planning horizon. The planning models shall reflect the projected Load growth of existing Network Customers and other transmission service and interconnection commitments. The models shall include any transmission projects identified in Service Agreements or Interconnection Agreements that are entered into in association with requests for transmission delivery service or interconnection service, as determined in Facilities Studies associated with such requests. Load forecasts applied to models will consider the forecast Load of Network Customers reported to the Transmission Provider in accordance with the requirements of Module B and RAR of this Tariff, and the Business Practices Manuals of the Transmission Provider. Models will be posted on an FTP site maintained by the Transmission Provider and accessible to stakeholders with security measures as provided for in the TPBPM. The Transmission Provider will provide an opportunity for stakeholders to review and comment on the posted models before commencing planning studies.

The schedules for such reviews are maintained in the TPBPM. Stakeholders shall be afforded opportunities to provide input on Load projections from Tariff reporting requirements or from Transmission Owner forecasts. After the base line forecast and model are established, the Transmission Provider and/or Transmission Owners may adjust the forecast as necessary on an ad hoc basis throughout the planning year to address customer requests for new Load interconnections arising from on-going dialogue with existing and prospective customers.

8. Planning Assumptions: Each MTEP report shall list in detail the planning assumptions upon which the analyses are based. In general, planning analyses will be based on the following:

a. Planning Horizons: The MTEP will identify Transmission Issues for a minimum planning horizon of five years and a maximum planning horizon of twenty years.

b. Load: Load demand will generally be modeled by the Transmission Provider as the most probable ("50/50") coincident Load projection for each Transmission Owner's service territory, for the season under study. Specific studies may model alternative Load probabilities or peak Load for areas within a Transmission Owner's service territory as dictated by operational and planning experience and/or local planning criteria, but in any case shall be treated consistently in the planning for native Load and transmission access requests.

c. Generation: Planning models of five years or longer will model generation, taking into consideration applicable planning reserve requirements, that are: (i) existing and expected to be in existence in the planning horizon; (ii) not existing but with executed interconnection agreements; and (iii) additional generation as determined with stakeholder input, as necessary to adequately and efficiently meet demand forecasted through the planning horizon and to facilitate compliance with statutory or regulatory mandates. The Transmission Provider shall apply a scenario analysis to determine alternative future generation portfolio possibilities.

Generation portfolio development for planning model purposes will be developed with input from the Planning Advisory Committee and its subcommittees, working groups, and task forces. Point-To-Point Transmission Service and Network Integration Transmission Service customers will have an opportunity to guide new generation portfolio development that is reflective of customer future resource plans.

d. Demand Response Resources: Planning solutions will be based upon the best available information regarding the expected amount and location of Load that can be effectively and efficiently reduced by demand response or energy efficiency programs, as well as the amount of behind-the-meter generation that can reliably be expected to produce Energy that could impact planning solutions. The Transmission Provider shall perform and report on sensitivity analyses that indicate the effectiveness of potential demand response as alternative planning solutions, to the extent that appropriate methodology for such analyses is developed with stakeholders and documented in the TPBPM.

e. Topology: Each planning study will use the best known topology based upon the most recently approved MTEP. Planning studies will include all projects approved by the Transmission Provider Board, and shall identify, as appropriate, and as detailed in the TPBPM, any system needs already identified in the most recent approved MTEP.

9. Evaluation of Alternatives: When the planning analyses, based on the foregoing principles, identifies Transmission Issues, the Transmission Provider will consider the inputs from stakeholders derived from the SPM processes, the inputs from the Planning Subcommittee and the Planning Advisory Committee, the plans of any Transmission Owner with its own FERC-approved local planning process, and the MTEP aggregate system analyses against applicable planning criteria, in determining the solutions to be included in the MTEP and recommended to the Transmission Provider Board for implementation.

10. Facility Design: Facility design and system configuration (such as conductor sizes, transformer design, bus configuration, protection schemes) are selected by the Transmission Owner, and must be consistently applied by the Transmission Owner for comparable system service conditions. Comparable application of system design does not preclude the consideration or selection of advanced or alternative transmission technology. For New Transmission Facilities associated with Open Transmission Projects, the Transmission Provider may provide limitations or requirements regarding facility design when necessary due to a planning driver or to ensure compatibility with existing transmission facilities to which the New Transmission Facilities will interconnect as further described in Section VIII.D of this Attachment FF.

11. Status of Recommended Facilities: Upon solicitation from the Transmission Provider and upon reaching pre-designated milestones in the project implementation process, the responsible Transmission Owner or Selected Transmission Developer shall report the status of all projects recommended for implementation in the MTEP. Status

reports shall, at a minimum, include: (i) changes to the schedule and to the estimated project cost; (ii) an explanation of the causes of, or reasons for, any such changes; and (iii) changes in project status (i.e., under construction, in service, or withdrawn). The Transmission Provider shall report such progress to the Transmission Provider Board on a quarterly basis, or as otherwise directed by the Transmission Provider Board.

Status of Developer Qualifications: Upon solicitation from the Transmission Provider and upon reaching pre-designated milestones in the project implementation process, Selected Transmission Developers shall report the following: (i) changes to the developer qualifications, as defined in the Binding Proposal Agreement, including changes in the developer constructing the project; (ii) an explanation of the causes of, or reasons for, such changes; and (iii) an assessment of the impact of the changes on the project. The Transmission Provider shall report such changes and any impact to the Transmission Provider Board on a quarterly basis, or as otherwise directed by the Transmission Provider Board.

a) Pre-designated milestones in the project implementation process of a typical MTEP development process are listed below. Requirements and timelines for data submittal, review, and comment at each of these milestone points are described in the TPBPM.

   i. Milestone 1: Final Sub-regional Planning Meeting / Out of Cycle Request Submittal

   ii. Milestone 2 a: Pre-project approval

   iii. Milestone 2b: Developer selection (Only applicable to Open

Transmission Projects, which by definition will proceed through the Transmission Provider's inclusive evaluation process to select the Selected Transmission Developer)

iv. Milestone 3: Long lead materials

v. Milestone 4: Pre-construction

vi. Milestone 5: Facility completion

12. Treatment of Critical Energy Infrastructure Information ("CEII") and Confidential Data: The Transmission Provider shall utilize a Non-Disclosure and Confidentiality Agreement ("NDA") to address sharing of CEII transmission planning information. FTP sites containing such information will require such agreements to be executed in order to obtain access to those sites. Stakeholder meetings at which CEII may be available shall be noticed to email exploders and shall require execution of NDAs prior to participation in such meetings. In the alternative, such meetings will be structured to have separate discussion of issues involving CEII data only with participants that agree to execute the NDA. Confidential information related to economic (e.g., congestion) studies, as well as CEII, is clearly sensitive information which must remain confidential. The Transmission Provider shall use generic, publicly available, cost information from industry sources in the economic studies to prevent the accidental release of confidential information. This approach will promote an open planning process because the results of economic studies are available to all interested parties.

13. Resolution of Stakeholder Input: The Transmission Provider shall solicit input and comments from all stakeholders, including Transmission Owners, during and after

stakeholder planning meetings, and will use reasonable efforts to reply to comments that the Transmission Provider does not elect to implement, together with reasons for such actions. The Transmission Provider shall develop a process for the documentation and resolution of stakeholder issues raised in the planning process, including but not limited to issues related to planning criteria.

14. Dispute resolution: Consistent with Attachment HH of this Tariff, the Transmission Provider shall resolve disputes concerning MTEP issues. The first step will be for designated representatives of the affected parties to work together to resolve the relevant issues in a manner that is acceptable to all parties. If that step is unsuccessful, each affected party shall designate an officer who shall review disputes involving them that their designated representatives are unable to resolve. The applicable officers of the parties involved in such dispute shall work together to resolve the disputes so referred in a manner that meets the interests of such parties, either until such agreement is reached, or until an impasse is declared by any party to such dispute. If such officers are unable to satisfactorily resolve the issues, the matter shall be referred to mediation. Parties that are not satisfied with the dispute resolution procedures may only file a complaint with the Commission during the negotiation or mediation steps.

If a matter remains unresolved, the affected parties may pursue arbitration.

D. Project Coordination: In the course of the MTEP process, the Transmission Provider shall seek out opportunities to coordinate or consolidate, where possible, individually defined transmission projects into more comprehensive cost-effective developments subject to the limitations imposed by prior commitments and lead-time constraints. The Transmission

Provider shall coordinate with Transmission Owners, and shall consider the input from the SPMs, Planning Subcommittee, and Planning Advisory Committee to develop expansion plans to meet the needs of the system. This multi-party collaborative process will allow for all projects with regional and inter-regional impact to be analyzed for their combined effects on the Transmission System. Moreover, this collaborative process is designed to ensure that the MTEP address Transmission Issues within the applicable planning horizon in the most efficient and cost effective manner, while giving consideration to the inputs from all stakeholders. In addition to the requirements of this Attachment FF, there may be state or local procedural requirements applicable to the planning or siting of transmission facilities by the Transmission Owners. A current list of those requirements can be found on the Transmission Provider's website.

1. Transmission Owners Electing to Integrate their Local Planning Processes into the Transmission Provider's Processes: Some Transmission Owners have agreed to integrate internal planning process with the Transmission Provider's open and coordinated planning processes for all of their transmission facilities to comply with Order 890 Planning Principles instead of filing a separate Attachment K. Through this election, the local planning for all transmission facilities of these Transmission Owners, regardless of whether the facilities are ultimately transferred to the functional control of the Transmission Provider, shall be integrated with and included in the regional planning processes of the Transmission Provider. These regional planning processes, as provided for in this Attachment FF and in additional detail in the TPBPM, ensure that the planning decisions for all such facilities are made in an open and transparent environment.

This planning environment provides opportunity for input from, and review by, stakeholders of the Open Access Transmission Tariff services throughout the planning process, and is in accordance with the Planning Principles of the Order 890 Final Rule. The open and transparent planning provisions of this Attachment FF shall not preclude interaction between stakeholders and Transmission Owners prior to the submittal of proposed projects to the regional planning process.

Transmission Owners integrating local planning processes into the regional planning processes are listed in Attachment FF-4. Such Transmission Owners shall be responsible for providing the Transmission Provider with sufficient information regarding all planning activities to enable the Transmission Provider to adequately review and incorporate all of the Transmission Owner's transmission facilities into the regional planning process of the Transmission Provider, as described in Sections I.D.1.a. and I.D.1.b. of this Attachment FF.

The foregoing Transmission Owners will utilize the planning stakeholder forums of the Transmission Provider to demonstrate the need for, identify the alternatives to, and report the status of non-transferred transmission facilities using the same open, transparent and coordinated planning process provided by the Transmission Provider for transferred facilities as described in this Attachment FF.

a. Local Planning Processes of Transmission Owners: In accordance with the ISO Agreement, each Transmission Owner engages in local system planning in order to carry out its responsibility for meeting its respective transmission needs in collaboration with the Transmission Provider subject to the requirements of applicable state law or regulatory authority. In meeting its responsibilities under the ISO Agreement, the Transmission Owners may, as appropriate, develop and propose plans involving modifications to any of the Transmission Owner's transmission facilities which are part of the Transmission System. The Transmission Owners shall include the following specific local planning steps in order to develop plans for potential inclusion in the regional plan, in accordance with the annual regional planning process as described in Section I.D.1.b. of this Attachment FF, and in accordance with the regional planning principles of Section I.C of this Attachment. In addition to the local planning steps below, Transmission Owners shall adhere to any applicable state or local regulatory planning processes.

i. Define local study area and study horizon;

ii. Develop appropriate power system models;

a) Utilize existing NERC or Transmission Provider cases to model external systems;

b) Insert detailed model of Transmission Owner system if required;

c) Insert updated detailed models of neighboring system models if required; and

d) Verify model topology and generation.

iii. Update loads (spatial and magnitude) in study area;

a) Review historical MW and MVAR data to develop growth trends;

b) Obtain Load forecasts from customers in study area; and

c) Obtain input from local distribution planners in the study area.

iv. Perform contingency analysis using applicable Transmission Owner planning criteria;

v. Identify any violations to planning criteria for each of study period;

vi. Develop alternative solutions to the criteria violations and test against the planning criteria;

a) Obtain cost estimates for each alternative and perform economic analyses; and

b) Determine non-cost attributes of each alternative such as operating flexibility, robustness, among others.

vii. Select alternative based on cost and non-cost attributes;

viii. Submit proposed solution and list of alternatives and assumptions to the Transmission Provider;

ix. Participate in stakeholder evaluations and discussions as a part of annual regional plan development process;

x. Perform additional analysis as required based on feedback from stakeholder groups (SPM/PS) in the regional planning process;

xi. Submit results of additional analysis (if performed) to the Transmission Provider for further discussion with stakeholders (SPM/PS);

xii. Consider regional planning process results, including stakeholder feedback on needs, proposed solutions, and alternatives, in determining whether or not to proceed with implementation of Transmission Owner proposed expansions; and

xiii. Post the planning criteria and assumptions, and power flow models used in development of each Transmission Owner's current local planning proposal in accordance with Section I.D.1.b below. To the extent that the Transmission Owner uses the MISO MTEP models in developing its list of newly proposed projects, the Transmission Owner shall indicate as per Section I.D.1.b. below, the associated MTEP model used.

The Transmission Provider will maintain a link to applicable MTEP models on its website together with instructions for accessing such models consistent with CEII criteria and suitable non-disclosure agreements. In the event that the Transmission Owner applies its own power flow models in developing its proposed local plans, the Transmission Owner shall provide such models to the Transmission Provider for posting, or shall provide to the Transmission Provider a link to the location of such Transmission Owner model(s) and to instructions for accessing such models consistent with the Transmission Owner's CEII and non-disclosure requirements. Transmission Provider shall post on its website links to such postings on Transmission Owner's website.

b. Integration of Local Planning Processes of Transmission Owners: Transmission Owners listed on Attachment FF-4 as integrating local planning processes with those of the Transmission Provider, shall integrate proposals for transmission expansions into the regional planning process as follows. Each Transmission Owner shall submit its proposals for transmission plans to the Transmission Provider prior to the start of each regional planning cycle. Each Transmission Owner's local plan, which consists of a list of proposed projects, shall be made available on the Transmission Provider's website for review by the PAC, the PS, and the SPM participants, subject to CEII and the confidentiality provisions in this Attachment FF. Such local plans shall be posted by September 15 each year in order to provide time for written comments by stakeholders. In addition to the list of proposed projects, each Transmission Owner submitting newly proposed projects by September 15 in any MTEP annual cycle shall provide to the Transmission Provider by June 1 of the same year identification of any MISO base power flow model used by the Transmission Owner in support of the identification of the list of proposed projects to be subsequently posted in September, or in the event that the Transmission Owner uses a non-MISO base power flow model in support of the identification of the list of proposed projects the Transmission Owner shall provide to the Transmission Provider such base power flow model or a link to the power flow model and assumptions used.

Each Transmission Owner's local planning model and associated assumptions shall be accessible on or through a link on the Transmission Provider's website for review, subject to CEII and the confidentiality provisions in this Attachment FF and consistent with section I.D.1.a. In the event that the Transmission Owner uses a non-MISO base power flow model, the Transmission Owner shall provide for posting updates if there are significant changes in the model by July 15, August 15, and September 15 of each year. Comments by stakeholders on the local planning models and assumptions that are provided to the Transmission Provider SPM Planning Contact by July 1, or August 1 or September 1 with respect to updates, shall be forwarded to the applicable Transmission

Owner by July 8, August 8, or September 8, respectively. The Transmission Provider shall address any unresolved stakeholder issues through the SPM process.

Each Transmission Owner shall also provide to the Transmission Provider by June 1 of each year any updates to the posted transmission planning criteria, or a notification that the posted documents have not changed. In the event a Transmission Owner has additional significant updates to the posted transmission planning criteria, the Transmission Owner shall provide such updates for posting by July 15, August 15, and September 15 of each year.

The Transmission Provider shall post on its website the lists of newly proposed projects, criteria and assumptions, and supporting base power flow models or links to supporting base power flow models, as provided by the Transmission Owners. Initial comments by stakeholders to the proposed projects should be provided to the Transmission Provider SPM Planning Contact 45 days after the posting of local plans otherwise comments may be made pursuant to Section I.C.2.c.ii. The Transmission Provider SPM Planning Contact shall be identified on the Transmission Provider's web site page devoted to Expansion Planning. The Transmission Provider shall provide to the applicable Transmission Owner within five working days of receipt, a copy of all stakeholder comments received within 45 days of the posted information regarding Transmission Owner planning criteria and assumptions, models applied, and list of proposed projects. The Transmission Provider shall address any unresolved stakeholder issues through the SPM process. Each Transmission Owner must participate in SPMs in the respective Planning sub-region as indicated in the Transmission Providers meeting schedule. Such

SPMs shall provide input to and review of the results of the needs assessments and adequacy of plans proposed by the Transmission Owners, or by stakeholders to the planning process, or by the Transmission Provider, to best meet the needs of the sub-region.

Transmission Owners identified in Attachment FF-4, must submit to the Transmission Provider, on an annual basis and at a time to be determined by the Transmission Provider, which shall be prior to the beginning of each regional planning cycle, all proposed transmission plans for both transferred and non-transferred transmission facilities. The submitted projects of such Transmission Owners shall be considered potential alternatives to system needs identified, and as such must be submitted when initially identified as a potential system solution, in order to permit the evaluation of such projects along with other potential alternatives that may be proposed by stakeholders or the Transmission Provider, in the SPM processes. Such alternatives may include transmission, generation, and demand-side resources. The Transmission Provider will review and evaluate such alternatives on a comparable basis and select the most appropriate solution. Comparability includes the ability of the Transmission Provider to obtain contractual assurances that the selected solution will be implemented by the required in-service dates. Contractual commitments associated with the construction of an MTEP Appendix A approved project by MISO Transmission Owner(s) and/or Selected Transmission Developer(s) are provided for by the ISO Agreement, this Tariff, and the Binding Proposal Agreement.

Contractual commitments associated with generation solutions require that a generator interconnection agreement be filed with the Commission pursuant to Attachment X of this Tariff by the time the alternative transmission solution would need to be committed to in order to ensure installation on the required need date. Contractual commitments associated with demand-side resource solutions require demonstration to the Transmission Provider of an executed contract between LSE and End-Use Customers. Such demand-side contracts must be in place by the time that the transmission solution would otherwise need to be committed to in order to ensure a timely solution to the identified planning need, and must be of a sufficient duration such that a reliable solution can be assured through the planning horizon. Notwithstanding the provisions of Section VII of the ISO Agreement regarding the Transmission Provider review of Transmission Owner plans, no proposed project of a Transmission Owner that has elected to integrate their local planning processes into the Transmission Provider's processes, as indicated on Attachment FF-4, shall be recommended in the MTEP for implementation until completion of the annual needs analysis carried out in the annual MTEP cycle, as described in Section I.C. of this Attachment FF, except as provided for in Section I.D.1.c. of this Attachment FF.

c. Out-of-Cycle Review of Transmission Owner Plans: In the event that a Transmission Owner determines that system conditions warrant the urgent development of system enhancements that would be jeopardized unless the Transmission Provider performs an expedited review of the impacts of the project, Transmission Provider shall use a streamlined approval process for reviewing and approving projects proposed by the

Transmission Owners so that decisions will be provided to the Owner within thirty (30) days of the projects submittal to the MISO unless a longer review period is mutually agreed upon.

2. Transmission Owners Filing Separate Attachment K: Some Transmission Owners as listed on the last page of Attachment FF-4 have developed individual open, local planning processes for their facilities, that comply with the Planning Principles of the Order 890 Final Rule. These Transmission Owners have an Attachment K that describes how the Transmission Owner will comply with the Order No. 890 Planning Principles for all transmission facilities that they plan for, regardless of whether those facilities are ultimately transferred to the functional control of the Transmission Provider. With the exception of Sections I.D.1.a and I.D.1.b., the provisions of this Attachment FF remain applicable to all Transmission Owners notwithstanding the filing by any Transmission Owner of an Attachment K pursuant to the Order 890 Final Rule.

E. Interregional Coordination and Cost Allocation: The MTEP shall be developed in accordance with the principles of interregional coordination through collaboration with representatives from adjacent transmission providers, their designated regional planning organizations, or regional transmission organizations, as provided for in this Attachment FF, or as otherwise provided for in existing joint agreements between the Transmission Provider and other regional entities that engage in planning activities. The Transmission Provider has developed region-specific interregional coordination and cost allocation provisions with regard to the following neighboring transmission planning regions:

- PJM Interconnection, L.L.C. ("PJM"), as provided for under Article IX and other applicable provisions of the Joint Operating Agreement between the Transmission Provider and PJM, as may be amended from time to time, including revisions the effective date of which is pending Commission approval in Docket No. ER13-1943-000;

- Southeastern Regional Transmission Planning ("SERTP"), as provided for under Section X of this Attachment FF, the effective date of which is pending Commission approval in Docket No. ER13-1923-000; and
- Southwest Power Pool ("SPP"), as provided for under Article IX and other applicable provisions of the Joint Operating Agreement between the Transmission Provider and SPP, as may be amended from time to time, including revisions the effective date of which is pending Commission approval in Docket No. ER13-1938-000;

The Transmission Provider also has planning coordination provisions as part of its coordination agreement with Manitoba Hydro. The following interregional coordination provisions shall continue to apply with regard to interregional coordination activities between the Transmission Provider and the Mid Continent Area Power Pool ("MAPP") transmission planning region. Moreover, the following interregional coordination provisions shall remain in effect for interregional coordination activities between the Transmission Provider and the SERTP transmission planning region until the Commission approves and grants an effective date for the SERTP interregional coordination and cost allocation filing pending in Docket No. ER13-1923-000.

1. Initial Contact: The Transmission Provider will initiate a meeting with representatives of adjacent transmission providers, their designated regional planning organizations, or regional transmission organizations with which existing joint

agreements are not already established with the Transmission Provider ("Regional Planning Coordination Entities" or "RPCEs"), in order to establish a Joint Planning Committee.

2. Joint Planning Committee. The Transmission Provider shall offer to form a Joint Planning Committee ("JPC") with the RPCE. The JPC shall be comprised of representatives of the Transmission Provider and the RPCE in numbers and functions to be identified from time to time. The JPC may combine with or participate in similarly established joint planning committees amongst multiple RPCEs or established under joint agreements to which the Transmission Provider is a signatory, for the purpose of providing for broader and more effective inter-regional planning coordination. The JPC shall have a Chairman. The Chairman shall be responsible for: the scheduling of meetings; the preparation of agendas for meetings; the production of minutes of meetings; and for chairing JPC meetings. The Chairmanship shall rotate amongst the Transmission Provider and the RPCEs on a mutually agreed to schedule, with each party responsible for the Chairmanship for no more than one planning study cycle in succession. The JPC shall coordinate planning of the systems of the Transmission Provider and the RPCEs, including the following:

a. Coordinate the development of common power system analysis models to perform coordinated system planning studies including power flow analyses and stability analyses. For studies of interconnections in close electrical proximity at the boundaries among the systems of the Transmission Provider and the RPCEs the JPC or its designated working group will coordinate the performance of a detailed review of the appropriateness of applicable power system models.

b. Conduct, on a regular basis, a Coordinated Regional Transmission Planning Study (CRTPS), as set forth in Section 8.3.4.

c. Coordinate planning activities under this Section 8, including the exchange of data and developing necessary report and study protocols.

d. Maintain an Internet site and e-mail or other electronic lists for the communication of information related to the coordinated planning process. Such sites and lists may be integrated with those existing for the purpose of communicating the open and transparent planning processes of the Transmission Provider.

e. Meet at least semi-annually to review and coordinate transmission planning activities.

f. Establish working groups as necessary to address specific issues, such as the review and development of the regional plans of the RPCE and the Transmission Provider, and localized seams issues.

g. Establish a schedule for the rotation of responsibility for data management, coordination of analysis activities, report preparation, and other activities.

3. Data and Information Exchange. The Transmission Provider shall make available to each RPCE the following planning data and information. Unless otherwise indicated, such data and information shall be provided annually. The Transmission Provider shall provide such data in accordance with the applicable CEII policy, and maintain data and information received from each RPCE in accordance with their applicable confidentiality policies.

a. Data required for the development of power flow cases, and stability cases, incorporating up to a ten year load forecasts as may be requested, including all critical assumptions that are used in the development of these cases.

b. Fully detailed planning models (up to the next ten (10) years as requested) on an annual basis and updates as necessary to perform coordinated studies that reflect system enhancement changes or other changes.

c. The regional plan documents, any long-term or short-term reliability assessment documents, and any operating assessment reports produced by the Transmission Provider and the RPCE.

d. The status of expansion studies, system impact studies and generation interconnection studies, such that the Transmission Provider and the RPCE have knowledge that a commitment has been made to a system enhancement as a result of any such studies.

e. Transmission system maps for the Transmission Provider and the RPCE bulk transmission systems and lower voltage transmission system maps that are relevant to the coordination of planning between or among the systems.

f. Contingency lists for use in load flow and stability analyses, including lists of all contingency events required by applicable NERC or Regional Entity planning standards, as well as breaker diagrams for the portions of the Transmission Provider and the RPCE transmission systems that are relevant to the coordination of planning between or among the systems. Breaker diagrams to be provided on an as requested basis.

g. The timing of each planned enhancement, including estimated completion dates, and indications of the likelihood that a system enhancement will be completed and whether the system enhancement should be included in system expansion studies, system impact studies and generation interconnection studies, and as requested the status of related applications for regulatory approval. This information shall be provided at the completion of each planning cycle of the Transmission Provider, and more frequently as necessary to indicate changes in status that may be important to the RPCE system.

h. Quarterly identification of interconnection requests that have been received and any long-term firm transmission services that have been approved, that may impact the operation of the Transmission Provider or the RPCE system.

i. Quarterly, the status of all interconnection requests that have been identified.

j. Information regarding long-term firm transmission services on all interfaces relevant to the coordination of planning between or among the systems.

k. Load flow data initially will be exchanged in PSS/E format. To the extent practical, the maintenance and exchange of power system modeling data will be implemented through databases. When feasible, transmission maps and breaker diagrams will be provided in an electronic format agreed upon by the Transmission Provider and the RPCE. Formats for the exchange of other data will be agreed upon by the Transmission Provider and the RPCE.

4. Coordinated System Planning. The Transmission Provider shall agree to coordinate with the RPCEs studies required to assure the reliable, efficient, and effective operation of the transmission system. Results of such coordinated studies will be included in the Coordinated

System Plan. The Transmission Provider shall agree to conduct with the RPCEs such coordinated planning as set forth below

a. Single Entity Planning. The Transmission Provider shall engage in such transmission planning activities, including expansion plans, system impact studies, and generator interconnection studies, as necessary to fulfill its obligations under the Tariff. Such planning shall conform to applicable reliability requirements of NERC, applicable regional reliability councils, and any successor organizations thereto.

Such planning shall also conform to any and all applicable requirements of Federal or State regulatory authorities. The Transmission Provider will prepare a regional transmission planning report that documents the procedures, methodologies, and business rules utilized in preparing and completing the report. The Transmission Provider shall agree to share the transmission planning reports and assessments with each RPCE, as well as any information that arises in the performance of its individual planning activities as is necessary or appropriate for effective coordination among the Transmission Provider and the RPCEs on an ongoing basis. The Transmission Provider shall provide such information to the RPCEs in accordance with the applicable CEII policy and shall maintain such information received from the RPCEs in accordance with their applicable confidentiality policies.

b. Analysis of Interconnection Requests. In accordance with the procedures under which the Transmission Provider provides interconnection service, the Transmission Provider will agree to coordinate with each RPCE the conduct of any studies required in determining the impact of a request for generator or merchant transmission interconnection. Results of such coordinated studies will be included in the impacts reported to the interconnection customers as appropriate. Coordination of studies shall include the following:

i. When the Transmission Provider receives a request under its interconnection procedures for interconnection, it will determine whether the interconnection potentially impacts the system of a RPCE. In that event, the Transmission Provider will notify the RPCE and convey the information provided in the interconnection queue posting. The Transmission Provider will provide the study agreement to the interconnection customer in accordance with applicable procedures.

ii. If the RPCE determines that it may be materially impacted by an interconnection on the Transmission Provider System, the RPCE may request participation in the applicable interconnection studies. The Transmission Provider will coordinate with the RPCE with respect to the nature of studies to be performed to test the impacts of the interconnection on the RPCE System, and who will perform the studies. The Transmission Provider will strive to minimize the costs associated with the coordinated study process undertaken by agreement with the RPCE.

iii. Any coordinated studies associated with requests for interconnection to the Transmission Provider's system will be performed in accordance with the study timeline requirements and scope of the applicable generation interconnection procedures of the Transmission Provider.

iv. The RPCE may participate in the coordinated study either by taking responsibility for performance of studies of its system, if deemed reasonable by the Transmission Provider, or by providing input to the studies to be performed by the Transmission Provider. The study cost estimates indicated in the study agreement between the Transmission Provider and the interconnection customer, will reflect the costs, and the associated roles of the study participants including the RPCE. The Transmission Provider will review the cost estimates and scope submitted by all participants for reasonableness, based on expected levels of participation, and responsibilities in the study. If the RPCE agrees to perform any aspects of the study, the RPCE must comply with the timelines and schedule of the Transmission Provider's interconnection procedures.

v. The Transmission Provider will collect from the interconnection customer the costs incurred by the RPCE associated with the performance of such studies and forward collected amounts, no later than thirty (30) days after receipt thereof, to the RPCE. Upon the reasonable request of the RPCE, the Transmission Provider will make their books and records available to the requestor pertaining to such requests for collection and receipt of collected amounts.

vi. The Transmission Provider will report the combined list of any transmission infrastructure improvements on either the RPCE and/or the

Transmission Provider's system required as a result of the proposed interconnection.

vii. Construction and cost responsibility associated with any transmission infrastructure improvements required as a result of the proposed interconnection shall be accomplished under the terms of the applicable OATT, Transmission Service Guidelines, controlling agreements, and consistent with applicable Federal or State regulatory policy and applicable law.

viii. Each transmission provider will maintain separate interconnection queues. The JPC will maintain a composite listing of interconnection requests for all interconnection projects that have been identified as potentially impacting the systems of the Transmission Provider and coordinating RPCEs. The JPC will post this listing on the Internet site maintained for the communication of information related to the coordinated system planning process.

c. Analysis of Long-Term Firm Transmission Service Requests. In accordance with applicable procedures under which the Transmission Provider provides long-term firm transmission service, the Transmission Provider will coordinate the conduct of any studies required to determine the impact of a request for such service. Results of such coordinated studies will be included in the impacts reported to the transmission service customers as appropriate. Coordination of studies will include the following:

i. The Transmission Provider will coordinate the calculation of ATC values associated with the service, based on contingencies on their systems that may be impacted by the granting of the service.

ii. When the Transmission Provider receives a request for long-term firm transmission service, it will determine whether the request potentially impacts the system of the RPCE. If the Transmission Provider determines that the RPCE system is potentially impacted, and that the RPCE would not receive a transmission service request to complete the service path, the transmission provider will notify the RPCE and convey the information provided in the posting.

iii. If the RPCE determines that its system may be materially impacted by granting the service, it may contact the Transmission Provider and request participation in the applicable studies. The Transmission Provider will coordinate with the RPCE with respect to the nature of studies to be performed to test the impacts of the requested service on the RPCE system, and will strive to minimize the costs associated with the coordinated study process. The JPC will develop screening procedures to assist in the identification of service requests that may impact systems of the JPC members other than the transmission provider receiving the request.

iv. Any coordinated studies for request on the transmission Provider's system will be performed in accordance with the study timeline and scope requirements of the applicable transmission service procedures of the Transmission Provider.

v. The RPCE may participate in the coordinated study either by taking responsibility for performance of studies of its system, if deemed reasonable by the Transmission Provider or by providing input to the studies to be performed by the Transmission Provider. The study cost estimates indicated in the study agreement between the Transmission Provider and the transmission service customer will reflect the costs and the associated roles of the study participants. The Transmission Provider will review the cost estimates and scope submitted by all participants for reasonableness, based on expected levels of participation and responsibilities in the study.

vi. The Transmission Provider will collect from the transmission service customer, and forward to the RPCE, the costs incurred by the RPCE with the performance of such studies.

vii. The Transmission Provider receiving the request will identify any transmission infrastructure improvements required as a result of the transmission service request.

viii. Construction and cost responsibility associated with any transmission infrastructure improvements required as a result of the transmission service request shall be accomplished under the terms of the applicable OATT, Transmission Service Guidelines, controlling agreements, and consistent with applicable Federal or State regulatory policy and applicable law.

d. Coordinated Regional Transmission Planning Study: The Transmission Provider agrees to participate in the conduct of a periodic Coordinated Regional Transmission Planning Study (CRTPS). The CRTPS shall have as input the results of ongoing analyses of requests for interconnection and ongoing analyses of requests for long-term firm transmission service. The Parties shall coordinate in the analyses of these ongoing service requests in accordance with Sections 8.3.2 and 8.3.3. The results of the CRTPS shall be an integral part of the expansion plans of each Party. Construction of upgrades on the Transmission System of the Transmission Provider that are identified as necessary in the CRTSP shall be under the terms of the Owners Agreement of the Transmission Provider, applicable to the construction of upgrades identified in the expansion planning process. Coordination of studies required for the development of the Coordinated System Plan will include the following:

i. Every three years, the Transmission Provider shall participate in the performance of a CRTPS. Sensitivity analyses will be performed, as required, during the off years based on a review by the JPC of discrete reliability problems or operability issues that arise due to changing system conditions.

ii. The CRTPS shall identify all reliability and expansion issues, and shall propose potential resolutions to be considered by The Transmission Provider and the coordinating RPCEs.

iii. As a result of participation in the CRTPS, except as provided for in Section II. A. 1., the Transmission Provider is not obligated in any way to construct, finance, operate, or otherwise support any transmission infrastructure improvements or other transmission-related projects identified in the CRTPS. Any decision to proceed with any transmission infrastructure improvements or other transmission-related projects identified in the CRTPS shall be based on the applicable reliability, operational and economic planning criteria established for the Transmission Provider as applicable to the development of the MTEP and set forth in this Attachment FF.

iv. As a result of participation in the CRTPS, the RPCEs are not entitled to any rights to financial compensation due to the impact of the transmission plans of the Transmission Provider upon the RPCE system, including but not limited to its decisions whether or not to construct any transmission infrastructure improvements or other transmission-related projects identified in the CRTPS.

v. The JPC will develop the scope and procedure for the CRTPS. The scope of the CRTPSs performed over time will include evaluations of the transmission systems against reliability criteria, operational performance criteria, and economic performance criteria applicable to the Transmission Provider and the RPCEs.

vi. In the conduct of the CRTPS, the Transmission Provider and the coordinating RPCEs will use planning models that are developed in accordance with the procedures to be established by the JPC. Exchange of power flow models will be in a format that is acceptable to the coordinating parties.

vii. Stakeholder Review Processes. The Transmission Provider, in coordination with coordinating RPCEs shall review the scope and results of the CRTPS with impacted stakeholders, and shall modify the study scope as deemed appropriate by the Transmission Provider in agreement with the coordinating RPCEs, after receiving stakeholder input. Such reviews will utilize the existing planning stakeholder forums of the coordinating parties including as applicable joint Sub Regional Planning Meetings.

II. Development Process for MTEP Projects: The Transmission Provider will develop the MTEP biennially or more frequently. The MTEP will identify expansion projects for inclusion in the MTEP according to the factors set forth in Appendix B of the ISO Agreement and Section I.C. of this Attachment FF. For purposes of assigning cost responsibility, expansion projects in the MTEP shall be categorized pursuant to the following criteria.

A. Reliability Needs: Reliability projects are identified either in the periodically performed Baseline Reliability Study, or in Facilities Studies associated with the request processes for new transmission access. Transmission access includes requests for both new transmission delivery service and new generation interconnection service.

1. Baseline Reliability Projects: Baseline Reliability Projects are Network Upgrades identified in the base case as required to ensure that the Transmission System is in compliance with applicable national Electric Reliability Organization ("ERO") reliability standards and reliability standards adopted by Regional Reliability Organizations and applicable within the Transmission Provider Region. Baseline Reliability Projects include projects that are needed to maintain reliability while accommodating the ongoing needs of existing Market Participants and Transmission Customers. Baseline Reliability Projects may consist of a number of individual facilities that in the judgment of the Transmission Provider constitute a single project for cost allocation purposes. The Transmission Provider shall collaborate with Transmission Owning members, other transmission providers, Transmission Customers, and other stakeholders to develop appropriate planning models that reflect expected system conditions for the planning horizon. The planning models shall reflect the projected load growth of existing network customers and other transmission service and interconnection commitments, and shall include any transmission projects identified in Service Agreements or interconnection agreements that are entered into in association with requests for transmission delivery service or transmission interconnection service, as determined in Facilities Studies associated with such requests. The Transmission Provider shall test the MTEP for adequacy and security based on commonly applicable national Electric Reliability Organization ("ERO") standards, and under likely and possible dispatch patterns

of actual and projected Generation Resources within the Transmission System and of external resources, including dispatch reflective of Long-Term Transmission Rights of Transmission Customers, and shall produce an efficient expansion plan that includes all Baseline Reliability Projects determined by the Transmission Provider to be necessary through the planning horizon of the MTEP. The Transmission Provider shall obtain the approval of the Transmission Provider Board, as set forth in Section VI, for each MTEP published.

2. New Transmission Access Projects: New Transmission Access Projects are defined for the purposes of Attachment FF as Network Upgrades identified in Facilities Studies and agreements pursuant to requests for transmission delivery service or transmission interconnection service under the Tariff. New Transmission Access Projects include projects that are needed to maintain reliability while accommodating the incremental needs associated with requests for new transmission or interconnection service, as determined in Facilities Studies associated with such requests. New Transmission Access Projects may consist of a number of individual facilities, which in the judgment of the Transmission Provider constitute a single project for cost allocation purposes. New Transmission Access Projects are either Generation Interconnection Projects or Transmission Delivery Service Projects as defined in Sections II.A.2.a. and II.A.2.b. The Transmission Provider shall consider the Baseline Reliability Projects already determined to be needed in the most current MTEP, as well as any other base-case needs not associated with the request for new service that

may be identified during the impact study process when determining the need for New Transmission Access Projects. Any identified base-case needs determined in the impact study process that are not a part of the Baseline Reliability Projects already identified in the most current MTEP shall become new Baseline Reliability Projects and shall be included in the next MTEP. New Transmission Access Projects identified in Facilities Studies and agreements pursuant to requests for transmission delivery service or transmission interconnection service under this Tariff shall be included in the next MTEP.

a. Generation Interconnection Projects: Generation Interconnection Projects are New Transmission Access Projects that are associated with interconnection of new, or increase in generating capacity of existing, generation under Attachments X to this Tariff.

b. Transmission Delivery Service Projects: Transmission Delivery Service Projects are New Transmission Access Projects that are needed to provide for requests for new Point-To-Point Transmission Service, or requests under Module B of the Tariff for Network Service or a new designation of a Network Resource(s).

B. Market Efficiency Projects: Market Efficiency Projects are Network Upgrades: (i) that are proposed by the Transmission Provider, Transmission Owner(s), ITC(s), Market Participant(s), or regulatory authorities; (ii) that are found to be eligible for inclusion in the MTEP or are approved pursuant to Appendix B, Section VII of the ISO Agreement after June 16, 2005, applying the factors set forth in Section I.C. of this Attachment FF; (iii) that have a Project

Cost of $5 million or more; (iv) that involve facilities with voltages of 345 kV or higher[1]; and that may include any lower voltage facilities of 100kV or above that collectively constitute less than fifty percent (50%) of the combined project cost, and without which the 345 kV or higher facilities could not deliver sufficient benefit to meet the required benefit-to-cost ratio threshold for the project as established in Section II.B.1.e, or that otherwise are needed to relieve applicable reliability criteria violations that are projected to occur as a direct result of the development of the 345 kV or higher facilities of the project; (v) that are not determined to be Multi Value Projects; and (vi) that are found to have regional benefits under the criteria set forth in Section II.B.1 of this Attachment FF.

1. Criteria to Determine Whether a Project Should be Included as a Market Efficiency Project: The Transmission Provider shall employ multiple future scenarios and multi-year analysis including sensitivity analyses guided by input from the Planning Advisory Committee to evaluate the anticipated benefits of a proposed Market Efficiency Project in order to determine if such a project meets the criteria for inclusion in the regional plan as a Market Efficiency Project eligible for regional cost sharing. Sensitivity analyses shall include, among other factors, consideration of: (i) variations in amount, type, and location of future generation supplies as dictated by future scenarios developed with stakeholder input and guidance; (ii) alternative transmission proposals; (iii) impacts of variations in load growth; and (iv) effects of demand response resources on transmission benefits.

[1] Transformer voltage is defined by the voltage of the low-side of the transformer for these purposes.

The Transmission Provider shall perform this inclusion analysis as follows:

a. The Transmission Provider shall utilize a weighted futures, no loss ("WFNL") metric to analyze the anticipated annual economic benefits of construction of a proposed Market Efficiency Project to Transmission Customers in each of the Local Resource Zones, as defined in Attachment WW, based upon adjusted production cost ("APC") savings. APC savings will be calculated as the difference in total production cost of the Resources in each Local Resource Zone adjusted for import costs and export revenues with and without the proposed Market Efficiency Project as part of the Transmission System. The WFNL metric for each Local Resource Zone shall be calculated using the weighted APC savings determined for each future scenario included in the analysis.

i. The WFNL metric shall utilize the future scenarios determined and identified by the Transmission Provider through the planning process, with input from all stakeholders. The weights applied to the results of each future scenario shall also be determined by the Transmission Provider with input from all stakeholders.

b. Project benefit evaluations will include benefits for the first 20 years of project life after the projected in-service date, with a maximum planning horizon of 25 years from the approval year. The annual benefit for a proposed Market Efficiency Project shall be determined as the sum of the WFNL values for each Local Resource Zone, as defined in Attachment WW. The total project benefit shall be determined by calculating the present value of annual benefits for the multiple year scenarios and multi-year evaluations.

c. The costs applied in the benefit to cost ratio shall be the present value, over the same period for which the project benefits are determined, of the annual Network Upgrade Charges for the project as determined in accordance with the formula in Attachment GG.

d. The present value calculation for both the annual benefits and annual costs will apply a discount rate representing the after-tax weighted average cost of capital of the Transmission Owners that make up the Transmission Provider Transmission System.

e. The Transmission Provider shall employ a benefit to cost ratio test to evaluate a proposed Market Efficiency Project. Only projects that meet a benefit to cost ratio of 1.25 or greater shall be included in the MTEP as a Market Efficiency Project and be eligible for regional cost sharing.

f. The benefits of the project used to determine the associated cost allocations as a percentage of project cost shall be determined one time at the time that the project is presented to the Transmission Provider Board for approval. Estimated Project Cost will be used to estimate the benefit to cost ratio and the eligibility for cost sharing at the time of project approval. To the extent that the Commission approves the collection of costs in rates for Construction Work in Progress (“CWIP”) for a constructing Transmission Owner, costs will be allocated and collected prior to completion of the project.

g. The aforementioned Market Efficiency Project inclusion criteria shall be used for the exclusive purpose of determining whether projects are eligible for regional cost sharing in accordance with Section III.A.2.f below. These criteria shall not affect the existing criteria set forth in Appendix B of the ISO Agreement for determining whether projects are eligible for inclusion in the MTEP. Moreover, the costs of projects included in the MTEP, but not eligible for regional cost sharing, shall continue to be eligible for inclusion in the calculation of Transmission Owner revenue requirements under Attachment O of this Tariff.

C. Multi Value Projects: A Multi Value Project is one or more Network Upgrades that address a common set of Transmission Issues and satisfy the conditions listed in Sections II.C.1, II.C.2., and II.C.3 of Attachment FF. All Network Upgrades associated with a Multi Value Project including any lower voltage facilities that may be needed to relieve applicable reliability criteria violations that are projected to occur as a direct result of the development of the Multi Value Project; may be cost shared per Section III.A.2.g of Attachment FF except for i) any Network Upgrade cost associated with constructing an underground or underwater transmission line above and beyond the cost of a feasible alternative overhead transmission line that provides comparable regional benefits, and ii) any DC transmission line and associated terminal equipment when scheduling and dispatch of the DC transmission line is not turned over to the Transmission Provider's markets, real-time control of the DC transmission line is not turned over to the Transmission Provider's automatic generation control system and/or the DC transmission line is operated in a manner that requires specific users to subscribe for DC transmission service.

1. A Multi Value Project must be evaluated as part of a Portfolio of projects, as designated in the transmission expansion planning process, whose benefits are spread broadly across the footprint.

2. A Multi Value Project must meet one of the three criteria outlined below:

a. Criterion 1. A Multi Value Project must be developed through the transmission expansion planning process for the purpose of enabling the Transmission System to reliably and economically deliver energy in support of documented energy policy mandates or laws that have been enacted or adopted through state or federal legislation or regulatory requirement that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation. The MVP must be shown to enable the transmission system to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade.

b. Criterion 2. A Multi Value Project must provide multiple types of economic value across multiple pricing zones with a Total MVP Benefit-to-Cost ratio of 1.0 or higher where the Total MVP Benefit -to-Cost ratio is described in Section II.C.7 of this Attachment FF. The reduction of production costs and the associated reduction of LMPs resulting from a transmission congestion relief project are not additive and are considered a single type of economic value.

c. Criterion 3. A Multi Value Project must address at least one Transmission Issue associated with a projected violation of a NERC or Regional Entity standard and at least one economic-based Transmission Issue that provides economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs based on the definition of financial benefits and Project Costs provided in Section II.C.7 of Attachment FF.

3. All of the following conditions must be satisfied in order for a project to be classified as a Multi Value Project:

a. Facilities associated with the transmission project must not be in service, under construction, or approved for construction by the Transmission Provider Board prior to July 16, 2010 or the date a Transmission Owner becomes a signatory member of the ISO Agreement, whichever is later. This section II.C.3.a shall not preclude the Multi Value Project classification of an Open Transmission Project that makes a Selected Transmission Developer eligible to become a Transmission Owner.

b. The transmission project must be evaluated through the Transmission Provider's transmission planning process and approved for construction by the Transmission Provider Board prior to the start of construction, where construction does not include preliminary site and route selection activities.

c. The transmission project must not contain any transmission facilities listed in Attachment FF-1 of this Tariff.

d. The total capital cost of the transmission project must be greater than or equal to $20,000,000.00.

e. The transmission project must include, but not necessarily be limited to, the construction or improvement of transmission facilities operating at voltages above 100 kV. A transformer is considered to operate above 100 kV when at least two sets of transformer terminals operate at voltages above 100 kV.

f. Network Upgrades driven solely by an Interconnection Request, as defined in Attachment X of the Tariff, or a Transmission Service request will not be considered Multi Value Projects.

4. Any transmission project that qualifies as a Multi-Value Project shall be classified as an MVP irrespective of whether such project is also a Baseline Reliability Project and/or Market Efficiency Project.

5. The specific types of economic value provided by a Multi Value Project include the following:

a. Production cost savings where production costs include generator startup, hourly generator no-load, generator energy and generator Operating Reserve costs. Production cost savings can be realized through reductions in both transmission congestion and transmission energy losses. Productions cost savings can also be realized through reductions in Operating Reserve requirements within Reserve Zones and, in some cases, reductions in overall Operating Reserve requirements for the Transmission Provider.

b. Capacity losses savings where capacity losses represent the amount of capacity required to serve transmission losses during the system peak hour including associated planning reserve.

c. Capacity savings due to reductions in the overall Planning Reserve Margins resulting from transmission expansion.

d. Long-term cost savings realized by Transmission Customers by accelerating a long-term project start date in lieu of implementing a short-term project in the interim and/or long-term cost savings realized by Transmission Customers by deferring or eliminating the need to perform one or more projects in the future.

e. Any other financially quantifiable benefit to Transmission Customers resulting from an enhancement to the Transmission System and related to the provisions of Transmission Service.

6. Any project to facilitate like-for-like capital replacements of plant originally installed as part of a Multi Value Project where replacement is due to aging, failure, damage or relocation requirements where such replacement is not the result of negligence by the constructing Transmission Owner will be treated as a Multi Value Project. The minimum project cost limitation for Multi Value Projects described in Section II.C.3.d of Attachment FF will not apply to the like for- like capital replacement projects described in this Section.

7. The following Total MVP Benefit-to-Cost Ratio will be applied to any Multi Value Project justified solely on the basis of Sections II.C.2.b or II.C.2.c of this Attachment FF to ensure such project qualifies as a Multi Value Project:

Total MVP Benefit-to-Cost Ratio = financial benefits / Project Costs.

For the purpose of this calculation, Financial Benefits will be set equal to the present value of all financially quantifiable benefits provided by the project projected for the first 20 years of the project's life and Project Costs will be set equal to the present value of the annual revenue requirements projected for the first 20 years of the project's life.

8. The aforementioned Multi Value Project inclusion criteria shall be used for the exclusive purpose of determining whether projects are eligible for regional cost sharing in accordance with Section III.A.2.g below. These criteria shall not affect the existing criteria set forth in Appendix B of the ISO Agreement for determining whether projects are eligible for inclusion in the MTEP. Moreover, the costs of projects included in the MTEP, but not eligible for regional cost sharing, shall continue to be eligible for inclusion in the calculation of Transmission Owner revenue requirements under Attachment O of this Tariff.

D. Identification of Potential Impacts of a Market Efficiency Project or Multi Value Project on Neighboring Transmission Planning Region(s)

As part of the evaluation of any proposed Market Efficiency Project or Multi Value Project, the Transmission Provider will determine whether the proposed Market Efficiency Project or Multi Value Project causes any violations of NERC reliability standards on the transmission system(s) of the adjacent neighboring transmission planning region(s). If the Transmission Provider's evaluation identifies any such violations of NERC reliability standards, the Transmission Provider will contact and coordinate with the other potentially affected adjacent neighboring transmission planning region(s) on any further evaluation.

III. Designation of Cost Responsibility for MTEP Projects: Based on the planning analysis performed by the Transmission Provider, which shall take into consideration all appropriate input from Market Participants or external entities, including, but not limited to, any indications of a willingness to bear cost responsibility for an enhancement or expansion, the recommended MTEP shall, for any enhancement or expansion that is included in the plan, designate: (i) the Market Participant(s) in one or more pricing zones that will bear cost responsibility for such enhancement or expansion, as and to the extent provided by any applicable provision of the Tariff, including Attachments N, X, or any applicable cost allocation method ordered by the Commission; or, (ii) in the event and to the extent that no provision of the Tariff so assigns cost responsibility, the Market Participant(s) or Transmission Customer(s) in one or more pricing zones from which the cost of such enhancements or expansions shall be recovered through charges established pursuant to Attachment GG of this Tariff, or as otherwise provided for under this Attachment FF.

Any designation under clause (ii) of the preceding sentence shall be determined as provided for in Section III.A and III.B of this Attachment FF. For all such designations, the Transmission Provider shall calculate the cost allocation impacts to each pricing zone. The results will be reviewed for unintended consequences by the Transmission Provider and the Tariff Working Group and any such identified consequences shall be reported to the Planning Advisory Committee, and the OMS.

A. Allocation of Costs Within the Transmission Provider Region

1. Default Cost Allocation: Except as otherwise provided for in this Attachment FF, or by any other applicable provision of this Tariff and consistent with the ISO Agreement, the responsibility for Network Upgrades included in the approved MTEP will be addressed in accordance with the provisions of the ISO Agreement.

2. Cost Allocation: The Transmission Provider will designate and assign cost responsibility on a regional, and sub-regional basis for Network Upgrades identified in the MTEP subject to the grand-fathered project provisions of Section III.A.2.b.

   a. Market Participant's Option to Fund: Notwithstanding the Transmission Provider's assignment of cost responsibility for a project included in the MTEP, one or more Market Participants may elect to assume cost responsibility for any or all costs of a Network Upgrade that is included in the MTEP. Provided however, in the event the Market Participant is also a Transmission Owner such election of the option to fund must be made on a consistent, non-discriminatory basis.

   b. Grandfathered Projects: The cost allocation provisions of this Attachment FF shall not be applicable to transmission projects identified in Attachment FF-1, which is based on the list of projects designated as Planned Projects in the MTEP approved by the Transmission Provider Board on June 16, 2005 (MTEP 05) and some additions of proposed projects that the Transmission Provider has determined to be in the advanced stages of planning.

c. Baseline Reliability Projects: Costs of Baseline Reliability Projects shall be recovered pursuant to Attachment O of this Tariff by the Transmission Owner(s) and/or ITC(s) developing such projects, subject to the requirements of the ISO Agreement.

d. Generation Interconnection Projects: Costs of Generation Interconnection Projects that are not determined by the Transmission Provider to be Baseline Reliability Projects, Market Efficiency Projects, or Multi-Value Projects, and the Network Upgrade costs associated with advancing a Baseline Reliability Project, Market Efficiency Project, or Multi-Value Project associated with a generator interconnection will be paid for by the Interconnection Customer(s) in accordance with Attachment X. For Generation Interconnection Projects interconnecting to the American Transmission Company LLC transmission system, such costs will be subject to the provision of Attachment FF – ATCLLC.

1) For Network Upgrades to facilities in voltage classes at or above 345 kV, the Interconnection Customer shall be repaid 10 percent of the costs of the Generation Interconnection Project funded by the Interconnection Customer once Commercial Operation is achieved. The Transmission Owner(s) constructing the Generation

Interconnection Project will repay 10% of the Generation Interconnection Project costs associated with Network Upgrade facilities in a voltage class of 345 kV or greater to the Interconnection Customer under repayment terms consistent with the schedules and other terms of Attachment X.

The 10% of the Project Cost associated with Network Upgrade facilities of voltage class 345 kV or above and repaid to the Interconnection Customer shall be allocated on a system-wide basis and recovered pursuant to Attachment GG of this Tariff.

2) An Interconnection Customer may be required to contribute to the cost of Shared Network Upgrades, as defined in Attachment X to the Tariff, that are funded by another Interconnection Customer as a Generation Interconnection Project pursuant to Attachment X.

Each Interconnection Customer with one or more Shared Network Upgrade(s) identified in Appendix A of its Generator Interconnection Agreement shall make a one-time payment under Schedule 26-B to the Transmission Provider in accordance with the terms in the Generator Interconnection Agreement. The one-time payment will reflect the cost of the Shared Network Upgrade assigned to the Interconnection Customer as determined by the Transmission Provider.

All revenue collected by the Transmission Provider through Schedule 26-B shall be distributed to the appropriate Interconnection Customer(s).

3) The Interconnection Customer shall be entitled, pursuant to Section 46 of this Tariff, to any Financial Transmission Rights or other rights to the extent provided for under this Tariff, for any Network Upgrade costs funded by or charged to the Interconnection Customer and not subject to repayment under the provisions of this Section III.A.2.d. In the event that a Generation Interconnection Project defers or displaces a Baseline Reliability Project, the costs of the Generation Interconnection Project up to the costs of the deferred or displaced Baseline Reliability Project shall be allocated consistent with the cost allocation for the Baseline Reliability Project.

4) International Transmission/Michigan Electric Transmission Company:

(a) For those Generation Interconnection Projects for which International Transmission Company or Michigan

Electric Transmission Company, LLC, ("International" or "METC") as Transmission Owners will be a signatory to the interconnection agreement under the terms of Attachment X of this Tariff or any successor provision of the Tariff executed by the parties after the effective date of this Attachment FF Section III.A.2.d.4, this Attachment FF Section III.A.2.d.4 shall apply.

(b) Generation Interconnection Projects: The cost of Network Upgrades for Generation Interconnection Projects that are not determined by the Transmission Provider to be Baseline Reliability Projects shall be reimbursed by the Transmission Owner as provided in this Section III.A.2.d.4. All costs of Network Upgrades for Generation Interconnection Projects will initially be paid by the Interconnection Customer in accordance with the terms of the Interconnection Agreement entered into pursuant to Attachment X of this Tariff. To the extent the Interconnection Customer demonstrates at the time of Commercial Operation of the Generating Facility one of the following:

i. Generating Facility has been designated as a Network Resource in accordance with the Tariff, or

ii. Contractual commitment has been entered into with a Network Customer for capacity, or in the case of an Intermittent Resource, for energy, from the Generating Facility for a period of one (1) year or longer.

The Interconnection Customer will receive up to one hundred percent (100%) reimbursement of reimbursable costs within ninety (90) days of the Commercial Operation Date, such reimbursement prorated by the percentage of the Generating Facility capacity or annual available energy output contracted for and as demonstrated to the satisfaction of the Transmission Provider.

If the Interconnection Customer is unable to demonstrate to the satisfaction of the Transmission Provider at the time of Commercial Operation of the Generating Facility that the Generating Facility has met the repayment obligations set forth in Attachment FF Sections III.A.2.d.4.b.i. or III.A.2.d.4.b.ii. the Interconnection Customer shall be directly assigned 100% of the costs of the Generation Interconnection Project. The Transmission Owner may effect this direct assignment of costs by either foregoing any repayment of costs funded by the Interconnection Customer, or by electing to repay 100% of the costs under repayment terms consistent with the schedules and other terms of Attachment X.

The Interconnection Customer shall be entitled, pursuant to Section 46 of this Tariff, to any Financial Transmission Rights or other rights to the extent provided for under this Tariff, for any Network Upgrade costs funded by or charged to the Interconnection Customer and not subject to repayment under the provisions of this Attachment FF Section III.A.2.d.4. In the event that a Generation Interconnection Project defers or displaces a Baseline Reliability Project, the costs of the Generation Interconnection Project up to the costs of the deferred or displaced Baseline Reliability Project shall be allocated consistent with the cost allocation for the Baseline Reliability Project.

(c) For all amounts to be reimbursed by a Transmission Owner to an Interconnection Customer in accordance with this Attachment FF Section III.A.2.d.4, the Transmission

Owner will reimburse the sums received from the Interconnection Customer in cash together with any applicable interest, in accordance with the terms of the Interconnection Agreement.

(d) Allocation of Generation Interconnection Reimbursement. For all amounts reimbursed by a Transmission Owner to an Interconnection Customer under this Attachment FF Section III.A.2.d.4, the reimbursement will be allocated as follows:

i. Projects of Voltage Below 345 kV: 50% of the applicable Project Cost for Generation Interconnection Projects with a voltage class below 345 kV shall be allocated on a sub-regional basis to all Transmission Customers in designated pricing zones. The designated pricing zones and the sub-regional allocation of the Project Cost shall be determined on a case-by-case basis in accordance with a Line Outage Distribution Factor Table ("LODF Table") developed by the Transmission Provider which is similar in form to that attached hereto as Attachment FF-2. The

LODF Table is based on Transmission System topology and Line-Outage Distribution Factors associated with the project under consideration and is used to determine the pricing zones to be included in the sub-regional allocation of the Project Cost. The percentage of the sub-regional allocation assigned to each designated pricing zone shall be determined based on the relative share between pricing zones of the sum of the absolute value of the product of the Line-Outage Distribution Factor on each Branch Facility in a pricing zone and the length in miles of the Branch Facility.

The remaining fifty percent (50%) of the reimbursement will not be subject to any regional or sub-regional cost allocation, but will be recovered by that Transmission Owner under its Attachment O transmission rate formula under this Tariff.

ii. Projects of Voltage 345 kV and Higher: 10% of the applicable Project Cost for

Generation Interconnection Projects with a voltage class of 345 kV or higher shall be allocated on a system-wide basis to all Transmission Customers and recovered through a system-wide rate. 40% of the applicable Project Cost for Generation Interconnection Projects with a voltage class of 345 kV or higher shall be allocated on a sub-regional basis to all Transmission Customers in designated pricing zones. The designated pricing zones and the sub-regional allocation of the Project Cost shall be determined on a case-by-case basis in accordance with a Line Outage Distribution Factor Table ("LODF Table") developed by the Transmission Provider similar in form to that attached hereto as Attachment FF-2. The LODF Table is based on Transmission System topology and Line-Outage Distribution Factors associated with the project under consideration and is used to determine the pricing zones to be included in the sub-regional allocation of the Project Cost. The percentage of the sub-regional allocation assigned to each designated pricing zone shall be determined based on the relative share between pricing zones of the sum of the absolute value of the product of the Line-Outage Distribution Factor on each Branch Facility in a pricing zone and the length in miles of the Branch Facility.

The remaining fifty percent (50%) of the reimbursement will not be subject to any regional or sub-regional cost allocation, but will be recovered by that Transmission Owner under its Attachment O transmission rate formula under this Tariff.

e. Transmission Delivery Service Projects: Costs of Transmission Delivery Service Projects shall be assigned and recovered in accordance with Attachment N of this Tariff.

f. Market Efficiency Projects: Costs of Market Efficiency Projects shall be allocated as follows:

i) Twenty percent (20%) of the Project Cost of the Market Efficiency Project shall be allocated on a system-wide basis to all Transmission Customers and recovered through a system-wide rate.

ii) Eighty percent (80%) of the costs of the Market Efficiency Projects shall be allocated to all Transmission Customers in each of the Local Resource Zones, as defined in Attachment WW. The cost allocated to each Local Resource Zone shall be based on the relative benefit determined for each Local Resource Zone that has a positive present value of annual benefits over the evaluation period using the methodology for project benefit determination of Section II.B.1.

iii) Excessive Funding or Requirements: The Transmission Provider shall seek to identify and manage the development of, as a part of the planning process for Market Efficiency Projects, portfolios of projects that tend to provide benefits throughout each Local Resource Zone, as defined in Attachment WW, over the planning horizon. The Transmission Provider shall analyze on an annual basis whether the project portfolios developed in accordance with this goal and the criteria in Section III. A.2.f unintentionally result in unjust or unreasonable annual capital funding requirements for any Transmission Owner or rate increases for Transmission Customers in designated pricing zones; or otherwise result in undue discrimination between the Transmission Customers, Transmission Owners, or any Market Participants; any such identified consequences shall be reported to the Planning Advisory Committee and to the Organization of MISO States. After discussing such assessments with the aforementioned stakeholder bodies, and taking into consideration the cumulative experience in applying this Attachment FF, the Transmission Provider will make a determination as to whether Tariff modifications are required, and if so file such modifications.

g. Multi Value Projects: Costs of Multi Value Projects will be allocated as follows:

i) One-hundred percent (100%) of the annual revenue requirements of the Multi Value Projects shall be allocated on a system-wide basis to Transmission Customers that withdraw energy, including External Transactions sinking outside the Transmission Provider's region, and recovered through an MVP Usage Charge pursuant to Attachment MM.

h. Treatment of Projects that meet both Baseline Reliability Project Criteria and/or New Transmission Access Project Criteria, and the Market Efficiency Project Criteria: If the Transmission Provider determines that a project designated as a Market Efficiency Project also meets the criteria to be designated as a Baseline Reliability Project and/or a New Transmission Access Project, the cost of such project shall be allocated in accordance with the Market Efficiency Project allocation procedures.

i. Other Projects: Unless otherwise agreed upon pursuant to Section III.A.2.a. of this Attachment FF, the costs of Network Upgrades that are included in the MTEP, but do not qualify as Baseline Reliability Projects, New Transmission Access Projects, Market Efficiency Projects or Multi-Value Projects, shall be eligible for recovery pursuant to Attachment O of this Tariff by the Transmission Owner(s) and/or ITC(s) paying the costs of such project, subject to the requirements of the ISO Agreement.

j. Withdrawal from MISO: A Transmission Owner that withdraws from the MISO as a Transmission Owner shall remain responsible for all financial obligations incurred pursuant to this Attachment FF while a Member of the MISO and payments applicable to time periods prior to the effective date of such withdrawal shall be honored by the MISO and the withdrawing Member.

k. New Transmission Owners: A new Transmission Owner joining the MISO will be responsible for the following financial obligations:

a. New Transmission Owners will not be responsible for any portion of Baseline Reliability Projects, Generation Interconnection Projects, Transmission Delivery Service Projects, or Market Efficiency Projects that were approved prior to their entry date.

b. For Multi-Value Projects approved prior to the new Transmission Owner's entry date, the load interconnected to the Transmission Owner's Transmission System will be responsible for one-hundred percent (100%) of the MVP usage charge described in Attachment MM for the years following the Transmission Owner's entry date applied to the Monthly Net Actual Energy Withdrawals for Load interconnected to the Transmission Owner's Transmission System.

l. Only a Transmission Owner shall be authorized to construct and/or own transmission facilities associated with a Baseline Reliability Project, Market Efficiency Project and/or Multi Value Project. For projects jointly developed between Transmission Owners and other parties the portion constructed and owned by a Transmission Owner may qualify as a Baseline Reliability Project, Market Efficiency Project and/or Multi Value Project.

IV. Merchant Transmission Project Data Requirements: A proposed merchant transmission developer assumes all financial risk and funding requirements for developing its transmission project(s) and constructing the proposed transmission facility(ies). In order for a proposed merchant transmission developer's facility to be interconnected to the Transmission System, it is first necessary for the impacted Transmission Owner and the Transmission Provider to analyze the reliability and operational impact of the proposed new merchant transmission facility(ies) on the Transmission System to determine if the new merchant transmission facilities can be reliably supported by the Transmission System, and if not, what Network Upgrades funded by the merchant transmission developer would be required to reliably support the proposed merchant transmission facility(ies). In order to perform the required reliability and operational analyses, the merchant transmission developer must provide the following data to the Transmission Provider:

(1) Each transmission circuit and substation, including new facilities, associated with the merchant transmission proposal;

(2) Nominal operating voltage level in kV and voltage characteristics (*i.e.*, AC or DC) for each transmission circuit associated with the merchant transmission proposal;

(3) Typical and maximum MW power flow schedules, in each direction, for all proposed DC transmission circuits associated with the merchant transmission proposal;

(4) Normal and emergency summer and winter load ratings for each transmission circuit associated with the merchant transmission proposal;

(5) Maximum allowable positive sequence impedance for each AC transmission circuit associated with the merchant transmission proposal, when applicable;

(6) List of all transmission buses associated with the merchant transmission proposal, including nominal operating voltage level in kV, voltage characteristics, and terminating transmission branches and shunts;

(7) Proposed substation one-line diagrams for all new substations associated with the merchant transmission proposal, including circuit breaker and bus configuration details;

(8) Load ratings, winding connections, impedances, tap data, and any other relevant information for load carrying equipment and facilities associated with the merchant transmission proposal, as applicable;

(9) Modeling files to model proposed facilities and relevant new contingencies in power flow, stability, short-circuit and other relevant study models; and

(10) Any other data determined pertinent to the study by the Transmission Provider and/or interconnecting Transmission Owners for the specific merchant transmission facility proposal.

V. Designation of Entities to Construct, Implement, Own, Operate, Maintain, Repair, Restore, and/or Finance MTEP Projects: With the exception of Open Transmission Projects, for each project included in the recommended MTEP Appendix A and prior to approval by the Transmission Provider Board, the plan shall designate one or more Transmission Owners to construct, own, operate, maintain, repair, restore, and finance the recommended project, based on the planning analysis performed by the Transmission Provider and based on other input from participants, including, but not limited to, any indications of a willingness to bear cost responsibility for the project; and applicable provisions of the ISO Agreement. Regarding Open Transmission Projects, upon the determination of the Selected Transmission Developer for such projects, as set forth in Section VIII of this Attachment FF, the Transmission Provider shall update the approved MTEP Appendix A by identifying the Selected Transmission Developer for each Open Transmission Project. Should the facilities from such Open Transmission Projects not be approved by state regulatory authorities as New Transmission Facilities, but instead as upgrades to existing transmission facilities, as defined in Section VIII.C of this Attachment FF, the Transmission Provider shall update MTEP Appendix A by designating the appropriate Transmission Owner(s) to construct, own, operate, maintain, repair, restore, and finance such facilities in accordance with the ISO Agreement.

VI. Implementation of the MTEP:

A. If the Transmission Provider and any Transmission Owner's planning representatives, or other designated entity(ies), cannot reach agreement on any element of the MTEP, the dispute may be resolved through the dispute resolution procedures provided in the Tariff, or in any applicable joint operating agreement, or by the Commission or state regulatory authorities, where appropriate. The MTEP shall have as one of its goals the satisfaction of all regulatory requirements as specified in Appendix B or Article IV, Section I, Paragraph C of the ISO Agreement.

B. The Transmission Provider shall present the MTEP, along with a summary of relevant alternative projects that were not selected, to the Transmission Provider Board for approval on a biennial basis, or more frequently if needed. The proposed MTEP shall include specific projects already approved as a result of the Transmission Provider entering into Service Agreements with Transmission Customers where such agreements provide for identification of needed transmission construction, timetable, cost, and Transmission Owner or other parties' construction responsibilities.

C. Approval of the MTEP by the Transmission Provider Board certifies it as the Transmission Provider plan for meeting the transmission needs of all stakeholders subject to any required approvals by federal or state regulatory authorities. The Transmission Provider shall provide a copy of the MTEP to all applicable federal and state regulatory authorities. The affected Transmission Owner(s), Selected Transmission Developer(s), or other designated entity(ies), shall make a good faith effort to design, certify, and build the designated facilities to fulfill the approved MTEP. However, in the event that an MTEP Appendix A project approved by the Transmission Provider Board or the selection of the Selected Transmission Developer is being challenged through the dispute resolution procedures under this Tariff or in court proceedings, the obligation of the Transmission Owners, or other designated entity(ies), to build that specific project (subject to required approvals) is waived until the approved project emerges from the dispute resolution procedures. The Transmission Provider Board shall allow the Transmission Owners, or other designated entity(ies), to optimize the final design of specific facilities and their in-service dates if necessary to accommodate changing conditions, provided that such changes comport with the approved MTEP and provided that any such changes are accepted by the Transmission Provider through the reevaluation process described in Section VI of this Attachment FF, as necessary. Any disagreements concerning such matters shall be subject to the dispute resolution procedures of this Tariff.

D. The Transmission Provider shall assist the affected Owner(s), Selected Transmission Developer(s), or other designated entity(ies), in justifying the need for, and obtaining certification of, any facilities required by the approved MTEP by preparing and presenting testimony in any proceedings before state or federal courts, regulatory authorities, or other agencies as may be required. The Transmission Provider shall publish annually, and distribute to all Members and all appropriate state regulatory authorities, a five-to-ten-year planning report of forecasted transmission requirements. Annual reports and planning reports shall be available to the general public upon request.

VII. Multi-Value Project Costs and Benefits Review and Reporting

A. Frequency and Reporting of Multi-Value Project Review: Every three (3) years, as provided below and in the Business Practices Manual for Transmission Planning, the Transmission Provider shall conduct a review of the cumulative costs and benefits associated with MVPs, and shall disseminate the results of such reviews to its stakeholders. The Transmission Provider shall use the review process and results to identify potential modifications to the MVP methodology and its implementation for projects to be approved at a future date.

1. Triennial Full MVP Review: Beginning with the MTEP for 2014 (“MTEP 14”), and every third year thereafter, the Transmission Provider shall conduct a full MVP review, as provided in section VII.B of this Attachment FF.

2. Annual Limited MVP Review: Beginning with the MTEP for 2015 (“MTEP 15”),

and each year thereafter when there is no full MVP review, the Transmission Provider shall conduct a limited MVP review, as provided in section VII.C of this Attachment FF.

3. Calculation of Costs and Benefits: The Triennial Full MVP Reviews and the Annual Limited MVP Reviews shall calculate costs and benefits on a forward-looking basis over both twenty (20)-year and forty (40)-year periods. The costs calculation shall use updated project costs and in-service dates provided in the latest MTEP quarterly status report, and the benefits calculation shall use updated future scenarios from the latest MTEP planning cycle. The results of the costs and benefits calculation shall be provided for each Local Resource Zone as defined in RAR. If the Local Resource Zones as defined in accordance with RAR are modified, the Transmission Provider, working with stakeholders, may define different Local Resource Zones for purposes of reporting the results of the review. The definition of different Local Resource Zones in connection with reporting the results of the review will be detailed in the Business Practices Manual for Transmission Planning.

4. Dissemination of the Results of the Full and Limited MVP Reviews: Within a reasonable time after completion of each MVP review, the Transmission Provider shall disseminate the results of and supporting analysis for the MVP review through: (a) publication in the MTEP; (b) posting on the appropriate section of the Transmission Provider's public website; and (c) presentation to the appropriate stakeholder committees.

B. Scope of Full Multi-Value Project Review: Each full MVP review shall at a minimum include the following:

1. Quantitative Benefits: Analysis of the quantifiable economic benefits resulting from the addition of MVPs, including, but not limited to:

    a. Congestion and Fuel Savings: Savings from increased access to lower cost Resources;

    b. Decreased Operating Reserves: Savings associated with lower Operating Reserve requirements;

    c. Decreased System Planning Reserve Margin: Savings associated with deferred generation investment due to a reduction in the system-wide Planning Reserve Margin; and

    d. Decreased Transmission Line Losses: Savings associated with deferred generation investment due to a reduction in the Capacity required to serve transmission losses during peak hours, to the extent that MVPs reduce such losses.

2. Public Policy and Other Qualitative Benefits: Analysis of the public policy and other qualitative benefits accruing from MVPs, such as newly interconnected wind units; and an increase in the percentage of the Transmission Provider's Energy needs being supplied by wind and/or other renewable resources, and wind curtailments.

3. Historical Data: Provision, beginning with the MTEP for 2017 ("MTEP 17"), and based on the historical data available to the Transmission Provider for the five (5)

prior years, of information on certain additional market trend metrics including, but not limited to:

a. Congestion costs;

b. Energy prices;

c. Fuel costs;

d. Planning Reserve Margin requirements;

e. Number of newly interconnected Resources, by Resource type; and

f. The share of the Transmission Provider's Energy supplied, by Resource type.

C. Scope of Limited Multi-Value Project Review: Each limited MVP review shall at a minimum include the items described in Sections VII.B.1.a and VII.B.3 of this Attachment FF, as well as project costs and in-service dates, based on the latest available data for the current year, in preparation for the next full MVP review.

VIII. Transmission Developer Qualification and Selection

A. Upgrades to Existing Transmission Facilities. A Transmission Owner shall have the right to develop, own and operate any upgrade to a transmission facility owned by the Transmission Owner, in accordance with this Tariff and the ISO Agreement.

1.1 Upgrades to Existing Transmission Lines. Upgrades to existing transmission line facilities include any expansion, replacement or modification, for any purpose, made to existing transmission line facilities that are classified as transmission plant and owned by one or more Transmission Owners, for reasons including, but not limited to:

(a) increasing the load capability of the transmission line or an associated circuit;

(b) increasing the nominal operating voltage of the transmission line or an associated circuit;

(c) installing additional plant on an existing overhead or underground transmission line facility, such as, but not limited to:

i. plant associated with an additional circuit installed on spare structure positions;

ii. additional structures to increase a sag limit or for other purposes;

iii. a sectionalizing switch installed on an existing transmission line circuit regardless of whether or not it is installed on an existing structure; and

iv. any other plant additions to existing transmission line facilities.

(d) any requirement or request to relocate transmission line facilities owned by an incumbent Transmission Owner where the purpose of the relocation is not part of the core scope of an Open Transmission Project, including, but not limited to, relocations driven by aesthetics, highway expansion projects, other infrastructure expansion projects, projects to improve the reliability or performance of the Transmission System, projects to reduce the cost to operate and maintain the Transmission System, projects to interconnect new generation and load, and projects to accommodate the relocation of an existing substation;

(e) any requirement or request to relocate existing transmission line facilities owned by an incumbent Transmission Owner to accommodate New Transmission Line Facilities associated with an Open Transmission Project, where such construction of the New Transmission Line Facilities requires or requests use of the incumbent Transmission Owner's right-of-way and, as a result, also requires or requests transfer of the existing transmission facilities to alternative right-of-way or an alternative position on the same right-of-way based on either mutual consent of the incumbent Transmission Owner and Selected Transmission Developer and/or the outcome of a state regulatory proceeding or court action;

(f) functionally equivalent capital replacement of an entire existing transmission line facility, or any portion thereof, with a new transmission line facility due to aging, deterioration, damage, poor performance, aesthetics, high operating and maintenance costs, or other similar reasons;

(g) replacing one or more existing components of any existing transmission line facility, such as, but not limited to:

i. replacing existing conductors with higher capacity conductors or better performing conductors;

ii. replacing existing structures;

iii. replacing insulators rated at a specific voltage with insulators rated at a higher voltage;

iv. replacing aging or defective components associated with the existing transmission line;

(h) improving the performance or characteristics of the existing transmission line for any reason;

(i) converting an existing overhead transmission line to an underground transmission line on the same right-of-way and/or converting an existing underground transmission line to an overhead transmission on the same right-of-way;

(j) improving land and land rights booked under the Commission's Uniform System of Accounts, Account Nos. 105, 350, and/or 380; or

(k) any other modifications to existing transmission facilities.

1.1.1 Combination of Upgrades and New Facilities. If a proposed transmission project includes a combination of new transmission line sections and upgrades to existing transmission line sections, and the new transmission line sections are less than twenty (20) contiguous miles in total length, construction of the new transmission line sections will be considered a transmission upgrade for the purpose of retaining a right of first refusal. In either event, upgrades made to the existing transmission line sections will be considered transmission upgrades for the purpose of retaining a right of first refusal.

1.1.2 Installation of Additional Transmission Circuits on Existing Transmission Lines. If an Open Transmission Project includes developing a new transmission circuit and either the project scope or subsequent state or local regulatory proceedings determine that all or a portion of the circuit must be installed on an existing transmission line that is part of the Transmission System (i.e., co-located with existing transmission circuits on the same structures), the following rules will be used to determine what constitutes an upgrade:

a) If the structures associated with the existing transmission line are multi circuit structures and have spare positions to accommodate installation of one or more additional transmission circuit(s), installation of the new transmission circuit(s) on these spare structure positions will be considered an upgrade.

b) If the structures associated with the existing transmission line can be expanded to accommodate installation of one or more additional transmission circuit(s), expansion of the structure and installation of the new transmission circuit(s) will be considered an upgrade.

c) If the structures associated with the existing transmission line are not multi circuit structures and cannot be expanded to accept additional circuits, do not have sufficient spare structure positions available to accommodate the new transmission circuit(s), or have spare structure positions that are reserved for future use by the incumbent Transmission Owner and not available for the new transmission circuit(s) in question, it will be necessary to rebuild the existing transmission line to accommodate one or more additional transmission circuits. Under this scenario, acquisition of additional right-of-way (if necessary), removal of the existing transmission line plant, construction of new transmission line structures, and transfer or replacement of the existing transmission line conductors, insulators, and shield wires will be considered an upgrade. Installation of new conductors and insulators associated with the new transmission circuit(s) will not be considered an upgrade. Therefore, the incumbent Transmission Owner will have the right of first refusal to engineer, construct, own, operate, restore, maintain, and collect revenue on all transmission plant associated with rebuilding the existing transmission line that is booked to Account Nos. 350, 352, 353, 354, 355, 357, 359, and 359.1 of the Commission's Uniform System of Accounts in accordance with such Uniform System of Accounts. Furthermore, the incumbent Transmission Owner will have the right of first refusal to engineer, construct, own, operate, restore, maintain, and collect revenue on all plant associated with existing transmission circuits that is booked to Account Nos. 356 and 358 of the Commission's Uniform System of Accounts in accordance with such Uniform System of Accounts. In addition, the incumbent Transmission Owner will have the right of first refusal to engineer, construct, own, operate, maintain, and collect revenue on all shield wires associated with the existing transmission line that is booked to Account No. 356 of the Commission's Uniform System of Accounts in accordance with such Uniform System of Accounts, except for any shield wire that consists of fiber optic cable and is intended to facilitate communications to support protection of the new transmission circuit(s) where the associated protective relay schemes at all terminals associated with the new transmission circuit(s) will be owned by the Selected Transmission Developer in accordance with the provisions of Attachment FF that govern whether or not substation improvements are considered an upgrade. The Selected Transmission Developer will have the right to engineer, design, own, operate, restore, maintain, and collect revenue on all plant associated with the new transmission circuit(s) that is booked to Account Nos. 356 and 358 of the Commission's Uniform System of Accounts in accordance with such Uniform System of Accounts and any shield wire that consists of fiber optic cable and is intended to facilitate communications to support protection of the new transmission circuit(s) where the associated protective relay schemes at all terminals associated with the new transmission circuit(s) will be owned by the Selected Transmission Developer in accordance with the provisions of Attachment FF that govern whether or not substation improvements are considered an upgrade. In such cases where an incumbent Transmission Owner and a Selected Transmission Developer both own plant associated with a rebuilt existing transmission line, each party will have the right to allocate their respective costs (i.e., revenue requirements for its portion of the investment) in accordance with the cost allocation provisions of this Tariff for Multi Value Projects or Market Efficiency Projects as appropriate. Furthermore, such parties shall, in good faith, develop, negotiate, and execute a joint-use agreement for these facilities that governs responsibilities (including who incurs associated costs) for permitting, engineering, construction, operations, maintenance, restoration, and facility access and file such executed agreement with the Commission, and submit a copy to the Transmission Provider. However, there is no obligation on the incumbent Transmission Owner to provide project implementation and/or operations and maintenance services to the Selected Transmission Developer for the Selected Transmission Developer's portion of the facility, nor is there any obligation on the Selected Transmission Developer to provide project implementation and/or operation and maintenance services to the incumbent Transmission Owners for the incumbent Transmission Owner's portion of the facility, other than the mutual coordination of activities.

1.2 Upgrades to Existing Substations. Upgrades to existing substations include any expansions, replacements or modifications made, in part or in whole, to any existing substation or portion thereof that is owned by one or more Transmission Owners, and where some or all of the plant within the existing substation is classified as transmission plant. These upgrades include, but are not limited to:

(a) replacing facilities and/or equipment within an existing substation footprint;

(b) installing additional plant within an existing substation footprint;

(c) modifying facilities and/or equipment within an existing substation footprint;

(d) expanding an existing substation footprint within the existing substation site boundaries and installing additional plant within the expanded area;

(e) acquiring additional land adjacent to the existing substation in conjunction with installation of additional plant within the boundaries of this additional land, including facilities to interconnect such plant to the existing substation plant; and

(f) developing an additional footprint near the existing substation to facilitate effective expansion of the existing substation as further described below in section 1.2.2.

1.2.1 Construction of a new substation facility at the common junction point(s) of a transmission line containing more than two terminals or along an existing two terminal transmission line, where such transmission line facilities are owned by an incumbent Transmission Owner, for the purpose of implementing: i) transmission line protection system upgrades; ii) improving operational flexibility; iii) improving customer service reliability indices (*e.g.*, reducing SAIFI, CAIDI, SAIDI, etc.); iv) increasing the load capability of the transmission line; v) improving transmission voltages and reactive power management; vi) mitigating the economic and/or reliability impact of contingencies; and vii) any other purpose other than facilitating the interconnection of a New Transmission Line Facility will be considered a transmission upgrade for the purpose of retaining a right of first refusal. Furthermore, construction of a new substation for the purpose of interconnecting two or more existing transmission circuits where all such existing transmission circuits are owned by incumbent Transmission Owner(s) will be considered a transmission upgrade for the purpose of retaining a right of first refusal. Examples of newly constructed substations that will be considered transmission upgrades for the purpose of retaining a right of first refusal include, but are not limited to, i) circuit breaker substations installed along an existing two-terminal transmission line to improve operational flexibility or customer service reliability via automatic sectionalizing; ii) series capacitor substations installed within an existing transmission line to increase load capability; iii) circuit breaker switching substations installed at the common junction point of a three-terminal line to improve loading and protection capabilities of protective relay systems; and iv) newly constructed switching substation to interconnect two existing transmission circuits at the point where they physically cross each other where such existing transmission circuits are owned by the same Transmission Owner. Examples of new substation facilities that would not be considered transmission upgrades for the purpose of retaining a right of first refusal include, but are not limited to, i) a New Substation Facility proposed to interconnect three New Transmission Line Facilities; ii) a New Substation Facility proposed to facilitate connecting a 345 kV New Transmission Line Facility to the midpoint of an existing 345 kV transmission circuit owned by an incumbent Transmission Owner; and iii) a 765-345 kV New Substation Facility constructed to interconnect a 765 kV New Transmission Line Facility with an existing double circuit 345 kV transmission line, where such 345 kV double circuit transmission line is owned by incumbent Transmission Owner(s).

1.2.2 Construction of a new substation footprint near an existing substation to facilitate expansion of the existing substation is considered an upgrade and is necessary when the transmission project calls for expansion of the existing substation and there is not sufficient space for such expansion. Upgrades through development of a second substation footprint can be accomplished in one of two ways. First, a second substation footprint can be developed near the existing substation footprint, and the two substation footprints will function electrically as a single substation and will be interconnected by bus extensions or connectors. An example would be expanding an existing substation that is landlocked by public roadways by developing a second substation footprint on the other side of one of the roads and then installing an overhead single span connector which would function as a substation bus to interconnect the two substation footprints. Second, an existing substation could be retired for many reasons such as but not limited to: lack of room for future expansions, physical conditions such as soil subsidence, earthquake reinforcement requirements, to prevent flood damage, regulatory/public necessity/economic reasons, and other similar factors. A new substation could be developed nearby on a different site and all transmission circuits into the existing substation could be rerouted to the new site, which is essentially the relocation of an existing substation. These scenarios represent upgrades to an existing substation when the intent of the transmission project produced by the transmission planning process is to expand the existing substation rather than develop a new substation or to relocate an existing substation for reasons not related to implementation of a regionally cost shared transmission project.

B. Transmission Developer Qualification

(1) **Qualified Transmission Developers.** Except as provided in Section VIII.B.2.b, only Qualified Transmission Developers may submit New Transmission Proposals in response to Transmission Proposal Requests posted by the Transmission Provider for Open Transmission Projects. A Qualified Transmission Developer Applicant will be designated a Qualified Transmission Developer through an annual prequalification process. A Qualified Transmission Developer Applicant must be certified, by the

Transmission Provider, as a Qualified Transmission Developer at the time a Transmission Proposal Request is posted in order to be eligible to submit a New Transmission Proposal. The Transmission Provider will maintain a list of Qualified Transmission Developers on its website that will be updated within thirty (30) days of the conclusion of the annual prequalification process described in Section VIII.B.2 of this Attachment FF.

(2) **Prequalification Process.** The annual prequalification process will be used by the Transmission Provider to: i) process Transmission Developer Applications; ii) certify, as a Qualified Transmission Developer, each Qualified Transmission Developer Applicant that meets the qualification requirements; iii) remove Qualified Transmission Developers from the Qualified Transmission Developer list upon request to do so by such Qualified Transmission Developer; and iv) confirm that existing Qualified Transmission Developers continue to meet applicable eligibility requirements and remove them from the Qualified Transmission Developer list if they no longer meet eligibility requirements.

a) **New Qualified Transmission Developers.**

A. New Transmission Developer Application Submission. In January of each year, the Transmission Provider will post on its website an invitation and application template for prospective transmission developers that are not Qualified Transmission Developers to submit a Transmission Developer Application. Each Qualified

Transmission Developer Applicant must submit, by the deadline specified on the invitation, but no less than thirty (30) days from the date the invitation was posted, a Transmission Developer Application using the template posted with the invitation and further described in the applicable Business Practices Manuals. The Qualified Transmission Developer Applicant may submit its completed Transmission Developer Application via e-mail, conventional mail, or delivered by courier, but must be received by the Transmission Provider by 5:00 PM EPT on the day specified as the deadline. The Transmission Developer Application must be accompanied by a non-refundable application fee in the amount of $20,000.00 to cover the cost of processing, reviewing, and certifying the Qualified Transmission Developer Applicant as a Qualified Transmission Developer should all qualification requirements be satisfied. The information submitted in the Transmission Developer Application must provide all qualification data required per Sections VIII.B.3, VIII.B.4, VIII.B.5, VIII.B.6, and VIII.B.7 of this Attachment FF.

B. Transmission Developer Application Cure Period

To the extent the Transmission Provider finds the Transmission Developer Application deficient of data necessary to support all qualification requirements, the Transmission Provider will notify the applicant by e-mail within thirty (30) days of receipt and the Qualified

Transmission Developer Applicant will have thirty (30) days from notification to submit the additional data required. No additional cure period will be allowed for the purpose of gaining qualification.

C. Qualified Transmission Developer Certification Notification

The Transmission Provider will certify those Qualified Transmission Developer Applicants that meet the requirements for qualification and will notify a Qualified Transmission Developer Applicant of the Transmission Provider's decision within one-hundred eighty (180) days of receipt of each Transmission Developer Application, except in the first year of such process, in which case notification will be made within two-hundred seventy (270) days of receipt of each Transmission Developer Application.

D. New Qualified Transmission Developer Updates

The Transmission Provider will update, on the Transmission Provider's website, the list of Qualified Transmission Developers within thirty (30) days of providing notification to the applicants found to be qualified. If the Transmission Provider does not certify a Qualified Transmission Developer Applicant, it will provide the applicant with a written explanation detailing its determination within thirty (30) days after notification.

E. Qualification of Joint Ventures

A group of individual, certified Qualified Transmission Developers that desire to be certified as a joint venture eligible to be a Qualified Transmission Developer shall be automatically qualified if the joint venture of Qualified Transmission Developers: (i) provide the necessary guarantees to utilize their respective resources to support the joint venture and (ii) submit a Transmission Developer Application in accordance with this Section VIII of Attachment FF to seek official status as a Qualified Transmission Developer.

F. Authority to Certify Qualified Transmission Developers

The Executive Oversight Committee shall have the exclusive and final authority to approve or reject Transmission Developer Applications and certify Qualified Transmission Developers.

b) **Local Qualifications of Transmission Owners.**

A Transmission Owner is automatically qualified to submit New Transmission Proposals and be selected as the Selected Transmission Developer for any Open Transmission Project where each group of contiguous New Transmission Facilities associated with the Open Transmission Project connects to an existing transmission facility owned by the Transmission Owner.

c) **Retiring Qualified Transmission Developers.** A Qualified Transmission Developer that desires to terminate its status as a Qualified Transmission Developer may do so at any time by notifying the Transmission Provider. Upon such notification, the Transmission

Provider will update the Qualified Transmission Developer list within thirty (30) days of notification. A retired Qualified Transmission Developer may renew its status as a Qualified Transmission Developer by following the process outlined in Section VIII.B.2.a for Qualified Transmission Developer Applicants seeking Qualified Transmission Developer status in subsequent annual qualification processes.

d) **Renewing Qualified Transmission Developers.** In January of each year, at the time the Transmission Provider posts on its website an invitation for prospective transmission developers to submit Transmission Developer Applications, the Transmission Provider will also send a notification to each existing Qualified Transmission Developer requesting a confirmation that the Qualified Transmission Developer continues to meet the requirements for a Qualified Transmission Developer.

1. Qualified Transmission Developer Renewal Submission. In response to the renewal invitation, Qualified Transmission Developers must: (i) update data currently on file with the Transmission Provider regarding qualification requirements that were used previously to establish or confirm the entity as a Qualified Transmission Developer if such data has materially changed; (ii) explain how any changes to data currently on file with the Transmission Provider do not invalidate the Qualified Transmission Developer's status; and (iii) submit such updates, including a signed confirmation that the Qualified Transmission Developer still meets all qualification requirements, within sixty (60) days of the date the Transmission Provider requests such data.

2. Clarifications of Qualified Transmission Developer Renewal Submission.

The Transmission Provider may, if necessary, within sixty (60) days of receipt of a Qualified Transmission Developer renewal submission, request clarification or further explanation to ensure the Qualified Transmission Developer continues to meet the qualification requirements.

3. Notification of Qualified Transmission Developer Renewal.

The Transmission Provider will notify the Qualified Transmission Developer, within one-hundred eighty (180) days of the initial notification requesting the Qualified Transmission Developer to confirm it continues to meet qualification requirements, as to whether or not such entity continues to meet the requirements for qualification.

4. Requalification as a Qualified Transmission Developer.

In the event a Qualified Transmission Developer no longer meets the requirements to be certified as a Qualified Transmission Developer, such Qualified Transmission Developer may seek re-qualification during any subsequent annual qualification process as described in

Section VIII.B.2.a of this Attachment FF.

e) The Executive Oversight Committee has the exclusive authority to terminate a Qualified Transmission Developer.

(3) **General Requirements for Qualified Transmission Developers.** The general requirements applicable to Qualified Transmission Developers include the following agreements:

a. The Qualified Transmission Developer Applicant must be a Transmission Owner or Non-owner Member in good standing at the time the Transmission Developer Application is filed to seek certification as a Qualified Transmission Developer, and must maintain such status throughout the entire prequalification process.

b. The Qualified Transmission Developer Applicant must submit a written commitment, signed by an authorized representative of the Qualified Transmission Developer Applicant, to execute the ISO Agreement if designated as a Selected Transmission Developer for a future Open Transmission Project. Execution of the ISO Agreement must take place after the facilities have been constructed but prior to energization of such New Transmission Facilities, unless the Qualified Transmission Developer Applicant is already a Transmission Owner;

c. The Qualified Transmission Developer Applicant must submit a written commitment, signed by an authorized representative of the Qualified Transmission Developer Applicant, to comply with all

Applicable Laws and Regulations, codes, and standards governing the engineering, design, construction, operation, and maintenance of transmission facilities including, but not limited to, federal laws; applicable state and local laws; applicable state and local building codes; federal regulatory requirements; applicable state and local regulatory requirements; applicable state and local licensing authorities; the National Electric Safety Code; the National Electric Code; Applicable Reliability Standards; and Good Utility Practice should the Qualified Transmission Developer be selected in the future as a Selected Transmission Developer for one or more Open Transmission Projects;

d. The Qualified Transmission Developer Applicant must submit a written commitment, signed by an authorized representative of the Qualified Transmission Developer Applicant, to register with NERC as the transmission owner (TO), transmission operator (TOP), and transmission planner (TP), as defined by NERC, for all transmission facilities that are part of the Transmission System that the Qualified Transmission Developer, if selected as the Selected Transmission Developer for one or more current or future Open Transmission Projects, will own;

e. The Qualified Transmission Developer Applicant must submit a written commitment, signed by an authorized representative of the

Qualified Transmission Developer Applicant, that if selected as the Selected Transmission Developer, the Qualified Transmission Developer Applicant shall either i) contract with the interconnecting Local Balancing Authority (LBA) to include the New Transmission Facilities within the boundaries of the interconnecting LBA and demonstrate to the satisfaction of the Transmission Provider and per agreement by the interconnecting LBA that applicable LBA-related tasks associated with the proposed New Transmission Facilities that may be delegated to an LBA by the Balancing Authority Agreement will be carried out either by the LBA or the Qualified Transmission Developer Applicant if selected as a Selected Transmission Developer; or ii) execute the Balancing Authority Agreement, register with NERC as a Balancing Authority (BA), and be designated as the Local Balancing Authority for any proposed New Transmission Facilities, unless the Qualified Transmission Developer Applicant is already registered with NERC as a BA and designated as an LBA for one or more of the existing transmission facilities that may interconnect directly with any New Transmission Facilities associated with the Open Transmission Project(s) that the Qualified Transmission Developer may be awarded;

f. The Qualified Transmission Developer Applicant must make a written commitment, signed by an authorized representative of the Qualified

Transmission Developer Applicant, that, if selected as a Selected Transmission Developer, it shall comply with the FERC Form 715 Part 4 TRPC, Transmission Planning Criteria and Guidelines on file with FERC and established by each incumbent Transmission Owner whose existing transmission facilities will interconnect directly with the New Transmission Line Facilities and/or New Substation Facilities; and

g. The Qualified Transmission Developer Applicant must make a written commitment, signed by an authorized representative of the Qualified Transmission Developer Applicant, that, if it is selected as a Selected Transmission Developer, it shall comply with current requirements and standards regarding the interconnection of transmission facilities published by each Transmission Owner to which New Transmission Line Facilities and/or New Substation Facilities will interconnect including, but not limited to, those standards and requirements required for compliance with the applicable NERC Facilities Design, Connections, and Maintenance ("FAC") Reliability Standards.

4. **Project Implementation Requirements for Qualified Transmission Developers.** The project implementation requirements applicable to a Qualified Transmission Developer include submission of the following documentation by the Qualified Transmission Developer Applicant to

demonstrate to the Transmission Provider sufficient capabilities and competencies to implement Open Transmission Projects:

a) The Qualified Transmission Developer Applicant shall provide a document that describes its planned or proposed project implementation management teams and the types of resources, including relevant capability and experience (in-house labor, contractors, other transmission providers, etc.), contemplated for use in project management, route and site evaluation, regulatory permitting, engineering and design, land surveying, right-of-way and land acquisition, material and equipment procurement, construction, and project commissioning.

b) The Qualified Transmission Developer Applicant shall provide documentation of its record regarding project management, route and site evaluation, regulatory permitting, engineering and design, land surveying, right-of-way and land acquisition, material and equipment procurement, construction, and commissioning of transmission facilities, including facilities both inside and outside of the Transmission Provider's footprint. This documentation should include i) performance as a project manager; ii) performance in meeting project milestones; iii) performance in meeting estimated budgets; and iv) other applicable information.

c) The Qualified Transmission Developer Applicant shall provide job descriptions or résumés for key management personnel that will be involved in project management, route and site evaluation, regulatory permitting, engineering and design, land surveying, right-of-way and land acquisition, material procurement, construction and commissioning of transmission projects.

d) The Qualified Transmission Developer Applicant shall provide a document that outlines and describes its business practices related to project implementation and demonstrates how such business practices are consistent with Good Utility Practice to ensure proper project management, route and site evaluation, regulatory permitting, engineering and design, land surveying, right-of-way and land acquisition, material procurement, construction, and commissioning of transmission projects.

e) The Qualified Transmission Developer Applicant shall provide a document that describes its procedures and historical practices for acquiring rights-of-way and land and for managing rights-of-way and land acquisition for transmission projects. If the Qualified Transmission Developer Applicant does not have such procedures, it shall provide a detailed description of its plan for acquiring rights-of-way and land and for managing rights-of-way and land acquisition.

f) The Qualified Transmission Developer Applicant shall provide a document that describes its procedures and historical practices for mitigating the impact of transmission facilities on affected landowners and for addressing public concerns regarding transmission facilities. If the Qualified Transmission Developer Applicant does not have such procedures, it shall provide a detailed description of its plan for mitigating the impacts on affected landowners and addressing public concerns regarding the transmission projects.

g) The Qualified Transmission Developer Applicant shall provide a document describing its project cost monitoring, reporting, and containment capabilities that will be applied to any assigned transmission project.

h) Once a Qualified Transmission Developer, the Transmission Provider may require submission of additional data related to the policies, processes, methods, capabilities, experience, and past performance of New Transmission Proposal Applicants regarding project implementation when deemed necessary by the Transmission Provider, including aspects specific to the transmission project and/or locations in question as part of any Transmission Proposal Request. Furthermore, the Transmission Provider may require inclusion of additional information regarding project implementation capabilities, including but not limited to, existing capabilities and past experience regarding project implementation as part of any New Transmission Proposal.

i) An incumbent Transmission Owner is assumed to fulfill the project implementation requirements for Open Transmission Projects that connect to the incumbent Transmission Owner's system.

5. Operations, Maintenance, Repair, and Replacement Requirements for Qualified Transmission Developers. The operations, maintenance, repair, and replacement requirements applicable to a Qualified Transmission Developer include the submission of a document that demonstrates to the Transmission Provider that the Qualified Transmission Developer Applicant possesses sufficient capabilities and competencies to adequately perform the following operations, maintenance, testing, inspection, repair, and replacement tasks for any New Transmission Facilities associated with an Open Transmission Project once such facilities are in service and part of the Transmission System:

(1) Forced outage response for transmission line circuits;

(2) Forced outage response for substations;

(3) Switching for transmission line circuits;

(4) Switching for substations;

(5) Transmission line emergency repair;

(6) Substation emergency repair and testing;

(7) Transmission line preventative and/or predictive maintenance, including vegetation management;

(8) Substation preventative and/or predictive maintenance including equipment testing;

(9) Maintenance and management of spare parts, spare structures, and/or spare equipment inventories for substations and/or transmission lines, as applicable, including description of any agreements to share spare equipment, spare parts, and/or spare structures with other transmission entities;

(10) Real-time operations monitoring and control capabilities; and

(11) Major facility replacements or rebuilds required as a result of catastrophic destruction or natural aging through normal wear and tear, including financial strategy to facilitate timely replacements and/or rebuilds.

(12) Once a Qualified Transmission Developer, the Transmission Provider may require additional demonstration of qualifications to operate, maintain, restore, test, inspect, and replace specific New Transmission Facilities associated with specific Open Transmission Projects for a specific New Transmission Proposal.

(13) An incumbent Transmission Owner is assumed to fulfill the operations, maintenance, repair, and replacement requirements for

Open Transmission Projects that connect to the incumbent Transmission Owner's system.

6. Legal Requirements for Qualified Transmission Developers. The legal requirements for a Qualified Transmission Developer include submission of the following information and demonstration to the Transmission Provider that the information submitted represents an acceptable level of risk to rely on the Qualified Transmission Developer Applicant, if designated a Selected Transmission Developer, to successfully implement a transmission project and own and operate the associated transmission facilities once in service. The information submitted must include written certification signed by an authorized representative of the Qualified Transmission Developer Applicant stating that the submitted information is accurate:

a) A list of each state within the Transmission Provider footprint where the Qualified Transmission Developer Applicant is authorized to conduct business and demonstration of legal status of the entity in each state where the entity is authorized to conduct business. There must be at least one state within the Transmission Provider footprint where the Qualified Transmission Developer is legally qualified to conduct business. Once a Qualified Transmission Developer, the Transmission Provider may require additional information for each specific New Transmission Proposal submitted by the Qualified Transmission Developer to develop a specific Open Transmission Project to demonstrate appropriate legal status in states or localities where the New Transmission Facilities associated with the Open Transmission Project are to be constructed (e.g., state law may require the Qualified Transmission Developer to be legally qualified to conduct business in the state prior to soliciting business, including responding to a Transmission Proposal Request to develop new transmission facilities within the state, etc.).

b) A summary of legal and/or regulatory violations during the past five years or, if the Qualified Transmission Developer Applicant has been in business for less than five years, the number of years for which the Qualified Transmission Developer Applicant has been in business, by the Qualified Transmission Developer Applicant found by federal or state courts, federal regulatory agencies, state public utility commissions, other regulatory agencies, or attorneys general. This includes, but is not limited to, Federal Energy Regulatory Commission ("FERC"), North American Electric Reliability Corporation ("NERC") Reliability Standards, Securities Exchange Commission ("SEC") regulations, U.S. Commodity Futures Trading Commission ("CFTC") regulations, and other applicable requirements.

c) A summary of any and all instances in which the Qualified Transmission Developer Applicant is currently under investigation or is a defendant in a proceeding involving an attorney general or any state or federal regulatory agency, for violation of any laws, including regulatory requirements, during the past five years or, if the Qualified Transmission Developer Applicant has been in business for less than five years, the number of years for which the Qualified Transmission Developer Applicant has been in business. The Qualified Transmission Developer Applicant shall include an affidavit signed by an authorized officer of the Qualified Transmission Developer Applicant's company stating that the information in the submission is true and accurate and that the Qualified Transmission Developer Applicant will comply with all applicable requirements in this Tariff, the Business Practices Manuals, or other applicable Transmission Provider documents or agreements.

d) Each Qualified Transmission Developer Applicant has an ongoing duty to provide an update to the Transmission Provider as soon as reasonably practical should there be any material changes to its (or relevant parent's) information submitted in compliance with Section VIII.B.6 after its Transmission Developer Application is submitted.

7. **Financial Requirements for Qualified Transmission Developers.** The financial requirements for a Qualified Transmission Developer include submission of the following information and demonstration to the Transmission Provider that the information submitted represents an acceptable level of risk to rely on the Qualified Transmission Developer Applicant to successfully implement a transmission project and own and operate the associated transmission facilities once in service. The information submitted must include written

certification signed by an authorized representative of the Qualified Transmission Developer Applicant stating that the submitted information is accurate:

a) A proposed financial plan demonstrating adequate capital resources (e.g., current assets, revolving lines, commercial paper, letter of credit, stock or bond issuance or other sources of liquidity) are available to the Qualified Transmission Developer Applicant to allow for Open Transmission Projects to be implemented on schedule and associated New Transmission Facilities to be operated and maintained appropriately after the facilities are in service.

b) The credit rating(s) for the Qualified Transmission Developer Applicant from Moody's Investor Services, Inc., Standard and Poor's Rating Group and/or other Nationally Recognized Statistical Rating Organization ("NRSRO") as recognized by the Securities and Exchange Commission ("SEC"). Such credit rating information may pertain to a parent company in lieu of the Qualified Transmission Developer Applicant if the parent company is making a written guarantee, which must be included with the application. A written guarantee must be in a form acceptable to the Transmission Provider. Qualified Transmission Developer Applicants must demonstrate and maintain an investment grade rating at all times to remain on the list of certified entities. In the event the Qualified Transmission Developer Applicant is rated by more than one NRSRO, then the lowest rating will be the benchmark for consideration of demonstrating and maintaining an investment grade credit rating. For example, an investment grade rating is considered to be a rating of Baa3 or above from Moody's Investor Services, Inc. or BBB- or above from Standard and Poor's Rating Group (equivalent ratings will be used for other rating agencies). The focus of the review will be on the entity's unsecured, senior long-term debt ratings (not supported by third-party enhancements). If unsecured, senior long-term debt ratings are not available, the Transmission Provider may consider Issuer Ratings.

c) General financial information, including two years of audited financial statements with notes to the financials and a signed commitment by an authorized representative of the Qualified Transmission Developer Applicant that it is not aware of any material events or circumstances that would likely result in a material adverse weakness in financial strength throughout project implementation of future Open Transmission Projects that it might be awarded after it is certified as a Qualified Transmission Developer. This information may pertain to a parent company in lieu of the Qualified Transmission Developer Applicant if the parent company is making a written guarantee, which must be included with the Qualified Transmission Developer Application. A written guarantee must be in a form acceptable to the Transmission Provider.

d) A summary of any history of bankruptcy, dissolution, merger, or acquisition of the Qualified Transmission Developer Applicant, or any predecessors in interest for the current calendar year and the five calendar years immediately preceding its submission of the application. This information must also be submitted for any parent company that is making a written guarantee to satisfy the requirements in Section VIII.B.7.b and VIII.B.7.c above. A written guarantee must be in a form acceptable to the Transmission Provider.

e) Each Qualified Transmission Developer Applicant has an ongoing duty to provide an update to the Transmission Provider as soon as reasonably practical should there be any material changes to its (or relevant parent's) financial information submitted in compliance with Section VIII.B.7 after its Transmission Developer Application is submitted.

8. Confidential Treatment of Qualified Transmission Developer Applications. All information submitted with Transmission Developer Applications will be considered Confidential Information and will not be publicly posted or shared with any individual except employees of the Transmission Provider and/or contractors of the Transmission Provider that have executed an appropriate non-disclosure agreement.

9. Alternative Dispute Resolution. Any Qualified Transmission Developer Applicant who is not approved as a Qualified Transmission Developer may request alternative dispute resolution under Attachment HH of the Transmission Provider's Tariff within 30 calendar days of receiving from the Transmission Provider the written explanation of its decision to deny the application.

C. New Transmission Proposal Data Submission

1. Determination of Open Transmission Projects. Upon the Transmission Provider Board's approval of transmission projects for inclusion in Appendix A of the MTEP, the Transmission Provider will develop a separate Transmission Proposal Request for each Open Transmission Project. These Transmission Proposal Request(s) will be posted on the Transmission Provider website within thirty (30) calendar days of the date the Transmission Provider Board approved the Open Transmission Project for inclusion in Appendix A of the MTEP. Pursuant to Applicable Laws and Regulations, only New Transmission Facilities eligible under state law will be included in the Open Transmission Project.

2. Transmission Proposal Requests

a. Qualification to Submit New Transmission Proposals. Except as provided in Section VIII.B.2.b, New Transmission Proposals may be submitted only in response to a posted Transmission Proposal Request and only by entities that are Qualified Transmission Developers.

b. Transmission Proposal Request Deposit. The New Transmission Proposal Applicant will submit an initial deposit of $100,000.00 with each New Transmission Proposal. The Transmission Provider shall evaluate all New Transmission Proposals submitted in response to each Transmission Proposal Request together and track all time and expenses specifically associated with the evaluation of all such

New Transmission Proposals. The Transmission Proposal Request deposits of all New Transmission Proposal Applicants will be applied equally to the cost of evaluating all the New Transmission Proposals. Any shortfall associated with evaluation of the New Transmission Proposals submitted in response to each Transmission Proposal Request will be billed by the Transmission Provider on a pro rata basis to each New Transmission Proposal Applicant. Each New Transmission Proposal Applicant shall be responsible for paying its pro rata share of any shortfall to the Transmission Provider within thirty (30) days of receiving notice of the shortfall. Any funds remaining after the evaluation of all New Transmission Proposals submitted in response to a Transmission Proposal Request, including refunds to New Transmission Proposal Applicants who are judged unqualified by the Transmission Provider, shall be refunded on a pro rata basis to each New Transmission Proposal Applicant within thirty (30) days following the designation of the Selected Transmission Developer, including interest payable at a rate consistent with 18 CFR § 35.19a.

c. Minimum Contents of Transmission Proposal Requests. The Transmission Proposal Request will specify i) each New Transmission Line Facility and/or each New Substation Facility associated with the Open Transmission Project that should be included in the New Transmission Proposal; ii) the date by which the New Transmission

Proposal must be submitted to the Transmission Provider, which shall not exceed one-hundred eighty (180) calendar days from the posting of the Transmission Proposal Request; iii) a list of the current transmission facility interconnection standards and requirements established by the Transmission Owner(s) to which the New Transmission Line Facilities and/or New Substation Facilities will interconnect; and iv) additional requirements or qualification criteria of a specific state(s) related to specific New Transmission Facilities to be located within that state's(s') boundaries.

i. Furthermore, where it involves one or more New Transmission Line Facilities, the Transmission Proposal Request will specify for each New Transmission Line Facility, at a minimum:

(1) Expected in-service date;

(2) Implementation schedule indicating the required steps to develop and construct the Open Transmission Project, including, but not limited to, all required regulatory approvals;

(3) Nominal operating voltage level in kV and voltage characteristics (*i.e.*, three-phase AC, bipolar DC, etc.) for each transmission circuit;

(4) Terminating substations and buses for each transmission circuit;

(5) Minimum required normal and emergency load ratings for both summer and winter seasons for each transmission circuit; and

(6) Maximum allowable positive sequence impedance for each transmission circuit when determined applicable by planning studies performed by the Transmission Provider.

ii. Where it involves one or more New Substation Facilities, the Transmission Proposal Request will specify for each New Substation Facility, at a minimum, the following information:

(1) Expected in-service date;

(2) Implementation schedule indicating the required steps to develop and construct the Open Transmission Project, including, but not limited to, all required regulatory approvals;

(3) List of all transmission buses within the New Substation Facility, including nominal operating voltage level in kV and voltage characteristics;

(4) List of all major equipment and facilities within the

New Substation Facility and associated terminating buses including power transformers, voltage regulators, phase angle regulators, series reactors, series capacitors, shunt reactors, shunt capacitors, static VAR compensators, DC converters, transmission line circuit terminals, generator terminals, and loads;

(5) Limitations on and/or requirements for bus configurations when determined applicable by planning studies performed by the Transmission Provider including required load ratings of circuit breakers, disconnects, bus sections and other load carrying equipment under alternative bus configurations;

(6) Required load ratings for all load carrying equipment and facilities identified in item (4) above;

(7) Winding connection and tap requirements for power transformers, voltage regulators, phase angle regulators and load tap changers when determined necessary by planning studies performed by the Transmission Provider;

(8) Impedance requirements for power transformers,

phase angle regulators, series reactors and series capacitors when determined necessary by planning studies performed by the Transmission Provider; and

(9) Limitations on and/or requirements for protection systems when determined applicable by a planning driver or Applicable Reliability Standard or in order to ensure a compatible interconnection with existing protection systems associated with existing transmission facilities to which the New Transmission Facilities will interconnect.

d. Other Requirements of Transmission Proposal Requests. The Transmission Provider reserves the right to specify in Transmission Proposal Requests, if deemed necessary and/or appropriate, additional information for any specific New Transmission Line Facilities and/or New Substation Facilities.

3. Contents of New Transmission Proposals. New Transmission Proposal Applicants that submit a New Transmission Proposal in response to a Transmission Proposal Request must submit all data required by the Transmission Proposal Request, including, but not limited to:

a. A detailed project implementation schedule for each New Transmission Facility, driven by the required in-service date, which must include proposed schedules for route and site evaluation, regulatory permitting, land acquisition, engineering and design, land surveying, material procurement, construction, and commissioning for all New Transmission Facilities;

b. Cost estimate data for each proposed New Transmission Line Facility and/or New Substation Facility;

c. Reasonably descriptive facility design proposals for each New Substation Facility and/or New Transmission Line Facility included in the Open Transmission Project;

d. Documentation of project implementation capabilities relative to the applicable locations and jurisdictions where the New Transmission Facilities will be constructed;

e. Documentation of operations, maintenance, repair, and replacement capabilities relative to the applicable locations and jurisdictions where the New Transmission Facilities will be constructed; and

f. Modeling data files for all proposed New Transmission Line Facilities and/or New Substation Facilities included in the Open Transmission Project.

5. **Cost Estimates.** Proposed cost estimate data must be based on the reasonably descriptive facility design proposals submitted in the New Transmission Proposal and will include, at a minimum:

a) Estimated project cost for each proposed New Transmission Line Facility and/or New Substation Facility; and

b) Estimated annual revenue requirements for the first 40 years the facilities included in the New Transmission Proposal will be in service in accordance with Attachment MM of the Tariff for Multi Value Projects and Attachment GG of the Tariff for Market Efficiency Projects, including the supporting detail on the annual allocation factors for operations and maintenance, general and common depreciation expense, taxes other than income taxes, income taxes, and return used to estimate the annual revenue requirements.

6. Reasonably Descriptive Facility Design Proposals. Reasonably descriptive facility design proposals must be submitted for each New Transmission Line Facility and/or New Substation Facility included in the Open Transmission Project. Reasonably descriptive facility design proposals represent descriptions of the core attributes and features of a design, not the detailed engineering and design calculations and documents.

a. **Reasonably Descriptive Facility Design Proposals for New Transmission Facilities.** For each New Transmission Line Facility, reasonably descriptive facility design proposals must include, at a minimum:

(1) Estimated length of New Transmission Line Facility in miles and basis for estimate;

(2) Proposed conductor type, size, and, if applicable, bundling configuration;

(3) Proposed default or typical structure design attribute(s) (*e.g.*, steel vs. wood vs. aluminum vs. concrete, monopole vs. H-frame vs. lattice, single circuit vs. double circuit, self-supporting vs. guyed, structural calculation assumptions, etc.) to be used for tangent, running angle, in-line dead-end, and angle dead-end structures when feasible and/or for the majority of the New Transmission Line Facility;

(4) Estimated positive sequence line impedance and pi-equivalent shunt susceptance;

(5) Calculated normal and emergency seasonal thermal loading ratings, including basis for calculations;

(6) Proposed type of lightning protection system to be used when feasible and/or for the majority of the New Transmission Line Facility (*e.g.*, shield wires vs. surge arresters, etc.) and key attributes (*e.g.*, shielding angle, arrester location and type, etc.);

(7) Proposed grounding method to be used when feasible and/or for the majority of the New Transmission Line Facility (*e.g.*, ground rods only, counterpoise, etc.) and key attributes (*e.g.*, targeted structure footing grounding resistance, etc.);

(8) Proposed method to address or mitigate adverse impacts of galloping conductors and/or Aeolian vibration, if any (*e.g.*, Stockbridge dampers, special conductors, etc.);

(9) Continuous rating of any load carrying switchgear installed on the New Transmission Line Facility; and

(10) Assumed communications systems to be used for the New Transmission Line Facility to facilitate protective relaying (*e.g.*, fiber optic, power line carrier, microwave, etc.).

b. **Reasonably Descriptive Facility Design Proposals for New Substation Facilities.** For New Substation Facilities, reasonably descriptive facility design proposals must include, at a minimum:

(1) Detailed one-line diagram;

(2) Proposed protection systems including protection schemes, any anticipated interaction with existing/other facilities and conceptual protection system design (including backup protection systems, if applicable). Remote system monitoring capability shall be described with major features listed (redundancy, monitored parameters, etc.);

(3) Detailed specifications for proposed power transformers;

(4) Description of other substation equipment items, including load ratings, voltage ratings, fault interrupting ratings, tap data, and impedances as applicable, where other substation equipment

includes, but is not limited to, bus sections, circuit breakers, circuit switchers, switches, disconnects, regulating transformers, station service transformers, series and shunt capacitors, series and shunt reactors, static VAR compensators, DC conversion equipment, instrument transformers (metering and relaying), wave traps, and surge arresters;

(5) Proposed line terminal ratings and basis for calculation, including limiting element;

(6) Basis for load rating calculations on any equipment where nameplate continuous ratings are not used; and

(7) Description of the communication system for remote monitoring, control and data acquisition facilities, including monitoring and control points.

Any specific Transmission Proposal Request may require submission of additional facility design data when deemed necessary by the Transmission Provider. Any New Transmission Proposal may also include additional facility data, including but not limited to, optional facility design data listed in the Business Practices Manual for Transmission Planning, which may be considered by the Transmission Provider in the evaluation and selection of New Transmission Proposals.

7. **Project Implementation Capabilities Relative to Specific Open Transmission Project.** Documentation of project implementation capabilities required in a New Transmission Proposal must include a description of existing and/or planned/proposed capabilities to be used by the New Transmission Proposal Applicant to perform the following tasks in the locations and jurisdictions where the New Transmission Facilities associated with the Open Transmission Project are to be located:

a) Project management;

b) Routing evaluation studies for New Transmission Line Facilities, if applicable;

c) Site evaluation studies for New Substation Facilities, if applicable;

d) Regulatory permitting;

e) Right-of-way acquisition for New Transmission Line Facilities, if applicable;

f) Land acquisition for New Substation Facilities, if applicable;

g) Engineering and surveying required for New Transmission Line Facilities and/or New Substation Facilities;

h) Material procurement for New Transmission Line Facilities and/or New Substation Facilities;

i) Construction of New Transmission Line Facilities and/or New Substation Facilities; and

j) Commissioning of New Transmission Line Facilities and/or New Substation Facilities.

Any specific Transmission Proposal Request may require submission of additional data related to the policies, processes, methods, capabilities, experience, and past performance of New Transmission Proposal Applicants regarding project implementation when deemed necessary by the Transmission Provider.

Any New Transmission Proposal may also include additional information regarding project implementation capabilities, including but not limited to, existing capabilities and past experience regarding project implementation, which may be considered by the Transmission Provider in the evaluation and selection of New Transmission Proposals.

An incumbent Transmission Owner is assumed to fulfill the project implementation requirements for Open Transmission Projects that connect to the incumbent Transmission Owner's system.

8. Operations, Maintenance, Repair, and Replacement Capabilities.

Documentation of operations, maintenance, repair, and replacement capabilities required in a New Transmission Proposal must include a description of existing capabilities and/or planned/proposed capabilities to be used by the New Transmission Proposal Applicant, and documented processes and methods to be used by the New Transmission Proposal Applicant to perform the following tasks in the locations and jurisdictions where the New Transmission Facilities associated with the Open Transmission Project are to be located:

a) Forced outage response for transmission line circuits;

b) Forced outage response for substations;

c) Switching for transmission line circuits;

d) Switching for substations;

e) Transmission line emergency repair;

f) Substation emergency repair and testing;

g) Transmission line preventative and/or predictive maintenance, including vegetation management;

h) Substation preventative and/or predictive maintenance including equipment testing;

i) Maintenance and management of spare parts, spare structures, and/or spare equipment inventories for substations and/or transmission lines, as applicable, including description of any agreements to share spare equipment, spare parts, and/or spare structures with other transmission entities;

j) Real-time operations monitoring and control capabilities, if the Open Transmission Project contains one or more New Substation Facilities; and

k) Major facility replacements or rebuilds required as a result of catastrophic destruction or natural aging through normal wear and tear, including financial strategy to facilitate timely replacements and/or rebuilds.

Any specific Transmission Proposal Request may require submission of additional data related to the policies, processes, methods, capabilities, experience, and past performance of entities regarding operations, maintenance, repair, and replacement when deemed necessary by the Transmission Provider. Additional information regarding operations, maintenance, repair, and replacement capabilities may also be included in any New Transmission Proposal, including but not limited to, existing capabilities and past experience regarding operations, maintenance, repair and replacement, which may be considered by the Transmission Provider in the evaluation and selection of New Transmission Proposals.

An incumbent Transmission Owner is assumed to fulfill the operations, maintenance, repair, and replacement requirements for Open Transmission Projects that connect to the incumbent Transmission Owner's system.

9. Transmission Provider Planning Process Participation Documentation.

While not required, should a New Transmission Proposal Applicant participate in the Transmission Provider planning process and desire to have such participation considered in the evaluation as described in Section VIII.G of this Attachment FF, the New Transmission Proposal Applicant should include in its New Transmission Proposal documentation regarding relevant planning studies performed by the New Transmission Proposal Applicant and results supplied to the Transmission Provider planning process, as well as documentation on past transmission project ideas submitted by the New Transmission Proposal Applicant to the Transmission Provider to address the same Transmission Issues being addressed by the Open Transmission Project for which the New Transmission Proposal is being submitted.

10. **Modeling Data.** Modeling data files submitted with the New Transmission Proposal must meet the requirements outlined in the Business Practices Manual for Transmission Planning, including, at a minimum, data files necessary:

I. To model New Transmission Line Facilities and/or New Substation Facilities in power flow and short-circuit models and

II. To model new contingencies associated with New Transmission Lines Facilities and/or New Substation Facilities.

11. **Period for Submission of New Transmission Proposals.** New Transmission Proposals must be submitted within 180 calendar days from the date the Transmission Proposal Request is posted, or within the time period specified in the Transmission Proposal Request, whichever comes first. If the due date falls on a federal holiday, Saturday, or Sunday, the New Transmission Proposals will be due on the next business day. Two copies of the New Transmission Proposal in hard copy form must be delivered to the address specified in the Transmission Proposal Request no later than 5:00 PM EPT on the due date and one electronic copy of the New Transmission Proposal must be e-mailed to the e-mail address specified in the Transmission Proposal Request no later than 5:00 PM EPT on the due date. Any inquiries by New Transmission Proposal Applicants regarding a Transmission Proposal Request prior to submission of a New Transmission Proposal should be made directly with the contacts listed in the Transmission Proposal Request and not to the interconnecting incumbent Transmission Owners.

12. **Additional Data Requests.** If, during the evaluation of New Transmission Proposals, the Transmission Provider determines that additional information is required to evaluate the New Transmission Proposals, the Transmission Provider will request, in writing, the additional data from all New Transmission Proposal Applicants, along with the timeframe that this data must be submitted within. If the additional data is not submitted within the specified timeframe, the New Transmission Proposal will not be evaluated or considered further. This timeframe will not be less than ten (10) business days from when the Transmission Provider issues the additional data request. This data request will not extend the evaluation timeframe defined in Section VIII.E.

13. **Confidential Treatment of New Transmission Proposals.** All information submitted with the New Transmission Proposal will be considered Confidential Information and will not be publicly posted or shared with any individual except employees of the Transmission Provider and/or contractors of the Transmission Provider that have executed an appropriate non-disclosure agreement.

D. Cure Period. Immediately after the date New Transmission Proposals are due, the Transmission Provider will review each New Transmission Proposal to ensure the New

Transmission Proposal Applicants are Qualified Transmission Developers and that all data requirements have been satisfied by each respective New Transmission Proposal Applicant. Should a New Transmission Proposal fail to satisfy one or more of the data requirements specified in this Tariff and/or in the Transmission Proposal Request, the Transmission Provider will, within ten (10) business days, via e-mail notify the submitting New Transmission Proposal Applicant, through the contact person designated in the New Transmission Proposal, of any deficiency. The New Transmission Proposal Applicant will have a single Cure Period of ten (10) business days from this notice to revise and resubmit the New Transmission Proposal to address the deficiency, except that if the New Transmission Proposal Applicant is not a Qualified Transmission Developer or otherwise qualified in Section VIII.B.1.b on the date the Transmission Proposal Request was posted, or ceases to be a Qualified Transmission Developer after the date the Transmission Proposal Request was posted, the New Transmission Proposal will not be evaluated or considered further. If a revised New Transmission Proposal is submitted after the Cure Period has elapsed, or continues to have one or more deficiencies with regard to qualifications or data requirements, the New Transmission Proposal will not be evaluated or considered further. The Transmission Provider will provide a written explanation identifying why the New Transmission Proposal has been disqualified.

E. Evaluation

1. **Steps of Evaluation and Selection Process.** Upon receipt of all New Transmission Proposals, sufficient in form and substance, by the due date specified in the Transmission Proposal Request, and upon completion of

the process outlined in Section VIII.D of this Attachment FF, the Transmission Provider will:

a) Evaluate each New Transmission Proposal submitted by a Qualified Transmission Developer;

b) Select one of the New Transmission Proposals for implementation based on application of the evaluation criteria below; and

c) Post the name of the Selected Transmission Developer on its website within 180 calendar days of the due date for the submission of New Transmission Proposals.

2. **General Criteria.** In evaluating each New Transmission Proposal, the Transmission Provider will consider the following general aspects of the proposal:

a) Cost and reasonably descriptive facility design quality;

b) Project implementation capabilities;

c) Operations, maintenance, repair, and replacement capabilities; and

d) Transmission Provider planning process participation.

3. **Cost and Reasonably Descriptive Facility Design.** When considering cost and reasonably descriptive facility design quality, the Transmission Provider shall evaluate, at a minimum:

a) Estimated project cost for each proposed New Transmission Line Facility and/or New Substation Facility;

b) Estimated annual revenue requirements for all New Transmission Facilities included in the New Transmission Proposal;

c) Description of capital resources available to fund project costs as they arise;

d) Cost estimate rigor, which shall include financial assumptions and supporting information to clearly demonstrate a thorough analysis in support of the cost estimate;

e) Reasonably descriptive facility design quality; and

f) Reasonably descriptive facility design rigor, which shall include facility studies performed and other specific supporting data that clearly documents and supports consideration and attention given to the proposed reasonably descriptive facility designs.

4. **Project Implementation Capabilities.** When considering project implementation capabilities, the Transmission Provider shall evaluate, at a minimum, existing or planned capabilities, competencies, and processes regarding the following project implementation categories relative to the locations and jurisdictions where the New Transmission Facilities associated with the Open Transmission Project are to be located as well as the strength of the project implementation capabilities, including financial measures, demonstrated in the prequalification process to qualify the New Transmission Proposal Applicant as a Qualified Transmission Developer:

a) Project management;

b) Route and site evaluation;

c) Land acquisition;

d) Engineering and surveying;

e) Material procurement;

f) Facility construction;

g) Final facility commissioning; and

h) Previous applicable experience and demonstrated ability.

5. **Operations, Maintenance, Repair, and Replacement Capabilities.**

When considering operations, maintenance, repair and replacement capabilities, the Transmission Provider shall evaluate, at a minimum, existing or planned capabilities, competencies, and processes regarding the following operations and maintenance categories relative to the locations and jurisdictions where the New Transmission Facilities associated with the Open Transmission Project are to be located as well as the strength of the operation and maintenance capabilities demonstrated in the prequalification process to qualify the New Transmission Proposal Applicant as a Qualified Transmission Developer, as applicable, based on the types of facilities included in the Transmission Proposal Request:

a) Forced outage response;

b) Switching;

c) Emergency repair and testing;

d) Spare parts;

e) Preventative and/or predictive maintenance and testing;

f) Real-time operations monitoring and control; and

g) Major facility replacement capabilities, including ongoing financial capabilities to restore facilities after catastrophic outages.

6. **Transmission Provider Planning Process Participation.** When considering transmission provider planning process participation, the Transmission Provider will consider relevant planning studies conducted by the Qualified Transmission Developer and the associated results supplied to the Transmission Provider planning process, as well as transmission project ideas submitted in the past by the Qualified Transmission Developer as potential solutions to address the same Transmission Issues addressed by the Open Transmission Project.

7. **General Criteria Weighting.** In evaluating each New Transmission Proposal, the Transmission Provider will apply the following weighting to each New Transmission Facility criteria evaluated:

a) **New Transmission Line Facilities.** The following weights will be applied to New Transmission Line Facility criteria:

i. Cost and reasonably descriptive facility design quality: 30%

ii. Project implementation capabilities: 35%

iii. Operations, maintenance, repair, and replacement capabilities: 30%

iv. Transmission Provider planning process participations: 5%

b) **New Substation Facilities.** The following weights will be applied to New Substation Facility criteria:

i. Cost and reasonably descriptive facility design quality: 30%

ii. Project implementation capabilities: 30%

iii. Operations, maintenance, repair, and replacement capabilities: 35%

iv. Transmission Provider planning process participations: 5%

8. **Evaluation and Selection.** Specific methods used to evaluate various aspects of a New Transmission Proposal shall be described in the Business Practices Manual for Transmission Planning. This evaluation will be conducted by Transmission Provider planning staff and/or independent consultants competent in the areas of finance, transmission facility design, transmission project implementation, and transmission operations, maintenance, repair, and replacement. The Transmission Provider planning staff, and any independent consultants, will be overseen by the Executive Oversight Committee, which will have exclusive and final authority to determine Selected Transmission Developers. Within thirty (30) calendar days of the designation of the Selected Transmission Developer, the Transmission Provider will provide a report in which it explains the basis for designating the Selected Transmission Developer for each Open Transmission Project. The Transmission Provider will include in this report a date(s) by which state approval(s) to construct must be achieved based upon when construction must begin to timely meet the Transmission Issue to be addressed by the Open Transmission Project(s)

and taking into account the project implementation schedule(s) provided by the Selected Transmission Developer in its New Transmission Proposal. Any disputes regarding the developer selection will be referred to the Dispute Resolution Process under Attachment HH of this Tariff.

The Selected Transmission Developer will assume the responsibility and obligation to construct the facilities it is selected to construct. If the Selected Transmission Developer is financially incapable of carrying out its construction responsibilities, alternate construction arrangements shall be identified. Depending on the specific circumstances, such alternate arrangements shall include solicitation of Transmission Owners to take on financial and/or construction responsibilities. If the delay in construction may adversely affect the Transmission System reliability, the Transmission Provider shall coordinate with and support the affected Transmission Owner(s) regarding any mitigation measures that may be required by Applicable Reliability Standards.

However, in the event that an MTEP Appendix A Open Transmission Project approved by the Transmission Provider Board or selection of the designated Selected Transmission Developer to construct the approved project is being challenged through the Dispute Resolution process under Attachment HH of this Tariff or a court proceeding, the obligation of the Selected Transmission Developer to build the specific Open Transmission Project (subject to required approvals) is waived until the Open

Transmission Project or Selected Transmission Developer emerges from the Dispute Resolution process or court proceedings as an approved project with a Selected Transmission Developer designated to construct, implement, own, operate, maintain, repair, restore, and/or finance the recommended Open Transmission Project.

9. **Recourse if No New Transmission Proposals are Received or Selected.** The Transmission Provider may decline to accept any or all New Transmission Proposals that do not meet the Tariff's requirements for the project classification in question or will not sufficiently address the Transmission Issue(s) the Transmission Proposal Request was intended to address. If no New Transmission Proposals are received from Qualified Transmission Developers or selected by the Transmission Provider, the Open Transmission Project will be assigned to the applicable Transmission Owner(s), as defined below:

(1) Ownership and the responsibility to construct facilities which are connected to a single Transmission Owner's system belong to that Transmission Owner;

(2) Ownership and the responsibilities to construct facilities which are connected between two (2) or more Transmission Owners' facilities belong equally to each Transmission Owner, unless such Transmission Owners otherwise agree; and

(3) Ownership and the responsibility to construct facilities which are connected between a Transmission Owner(s)' system and a system or systems that are not part of the Transmission Provider belong to such

Transmission Owner(s) unless the Transmission Owner(s) and the non-Transmission Provider party or parties otherwise agree.

IX. Reevaluation. After Transmission Provider Board MTEP Appendix A approval, certain circumstances or events may significantly affect such an Open Transmission Project in a manner and to a degree that would require the Transmission Provider to perform Variance Analysis. Such circumstances or events may include, but are not limited to: material schedule delays, cost increases, or changes to the Selected Transmission Developer's qualifications, as compared to the schedule, cost estimates, and qualifications represented in the New Transmission Project Proposal and/or MTEP Appendix A, as applicable. The Variance Analysis shall consider, among other things: (i) causes of, or reasons for, any such circumstance or event; (ii) impacts, including potential reliability impacts of a delay in the Open Transmission Project, canceling the Open Transmission Project, or replacing the Selected Transmission Developer; (iii) mitigation measures and responsibilities; and (iv) solutions, and the timetable for the implementation of such solutions. This process will begin at assignment of an Open Transmission Project and end when construction begins.

a. Grounds for Variance Analysis

The following factors shall trigger the Transmission Provider's Variance Analysis for an Open Transmission Project. The Variance Analysis will focus on the materiality of the changes identified and determine the need for full reevaluation.

1. Cost Increases

Any project cost increase which reduces the benefit-cost ratio of an economically-driven Open Transmission Project to less than the required benefit-to-cost threshold, as defined in Section II.B.1.e or Section II.C.7 of this Attachment FF of the Tariff.

2. Schedule Delays

A reported or otherwise identified delay of 6 months or more from the in-service date established in MTEP Appendix A and agreed upon in the accepted New Transmission Proposal and Binding Proposal Agreement of any assigned Open Transmission Project. This analysis may also be based upon failure to obtain necessary regulatory approvals; failure to execute necessary agreements; or failure to take the actions described in the Selected Transmission Developer's accepted New Transmission Proposal.

3. Deviation From Selected Transmission Developer Qualifications

Material changes in the condition and characteristics of the Selected Transmission Developer, as described in its accepted New Transmission Proposal.

Material changes in this subsection may include, but are not limited to, any delegation or assignment not described in the New Transmission Proposal of project responsibilities to another entity, including affiliates, or a partner that is either previously undisclosed, or disclosed but assigned to or designated for different responsibilities or failure to conform to the terms described in the Selected Transmission Developer's accepted New Transmission Proposal.

b. Project Reevaluation

If required by the results of the above-described additional analysis, the Transmission Provider shall perform a reevaluation of the Open Transmission Project and/or Selected Transmission Developer, including, but not limited to:

1. **Cost Increases**

   As applicable and necessary based upon the Variance Analysis, the Transmission Provider shall use the Open Transmission Project's current cost estimate to perform an analysis and determine if said Open Transmission Project's currently estimated benefit is sufficient to justify its continued construction.

2. **Schedule Delays**

   As necessary based upon the Variance Analysis, the Transmission Provider shall perform an analysis to determine if the delay in the achievement of any significant schedule milestone(s) (including, but not limited to, failure to obtain necessary regulatory approvals) will delay the applicable Open Transmission Project's in-service date, and if so, whether such delay poses risks of adverse impacts on Transmission System reliability, and what mitigation measures and plan should be implemented.

3. **Deviation From Selected Transmission Developer Qualifications**

   As necessary based upon the Variance Analysis, the Transmission Provider shall perform an analysis to determine if the Selected Transmission Developer remains qualified to construct, implement, operate, maintain, and/or restore the Open Transmission Project.

c. Reevaluation Outcomes

Based on all the required analysis described in subparagraphs a and b of this section, the Transmission Provider may decide to (i) make no change to the Open Transmission Project; (ii) reassign the Open Transmission Project to a different Qualified Transmission Developer; (iii) cancel the Open Transmission Project (iv) implement a reliability mitigation plan, in coordination with the affected Transmission Owner(s); or (v) such other remedy or solution as may be appropriate under the circumstances, including a suitable combination of two or more of the foregoing courses of action.

1. Reassignment

If a Selected Transmission Developer is found to no longer be a Qualified Transmission Developer, the applicable Open Transmission Project may be reassigned. Open Transmission Projects will be offered to the applicable Transmission Owner, as defined below:

(1) Ownership and the responsibility to construct facilities which are connected to a single Transmission Owner's system belong to that Transmission Owner; (2) Ownership and the responsibilities to construct facilities which are connected between two (2) or more Owners' facilities belong equally to each Transmission Owner, unless such Transmission Owners otherwise agree; and (3) Ownership and the responsibility to construct facilities which are connected between a Transmission Owner(s)' system and a system or systems that are not part of the Transmission Provider belong to such Transmission Owner(s) unless the Transmission

Owner(s) and the non-Transmission Provider party or parties otherwise agree.

If the applicable Transmission Owner(s) decline to construct the Open Transmission Project, it will be reassigned, as applicable, through the developer evaluation process, as described in Section VIII.F.

2. Project Cancellation

Following reevaluation, the Transmission Provider may cancel economically-driven Open Transmission Projects if (1) cost increases reduce the benefit-cost ratio to the point where the currently estimated cost exceed previously defined benefits; and (2) reliability and/or public policy benefits (if any), are insufficient to justify continuation and completion of the project.

3. Reliability Mitigation Plan

If the Transmission Provider's analysis determines that Transmission System reliability may be adversely affected by the delay of an assigned Open Transmission Project, the Transmission Provider shall coordinate with and support the affected Transmission Owner(s) regarding any mitigation measures that may be required by Applicable Reliability Standards. The mitigation measures may include, without limitation, any one or combination of the following components: i) an updated implementation plan of the Selected Transmission Developer to meet the required in-service date; ii) an operating procedure; or iii) an alternative project to mitigate the reliability violation.

ATTACHMENT FF-1

List of Planned Projects to be Excluded from Regional Cost Allocation

Reporting Source	Pro- ID	Estimated Cost	Project Description	MTEP 05 Status	Fac- ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
ALT	90	$8,000,000	Emery – Lime Creek 161 ckt 2, Sum rate 326	Planned	189	Emery	Lime Creek	2	161		1-Jun-06
ALT	93	$6,200,000	Poweshiek – Reasnor 161 ckt 1, Sum Rate 326	Planned	187	Poweshiek	Reasnor	1	161		1-Jun-05
ALT	588	$411,940	Asbury – Lore 161 kV line	Planned	660	Asbury	Lore	1	161		1-Jun-05
Ameren	77	$28,776,100	Callaway – Franks	Planned	46	Callaway	Franks	1	345		1-Dec-06

Reporting Source	Pro-ID	Estimated Cost	Project Description	MTEP 05 Status	Fac-ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
			345 kV line								
Ameren	78	$13,297,900	Jefferson City Area Development (Moreau – Apache Flats 161, Loose Creek – Jefferson City 345, Jefferson City 345/161 tx)	Planned	50	Moreau	Apache Flats	1	161		1-Jun-07
Ameren	78	$7,242,200	Jefferson City Area Development	Planned	59	Loose Creek	Jefferson City	1	345		1-Jun-07

		(Moreau – Apache Flats 161, Loose Creek – Jefferson City 345, Jefferson City 345/161 tx)							
Ameren	78 $4,677,200	Jefferson City Area Planned Development (Moreau – Apache Flats 161, Loose Creek – Jefferson City 345, Jefferson City 345/161 tx)	65	Jefferson City 345/161	transformer	1	345	161	1-Jun-07
Ameren	87 $12,102,400	St. Francois – Planned Rivermines 138 ckt 3, Sum rate 418	53	St. Francois	Rivermines	3	138		1-Jun-05
Ameren	88 $8,468,800	Tazewell – E. Planned Springfield 138 kV line rebuild	42	Tazewell	E. Springfield	1	138		28-Feb-05

Reporting Source	Pro- ID Estimated Cost	Project Description MTEP 05 Status	Fac- ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
Ameren	126 $2,581,200	Rivermines – Planned Clark 138 ckt 1, Sum rate 418	29	Rivermines	Clark	1	138		1-Jun-05
Ameren	127 $447,500	Newton Plant – Planned breaker replacements (2), 138 ckt, Sum rate	41	Newton Plant	breaker replacements (2)		138		1-Jun-05
Ameren	128 $289,300	California – Planned Barnett 161 ckt 1, Sum rate 180	45	California	Barnett	1	161		1-Jun-05

Ameren	129 $635,300	Conway – breaker Planned additions 138 ckt, Sum rate	49	Conway	breaker additions		138	1-Jun-06
Ameren	130 $618,300	Warson – breaker Planned additions 138 ckt, Sum rate	54	Warson	breaker additions		138	1-Jun-06
Ameren	131 $904,600	Kansas West – Planned Sidney (breaker addition at Kansas) 345 ckt 1, Sum rate	387	Kansas West	Sidney (breaker addition at Kansas)	1	345	1-Jun-05
Ameren	132 $540,300	Paxton – Paxton Planned East (reconductor) 138 ckt 1, Sum rate	389	Paxton	Paxton East (reconductor)	1	138	1-Jun-05

Reporting Source	Pro-ID	Project Description	Fac-ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD	Estimated Cost	MTEP 05 Status
Ameren	133	Cahokia – Meramec (reconductor) 138 ckts 1 & 2, Sum rate 473	43	Cahokia	Meramec (reconductor)	1	138		1-Jun-06	$1,287,200	Planned
Ameren	133	Cahokia – Meramec (reconductor) 138 ckts 1 & 2, Sum rate 473	44	Cahokia	Meramec (reconductor)	2	138		1-Jun-06	$1,287,200	Planned
Ameren	135	Campbell – Maline (reconductor) 138 ckts 1 & 2, Sum rate 478	47	Campbell	Maline (reconductor)	1	138		1-Jun-06	$712,150	Planned
Ameren	135	Campbell – Maline (reconductor) 138 ckts 1 & 2, Sum rate 478	48	Campbell	Maline (reconductor)	2	138		1-Jun-06	$712,150	Planned

Reporting Source	Project ID	Estimated Cost	Project Description	MTEP 05 Status	Fac-ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
Ameren	138	$762,650	Roxford – Mississippi Tap (reconductor) 138 ckts 1 & 2, Sum rate 418	Planned	63	Roxford	Mississippi Tap (reconductor)	1	138		1-Jun-06
Ameren	138	$762,650	Roxford – Mississippi Tap (reconductor) 138 ckts 1 & 2, Sum rate 418	Planned	64	Roxford	Mississippi Tap (reconductor)	2	138		1-Jun-06
Ameren	140	$5,461,700	Newton – Effingham (reconductor) 138 ckt 1, Sum rate 351	Planned	390	Newton	Effingham (reconductor)	1	138		1-Jun-06
Ameren	143	$427,200	Cahokia – N. Coulterville 230 ckt 1,	Planned	56	Cahokia	N. Coulterville	1	230		1-Jun-07

		Sum rate 353							
Ameren	144 $2,466,500	Crab Orchard – Planned Marion South (reconductor) 138 ckt 1, Sum rate 351	392	Crab Orchard	Marion South (reconductor)	1	138		1-Jun-07
Ameren	145 $3,282,100	Havana – Ipava Planned (reconductor) 138 ckt 1, Sum rate 212	393	Havana	Ipava (reconductor)	1	138		1-Jun-06
Ameren	149 $502,900	Mason – Sioux Planned (breaker addition at Mason) 345 ckt 1, Sum rate	397	Mason	Sioux (breaker addition at Mason)	1	345		1-Jun-07
Ameren	155 $12,597,700	Joachim 345/138 Planned ckt 1, Sum rate 560	401	Joachim 345/138 kV	transformer	1	345	138	1-Jun-07

Ameren	704 $413,500	Grand Tower – Planned Carbondale, Northwest 138 ckt 1	1395	Grand Tower	Carbondale, Northwest	1	138		1-Jun-05
Ameren	705 $1,316,600	Kinmundy – Planned Louisville (increase ground clearance) 138 ckt 1	1396	Kinmundy	Louisville (increase ground clearance)	1	138		1-Jun-05
Reporting **Source**	**Pro-** **Estimated** **ID** **Cost**	**Project** **MTEP 05** **Description** **Status**	**Fac-** **ID**	**From Sub**	**To Sub**	**Ckt**	**Line** **or** **HS** **kV**	**LS** **kV**	**Expected** **ISD**
Ameren	707 $167,400	Adair (install breaker Planned for Thomas Hill Line) – install 161 kV breaker at Adair 161	1398	Adair (install breaker for Thomas Hill Line)	install 161 kV breaker at Adair		161		1-Jun-06
Ameren	708 $350,100	Casey – Breed Planned (reconductor riv.	1399	Casey	Breed (reconductor	1	345		1-Jun-06

		crossing) 345 ckt 1			riv. crossing)				
Ameren	709	Frederick – Meredosia	1400	Frederick	Meredosia	1	138		1-Jun-06
	$704,600	Planned							
		(increase ground			(increase ground				
		clearance) 138 ckt 1			clearance)				
Ameren	710	Kinmundy – Salem	1401	Kinmundy	Salem	1	138		1-Jun-06
	$604,200	Planned							
		(increase ground			(increase ground				
		clearance) 138 ckt 1			clearance)				
Ameren	711	Wood River – Gillespie	1402	Wood River	Gillespie	1	138		1-Jun-07
	$800,000	Planned							
		(reconductor) 138 ckt 1			(reconductor)				
Ameren	712	Mason – Labadie Mason-3	1403	Mason	Labadie-Mason-3	1	345		1-Jun-07
	$177,500	Planned							
		term. equipment			term. equipment				
		replacement 345 ckt 1			replacement				
Ameren	713	Meramec Plant –	1404	Meramec Plant	replace 4-138 kV breakers		138		1-Jun-07
	$947,600	Planned							
		replace 4-138 kV breakers							

Reporting Source	Project ID / Estimated Cost	Project Description / MTEP 05 Status	Facility ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
Ameren	715 $62,050	Wildwood – Gray Summit Planned (reconductor) 138 ckt 1	1406	Wildwood	Gray Summit (reconductor)	1	138		1-Jun-07
Ameren	716 $62,050	Wildwood – Gray Summit Planned (reconductor) 138 ckt 2	1407	Wildwood	Gray Summit (reconductor)	2	138		1-Jun-07
Ameren	717 $5,000	Conway – Orchard Planned Gardens (increase ground clearance) 138 ckt 1	1408	Conway	Orchard Gardens (increase ground clearance)	1	138		1-Jun-08
Ameren	718 $5,000	Conway – Orchard Planned Gardens (increase ground clearance) 138 ckt 2	1409	Conway	Orchard Gardens (increase ground clearance)	2	138		1-Jun-08
Ameren	720 $576,900	Page Substation – Planned replace 3-138 kV breakers	1411	Page Substation	replace 3-138 kV breakers		138		1-Jun-08

AmerenIP	542 $500,000	South Street sub 138 Planned kV 50 MVAR capacitor	3096	Kewanee South St.	capacitor		138		1-Jun-05
AmerenIP	724 $1,900,000	Rising (138 kV breaker Planned addition) – Bondville Rt. 10 138 ckt 1	1417	Rising (138 kV breaker addition)	Bondville Rt. 10	1	138		1-Jun-06
AmerenIP	725 $13,300,000	N. LaSalle (138 kV Planned breaker addition) – N. Ottawa (new 3 terminal ring bus) 138 ckt 1	1418	N. LaSalle (138 kV breaker addition)	N. Ottawa (new 3 terminal ring bus)	1	138		1-Jun-07
AmerenIP	726 $2,000,000	N. Ottawa – Ottawa Planned (2 new 138 kV breakers) 138 ckt 1	1419	N. Ottawa	Ottawa (2 new 138 kV breakers)	1	138		1-Jun-07
Reporting **Source**	**Pro-** **Estimated** **ID** **Cost**	**Project** **MTEP 05** **Description** **Status**	**Fac-** **ID**	**From Sub**	**To Sub**	**Ckt**	**Line** **or** **HS** **kV**	**LS** **kV**	**Expected** **ISD**

AmerenIP	727 $4,000,000	N. Ottawa – Wedron Planned 138 ckt 1	1420	N. Ottawa	Wedron	1	138	1-Jun-07
AmerenIP	733 $424,000	Cuba Switching Station Planned – Galesburg Monmouth Blvd. (install breaker between taps to tfr 1 & tfr 5) 138 ckt 1	1426	Cuba Switching Station	Galesburg Monmouth Blvd. (install breaker between taps to tfr 1 & tfr 5)	1	138	1-Jun-05
AmerenIP	738 $1,500,000	Line 1342C tap – Line Planned 1342A (structure 423 to 467A reconductor) 138 ckt 1	1431	Line 1342C tap	Line 1342A (structure 423 to 467A reconductor)	1	138	1-Jun-06
AmerenIP	785 $500,000	Oglesby 138 kV 54 Planned MVAR capacitor	3097	Oglesby	capacitor		138	1-Jun-05
AmerenIP	786 $400,000	South Ottawa 138 kV Planned	3098	South Ottawa	capacitor		138	1-Jun-05

Reporting Source	Project ID	Estimated Cost	Project Description	MTEP 05 Status	Fac-ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
			30 MVAR capacitor								
ATC LLC	1	$2,300,00	Arrowhead – Gardner Park 345 kV line	Planned	121	Dewey Tap	Weston		115		1-Jun-06
ATC LLC	1	$1,100,000	Arrowhead – Gardner Park 345 kV line	Planned	127	Northpoint	Dewey Tap		115		1-Jun-06
ATC LLC	1	$364,645,723	Arrowhead – Gardner Park 345 kV line	Planned	135	Arrowhead	Gardner Park	1	345		30-Jun-08
ATC LLC	1	$12,992,000	Arrowhead – Gardner Park 345 kV line	Planned	136	Gardner Park (was Weston) 345-115	transformer	1	345	115	1-Jun-06
ATC LLC	1	$12,992,000	Arrowhead – Gardner	Planned	137	Gardner Park	transformer	2	345	115	1-Jun-06

		Park 345 kV line		(was Weston) 345-115					
ATC LLC	1 $13,741,773	Arrowhead – Gardner Planned	318	Arrowhead	phase-shifter	1	230	230	30-Jun-08
		Park 345 kV line		230-230 kV					
ATC LLC	1 $10,400,000	Arrowhead – Gardner Planned	319	Arrowhead	transformer	1	345	230	30-Jun-08
		Park 345 kV line		345/230 kV					
ATC LLC	1 $0	Arrowhead – Gardner Planned	472	Gardner Park	Weston	1	115		1-Jun-06
		Park 345 kV line		(new Weston)					
ATC LLC	1 $0	Arrowhead – Gardner Planned	473	Gardner Park	Weston	2	115		1-Jun-06
		Park 345 kV line		(new Weston)					
ATC LLC	1 $0	Arrowhead – Gardner Planned	1454	Highway V	Preble		138		1-Dec-05
		Park 345 kV line		(5 ohm reactor)					
ATC LLC	1 $1,858,227	Arrowhead – Gardner Planned	2039	Arrowhead	capacitor		230		30-Jun-08
		Park 345 kV line							

Reporting Source	Pro- Estimated ID Cost	Project MTEP 05 Description Status	Fac- ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
ATC LLC	1 $882,714	Arrowhead – Gardner Planned Park 345 kV line	2042	Gardner Park (was Weston)	capacitor bank		115		30-Jun-08
ATC LLC	11 $8,900,000	Rhinelander 115 kV Planned loop short-term solution	97	Skanawan	Highway 8	2	115		1-Jun-05
ATC LLC	12 $6,900,00	West Marinette – Planned Menominee – Rosebush – Amberg 138 ckt (convert/rebuild), Sum rate 477	599	West Marinette (double ckt 69/138)	Menominee	1	138		1-Jun-05
ATC LLC	12 $11,400,000	West Marinette – Planned Menominee – Rosebush – Amberg 138 ckt	600	Menominee	Rosebush (convert)		138		1-Jun-05

		(convert/rebuild), Sum rate 477					
ATC LLC	12 $6,800,000	West Marinette – Planned Menominee – Rosebush – Amberg 138 ckt (convert/rebuild), Sum rate 477	601	Rosebush	Amberg (rebuild)	138	1-Jun-05
ATC LLC	15 $7,500,000	Plains – Amberg – Planned Stiles 138 kV line rebuild	116	Amberg	Plains (rebuild)	138	1-Aug-05
ATC LLC	15 $7,500,000	Plains – Amberg – Planned Stiles 138 kV line rebuild	117	Amberg	Crivitz (rebuild)	138	1-Jun-06
ATC LLC	15 $7,500,000	Plains – Amberg – Planned Stiles 138 kV line rebuild	120	Crivitz	Stiles (rebuild)	138	1-Jun-06
ATC LLC	15 $7,500,000	Plains – Amberg – Planned	128	NOW	Amberg	138	1-Jun-06

		Stiles 138 kV line rebuild			(rebuild)				
Reporting Source	Pro- ID Estimated Cost	Project MTEP 05 Description Status	Fac- ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
ATC LLC	15 $7,500,000	Plains – Amberg – Planned Stiles 138 kV line rebuild	129	Plains	NOW (rebuild)		138		1-Jun-06
ATC LLC	15 $7,500,000	Plains – Amberg – Planned Stiles 138 kV line rebuild	133	Stiles	Amberg (rebuild)		138		1-Jun-06
ATC LLC	22 $7,420,000	Femrite – Sprecher 138 Planned (new), Sprecher – Reiner 138 (conversion), Reiner – Sycamore 138 (conversion)	123	Femrite	Sprecher (new 138 kV)	1	138		1-Jun-07
ATC LLC	22 $1,250,000	Femrite – Sprecher 138 Planned (new), Sprecher – Reiner 138 (conversion), Reiner – Sycamore 138 (conversion)	131	Reiner	Sycamore (conversion to 138 kV)		138		1-Jun-07

ATC LLC	22	$1,250,000	Femrite – Sprecher 138 (new), Sprecher – Reiner 138 (conversion), Reiner – Sycamore 138 (conversion)	Planned	132	Sprecher	Reiner (conversion to 138 kV)		138		1-Jun-07
ATC LLC	62	$1,500,000	Wien – Stratford – McMillan 115 ckt, Sum rate 202	Planned	108	Stratford	McMillan		115		1-May-05
ATC LLC	62	$1,500,000	Wien – Stratford – McMillan 115 ckt, Sum rate 202	Planned	110	Wien	Stratford		115		1-May-05

Reporting Source	Pro- ID	Estimated Cost	Project Description	MTEP 05 Status	Fac- ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
ATC LLC	64	$2,410,000	Kegonsa – McFarland	Planned	86	Kegonsa	McFarland		138		1-Jun-07

		– Femrite conversion to 138 kV			(conversion to 138 kV)		
ATC LLC	64 $1,000,000	Kegonsa – McFarland Planned – Femrite conversion to 138 kV	87	McFarland	Femrite (conversion to 138 kV)	138	1-Jun-07
ATC LLC	66 $2,093,333	Morgan – Falls – Planned Pioneer – Stiles 138 ckt, Sum rate 290	98	Falls	Pioneer	138	1-Jun-05
ATC LLC	66 $2,093,333	Morgan – Falls – Planned Pioneer – Stiles 138 ckt, Sum rate 290	99	Morgan	Falls	138	1-Jun-05
ATC LLC	66 $2,093,333	Morgan – Falls – Planned Pioneer – Stiles 138 ckt, Sum rate 290	100	Pioneer	Stiles	138	1-Jun-05
ATC LLC	69 $5,650,000	Waukesha – Planned	102	Duplainville	Sussex	138	1-Oct-05

		Duplainville – Sussex 138 kV line							
ATC LLC	69 $5,650,000	Waukesha – Planned Duplainville – Sussex 138 kV line	109	Waukesha	Duplainville		138		1-Oct-05

Reporting Source	Pro- Estimated ID Cost	Project MTEP 05 Description Status	Fac- ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
ATC LLC	101 $4,160,000	Kelly – Whitcomb 115 Planned ckt, Sum rate 241	125	Kelly	Whitcomb		115		30-Jun-08
ATC LLC	112 $6,000,000	Columbia – North Planned Madison 345 line & North Madison 345/138 tx replacement	333	Columbia	North Madison (convert)		345		1-Jun-06

ATC LLC	112 $9,500,000	Columbia – North Planned Madison 345 line & North Madison 345/138 tx replacement	334	North Madison 345-138 (replace)	transformer	1	345	138	1-Jun-06
ATC LLC	112 $9,500,000	Columbia – North Planned Madison 345 line & North Madison 345/138 tx replacement	438	North Madison 345-138 (replace)	transformer	2	345	138	1-Jun-06
ATC LLC	159 $1,100,000	Bell Plaine – Planned Badger/Caroline 115 ckt, Sum rate 120	602	Bell Plaine	Badger/Caroline		115		1-Jun-04
ATC LLC	160 $5,600,000	Wempletown – Planned Paddock 345 ckt 2, Sum rate 1200	344	Wempletown	Paddock	2	345		1-Jun-05
ATC LLC	161 $480,000	Bunker Hill – Pine Planned	424	Bunker Hill	Pine		115		1-Jun-05

		115 ckt, Sum rate 242							

Reporting Source	Pro- ID	Project Description	Fac- ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
	Estimated Cost	MTEP 05 Status							
ATC LLC	162	Edgewater transformer	427	Edgewater	transformer	2	345	138	1-Jun-05
	$3,460,000	Planned							
		– 345/138 ckt 2, Sum rate 500		345/138					
ATC LLC	163	Kegonsa – Christiana	428	Kegonsa	Christiana	2	138		1-Jun-05
	$6,500,000	Planned							
		(reconductor & reconfigure			(reconductor & reconfigure				
		double ckt at Kegonsa)			double ckt at Kegonsa)				
		138 ckt 2, Sum rate 478							
ATC LLC	164	Morgan – White Clay	437	Morgan	White Clay		138		1-Jun-05
	$1,067,000	Planned							
		(uprate) 138 ckt,			(uprate)				
		Sum rate 345							
ATC LLC	167	Lewiston – Kilbourn	605	Lewiston	Kilbourn		138		1-Jun-05
	$100,000	Planned							

Reporting Source	Project ID Estimated Cost	Project Description MTEP 05 Status	Facility ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
		(uprate) 138 ckt, Sum rate 286			(uprate)				
ATC LLC	169 $8,200,000	Forest Junction/ Cedarsauk Tap – Howard's Grove 138 ckt, Sum rate 290 Planned	590	Forest Junction/ Cedarsauk Tap	Howard's Grove		138		1-Jun-05
ATC LLC	171 $1,700,000	Weston – Kelly 115 ckt, Sum rate 239 Planned	439	Weston	Kelly		115		1-Jun-06
ATC LLC	327 $150,000	Boxelder – Rockdale – Lakehead Camrbridge – Jefferson 138 kV line, 383 MVA Planned	429	Lakehead Cambridge	Jefferson		138		1-Jun-07

ATC LLC	327 $150,000	Boxelder – Rockdale – Planned Lakehead Cambridge – Jefferson 138 kV line, 383 MVA	433	Rockdale	Lakehead Cambridge		138	1-Jun-07
ATC LLC	327 $300,000	Boxelder – Rockdale – Planned Lakehead Cambridge – Jefferson 138 kV line, 383 MVA	434	Rockdale	Boxelder	1	138	1-Jun-07
ATC LLC	333 $2,100,000	Straits – Pine River – Planned Hiawatha – Indian Lake 138 kV line	474	Hiawatha	Indian Lake (rebuild in 2004/2005 & convert in 2009)	1	138	1-May-09
ATC LLC	333 $200,000	Straits – Pine River – Planned Hiawatha – Indian Lake 138 kV line	596	Hiawatha	Indian Lake (string second 138 kV circuit)	2	138	1-May-09
ATC LLC	339 $5,630,000	Jefferson – Lake Mills – Planned	449	Jefferson	Lake Mills		138	1-Jun-07

		Stonybrook 138 kV line, 386 MVA							
ATC LLC	343 $200,000	Columbia – Portage Planned 138 kV lines 1 & 2, 386 MVA	422	Columbia	Portage	2	138		1-May-05
ATC LLC	343 $200,000	Columbia – Portage Planned 138 kV lines 1 & 2, 386 MVA	423	Columbia	Portage	1	138		1-May-05

Reporting **Source**	**Pro-** **Estimated** **ID** **Cost**	**Project** **MTEP 05** **Description** **Status**	**Fac-** **ID**	**From Sub**	**To Sub**	**Ckt**	**Line** **or** **HS** **kV**	**LS** **kV**	**Expected** **ISD**
ATC LLC	350 $250,000	Weston – Sherman Planned Street – Hilltop 115 kV line rebuild as double circuit	451	Morrison Ave.	Sherman St.		115		1-Jun-07
ATC LLC	350 $250,000	Weston – Sherman Planned	458	Weston	Morrison Ave.		115		1-Jun-07

		Street – Hilltop 115 kV					
		line rebuild as double					
		circuit					
ATC LLC	350	Weston – Sherman	459	Weston	Sherman St.	115	1-Jun-07
	$3,750,000	Planned					
		Street – Hilltop 115 kV					
		line rebuild as double					
		circuit					
ATC LLC	350	Weston – Sherman	1247	Weston	Hilltop	115	1-Jun-07
	$3,750,000	Planned					
		Street – Hilltop 115 kV					
		line rebuild as double					
		circuit					
ATC LLC	408	Hodag 115, 10 MVAR	2015	Hodag	capacitor bank	115	1-May-05
	$810,984	Planned					
		(addition) capacitor bank					
ATC LLC	429	Council Creek 138,	2058	Council Creek	capacitor bank	138	
	1-May-05	$688,415 Planned					
		16.4 MVAR capacitor bank					

Reporting Source	Project ID / Estimated Cost	Project Description / MTEP 05 Status	Facility ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
ATC LLC	551 $8,100,000	Stone Lake 345/161 tap Planned of Arrowhead – Gardner Park 345 kV line	1242	Stone Lake 345-161 kV	transformer	1	345	161	1-Jun-06
ATC LLC	564 $5,000,000	Paris – St. Martins 138 kV Planned line rebuilding with 477 T2-ACSR conductor	1241	Paris	St. Martins	1	138		1-Jun-05
ATC LLC	566 $3,500,000	Forest Junction/Charter Planned Street to Plymouth 138 kV line & T-D substation; construct 1.3 mile double circuit from Plymouth municipal utility to existing line	1244	Plymouth	Forest Junction/ Charter Street	1	138		1-Jun-07

ATC LLC	567 $250,000	North Appleton – Lawn Planned Road – White Clay 138 kV line upgrade; this project increases line clearance on the 30 mile line	1245	North Appleton	Lawn Road	1	138		1-Jun-07
ATC LLC	567 $250,000	North Appleton – Lawn Planned Road – White Clay 138 kV line upgrade; this project increases line clearance on the 30 mile line	1246	Lawn Road	White Clay	1	138		1-Jun-07
ATC LLC	568 $1,250,000	North Lake Geneva – Planned White River 138 kV line	1249	North Lake Geneva	White River	1	138		1-Jun-08
Reporting Source	**Pro-Estimated ID Cost**	**Project MTEP 05 Description Status**	**Fac-ID**	**From Sub**	**To Sub**	**Ckt**	**Line or HS kV**	**LS kV**	**Expected ISD**

ATC LLC	570 $1,610,612	Rock River – Bristol – Planned Elkhorn conversion to 138 kV	1252	Rock River	Turtle	1	138	1-Jun-08
ATC LLC	570 $1,610,612	Rock River – Bristol – Planned Elkhorn conversion to 138 kV	1253	Turtle	Sunrise	1	138	1-Jun-08
ATC LLC	570 $1,610,612	Rock River – Bristol – Planned Elkhorn conversion to 138 kV	1254	Turtle	La Prairie RCEC	1	138	1-Jun-08
ATC LLC	570 $1,610,612	Rock River – Bristol – Planned Elkhorn conversion to 138 kV	1255	La Prairie RCEC	Bradford RCEC	1	138	1-Jun-08
ATC LLC	570 $3,410,708	Rock River – Bristol – Planned Elkhorn conversion to	1256	Bradford RCEC	West Darien	1	138	1-Jun-08

		138 kV							
ATC LLC	570 $1,610,612	Rock River – Bristol – Planned Elkhorn conversion to 138 kV	1257	West Darien	Southwest Delavan	1	138		1-Jun-08
ATC LLC	570 $3,410,708	Rock River – Bristol – Planned Elkhorn conversion to 138 kV	1258	Southwest Delavan	North Shore	1	138		1-Jun-08

Reporting Source	Pro- ID Estimated Cost	Project Description MTEP 05 Status	Fac- ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
ATC LLC	570 $1.610.612	Rock River – Bristol – Planned Elkhorn conversion to 138 kV	1259	North Shore	Bristol	1	138		1-Jun-08
ATC LLC	570 $3,410,708	Rock River – Bristol – Planned	1260	Bristol	Elkhorn	1	138		1-Jun-08

		Elkhorn conversion to 138 kV							
ATC LLC	571 $6,500,000	North Madison – Planned Waunakee 138 kV line & expansion at Waunakee to accommodate new 138 kV facilities	1261	North Madison	Waunakee	1	138		1-Jun-08
ATC LLC	572 $3,721,083	Loop West Marinette – Planned Bay de Noc 138 kV line into Menominee; total project cost $3,000,000	1262	West Marinette	Menominee	2	138		1-Jun-08
ATC LLC	572 $1,793,938	Loop West Marinette – Planned Bay de Noc 138 kV line into Menominee; total project cost $3,000,000	1263	Menominee	Bay de Noc	1	138		1-Jun-08

Reporting Source	Project ID	Estimated Cost	Project Description	MTEP 05 Status	Fac-ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
ATC LLC	576	$5,100,000	Southest Fitchburg – Sugar River 138 kV line with Sugar River 138/69 kV substation	Planned	1273	Southeast Fitchburg	Sugar River	1	138		1-Jun-09
ATC LLC	803	$500,000	Paris – Albers 138 kV line upgrade	Planned	1455	Paris	Albers		138		1-Jun-05
CILCO	125	$417,200	Hines – Pioneer (convert UG to OH) 138 ckt 1, Sum rate	Planned	384	Hines	Pioneer (convert UG to OH)	1	138		1-Jun-04

Reporting Source	Pro-ID Estimated Cost	Project Description MTEP 05 Status	Fac-ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
CILCO	141 $361,800	Duck Creek – Tazewell Planned (convert bus duct to OH) 345 ckt 1, Sum rate	386	Duck Creek	Tazewell (convert bus duct to OH)	1	345		1-Jun-06
CIN	42 $752,906	Bedford – Shawswick – Planned Pleasant Grove – Airport Road Jct. – Seymour 138 ckt 1, Sum rate 304	181	Airport Road Jct.	Seymour	1	138		1-Jun-09
CIN	42 $2,110,106	Bedford – Shawswick – Planned Pleasant Grove – Airport Road Jct. – Seymour 138 ckt 1, Sum rate 304	182	Bedford	Shawswick	1	138		1-Jun-07

CIN	42 $3,388,077	Bedford – Shawswick – Planned Pleasant Grove – Airport Road Jct. – Seymour 138 ckt 1, Sum rate 304	183	Pleasant Grove	Airport Road Jct.	1	138		1-Jun-09
CIN	42 $4,719,516	Bedford – Shawswick – Planned Pleasant Grove – Airport Road Jct. – Seymour 138 ckt 1, Sum rate 304	184	Shawswick	Pleasant Grove	1	138		1-Jun-09
CIN	115 $9,455,194	New London – Webster Planned 230 ckt 1, Sum rate 800	366	New London	Webster	1	230		1-Jun-07
CIN	116 $6,093,584	Westwood – Dequine Planned 345 kV line & Westwood 345/138 tx 2	357	Westwood 345/138	transformer	2	345	138	1-Jun-07
CIN	116 $588,366	Westwood – Dequine Planned	367	Westwood	Dequine	1	345		1-Jun-07

		345 kV line & Westwood							
		345/138 tx 2							
CIN	190 $46,532	Cayuga – Nucor Planned	612	Cayuga	Nucor	1	345		1-May-05
		345 ckt 1, Sum rate 1386							
CIN	191 $4,638,538	Buffington – Planned	359	Buffington	transformer	2	345	138	1-Jun-05
		315/138 ckt 2, Sum rate 499		345/138					
CIN	192 $1,044,596	Warren – Todhunter Planned	361	Warren	Todhunter	1	138		1-Jun-05
		138 ckt 1, Sum rate 309							

Reporting Source	Pro- Estimated ID Cost	Project MTEP 05 Description Status	Fac- ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
CIN	193 $1,355,424	Beckjord – Feldman Planned	363	Beckjord	Feldman	1	138		1-Jun-05
		138 ckt 1, Sum rate 308							
CIN	195 $2,029,712	Beckjord – Silver Grove Planned	365	Beckjord	Silver Grove	1	138		1-Jun-05

		138 ckt 1, Sum rate 304							
CIN	196 $9,609,813	Madison West – Planned Scottsburg 138 ckt 1, Sum rate 215	516	Madison West	Scottsburg	1	138		1-Jun-05
CIN	197 $66,400	Louisville Cement Jct. – Planned Louisville Cement 138 ckt 1, Sum rate 130	520	Louisville Cement Jct.	Louisville Cement	1	138		1-Dec-05
CIN	198 $510,706	Port Union – Hall Planned 138 ckt 1, Sum rate 300	594	Port Union	Hall	1	138		1-Jun-06
CIN	199 $3,278,756	Kokomo – Planned 230/138 ckt 1, Sum rate 200	356	Kokomo 230/138	transformer	2	230	138	1-Jun-07
CIN	200 $9,878	West Lafayette Purdue – Planned Purdue NW Tap 138 ckt 1, Sum rate 179	618	West Lafayette Purdue	Purdue NW Tap	1	138		1-Jun-07

CIN	201 $100,000	NW Tap – West Planned Lafayette 138 ckt 1, Sum rate 240	536	NW Tap	West Lafayette	1	138		1-Jun-08

Reporting Source	Pro- ID Estimated Cost	Project Description MTEP 05 Status	Fac- ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
CIN	302 $97,595	Shawswick – Planned Pleasant Grove – Airport Road Jct. 138 kV line	614	Shawswick	Pleasant Grove	1	138		1-May-05
CIN	302 $97,595	Shawswick – Planned Pleasant Grove – Airport Road Jct. 138 kV line	615	Pleasant Grove (terminal)	Airport Road Jct. (terminal)	1	138		1-May-05
CIN	304 $100,000	Gibson – Duff Planned 345 ckt 1, Sum rate 1386	619	Gibson	Duff	1	345		1-Jun-05

CIN	426 $391,514	Lafayette 138, Planned 86.4 MVAR capacitor	2051	Lafayette	capacitor		138	1-Jun-05
CIN	445 $0	Buffington – Florence Planned 138, 337 MVA reactor (change impedance from 5% to 3%)	2081	Buffington (Buffington – Florence 138)	reactor (change impedance from 5% to 3%)		138	1-Jun-05
CIN	449 $721,909	Batesville 138, Planned 86.4 MVAR capacitor	2085	Batesville	capacitor		138	1-Jun-05
CIN	619 $200,000	IPL Petersburg 345 Planned	1292	IPL Petersburg			345	1-Jun-06
CIN	620 $1,150,000	Trenton – Todhunter Planned 138	1294	Trenton	Todhunter		138	1-Jun-06
CIN	621 $60,760	Veedersburg West – Planned Cayuga 230 kV (wavetrap)	1296	Veedersburg West	Cayuga	1	230	1-Jun-06

Reporting Source	Pro- Estimated ID Cost	Project MTEP 05 Description Status	Fac- ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
CIN	622 $60,760	Walton – Kokomo Planned Webster St. 230 ckt 1	1297	Walton	Kokomo Webster St.	1	230		1-Jun-06
CIN	623 $1,350,000	Warren – Hillsboro Planned 138 kV	1298	Warren	Hillsboro		138		1-Jun-06
CIN	624 $4,545,972	Cloverdale – Plainfield Planned South 138 ckt 1	1300	Cloverdale	Plainfield South	1	138		1-Dec-06
CIN	626 $1,000,134	Buffington – Hands Planned 138 ckt 1	1303	Buffington	Hands	1	138		1-Jun-07
CIN	627 $1,980,041	Kenton – West End Planned 138 ckt 1	1304	Kenton	West End	1	138		1-Jun-07

Reporting Source	Project ID / Estimated Cost	Project Description / MTEP 05 Status	Facility ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
CIN	628 $100,000	Kokomo Delco – Planned Kokomo Highland Park – Kokomo Chrysler 138 ckt 1	1305	Kokomo Highland Park	Kokomo Chrysler	1	138		1-Jun-07
CIN	628 $100,000	Kokomo Delco – Planned Kokomo Highland Park – Kokomo Chrysler 138 ckt 1	1306	Kokomo Highland Park	Kokomo Delco	1	138		1-Jun-07
CIN	630 $154,757	West Lafayette – Planned Cumberland 130 ckt 1	1307	West Lafayette	Cumberland	1	138		1-Jun-07
CIN	631 $100,000	Columbus – Seymour Planned 138 ckt 1	1308	Columbus	Seymour	1	138		1-Jun-09

Reporting Source	Pro- ID Estimated Cost	Project Description MTEP 05 Status	Fac- ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD

CIN	632	Gallagher – HE	1309	Gallagher	HE Georgetown	1	138		1-Jun-09
	$300,000	Planned							
		Georgetown 138 ckt 1							
CIN	764	Staunton 138 kV	3054	Staunton	capacitor		138		1-Jun-06
	$500,000	Planned							
		MVAR capacitor							
CIN	765	Cloverdale 138 kV	3058	Cloverdale	capacitor		138		1-Dec-06
	$524,860	Planned							
		43.2 MVAR capacitor							
CIN	766	Clarksville 138 kV	3060	Clarksville	capacitor		138		1-Jun-07
	$500,000	Planned							
		57.6 MVAR capacitor							
CIN	767	Greenfield Hastings	3062	Greenfield Hastings Park	capacitor		138		1-Jun-07
	$500,000	Planned							
		Park 138 kV 57.6							
		MVAR capacitor							
FE	203	Beaver – Greenfield	375	Beaver	Greenfield	1	138		1-Jun-04
	$4,500,000	Planned							
		138 ckt 1, Sum rate							

FE	428 $4,301,069	Fowels 138, 221 MVAR Planned capacitor bank (4 units)	2054	Fowels	capacitor bank (4 units)		138		1-Jun-04
FE	614 $4,486,000	Star 345/138 kV Planned transformer prep	1282	Star 345 kV tx prep	Star 138 kV tx prep		345	138	1-Dec-05
FE	615 $1,000,000	Galion 345/138 kV Planned transformer prep	1283	Galion 345 kV tx prep	Galion 138 kV tx prep		345	138	1-Dec-06
FE	616 $4,750,000	Crissinger – Tangy Planned 138 kV line	1284	Crissinger	Tangy	1	138		1-Jun-06
Reporting **Source**	**Pro-** **Estimated** **ID** **Cost**	**Project** **MTEP 05** **Description** **Status**	**Fac-** **ID**	**From Sub**	**To Sub**	**Ckt**	**Line** **or** **HS** **kV**	**LS** **kV**	**Expected** **ISD**
FE	759 $1,039,000	Eastlake 138 kV 2 x Planned 52.8 MVAR capacitors	3036	Eastlake	two 52.8 MVAR capacitors		138		1-Jun-05
FE	760 $958,000	Allen Junction 138 kV Planned	3037	Allen Junction	two 52.8 MVAR capacitors		138		1-Jun-05

		2 x 52.8 MVAR capacitors						
FE	761 $484,000	Wauseon 138 kV 53 MVAR Planned one 52.8 MVAR capacitor	3038	Wauseon	one 52.8 MVAR capacitor		138	1-Jun-05
FE	762 $1,229,000	Chamberlin 138 kV 53 Planned MVAR one 52.8 MVAR capacitor	3039	Chamberlin	one 52.8 MVAR capacitor		138	1-Jun-05
FE	763 $1,965,000	Carlisle 138 kV 2 x Planned 52.8 MVAR capacitors	3040	Carlisle	two 52.8 MVAR capacitors		138	1-Jun-05
GRE	596 $2,750,000	Vermillion River – Planned Empire 115 kV line	1076	Vermillion River	Empire	1	115	1-May-07
GRE	597 $3,660,000	Parkers Lake – Planned Plymouth – Elm Creek 115 kV line	1081	Parkers Lake	Plymouth	1	115	1-May-06
GRE	597 $9,000,000	Parkers Lake – Planned	1082	Plymouth	Elm Creek	1	115	1-May-06

		Plymouth – Elm Creek 115 kV line							
GRE	599 $3,600,000	Crooked Lake – Planned Enterprise Park 115 kV line	753	Crooked Lake	Enterprise Park	1	115		1-Jun-09

Reporting Source	Pro-ID Estimated Cost	Project Description MTEP 05 Status	Fac-ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
GRE	600 $3,500,000	Baxter – Southdale Planned 115 kV line	1078	Baxter	Southdale	1	115		31-Dec-06
GRE	601 $6,000,000	Mud Lake – Wilson Lake Planned 115 kV line	641	Mud Lake	Wilson Lake	1	115		1-Jun-08
GRE	753 $594,661	Hubbard 115 kV Planned 27 MVAR capacitor	3022	Hubbard	capacitor		115		1-Jun-05

IPL	40	Indian Creek – Julietta	177	Indian Creek	Julietta	1	138	1-Dec-06
	$951,838	Planned						
		– Cumberland 138 ckt 1,						
		Sum rate 286						
IPL	40	Indian Creek – Julietta	178	Julietta	Cumberland	1	138	1-Dec-06
	$866,173	Planned						
		– Cumberland 138 ckt 1,						
		Sum rate 286						
ITC	213	Arizona – Dayton –	508	Arizona	Dayton	1	120	31-Dec-05
	$1,100,000	Planned						
		Collins 120 kV line		120	120			
ITC	213	Arizona – Dayton –	509	Collins	Dayton	1	120	31-Dec-05
	$1,400,000	Planned						
		Collins 120 kV line		120	120			

Reporting Source	Pro- ID	Estimated Cost	Project Description	MTEP 05 Status	Fac- ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
ITC	215	$5,000,000	Thumb Loop rebuild: rebuild Bergen – Tuscola 120 kV to double circuit creating Hunters Creek – Lapeer – Bergen TP – Tuscola 120 & Hunters Creek – Fawn – Rush TP – Tuscola 120 kV	Planned	528	Hunters Creek 120	Lapeer 120	1	120		1-Jan-06
ITC	215	$4,400,000	Thumb Loop rebuild: rebuild Bergen – Tuscola 120 kV to double circuit creating Hunters Creek – Lapeer – Bergen TP – Tuscola 120 & Hunters	Planned	529	Lapeer 120	Bergen TP 120	1	120		1-Jan-06

		Creek – Fawn – Rush TP – Tuscola 120 kV							
ITC	215 $3,500,000	Thumb Loop rebuild: Planned rebuild Bergen – Tuscola 120 kV to double circuit creating Hunters Creek – Lapeer – Bergen TP – Tuscola 120 & Hunters Creek – Fawn – Rush TP – Tuscola 120 kV	530	Bergen TP 120	Tuscola 120	1	120		1-Jan-06

Reporting Source	Pro- ID	Estimated Cost	Project Description	MTEP 05 Status	Fac- ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
ITC	215	$4,800,000	Thumb Loop rebuild: rebuild Bergen – Tuscola 120 kV to double circuit	Planned	531	Hunters Creek 120	Fawn 120	1	120		1-Jan-06

		creating Hunters Creek – Lapeer – Bergen TP – Tuscola 120 & Hunters Creek – Fawn – Rush TP – Tuscola 120 kV						
ITC	215 $3,300,000	Thumb Loop rebuild: Planned rebuild Bergen – Tuscola 120 kV to double circuit creating Hunters Creek – Lapeer – Bergen TP – Tuscola 120 & Hunters Creek – Fawn – Rush TP – Tuscola 120 kV	532	Fawn 120	Rush TP 120	1	120	1-Jan-06
ITC	215 $6,400,000	Thumb Loop rebuild: Planned rebuild Bergen – Tuscola 120 kV to double circuit creating Hunters Creek – Lapeer – Bergen TP –	533	Rush TP 120	Tuscola 120	1	120	1-Jan-06

		Tuscola 120 & Hunters Creek – Fawn – Rush TP – Tuscola 120 kV								

Reporting Source	Pro- ID	Project Description	Fac- ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
	Estimated Cost	MTEP 05 Status							
ITC	322	Milan 345/120 substation,	521	Dorset	Spruce	1	120		30-Dec-05
	$1,100,000	Planned							
		Milan – Lulu 345, Milan – Dorset, Kentucky, Majestic, Pioneer 120 kV lines		120	120				
ITC	322	Milan 345/120 substation,	522	Dorset	Noble	1	120		30-Dec-05
	$750,000	Planned							
		Milan – Lulu 345, Milan – Dorset, Kentucky, Majestic, Pioneer 120 kV lines		120	120				
ITC	322	Milan 345/120 substation,	523	Dorset	Milan	1	120		30-Dec-05
	$2,300,000	Planned							

Reporting Source	Pro-ID / Estimated Cost	Project Description / MTEP 05 Status	Fac-ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
		Milan – Lulu 345, Milan – Dorset, Kentucky, Majestic, Pioneer 120 kV lines		120	120				
ITC	322 $450,000	Milan 345/120 substation, Planned	524	Kentucky	Milan	1	120		30-Dec-05
		Milan – Lulu 345, Milan – Dorset, Kentucky, Majestic, Pioneer 120 kV lines		120	120				
ITC	322 $1,100,000	Milan 345/120 substation, Planned	527	Milan	Pioneer	1	120		30-Dec-05
		Milan – Lulu 345, Milan – Dorset, Kentucky, Majestic, Pioneer 120 kV lines		120	120				

ITC	396	Wixom Station expansion:	506	Placid	Wixom	1	345	31-Dec-05
	$2,200,000	Planned						
		split existing Placid – Wayne		345	345			
		345 kV circuit into Placid –						
		Wixom & Wixom – Wayne						
		345 kV lines						
ITC	396	Wixom Station expansion:	507	Wixom	Wayne	1	345	31-Dec-05
	$3,300,000	Planned						
		split existing Placid – Wayne		345	345			
		345 kV circuit into Placid –						
		Wixom & Wixom – Wayne						
		345 kV lines						
ITC	503	Quaker Project	757	Wixom	Quaker	1	230	30-Dec-07
	$2,300,000	Planned						
		(conceptual): converting		230	230			
		Wixom – Quaker 120 kV						
		line to 230 kV, Wixom						
		345/230 tx, Quaker 230/120						
		tx, Quaker – Southfield						

		120 kV line							
ITC	503 $5,000,000	Quaker Project Planned (conceptual): converting Wixom – Quaker 120 kV line to 230 kV, Wixom 345/230 tx, Quaker 230/120 tx, Quaker – Southfield 120 kV line	758	Wixom 345/230	transformer	1	345	230	30-Dec-07

Reporting Source	Pro-ID Estimated Cost	Project Description MTEP 05 Status	Fac-ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
ITC	503 $1,500,000	Quaker Project Planned (conceptual): converting Wixom – Quaker 120 kV line to 230 kV, Wixom 345/230 tx, Quaker 230/120 tx, Quaker – Southfield	759	Quaker 230-120 kV	transformer	1	230	120	30-Dec-07

		120 kV line						
ITC	503 $1,200,000	Quaker Project Planned (conceptual): converting Wixom – Quaker 120 kV line to 230 kV, Wixom 345/230 tx, Quaker 230/120 tx, Quaker – Southfield 120 kV line	760	Hancock 120	Southfield 120	1	120	30-May-07
ITC	509 $1,750,000	Lenox Station: Lenox – Planned Jewel 345 kV line, Lenox 345/120 kV station, a 120 kV bus that ties together several 120 kV lines in the area (Jewel, Belle River, St. Clair, Victor, Augusta Tap, Grayling); was New Haven, name changed to Lenox	761	Lenox 345	Jewel 345	1	345	30-May-07

Reporting Source	Pro- Estimated ID Cost	Project MTEP 05 Description Status	Fac- ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
ITC	509 $1,750,000	Lenox Station: Lenox – Planned Jewel 345 kV line, Lenox 345/120 kV station, a 120 kV bus that ties together several 120 kV lines in the area (Jewel, Belle River, St. Clair, Victor, Augusta Tap, Grayling); was New Haven, name changed to Lenox	762	Lenox 345	Belle River 345	1	345		30-May-07
ITC	509 $5,000,000	Lenox Station: Lenox – Planned Jewel 345 kV line, Lenox 345/120 kV station, a 120 kV bus that ties together	763	Lenox 345-120 kV	transformer	1	345	120	30-May-07

several 120 kV lines in the area (Jewel, Belle River, St. Clair, Victor, Augusta Tap, Grayling); was New Haven, name changed to Lenox

Reporting Source	Pro- ID Estimated Cost	Project Description MTEP 05 Status	Fac- ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
ITC	509 $1,300,000	Lenox Station: Lenox – Jewel 345 kV line, Lenox 345/120 kV station, a 120 Planned	764	Lenox 120	St. Clair 120	1	120		30-May-07

		kV bus that ties together							
		several 120 kV lines in the							
		area (Jewel, Belle River, St.							
		Clair, Victor, Augusta Tap,							
		Grayling); was New Haven,							
		name changed to Lenox							
ITC	509	Lenox Station: Lenox –	765	Lenox	Victor	1	120		30-May-07
	$1,300,000	Planned							
		Jewel 345 kV line, Lenox		120	120				
		345/120 kV station, a 120							
		kV bus that ties together							
		several 120 kV lines in the							
		area (Jewel, Belle River, St.							
		Clair, Victor, Augusta Tap,							
		Grayling); was New Haven,							
		name changed to Lenox							

Reporting Source	Pro- Estimated ID Cost	Project MTEP 05 Description Status	Fac- ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
ITC	509	Lenox Station: Lenox –	766	Lenox	Augusta Tap	1	120		30-May-07
	$1,300,000	Planned							
		Jewel 345 kV line, Lenox		120	120				
		345/120 kV station, a 120							
		kV bus that ties together							
		several 120 kV lines in the							
		area (Jewel, Belle River, St.							
		Clair, Victor, Augusta Tap,							
		Grayling); was New Haven,							
		name changed to Lenox							
ITC	509	Lenox Station: Lenox –	767	Lenox	Grayling 2	1	120		30-May-07
	$1,300,000	Planned							
		Jewel 345 kV line, Lenox		120	120				

		345/120 kV station, a 120 kV bus that ties together several 120 kV lines in the area (Jewel, Belle River, St. Clair, Victor, Augusta Tap, Grayling); was New Haven, name changed to Lenox							

Reporting Source	Pro-ID Estimated Cost	Project Description MTEP 05 Status	Fac-ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
ITC	509 $1,300,000	Lenox Station: Lenox – Planned	768	Lenox	Grayling 1	1	120		30-May-07

		Jewel 345 kV line, Lenox		120	120				
		345/120 kV station, a 120							
		kV bus that ties together							
		several 120 kV lines in the							
		area (Jewel, Belle River, St.							
		Clair, Victor, Augusta Tap,							
		Grayling); was New Haven,							
		name changed to Lenox							
ITC	518	Bismark – Golf 120 kV	769	Golf	Bismark	1	120		31-Dec-05
	$2,500,000	Planned							
		line: create a 120 kV bus		120	120				
		group at Golf & building a new							
		120 kV line from Bismark – Golf							
ITC	518	Bismark – Golf 120 kV	770	Golf	Boyne	1	120		30-May-07
	$1,200,000	Planned							
		line: create a 120 kV bus		120	120				
		group at Golf & building a new							
		120 kV line from Bismark – Golf							

ITC	518 $1,200,000	Bismark – Golf 120 kV Planned line: create a 120 kV bus group at Golf & building a new 120 kV line from Bismark – Golf	771	Golf 120	Houston 2 120	1	120		30-May-07

Reporting Source	Project ID Estimated Cost	Project Description MTEP 05 Status	Fac-ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
ITC	518 $1,000,000	Bismark – Golf 120 kV Planned line: create a 120 kV bus group at Golf & building a new 120 kV line from Bismark – Golf	772	Golf 120	Macomb 120 #1	1	120		31-Dec-05
ITC	518 $1,600,000	Bismark – Golf 120 kV Planned line: create a 120 kV bus group at Golf & building a new	773	Golf 120	Macomb 120 #2	2	120		30-May-07

		120 kV line from Bismark – Golf							
ITC	518	Bismark – Golf 120 kV	1375	Bismark	Malta	1	120		31-Dec-05
	$700,000	Planned							
		line: create a 120 kV bus		120 kV	120 kV				
		group at Golf & building a new							
		120 kV line from Bismark – Golf							
ITC	523	ITC-METC interface	700	Atlanta	transformer	1	138	120	30-May-05
	$1,200,000	Planned							
		upgrade (rebuilding of		138-120					
		Genoa – Latson 138 kV,							
		Hunters Creek –							
		Hemphill 138 kV, Atlanta							
		138-120 kV transformer,							
		Genoa 138-120 kV							
		transformer); this project							
		involves replacing existing							
		transformers with higher							
		rated units							

Reporting Source	Project ID	Estimated Cost	Project Description	MTEP 05 Status	Fac-ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
ITC	523	$1,200,000	ITC-METC interface upgrade (rebuilding of Genoa – Latson 138 kV, Hunters Creek – Hemphill 138 kV, Atlanta 138-120 kV transformer, Genoa 138-120 kV transformer); this project involves replacing existing transformers with higher rated units	Planned	701	Genoa 138-120 kV	transformer	1	138	120	30-May-05
ITC	523	$900,000	ITC-METC interface upgrade (rebuilding of Genoa – Latson 138 kV,	Planned	703	Hunters Creek 120	Hemphill 120	1	120		30-May-05

		Hunters Creek – Hemphill 138 kV, Atlanta 138-120 kV transformer, Genoa 138-120 kV transformer); this project involves replacing existing transformers with higher rated units								

Reporting Source	Pro- ID	Estimated Cost	Project Description	MTEP 05 Status	Fac- ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
ITC	523	$350,000	ITC-METC interface upgrade (rebuilding of Genoa – Latson 138 kV, Hunters Creek –	Planned	776	Atlanta 120	Tuscola 120	1	120		30-May-05

		Hemphill 138 kV, Atlanta 138-120 kV transformer, Genoa 138-120 kV transformer); this project involves replacing existing transformers with higher rated units						
ITC	529 $535,000	Macomb 120 kV Planned capacitor	2087	Macomb	capacitor bank		120	31-May-05
ITC	565 $350,000	Pontiac – Hampton Planned 120 kV line upgrade	702	Oakly 120	Tuscola 120	1	120	30-May-05
ITC	565 $250,000	Pontiac – Hampton Planned 345 kV line upgrade	704	Pontiac 345	Hampton 345	1	345	30-May-05
ITC	578 $3,500,000	DVARs at Bad Axe Planned & Lee	2100	Bad Axe	DVAR		120	31-May-05

ITC	578	$3,500,000	DVARs at Bad Axe & Lee	Planned	2101	Lee	DVAR		120		31-May-05
ITC	581	$14,300,000	Caniff – Stephens 345 kV cable replacement	Planned	775	Stephens 345	Caniff 345	1	345		30-May-05
Reporting Source	**Pro- ID**	**Estimated Cost**	**Project Description**	**MTEP 05 Status**	**Fac- ID**	**From Sub**	**To Sub**	**Ckt**	**Line or HS kV**	**LS kV**	**Expected ISD**
ITC	683	$250,000	Northeast 120 kV – Lincoln 120 kV	Planned	1373	Northeast 120 kV	Lincoln 120 kV	1	120		30-May-05
ITC	684	$5,000,000	Milan 345/120 kV	Planned	1374	Milan 345/120 kV	transformer	1	345	120	30-Dec-05
ITC	685	$500,000	Pontiac 120 kV – Stratford 120 kV	Planned	1376	Pontiac 120 kV	Stratford 120 kV	1	120		31-Dec-05
LES	242	$3,100,000	19th & Alvo – NW 12th	Planned	191	19th & Alvo	NW 12th & Arbor	1	115		1-May-05

		& Arbor 115 ckt 1, Sum rate 373						
LES	246 $4,608,246	NW 68th & Holdrege – Planned NW 12th & Arbor 115 ckt 1, Sum rate 373	193	NW 68th & Holdrege	NW 12th & Arbor	1	115	1-May-07
LES	247 $22,033,174	Wagener – NW 68th Planned & Holdrege 345 ckt 1, Sum rate 1088	541	Wagener	NW 68th & Holdrege	1	345	1-May-08
LES	590 $1,674,138	56th & Pine Lake – Planned 40th & Rokeby – 27th & Pine Lake 115 kV line	684	27th & Pine Lake	40th & Rokeby	1	115	1-May-06
LES	590 $1,674,138	56th & Pine Lake – Planned 40th & Rokeby – 27th & Pine Lake 115 kV line	685	56th & Pine Lake	40th & Rokeby	1	115	1-May-06

Line

							or		
Reporting	Pro-	Project	Fac-				HS	LS	Expected
	Estimated	MTEP 05							
Source	ID	Description	ID	From Sub	To Sub	Ckt	kV	kV	ISD
	Cost	Status							
LGEE	305	Middletown 345/138	490	Middletown	transformer	1	345	138	31-May-04
	$125,000	Planned							
		transformers 1, 2 & 3		345-138 kV					
		to 448 MVA							
LGEE	305	Middletown 345/138	491	Middletown	transformer	2	345	138	31-May-04
	$125,000	Planned							
		transformers 1, 2 & 3		345-138 kV					
		to 448 MVA							
LGEE	305	Middletown 345/138	492	Middletown	transformer	3	345	138	31-May-04
	$125,000	Planned							
		transformers 1, 2 & 3		345-138 kV					
		to 448 MVA							
LGEE	310	Northside – Beargrass	489	Beargrass	Jeffersonville Jct.	1	138		31-May-04
	$52,000	Planned							
		– Jeffersonville Jct.			(CIN)				
		(CIN) 138 kV lines							

LGEE	310 $52,000	Northside – Beargrass Planned – Jeffersonville Jct. (CIN) 138 kV lines	494	Northside	Beargrass	1	138		31-May-04
LGEE	310 $52,000	Northside – Beargrass Planned – Jeffersonville Jct. (CIN) 138 kV lines	495	Northside	Jeffersonville Jct. (CIN)	1	138		31-May-04
LGEE	313 $5,000	Middletown – Buckner Planned 345 ckt 1, Sum rate 1066	493	Middletown	Buckner	1	345		31-May-04
METC	120 $3,150,000	Farr Road – Tippy – Planned Hodenpyl 138 line	534	Farr Road J.	Tippy	1	138		1-May-05

Reporting Source	Pro- ID Estimated Cost	Project Description MTEP 05 Status	Fac- ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
METC	120 $2,200,000	Farr Road – Tippy – Planned Hodenpyl 138 line	535	Tippy	Hodenpyl	1	138		1-May-06

METC	227 $215,000	METC – Gaylord Planned 138 ckt 1, Sum rate	631	METC	Gaylord	1	138	1-Oct-04
METC	229 $252,000	METC – Barnum Planned Creek 138 ckt 1, Sum rate 190	345	METC	Barnum Creek	1	138	1-Dec-04
METC	230 $80,000	METC – Cheesman Planned 138 ckt 1, Sum Rate	632	METC	Cheesman	1	138	1-Dec-04
METC	231 $905,000	Cobb – Brickyard Planned 138 ckt 1, Sum rate	346	Cobb	Brickyard J.	1	138	1-May-05
METC	232 $4,200,000	Pere Marquette – Planned Stronach 138 ckt 1, Sum rate	518	Pere Marquette	Stronach	1	138	1-May-05
METC	234 $1,100,000	METC – Ransom Planned	342	METC	Ransom	1	138	1-Jun-05

		138 ckt 1, Sum rate 386							
METC	236 $107,000	METC – Bayberry Planned 138 ckt 1, Sum rate	519	METC	Bayberry	1	138		31-Dec-05
METC	237 $160,000	METC – Titus Planned 138 ckt 1, Sum rate	634	METC	Titus	1	138		1-Jun-05

Reporting Source	Pro- Estimated ID Cost	Project MTEP 05 Description Status	Fac- ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
METC	238 $184,000	METC – Vernon Planned 138 ckt 1, Sum rate	635	METC	Vernon/Bard	1	138		1-Jun-05
METC	239 $184,000	METC – Withey Lake Planned 138 ckt 1, Sum rate	636	METC	Withey Lake	1	138		1-Jun-05
METC	240 $1,900,000	Garfield – Hemphill Planned	336	Garfield	Hemphill	1	138		1-Jun-08

		138 ckt 1, Sum rate 521						
METC	476	Alma 138 kV 7.2 MVAR	3076	Alma	capacitor addition		138	1-Jun-05
	$50,000	Planned						
		capacitor addition						
METC	477	Batavia 138 kV 7.2 MVAR	3077	Batavia	capacitor addition		138	1-Jun-05
	$50,000	Planned						
		capacitor addition						
METC	482	Tittabawassee 5 ohm	1315	Tittabawassee		1 & 2	138	1-May-05
	$1,200,000	Planned						
		reactors (add)	reactors					
METC	484	Black River 138 kV	2046	Black River	capacitor addition		138	1-Jun-05
	$800,000	Planned						
		26 MVAR capacitor						
		addition						
METC	485	Gallagher 138 kV	3078	Gallagher	capacitor		138	1-Jun-05
	$900,000	Planned						
		36 MVAR capacitor						
METC	490	Croton – Felch Road	1318	Croton	Felch Road	1	138	1-Jun-05
	$180,000	Planned						

		138 kV (increase capacity)		(switches)					

Reporting Source	Pro- ID	Project Description	Fac- ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
	Estimated Cost	MTEP 05 Status							
METC	634	Gaylord 138 – Gaylord 138 bus switches 138 ckt 1	1313	Gaylord 138	Gaylord 138 bus switches	1	138		31-Dec-04
	$110,000	Planned							
METC	635	METC – West Fenton 138 ckt 1	1314	METC	West Fenton	1	138		1-May-05
	$20,000	Planned							
METC	637	Hemphill – Hunters Creek 138 ckt 1	1319	Hemphill	Hunters Creek (ITC)	1	120		1-Jun-05
	$220,000	Planned							
METC	638	Hemphill 138 –	1320	Hemphill	Hemphill	1	138		1-Jun-05
	$50,000	Planned							

		Hemphill bus switches		130	bus switches				
		138 ckt 1							
METC	639	METC – Packard	1321	METC	Packard	1	138		1-Jun-05
	$100,000	Planned							
		138 ckt 1							
METC	640	METC – David	1323	METC	David	1	138		1-Nov-05
	$170,000	Planned							
		138 ckt 1							
METC	644	METC – Rogue River	1327	METC	Rogue River	1	138		1-Jun-06
	$160,000	Planned							
		138 ckt 1							
METC	740	METC 345 kV line	1434	Gallagher	Tittabawassee	1	345		31-Dec-05
	$1,000.000	Planned							
		relaying &							
		communications							
		upgrade project							
							Line		
							or		
Reporting	**Pro-**	**Project**	**Fac-**				**HS**	**LS**	**Expected**
	Estimated	**MTEP 05**							

Source	ID Cost	Description Status	ID	From Sub	To Sub	Ckt	kV	kV	ISD
METC	740 $1,000.000	METC 345 kV line Planned relaying & communications upgrade project	1435	Keystone	Livingston	1	345		31-Dec-05
METC	740 $794.000	METC 345 kV line Planned relaying & communications upgrade project	1436	Livingston	Gallagher	1	345		31-Dec-05
METC	769 $500,000	Tittabawassee 345 kV Planned breaker replacements 3000 amp	3074	Tittabawassee	breaker replacements		345		31-Dec-04
METC	770 $500,000	Hampton 345 kV Planned breaker replacement 3000 amp	3075	Hampton	breaker replacement		345		1-Apr-05

METC	771 $1,400,000	Hemphill, Thetford & Planned Tallmadge 138 kV breaker replacements 40 kA	3079	Hemphill, Thetford & Tallmadge	breaker replacements		138		1-Jun-05
METC	772 $258,000	Tallmadge 345 kV Planned transformer bushing replacements TBD	3080	Tallmadge	transformer bushing replacements		345		1-Jun-05

Reporting Source	Pro- ID Estimated Cost	Project Description MTEP 05 Status	Fac- ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
METC	773 $1,600,000	Tittabawassee & Kenoa Planned 345 kV breaker replacements 3000 amp	3081	Tittabawassee & Kenoa	breaker replacements		345		31-Dec-05

NIPS	118 $4,000,000	Hiple 345 kV Planned interconnection (NIPS-AEP) to East Elkhart – Collingwood 345	382	Hiple	East Elkhart	1	345	1-Apr-04
NIPS	118 $4,000,000	Hiple 345 kV Planned interconnection (NIPS-AEP) to East Elkhart – Collingwood 345	383	Hiple	Collingwood	1	345	1-Apr-04
NIPS	437 $1,400,000	Hiple 138, 60 MVAR Planned capacitor bank (2 steps of 30 MVAR)	2070	Hiple	capacitor bank (2 steps of 30 MVAR)		138	1-Nov-04
NIPS	438 $1,600,000	Leesburg 138, 84 MVAR Planned capacitor bank (2 steps of 42 MVAR)	2071	Leesburg	capacitor bank (2 steps of 42 MVAR)		138	1-Nov-04
NIPS	467 $211,000	Northeast – Kline 138 Planned	1278	Northeast	Kline	1	138	1-Jun-05

Reporting Source	Pro- Estimated ID Cost	Project MTEP 05 Description Status	Fac- ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
NIPS	613 $167,000	Dune Acres – Michigan Planned City 138 kV double circuit; upgrade terminal equipment & 1 mile reconductor	1280	Dune Acres	Michigan City	1	138		1-Feb-05
NIPS	613 $167,000	Dune Acres – Michigan Planned City 138 kV double circuit; upgrade terminal equipment & 1 mile reconductor	1281	Dune Acres	Michigan City	2	138		1-Feb-05
NIPS	757 $1,034,000	Dune Acres 138 kV Planned 100 MVAR capacitor bank (1 step)	3034	Dune Acres	capacitor bank (1 step)		138		1-Jun-06

NIPS	758	Miller 138 kV 100 MVAR	3035	Miller	capacitor bank		138		1-Jun-06
	$990,500	Planned							
		capacitor bank (1 step)			(1 step)				
OTP/MPC	263	Wilton 230 – 230/115	238	Wilton	transformer	2	230	115	1-Jun-05
	$4,073,336	Planned							
		ckt 2, Sum rate 187		230-115 kV					
OTP/MPC	46	Maple River 230/115 tx	233	Maple River	transformer	2	230	115	1-Jun-05
	$4,684,476	Planned							
/XEL		#2 187 MVA, Maple River		230-115 kV					
		345/230 tx #3 336 MVA,							
		Winter 230-115 tx 187 MVA							
SIPC	81	Marion – Carrier Mills	60	Marion	Carrier Mills	1	161		1-Jun-06
	$7,083,000	Planned							
		161 ckt 1, Sum rate 286							
Vectren	180	A B Brown – Henderson	380	A B Brown	Northwest	2	138		1-Jun-06
	$2,650,000	Planned							
		(add 9 ohm reactor) 138		(SIGE)	(SIGE)				
		& A B Brown (SIGE) –							
		Northwest (SIGE) 138 ckt 2							
							Line		

Reporting Source	Project ID	Estimated Cost	Project Description	MTEP 05 Status	Fac-ID	From Sub	To Sub	Ckt	HS or kV	LS kV	Expected ISD
Vectren	677	$2,150,000	Duff (SIGE) – Dubois (SIGE) 138 ckt 2	Planned	1366	Duff (SIGE)	Dubois (SIGE)	2	138		1-Jun-06
Vectren	781	$500,000	Heidelbach 138 kV 31 MVAR capacitor bank	Planned	3089	Heidelbach	capacitor bank		138		31-May-05
Vectren	782	$550,000	Angel Mounds 138 kV 31 MVAR capacitor bank	Planned	3090	Angel Mounds	capacitor bank		138		31-May-05
XEL	56	$10,100,000	Chisago – Lawrence Creek 115, Lawrence Creek – St. Croix Falls – Apple River 161	Planned	301	Chisago	Lindstrom	1	115		31-Dec-07
XEL	56	$9,080,000	Chisago – Lawrence Creek 115, Lawrence	Planned	303	Lawrence Creek	St. Croix Falls	1	161		31-Dec-07

		Creek – St. Croix Falls –							
		Apple River 161							
XEL	56	Chisago – Lawrence	304	Lawrence Creek	transformer	1	161	115	31-Dec-07
	$6,000,000	Planned							
		Creek 115, Lawrence		161-115 kV					
		Creek – St. Croix Falls –							
		Apple River 161							
XEL	56	Chisago – Lawrence	306	Lindstrom	Shafer	1	115		31-Dec-07
	$5,800,000	Planned							
		Creek 115, Lawrence							
		Creek – St. Croix Falls –							
		Apple River 161							

Reporting Source	Pro- Estimated ID Cost	Project MTEP 05 Description Status	Fac- ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
XEL	56	Chisago – Lawrence	310	Shafer	Lawrence Creek	1	115		31-Dec-07
	$3,500,000	Planned							
		Creek 115, Lawrence							

		Creek – St. Croix Falls – Apple River 161						
XEL	56 $23,790,000	Chisago – Lawrence Planned Creek 115, Lawrence Creek – St. Croix Falls – Apple River 161	312	St. Croix Falls	Apple River	1	161	31-Dec-07
XEL	257 $975,391	Aldrich – St. Louis Park Planned 115 ckt 1, Sum rate 310	249	Aldrich	St. Louis Park	1	115	1-Jun-06
XEL	262 $1,137,956	Red Rock – Rogers Lake Planned 115 ckt 2, Sum rate 310	250	Red Rock	Rogers Lake	2	115	15-Dec-04
XEL	265 $4,282,860	Glencoe – McLeod 115 Planned ckt 1, Sum rate 300	561	Glencoe	McLeod	1	115	1-May-05
XEL	267 $829,667	Lawrence – Minnehaha Planned 115 ckt 1, Sum rate 310	563	Lawrence	Minnehaha	1	115	1-Jun-06

Reporting Source	Pro- ID Estimated Cost	Project Description MTEP 05 Status	Fac- ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
XEL	268 $925,398	Minnehaha – Lincoln Planned County 115 ckt 1, Sum rate 310	564	Minnehaha	Lincoln County	1	115		1-Jun-06
XEL	269 $9,110,072	Prairie Island – Red Planned Rock 345 ckt 2, Sum rate 1198	1137	Prairie Island	Red Rock	2	345		1-Jun-06
XEL	276 $2,211,655	Inver Hills – Koch Planned 115 ckt 2, Sum rate 310	576	Inver Hills	Koch	2	115		1-Jun-06
XEL	366 $2,432,170	Sherco – Monticello Planned 115 & Sherco – St. Cloud 155 kV lines, Sherco 345/115 tx	569	I-94 Industrial Park Tap	Salida Crossing	1	115		1-Jun-06

XEL	366	Sherco – Monticello	571	Salida Crossing	Sherco	1	115		1-Jun-06
	$765,368	Planned							
		115 & Sherco – St.							
		Cloud 155 kV lines,							
		Sherco 345/115 tx							
XEL	366	Sherco – Monticello	572	Sherco	Monticello	1	115		1-Jun-06
	$714,344	Planned							
		115 & Sherco – St.							
		Cloud 155 kV lines,							
		Sherco 345/115 tx							
XEL	366	Sherco – Monticello	573	Sherco	transformer	1	345	115	1-Jun-06
	$3,001,443	Planned							
		115 & Sherco – St.		345-115 kV					
		Cloud 155 kV lines,							
		Sherco 345/115 tx							
XEL	366	Sherco – Monticello	574	St. Cloud	I-94 Industrial Park	1	115		1-Jun-06
	$850,409	Planned							
		115 & Sherco – St.			Tap				
		Cloud 155 kV lines,							
		Sherco 345/115 tx							

Reporting Source	Pro- Estimated ID Cost	Project MTEP 05 Description Status	Fac- ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
XEL	417 $1,500,000	Westgate 115, Planned 80 MVAR capacitor	2038	Westgate	capacitor		115		1-Jun-08
XEL	561 $2,500,000	Granite City 115 kV Planned 2 x 40 MVAR Capacitors	2086	Granite City	capacitors		115		1-Jun-05
XEL	666 $800,000	Maple River – Red Planned River 15 ckt 1	1354	Maple River	Red River	1	115		1-Jun-05
XEL	671 $800,000	Oakdale – Tanners Planned Lake 115 ckt 1	1359	Oakdale	Tanners Lake	1	115		1-Jun-06
XEL	672 $1,300,000	Wilmarth – Eastwood Planned	1360	Wilmarth	Eastwood	1	115		1-Jun-06

Reporting Source	Pro- Estimated ID Cost	Project MTEP 05 Description Status	Fac- ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
		115 ckt 1							
ATC LLC	11 $1,044,808	Rhinelander 115 kV Proposed loop short-term solution	2007	cross country	capacitor bank		138		1-May-04
ATC LLC	22 $1,044,808	Femrite – Sprecher Proposed 138 (new), Sprecher – Reiner 138 (conversion), Reiner – Sycamore 138 (conversion)	2011	Kegonsa	capacitor bank		138		1-May-04
ATC LLC	407 $1,034,183	Loch Mirror (Birchwood) Proposed 138, 24 MVAR capacitor bank	2012	Loch Mirror (Birchwood)	capacitor bank		138		1-May-04

ATC LLC	404	Clear Lake 115, 6 MVA	2006	Clear Lake	facts (D-SMES)	115		1-Jul-04
	$1,900,000	Proposed						
		facts (D-SMES)						
ATC LLC	431	Moorland 138, 54 MVAR	2060	Moorland	capacitor bank	138		1-Jun-05
	$750,000	Proposed						
		capacitor bank						
ATC LLC	678	North Appleton –	1367	North Appleton	Werner West	345		1-Dec-05
	$2	Proposed						
		Werner West (uprate)			(uprate)			
		345 kV						
ATC LLC	679	Werner West –	1368	Werner West	Rocky Run	345		1-Dec-05
	$2	Proposed						
		Rocky Run (uprate)			(uprate)			
		345 kV						
ATC LLC	168	Werner West tx –	436	Werner West	transformer	345	138	1-May-06
	$13,500,000	Proposed						
		345/138 ckt, Sum rate 500						
ATC LLC	1	Arrowhead – Gardner	1453	Cornell	Fiebrantz	138		1-Jun-06
	$0	Proposed						
		Park 345 kV line		(4.5 ohm reactor)				

ATC LLC	175 $2,500,000	Ellinwood – Sunset Proposed Point 138 ckt, Sum rate	463	Ellinwood	Sunset Point		138		1-Jun-06
ATC LLC	430 $1,000,000	Burlington 138, Proposed 50 MVAR capacitor bank	2059	Burlington	capacitor bank		138		1-Jun-06
ATC LLC	433 $500,000	Wautoma 138, 32.6 Proposed MVAR capacitor bank	2062	Wautoma	capacitor bank		138		1-Jun-06

Reporting Source	Pro- Estimated ID Cost	Project MTEP 05 Description Status	Fac- ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
ATC LLC	446 $750,000	Butler Ridge 138 kV, Proposed 36 MVAR capacitor bank	2082	Butler Ridge (new generation site near Hartford)	capacitor bank		138		1-Jun-06
ATC LLC	432 $1,820,000	Antigo (was Hogan St.) Proposed	2061	Antigo	capacitor bank		115		1-Jun-06

		115, 13.6 MVAR			(was Hogan St.)							
		capacitor bank										
CILCO	142	R S Wallace –		391		R S Wallace		substation		1	138	
	1-Jun-06	$5,082,700	Planned									
		substation (sub					(sub relocation)					
		relocation) 138 ckt 1,										
		Sum rate										
CIN	618	Beckjord 138		1290	Beckjord		(rebuild substation)			138		1-Jun-06
	$1,738,266	Proposed										
CIN	625	Pierce/Beckjord		1301	Pierce/Beckjord		transformer		C	345	138	1-Dec-06
	$1,600,000	Proposed										
		345/138 ckt C			345/138 kV							
ITC	528	Placid 120 kV		2088	Placid		capacitor bank			120		31-May-05
	$425,000	Proposed										
		capacitor										
LGEE	314	Lake Reba Tap – JK		161	Lake Reba Tap		JK Smith		1	138		30-Nov-05
	$5,000	Proposed										
		Smith (EKPC) 138 ckt 1,					(EKPC)					
		Sum rate 251										

LGEE	315 $3,320,000	Plainview Tap – Proposed Middletown – Bluegrass Parkway 138 kV line	620	Middletown	Bluegrass Parkway	1	138		31-Dec-05
Reporting **Source**	**Pro-** **Estimated** **ID** **Cost**	**Project** **MTEP 05** **Description** **Status**	**Fac-** **ID**	**From Sub**	**To Sub**	**Ckt**	**Line** **or** **HS** **kV**	**LS** **kV**	**Expected** **ISD**
METC	494 $50,000	Battle Creek – Verona Proposed 138 kV 1 & 2 line, remove sag limit	1317	Battle Creek	Verona (sag)	2	138		1-Jun-05
METC	497 $1,000	Tallmadge – Wealthy Proposed Street 138 kV line 2	1322	Tallmadge	Wealthy	2	138		1-Jun-05
METC	636 $1,000	Amber 1 – Amber 2 Proposed 138 ckt 1	1316	Amber 1	Amber 2	1	138		1-Jun-05

METC	641	Redwood – Oceana	1324	Redwood	Oceana	1	138	1-Dec-05
	$2,000,000	Proposed						
		138 ckt 1						
METC	422	Various 138, 200 MVAR	2047	various	capacitors		138	1-Jun-06
	$2,000,000	Proposed						
		capacitors						
METC	642	Argenta – Hazelwood	1325	Argenta	Hazelwood	1	138	1-Jun-06
	$50,000	Proposed						
		(sag) 138 ckt 1			(sag)			
METC	643	Gaines – Thompson	1326	Gaines	Thompson Road	1	138	1-Jun-06
	$500,000	Proposed						
		Road 138 ckt 1						
METC	774	Gaylord 138 kV 36 MVAR	3082	Gaylord	capacitors		138	1-Jun-06
	$900,000	Proposed						
		capacitors						
METC	775	Iosco 138 kV 18 MVAR	3083	Iosco	capacitors		138	1-Jun-06
	$800,000	Proposed						
		Capacitors						

Reporting Source	Pro- ID / Estimated Cost	Project Description / MTEP 05 Status	Fac- ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
METC	741 $3,000,000	METC 345 kV line Proposed relaying & communications upgrade project – phase 2	1437	Argenta	Battle Creek	1	345		31-Dec-06
METC	741 $3,000,000	METC 345 kV line Proposed relaying & communications upgrade project – phase 2	1438	Battle Creek	Oneida	1	345		31-Dec-06
METC	741 $2,415,000	METC 345 kV line Proposed relaying & communications	1439	Argenta	Tompkins	1	345		31-Dec-06

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		upgrade project – phase 2							
Vectren	436 $550,000	Northeast 138, 60 MVAR Proposed Capacitor bank	2069	Northeast	capacitor bank		138		31-May-05
XEL	270 $382,923	Champlin – Champlin Proposed Tap 115 ckt 1, Sum rate 310	1138	Champlin	Champlin Tap	1	115		1-Jun-06
XEL	609 $760,000	Long Lake – Proposed Woodbury 115 kV line	800	Long Lake	Oakdale (from Woodbury)	1	115		1-Jun-06

Reporting Source	Pro-ID Estimated Cost	Project Description MTEP 05 Status	Fac-ID	From Sub	To Sub	Ckt	Line or HS kV	LS kV	Expected ISD
XEL/WAPA	610 $12,179,190	White – Buffalo Ridge Proposed 115 kV line & White	646	White 345-115 kV	transformer	1	345	115	1-Jun-06

		345/115 kV tx 2						
XEL/WAPA	610	White – Buffalo Ridge	645	White	Buffalo Ridge	1	115	1-Jun-06
	$10,178,228	Proposed						
		115 kV line & White						
		345/115 kV tx 2						

Entergy 2014 - 2018 Final Construction Plan

	Project Driver	Project Name	LE	MTEP 14 Designation	Proposed ISD (Planning)	2013 Funding Comments	Project Status	Actual ISD	Other Comments
10-EAI-018-CP	Transmission Reliability - Meeting Planning Criteria	Ebony 161 kV Switching Station: Install 5 Breaker Ring Bus Lines Terminating Into New Ebony Substation (ratings unchanged): Ebony - Kuhn Road 161 kV Line Ebony - WM Lehi - WM Polk - WM EHV 161 kV Line Ebony - WM Dover - WM Gateway 161 kV Line Ebony - Marked Tree 161 kV Line Ebony - WM Lehi - WM EHV 161 kV Line	EAI	Complete	2012 Winter	Approved	Complete	11/16/12	Delayed to winter due to construction feasibility
11-EAI-006-CP	Transmission Reliability - Meeting Planning Criteria	Ebony 161 kV Switching Station: Add 36 MVAR Capacitor Bank	EAI	Complete	2012 Winter	Approved	Complete	11/30/12	Delayed to winter due to construction feasibility
11-EAI-010-CP	Transmission Reliability - Meeting Planning Criteria	Wilmar Substation: Add 21.6 MVAR Capacitor Bank (Formerly Hilo Substation)	EAI	Complete	2012 Winter	Approved	Complete	1/21/13	Delayed to winter due to construction feasibility
10-EAI-020-CP	Transmission Reliability - Meeting Planning Criteria	Benton North to Benton South: Construct New 115 kV Line Rated at least 170 MVA Install Switching Stations at Benton North and Benton South	EAI	Complete	2012 Winter	Approved	Complete	4/22/13	May be delayed to summer due to routing difficulties
11-EAI-012-CP	Transmission Reliability - Meeting Planning Criteria	Stuttgart Ricuskey 115 kV Substation: Expand Capacitor Bank to 39 MVAR	EAI	Complete	2013 Summer	Approved	Complete	6/3/13	
11-EAI-026-CP	Transmission Reliability - Meeting Planning Criteria	NLR Westgate - NLR Levy: Reconductor 115 kV Line	EAI	Pre-Planned	2013 Summer	Approved	Design/Scoping		Delayed to winter 2013 due to outage scheduling
13-EAI-004-CP	Transmission Reliability - Meeting Planning Criteria	Monticello East - Add 21.6 MVAR capacitor bank	EAI	Complete	2013 Summer	Approved	Complete	5/29/13	Replaces Monticello East SVC project 12-EAI-007-CP
13-EAI-008-CP	Transmission Reliability - Meeting Planning Criteria	Hot Springs EHV Substation: Replace two 115 kV autotransformer breakers	EAI	Complete	2013 Summer	Approved	Complete	6/20/13	New Project to address fault interrupting requirements
13-EAI-009-CP	Transmission Service	Hot Spring Transmission Service: White Bluff to Pine Bluff Arsenal C - Upgrade terminal equipment at White Bluff	EAI	Pre-Planned	2013 Winter	Approved	Design/Scoping		New Project
11-EAI-003-CP	Transmission Reliability - Meeting Planning Criteria	Fordyce: Relocate capacitor bank to 115 kV bus. Install switch on line side of capacitor bank.	EAI	Pre-Planned	2014 Summer	Proposed & In Target	Design/Scoping		Updated project description

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11-EAI-004-1-CP	Economic	Sheridan South 500 kV FG Upgrade: Mabelvale 500 kV Substation replace 3 breakers, 13 switches, and 2 line traps	EAI	Pre-Planned	2014 Summer	Approved	Construction		
11-EAI-004-2-CP	Economic	Sheridan South 500 kV FG Upgrade: Sheridan 500 kV Substation replace 11 switches, and 6 line traps	EAI	Pre-Planned	2014 Summer	Approved	Construction		
11-EAI-004-3-CP	Economic	Sheridan South 500 kV FG Upgrade: White Bluff 500 kV Substation replace 5 switches, and 2 line traps	EAI	Pre-Planned	2014 Summer	Approved	Construction		
11-EAI-004-4-CP	Economic	Sheridan South 500 kV FG Upgrade: Eldorado 500 kV Substation replace 1 switch and 2 line traps	EAI	Pre-Planned	2014 Summer	Approved	Construction		
12-EAI-002-CP	Transmission Reliability - Meeting Planning Criteria	Woodward - Pine Bluff West - Pine Bluff McCamant: Reconductor 115 kV	EAI	Pre-Planned	2014 Summer	Approved	Design/Scoping		
12-EAI-005-CP	Transmission Reliability - Meeting Planning Criteria	Camden McGuire - Camden North 115kV Line: Construct New Line	EAI	Pre-Planned	2014 Summer	Approved	Construction		
12-EAI-008-01-CP	Transmission Reliability - Meeting Planning Criteria	LV Bagby to Macon Lake: Construct new 230 kV line and operate at 115 kV	EAI	Pre-Planned	2014 Summer	Approved	Design/Scoping		Project split into two phases. Formerly 12-EAI-008-CP
12-EAI-023-CP	Transmission Reliability - Meeting Planning Criteria	Woodward to Pine Bluff Watson Chapel: Rebuild line to 230 kV construction and operate at 115 kV.	EAI	Pre-Planned	2014 Summer	Approved	Design/Scoping		
14-EAI-002-CP	Transmission Service	Hot Springs Transmission Service: McCrory-Bailey: Upgrade line to 100C	EAI	Pre-Planned	2014 Summer	Approved	Design/Scoping		ISD moved up from Winter to Summer
12-EAI-001-CP	Transmission Reliability - Meeting Planning Criteria	Calico Rock-Melbourne - Upgrade 161kV Line	EAI	Pre-Planned	2014 Winter	Approved	Design/Scoping		
14-EAI-008-CP	Transmission Service	Haskell to Woodlawn 115 kV line - Upgrade line	EAI	Pre-Planned	2014 Winter	Approved	Design/Scoping		New Project
14-EAI-021-CP	Transmission Service	Trumann Substation - Add Capacitor Bank	EAI	Pre-Planned	2014 Winter	Approved	Design/Scoping		New Project
11-EAI-007-CP	Transmission Reliability - Meeting Planning Criteria	Hot Springs Hamilton (Albright) - Carpenter Dam: Construct new 115 kV Line and convert Mountain Pine South to ring bus stations.	EAI	Pre-Planned	2015 Summer	Approved	Design/Scoping		
13-EAI-003-CP	Transmission Reliability - Meeting Planning Criteria	Monticello East to Reed: Construct new 115 kV transmission line. Construct to 230 kV but operate at 115 kV.	EAI	Pre-Planned	2015 Summer	Proposed & In Target	Design/Scoping		Replaces Monticello East SVC project 12-EAI-007-CP
11-EAI-008-CP	Transmission Reliability - Meeting Planning Criteria	Pine Bluff Voltage Support Project: Phase 2 Woodward: Construct 230 kV ring bus and construct new White Bluff to Woodward 230 kV line	EAI	Pre-Planned	2015 Summer	Proposed & In Target	Design/Scoping		
11-EAI-017-CP	Transmission Reliability - Meeting Planning	White Bluff: Reconfigure 500 kV Station and construct 230 kV ring bus	EAI	Pre-Planned	2015 Summer	Proposed & In Target	Design/Scoping		

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	Criteria								
12-EAI-035-CP	Transmission Reliability - Meeting Planning Criteria	Beebe: Install 21.6 MVAR capacitor bank	EAI	Pre-Planned	2015 Summer	Proposed & In Target	Design/Scoping		Changed location from Ward substation to Bebee
14-EAI-017-CP	Transmission Reliability - Meeting Planning Criteria	Driver 500-230 kV Substation: Construct new substation and loop in and out of San Souci to Shelby 500 kV line	EAI	Pre-Planned	2015 Summer	Approved	Design/Scoping		New Project
14-EAI-009-CP	Enhanced Transmission Reliability	Kings River (SWEPCO Tie) - Tap Osage Creek to Berryville 161 kV and Osage Creek to Grandview 161 kV lines	EAI	Pre-Planned	2016 Summer	Proposed & In Target	Design/Scoping		New Project. New tie project needed to facilitate SPP Kings River project.
11-EAI-025-CP	Transmission Reliability - Meeting Planning Criteria	Norfork-Calico Rock : Upgrade 161 kV Line	EAI	Pre-Planned	2016 Summer	Proposed & In Target	Design/Scoping		
11-EAI-027-CP	Transmission Reliability - Meeting Planning Criteria	AECC L&D 2 to Gillett: Construct new 115 kV Line	EAI	Pre-Planned	2016 Summer	Approved	Design/Scoping		
12-EAI-008-02-CP	Transmission Reliability - Meeting Planning Criteria	Macon Lake to Reed: Construct new 230 kV line and operate at 115 kV	EAI	Pre-Planned	2017 Summer	Approved	Design/Scoping		Project split into two phases. Formerly 12-EAI-008-CP
12-EGL-014-CP	Transmission Reliability - Meeting Planning Criteria	Lake Charles Bulk Substation: Replace four 69 kV, 600 A switches on transformers and bus section breaker with 1200 A switches	EGSL	Complete	2012 Fall	Approved	Complete	1/28/13	
11-EGL-013-1-CP	Transmission Reliability - Meeting Planning Criteria	Fireco to Copol 69 kV line: Upgrade line conductor	EGSL	Complete	2012 Winter	Approved	Complete	12/17/12	
10-EGL-011-CP	Transmission Reliability - Meeting Planning Criteria	Mossville - Cut-in line 616 (Nelson to Carlyss 138 kV) into Mossville 138 kV Substation	EGSL	Pre-Planned	2013 Summer	Approved	Design/Scoping		
11-EGL-004-CP	Transmission Reliability - Meeting Planning Criteria	Bloomfield to Bosco 138 kV line (formerly Vatican project) Construct new Bloomfield 138 kV SS north of Vatican Construct new Bosco 138 kV SS on Scott to Scanlan 138 kV line Construct new Bloomfield to Bosco 138 kV line Install 5 ohm reactor at Bosco substation	EGSL	Complete	2013 Summer	Approved	Complete	12/20/12	
11-EGL-008-CP	Transmission Reliability - Meeting Planning Criteria	Francis 69 kV substation - Add 14.4 MVAR, 69 kV capacitor bank (Previously considered Marydale as alternative location)	EGSL	Complete	2013 Summer	Approved	Complete	3/25/13	
11-EGL-015-3-CP	Transmission Service	Acadia Generation - Upgrade Moril to Hopkins 138 kV line	EGSL	Complete	2013 Summer	Approved	Complete	10/30/12	
11-EGL-015-4-CP	Transmission Service	Acadia Generation - Upgrade 69 kV breaker at Scott 18220	EGSL	Complete	2013 Summer	Approved	Complete	10/11/12	

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12-EGL-003-CP	Transmission Reliability - Meeting Planning Criteria	Champagne to Plaisance 138 kV line - Modify/Replace CTs at Champagne	EGSL	Complete	2013 Summer	Approved	Complete	12/26/12	
11-EGL-016-01-CP	Transmission Reliability - Meeting Planning Criteria	Mossville to Canal - Phase 1: Upgrade 69 kV Line	EGSL	Pre-Planned	2013 Winter	Approved	Design/Scoping		Project split into two phases. Formerly 11-EGL-016-CP
12-EGL-015-CP	Economic	Willow Glen to Conway - Construct new 230 kV line	EGSL	Pre-Planned	2014 Spring	Approved	Design		Project ISD moved from 2013 Winter to 2014 Spring
11-EGL-016-02-CP	Transmission Reliability - Meeting Planning Criteria	Mossville to Canal - Phase 2: Upgrade 69 kV Line	EGSL	Pre-Planned	2014 Winter	Proposed & In Target	Design/Scoping		Project split into two phases. Formerly 11-EGL-016-CP
12-EGL-008-CP	Transmission Reliability - Meeting Planning Criteria	Copol to Bourbeaux: Upgrade 69 kV line	EGSL	Complete	2014 Winter	Approved	Complete	4/18/13	
14-EGL-001-CP	Transmission Reliability - Meeting Planning Criteria	Longfellow to Cade Switch - Move Normally Open Point	EGSL	Pre-Planned	2015 Summer	Proposed & In Target	Design/Scoping		New Project
13-EGL-002-CP	Transmission Reliability - Meeting Planning Criteria	Lake Arthur 69 kV: Move normally open point	EGSL	Pre-Planned	2015 Summer	Proposed & In Target	Design/Scoping		New Project (Accelerated from Horizon Plan)
12-EGL-010-CP	Transmission Reliability - Meeting Planning Criteria	New Iberia: Add 138-69 kV transformer	EGSL	Pre-Planned	2015 Summer	Proposed & In Target	Design/Scoping		New Project (Accelerated from Horizon Plan)
14-EGL-006-CP	Transmission Reliability - Meeting Planning Criteria	LeBlanc - New Cap Bank #1	EGSL	Pre-Planned	2015 Summer	Proposed & In Target	Design/Scoping		Accelerated from 2017 to 2015 for loss of Cleco Unit
14-EGL-003-CP	Transmission Reliability - Meeting Planning Criteria	Willow Glenn: Upgrade 500-230 kV single phase transformer bank with 1200 MVA units	EGSL	Pre-Planned	2016 Summer	Proposed & In Target	Design/Scoping		New Project
14-EGL-019-CP	Transmission Reliability - Meeting Planning Criteria	Mud Lake 230 kV Substation: Loop Sabine to Big 3 230 kV Line into new Mud Lake 230 kV substation and add (2) 230 kV capacitor banks at Mud Lake	EGSL	Pre-Planned	2016 Fall	Approved	Design/Scoping		New Project
11-EGL-010-CP	Transmission Reliability - Meeting Planning Criteria	Sorrento Upgrade 138/115 kV Auto and upgrade Gonzales - Sorrento 138 kV Line	EGSL/ ELL	Pre-Planned	2014 Summer	Approved	Design/Scoping		
13-ELL-002-CP	Transmission Reliability - Meeting Planning Criteria	McCall 115 kV Substation: Add 20.4 MVAR Capacitor Bank (Formerly Napoleonville add capacitor bank)	ELL	Complete	2013 Fall	Approved	Complete	8/19/13	
10-ELL-008-CP	Transmission Reliability - Meeting Planning Criteria	Southeast LA Coastal Improvement Plan: Phase 3 Construct Oakville to Alliance 230kV Line Add 230 - 115 kV Autotransformer at	ELL	Pre-Planned	2013 Summer	Approved	Design/Construction		Routing issues may result in potential delay to spring 2015

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		Alliance Substation								
11-ELL-003-1-CP	Transmission Reliability - Meeting Planning Criteria	NE Louisiana Improvement Project - Phase 1 Swartz to Oakridge - Construct new 115 kV Line (1272 ACSS) Operate Sterlington to Oakridge normally open	ELL	Complete	2013 Summer	Approved	Complete	3/22/13	
13-ELL-001-CP	Transmission Reliability - Meeting Planning Criteria	Golden Meadow to Barataria: Upgrade switch	ELL	Complete	2013 Summer	Approved	Complete	4/25/13	
11-ELL-002-CP	Transmission Reliability - Meeting Planning Criteria	Mt. Olive: Add Shunt Reactor	ELL	Pre-Planned	2013 Winter	Approved	Design/Scoping		
11-ELL-001-CP	Enhanced Transmission Reliability	Golden Meadow to Leeville 115 kV - Rebuild/relocate 115 kV transmission line	ELL	Pre-Planned	2014 Spring	Approved	Design/Scoping		
11-ELL-003-2-CP	Transmission Reliability - Meeting Planning Criteria	NE Louisiana Improvement Project - Phase 2 Oakridge to new Dunn Substation - Construct new 115 kV Line (1272 ACSS) Add 115 kV breakers at Dunn	ELL	Pre-Planned	2014 Summer	Approved	Design/Scoping		
11-ELL-009-1-CP	Generation Interconnection	NM6: Modify Ninemile switchyard for interconnection	ELL	Pre-Planned	2014 Winter	Approved	Construction		
11-ELL-010-1-CP	Transmission Service	NM6: Upgrade Ninemile to Southport 230 kV transmission line No.1	ELL	Pre-Planned	2014 Winter	Approved	Design/Scoping		
11-ELL-010-2-CP	Transmission Service	NM6: Upgrade Ninemile to Southport 230 kV transmission line No.2	ELL	Pre-Planned	2014 Winter	Approved	Design/Scoping		
10-ELL-009-CP	Transmission Reliability - Meeting Planning Criteria	Iron Man to Tezcuco 230 kV line - Construct new line	ELL	Pre-Planned	2015 Summer	Approved	Design/Construction		
11-ELL-012-CP	Transmission Reliability - Meeting Planning Criteria	Valentine to Clovelly 115 kV upgrade	ELL	Pre-Planned	2015 Summer	Approved	Design/Scoping		
13-ELL-004-CP	Transmission Reliability - Meeting Planning Criteria	Minden Improvement Project Ph 1-Place cap bank at Minden REA	ELL	Pre-Planned	2015 Summer	Proposed & In Target	Design/Scoping		
11-ELL-004-CP	Transmission Reliability - Meeting Planning Criteria	Northeast LA Improvement Project Phase 3 Upgrade Sterlington to Oakridge 115 kV Line	ELL	Pre-Planned	2015 Summer	Proposed & In Target	Design/Scoping		Updated Project Description
11-EMI-004-CP	Transmission Reliability - Meeting Planning Criteria	Ray Braswell to West Jackson 115 kV line: Reconductor line	EMI	Complete	2012 Winter	Approved	Complete	11/21/12	Final relay settings completed and installed March 2013. Line now up to full conductor rating.

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14-EMI-001-CP	Transmission Reliability - Meeting Planning Criteria	Horn Lake to Greenbrook 115kV line: Upgrade 4 switches	EMI	Pre-Planned	2013 Summer	Approved	Construction		Complete pending relay upgrades and transfer bus switch scheduled for Fall 2013. Transfer switch has no impact on rating of circuit.
10-EMI-017-CP	Transmission Reliability - Meeting Planning Criteria	Ray Braswell - Wyndale 115kV Line: Construct New 260 MVA Construct new 115 kV Switching Station between Byram and Terry Wyndale SS to be designed for future 230-115 kV auto and distribution facilities	EMI	Pre-Planned	2013 Summer	Approved	Construction		
10-EMI-017-01-CP	Transmission Reliability - Meeting Planning Criteria	Ray Braswell to Spring Ridge Road 115kV line upgrade	EMI	Complete	2013 Summer	Approved	Complete	5/16/13	Identified as part of 10-EMI-017-CP project requirement due to swapping of line bays
10-EMI-018-CP	Transmission Reliability - Meeting Planning Criteria	Getwell to Church Road 230 kV construct new 230 kV Transmission Line	EMI	Complete	2013 Summer	Approved	Complete	5/10/13	
13-EMI-001-CP	Transmission Reliability - Meeting Planning Criteria	Upgrade CTs at Vicksburg for Vicksburg-B.Wilson ckt 1 (ckt without Spencer Potash on it)	EMI	Complete	2013 Summer	Approved	Complete	6/13/13	
13-EMI-006-CP	Enhanced Transmission Reliability	Bolton 115 kV Substation: Add 115 kV breakers	EMI	Complete	2013 Summer	Approved	Complete	3/28/13	
13-EMI-004-CP	Transmission Service	SMEPA Plum Point Transmission Service: Horn Lake to Greenbrook 115 kV line: Upgrade station equipment at Horn Lake	EMI	Complete	2013 Summer	Approved	Complete	4/19/13	
11-EMI-002-CP	Transmission Reliability - Meeting Planning Criteria	Baxter Wilson to S.E. Vicksburg - Upgrade 115 kV line	EMI	Pre-Planned	2015 Summer	Proposed & In Target	Design/Scoping		
14-EMI-002-CP	Transmission Reliability - Meeting Planning Criteria	Bozeman Rd to Tinnin Rd 230kV: Build new 230kV line from Bozeman Road to GASES-Ray Braswell 230kV and add new breaker station	EMI	Pre-Planned	2017 Summer	Proposed & In Target	Design/Scoping		New Project
14-EMI-003-CP	Transmission Reliability - Meeting Planning Criteria	Natchez Improvement Project Phase 1: Baxter Wilson to Natchez SES 115kV Build new 115kV line rated 260MVA (230kV constructed)	EMI	Pre-Planned	2018 Summer	Proposed & In Target	Design/Scoping		New Project
14-EMI-005-CP	Enhanced Transmission Reliability	Vicksburg Area Improvement Project: Build new 115kV switching station and rebuild E.Vicksburg-R.Braswell 115kV and SE Vicksburg-new switching station. Upgrade station equipment at SE Vicksburg and Bovina	EMI	Pre-Planned	2018 Summer	Proposed & In Target	Design/Scoping		New Project
11-ENO-001-CP	Generation Interconnection	NM6: Upgrade Michoud breaker N9803	ENOI	Complete	2014 Winter	Approved	Complete	7/18/13	
12-ETI-015-CP	Enhanced Transmission Reliability	College Station SS: Create emergency tie point with ERCOT (asynchronous)	ETI	Complete	2013 Spring	Approved	Complete	7/3/13	
10-ETI-017-CP	Transmission Reliability -	Jasper to Rayburn 138 kV line: Upgrade line to 100 deg C design	ETI	Complete	2013 Summer	Approved	Complete	5/14/13	Clarified project description

	Meeting Planning Criteria								
11-ETI-008-01-CP	Transmission Reliability - Meeting Planning Criteria	Plantation to Conroe 138 kV line: Upgrade station equipment at Plantation	ETI	Complete	2013 Summer	Approved	Complete	4/4/13	
11-ETI-008-CP	Transmission Reliability - Meeting Planning Criteria	Cedar Hill to Plantation 138 kV line: Upgrade line conductor and station equipment at Plantation	ETI	Complete	2013 Summer	Approved	Complete	2/21/13	
11-ETI-036-CP	Transmission Reliability - Meeting Planning Criteria	Plantation to Conroe 138 kV line: Reconductor Line	ETI	Complete	2013 Summer	Approved	Complete	4/4/13	
11-ETI-041-CP	Transmission Reliability - Meeting Planning Criteria	Eastgate to Dayton Bulk: Upgrade terminal equipment at Eastgate (formerly reconductor)	ETI	Complete	2013 Summer	Approved	Complete	4/19/13	
11-ETI-043-CP	Transmission Reliability - Meeting Planning Criteria	Expand Cap Bank at Calvert 69kV	ETI	Complete	2013 Summer	Approved	Complete	5/8/13	
12-ETI-003-CP	Transmission Reliability - Meeting Planning Criteria	Bentwater Substation: Add 138 kV Capacitor Bank	ETI	Complete	2013 Summer	Approved	Complete	5/1/13	
11-ETI-020-CP	Transmission Reliability - Meeting Planning Criteria	Hickory Ridge-Eastgate 138kV: Upgrade terminal equipment at Eastgate	ETI	Complete	2013 Summer	Approved	Complete	4/5/13	Needed in 2016 Summer but being worked in conjunction with 11-ETI-041-CP
12-ETI-004-CP	Transmission Reliability - Meeting Planning Criteria	Ponderosa Switching Station: tie lines Longmire to Fish Creek and Conroe to Woodhaven into new switching station	ETI	Pre-Planned	2013 Winter	Approved	Design/Scoping		Projected delayed to Winter due to site acquisition
11-ETI-010-CP	Transmission Reliability - Meeting Planning Criteria	Leach to Newton Bulk 138 kV line: Upgrade terminal equipment at Newton Bulk	ETI	Complete	2013 Winter	Proposed & In Target	Complete	3/18/13	
13-ETI-010-01-CP	Transmission Reliability - Meeting Planning Criteria	Pansy to Lovell's Lake 69 kV line: Upgrade line to 100 deg design	ETI	Pre-Planned	2013 Winter	Proposed & In Target	Design/Scoping		
13-ETI-010-02-CP	Transmission Reliability - Meeting Planning Criteria	Lovells Lake to Texaco Hillebrandt 69 kV line: Upgrade line to 100 deg design	ETI	Pre-Planned	2013 Winter	Proposed & In Target	Design/Scoping		
11-ETI-033-CP	Transmission Reliability - Meeting Planning Criteria	Toledo Bend to Leach 138 kV - Upgrade line	ETI	Pre-Planned	2014 Fall	Proposed & In Target	Design/Scoping		2014 Fall DETEC project results in project acceleration by 3 years
13-ETI-011-CP	Transmission Reliability - Meeting Planning Criteria	Lewis Creek to Egypt 138 kV line: Reconductor	ETI	Pre-Planned	2014 Summer	Proposed & In Target	Design/Scoping		

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11-ETI-042-CP	Transmission Reliability - Meeting Planning Criteria	New 50.2 MVAR Cap Bank at Parkway 138kV	ETI	Pre-Planned	2014 Summer	Proposed & In Target	Design/Scoping		
14-ETI-004-CP	Transmission Reliability - Meeting Planning Criteria	Leach 138 kV Substation: DTEC add 138 kV breakers (To accommodate DTEC/TEXLA Tie Project to close normally open point)	ETI	Pre-Planned	2014 Fall	Proposed & In Target	Design/Scoping		New DTEC Project resulting in associated ETI facility modifications
11-ETI-039-CP	Transmission Reliability - Meeting Planning Criteria	Upgrade Jacinto - Splendora 138 kV Line	ETI	Pre-Planned	2015 Summer	Proposed & In Target	Design/Scoping		
12-ETI-007-CP	Transmission Reliability - Meeting Planning Criteria	Alden 138 kV Substation: Add Capacitor Bank	ETI	Pre-Planned	2015 Summer	Proposed & In Target	Design/Scoping		
13-ETI-006-CP	Transmission Reliability - Meeting Planning Criteria	Magnolia Groveton: Add 25.1 MVAR Cap Bank	ETI	Pre-Planned	2015 Summer	Proposed & In Target	Design/Scoping		Accelerated from Horizon Plan (2021 Summer to 2015 Summer)
11-ETI-018-CP	Transmission Reliability - Meeting Planning Criteria	Construct new China to Amelia 230kV line	ETI	Pre-Planned	2016 Summer	Approved	Design/Scoping		
13-ETI-009-01-CP	Transmission Reliability - Meeting Planning Criteria	Ponderosa to Grimes: Construct new 230 kV Line Add 345-230 kV Auto at Grimes Add 230-138 kV Auto at Ponderosa	ETI	Pre-Planned	2016 Summer	Approved	Design/Scoping		
13-ETI-009-02-CP	Transmission Reliability - Meeting Planning Criteria	Conroe to Ponderosa 138 kV line: Upgrade Line	ETI	Pre-Planned	2016 Summer	Approved	Design/Scoping		
13-ETI-012-CP	Transmission Reliability - Meeting Planning Criteria	Construct new Porter to Forest 138 kV transmission line - Construct new line from Porter to Oakridge area and tie into de-energized line 403 - Terminate line 403 into Forest 138 kV substation	ETI	Pre-Planned	2016 Summer	Proposed & In Target	Design/Scoping		Project eliminates need for WRRIP-Add Alden SVC 11-ETI-022-CP
11-ETI-003-CP	Transmission Reliability - Meeting Planning Criteria	Deweyville (JNEC) - Add 69 kV capacitor bank	ETI	Pre-Planned	2014 Winter	Proposed & In Target	Design/Scoping		Facilities owned by JNEC. Entergy and JNEC are working to establish final projected in-service date. Current expectations are 2014 Winter.
11-ETI-023-CP	Transmission Reliability - Meeting Planning Criteria	Orange County 230kV Project: Construct new Chisholm Road 230 kV substation, Construct new line from Hartburg to Chisholm Road, add 2nd Hartburg 500-230 kV auto	ETI	Pre-Planned	2017 Summer	Proposed & In Target	Design/Scoping		

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Cleco

Proj No	Project Name	Project Description	Proposed In-Service Date
1	Mansfield Reactor	Install 18 ohm series reactor at Mansfield substation on the Mansfield - IP Mansfield 138 kV line	June 2014
2	Pineville 230/138 kV 2nd autotransformer	Install 2nd auto transformer at Pineville	June 2014
3	New 500/230 kV substation near Messick	Joint project between Cleco and AEP to install a new 500/230 kV substation near Cleco's Messick subsattion	Dec 2015
4	Construct Sherwood-Shady Oaks 230 kV line	Construct a new line from Sherwood - Shady Oaks	Dec 2016
5	Rehabilitate Carroll-Messick 230 kV line	Re-conductor Carroll-Messick 230 kV line to 600 MVA	Dec 2016

SMEPA

Project	Projected ISD
Build L180 Moselle - S. Hoy 161kV	2015
Homewood - Station Creek 161kV	2015
Northwest Perry 161/69kV	2015

East Texas Electric Cooperative

Project Name	Project Description	From Substation	To Substation	Voltage (kV)	Expected In-service date
DTEC interconnection	Close normal open point.	Six Mile (509125)	Leach (334286)	138	4th Qtr 2014
	Construct 12 miles of 138 kV line with 795 ACSR conductor.	Chireno (509107)	Etoile (334334)	138	4th Qtr 2014

Lafayette Utilities System

No.	Project Name	Project Description	From/To Sub	Voltage	In-Service Date
1	La Neuville Substation (New)	Construct a new 69kV substation	N/A	69/13.8kV	October 2014 (construction in-progress)
2	Hargis-Hebert to La Neuville Transmission Line	Construct a 69kV transmission line from Hargis-Hebert to newly constructed La Neuville substation	Hargis-Hebert/La Neuville	69kV	October 2014 (construction in-progress)
3	Mall-Flanders Transmission Pole Replacement	Replace steel poles on Mall-Flanders 230kV transmission line	Mall/Flanders	230kV	Dec-14

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ATTACHMENT FF-2

LODF TABLE

Sample Sub-Regional Allocations for 22 Facilities Based on LODF

				FE	HE	CIN	VECT	LGEE	IPL	NIPS	METC	ITC
	ALTW	CWLD	AMRN	IPL	CILCO							
				202	207	208	210	211	216	217	218	219
	331	355	356	357	359							
Prairie State Power Plant												
transmission outlet												
		74%	**26%**									
Chisago-Apple River												
	2%											
Jefferson City 345/161				0%	0%	0%	0%	0%	0%	0%	0%	0%
	0%	0%	**98%**	0%	0%							
Jefferson-Loose Creek 345				0%	0%	0%	0%	0%	0%	0%	0%	0%
	0%	0%	**98%**	0%	0%							
Moreau-Apache Flats 161												
Rosser-Silver 230, 2005				0%	0%	0%	0%	0%	0%	0%	0%	0%
	0%	0%	**99%**	0%	0%							
Rosser-Silver 230, 2005												
Callaway-Franks 345, 2006												
		97%	**3%**									
Columbia-N. Madison 138 kV												
converted to 345, 2006												
Wagner-NW 68th & Holdrege, 2008												

Buffalo Ridge Split Rock-Nobles Co. 345 kV	0%	0%	0%	0%	0%	0%	0%	0%	0%	**23%**	0%	0%	0%	0%
Buffalo Ridge Nobles-Lakefield 345 kV	0%	0%	0%	0%	0%	0%	0%	0%	0%	**24%**	0%	0%	0%	0%
Buffalo Ridge Nobles Co. 345-115	0%	0%	0%	0%	0%	0%	0%	0%	0%	**6%**	0%	0%	0%	0%
Buffalo Ridge Buffalo-White 115	0%	0%	0%	0%	0%	0%	0%	0%	0%	**1%**	0%	0%	0%	0%
Buffalo Ridge Chanrmb-Fenton 115	0%	0%	0%	0%	0%	0%	0%	0%	0%	**6%**	0%	0%	0%	0%
Buffalo Ridge Fenton-Nobles 115	0%	0%	0%	0%	0%	0%	0%	0%	0%	**6%**	0%	0%	0%	0%
Mill Creek-Hardin 345		**3%**	**14%**	**2%**	**77%**						**3%**	**1%**		
Callaway-Franks 345											**97%**	**3%**		
Stone Lake 345/161										**2%**				
Auburn N.-Chatham 138											**45%**	**24%**	**14%**	
North Madison-Waunakee														
Milan-Pioneer 120	**10%**								**90%**					
Hilcrest-Eastwood 138 kV	0%	0%	**100%**	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

	CWLP	SIPC	ATC	NSP	MP	GRE	OTP	LES	MDU
	360	361	364	600	608	618	626	650	661
Prairie State Power Plant transmission outlet									
Chisago-Apple River			**5%**	**85%**	**7%**	**1%**			
Jefferson City 345/161	0%	0%	0%	0%	0%	0%	0%	0%	0%
Jefferson-Loose Creek 345	0%	0%	0%	0%	0%	0%	0%	0%	0%
Moreau-Apache Flats 161									
Rosser-Silver 230, 2005	0%	0%	0%	0%	0%	0%	0%	0%	0%
Rosser-Silver 230, 2005				**100%**					
Callaway-Franks 345, 2006									
Columbia-N. Madison 138 kV converted to 345, 2006			**100%**						
Wagner-NW 68th & Holdrege, 2008								**100%**	
Buffalo Ridge Split Rock-Nobles Co. 345 kV	0%	0%	**1%**	**70%**	**2%**	1%	**4%**		
Buffalo Ridge Nobles-Lakefield 345 kV	0%	0%	**1%**	**66%**	**2%**	1%	**5%**		
Buffalo Ridge Nobles Co. 345-115	0%	0%	0%	**87%**	**2%**	**1%**	**3%**		
Buffalo Ridge Buffalo-White 115	0%	0%	0%	**92%**	0%	1%	**6%**		
Buffalo Ridge Chanrmb-Fenton 115	0%	0%	0%	**87%**	**2%**	**1%**	**3%**		
Buffalo Ridge Fenton-Nobles 115	0%	0%	0%	**87%**	**2%**	**1%**	**3%**		
Mill Creek-Hardin 345									
Callaway-Franks 345									

Stone Lake 345/161			**31%**	**47%**	**19%**	**1%**			
Auburn N.-Chatham 138	**17%**								
North Madison-Waunakee			**100%**						
Milan-Pioneer 120									
Hilcrest-Eastwood 138 kV	0%	0%	0%	0%	0%	0%	0%	0%	0%

ATTACHMENT FF-3

TRANSMISSION OWNERS ASSOCIATED WITH EACH PLANNING SUB-REGION

<u>CENTRAL</u>

AmerenCILCO

AmerenIP

AmerenUE and AmerenCIPS

Big Rivers Electric Corporation

City Water, Light and Power (Springfield IL)

Duke Energy Business Services, LLC (f/k/a Cinergy Services, Inc.) Duke Energy Indiana, Inc. (f/k/a PSI Energy, Inc.)

Hoosier Energy Rural Electric Cooperative, Inc.

Indiana Municipal Power Agency

Indianapolis Power & Light Company

Southern Illinois Power Cooperative

Vectren Energy for Southern Indiana Gas & Electric Company

Wabash Valley Power Association, Inc.

<u>EAST</u>

Michigan Electric Transmission Company, LLC.

Michigan Public Power Agency

Michigan South Central Power Agency

Northern Indiana Public Service Company

Wolverine Power Supply Cooperative

International Transmission Company

SOUTHERN

Cleco Power LLP

Entergy Arkansas, Inc.

Entergy Gulf States Louisiana, L.L.C.

Entergy Louisiana, LLC

Entergy Mississippi, Inc.

Entergy New Orleans, Inc.

Entergy Texas, Inc.

WEST

Allete, Inc. d/b/a Minnesota Power

American Transmission Company, LLC

Dairyland Power Cooperative

Great River Energy

ITC Midwest, LLC

MidAmerican Energy Company

Missouri River Energy Services

Montana-Dakota Utilities Co.

Muscatine Power and Water

Northern States Power Companies (Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation)

Northwestern Wisconsin Electric Company

Otter Tail Power Company

Southern Minnesota Municipal Power Agency

ATTACHMENT FF-4

TRANSMISSION OWNERS INTEGRATING LOCAL PLANNING PROCESSES INTO

TRANSMISSION PROVIDER PLANNING PROCESSES

FOR ORDER 890 COMPLIANCE

(NOT FILING A SEPARATE LOCAL PLANNING PROCESSES)

Allete, Inc. d/b/a Minnesota Power

AmerenCILCO

AmerenIP

AmerenUE and AmerenCIPS

Big Rivers Electric Corporation

City Water, Light and Power (Springfield IL)

Cleco Power LLP

Dairyland Power Cooperative

Duke Energy Business Services, LLC (f/k/a Cinergy Services, Inc.) Duke Energy Indiana, Inc. (f/k/a PSI Energy, Inc.)

East Texas Electric Cooperative, Inc.

Entergy Arkansas, Inc.

Entergy Gulf States Louisiana, L.L.C.

Entergy Louisiana, LLC

Entergy Mississippi, Inc.

Entergy New Orleans, Inc.

Entergy Texas, Inc.

Great River Energy

Hoosier Energy Rural Electric Cooperative, Inc.

Indiana Municipal Power Agency

Indianapolis Power & Light Company

ITC Midwest, LLC

Lafayette City-Parish Consolidated Government

Michigan Electric Transmission Company, LLC.

Michigan Public Power Agency

Michigan South Central Power Agency

Missouri River Energy Services

Montana-Dakota Utilities Co.

Muscatine Power and Water

Northern Indiana Public Service Company

Northern States Power Companies (Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation)

Northwestern Wisconsin Electric Company

Otter Tail Power Company

South Mississippi Electric Power Association

Southern Illinois Power Cooperative

Southern Minnesota Municipal Power Agency

Vectren Energy for Southern Indiana Gas & Electric Company

Wabash Valley Power Association, Inc.

Wolverine Power Supply Cooperative

INDEPENDENT TRANSMISSION COMPANIES:

International Transmission Company

ATTACHMENT FF-5

TRANSMISSION OWNERS WITH SEPARATE LOCAL PLANNING PROCESSES

American Transmission Company, LLC

MidAmerican Energy Company

TRANSMISSION EXPANSION PLANNING AND COST ALLOCATION FOR SECOND PLANNING AREA'S TRANSITION

I. Transmission Expansion Plan

This Attachment FF-6 describes the planning process to be used by the Transmission Provider to develop the MISO Transmission Expansion Plan ("MTEP") and the applicable cost allocation of Network Upgrades during and after the Second Planning Area's Transition Period. Except as specifically identified in this Attachment FF-6, the allocation of the cost of MTEP projects shall in all other respects be governed by Attachment FF.

II. Planning of MTEP Projects

A. Applicability of MTEP Process

During and after the Second Planning Area's Transition Period, Attachment FF's MTEP process shall apply to MTEP projects terminating, whether exclusively or partly, in the Second Planning Area.

B. MTEP Studies and Plans to Evaluate Comparability

During the Second Planning Area's Transition Period, the Transmission Provider shall review the current states of the transmission systems in the First Planning Area and the Second Planning Area, using the planning processes identified in Attachment FF to the Tariff. The Transmission Provider shall also determine, pursuant to this Attachment FF-6, the comparability of the First Planning Area and the Second Planning Area with respect to their compliance with the Attachment FF Planning Criteria. To evaluate comparability of transmission system conditions during the Second Planning Area's Transition Period, the Transmission Provider will conduct planning studies for (1) Baseline Reliability Projects ("BRP"), (2) Market Efficiency Projects

("MEP"), and (3) Multi-Value Projects ("MVP").

1. Baseline Reliability Projects: The Transmission Provider shall apply the BRP criteria identified in Attachment FF to the planning of BRPs for the Second Planning Area to determine, pursuant to this Attachment FF-6, to what extent the Second Planning Area is not comparable in terms of the Transmission Provider's BRP criteria. When a BRP planned during the Second Planning Area's Transition Period will terminate exclusively in one Planning Area, the Transmission Provider's benefit assessment will consider only the BRP's benefits in the Planning Area where it terminates. These analyses of potential BRPs shall happen annually, with qualifying projects approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP as part of the normal MTEP cycle. At the end of the Second Planning Area's Transition Period, the Transmission Provider shall have identified BRPs for the Second Planning Area based on the same BRP process and criteria applicable to the First Planning Area, in order to achieve comparability of the Second Planning Area's compliance with the BRP criteria, pursuant to this Attachment FF-6. This identification of projects to achieve comparability shall include BRPs that have been approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP, and also BRPs that have been determined to be a solution to meet an identified need, but have not yet been approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP by the end of the fifth year of the Second Planning Area's Transition Period, with a forecast in-service date that is no more than five (5) years after the end of the Second Planning Area's Transition Period.

2. Market Efficiency Projects: The Transmission Provider shall apply the MEP criteria identified in Attachment FF to the planning of MEPs in the Second Planning Area. When an MEP planned during the Second Planning Area's Transition Period will terminate exclusively in one Planning Area, the Transmission Provider's benefit assessment will consider only the MEP's benefits in the Planning Area where it terminates. These analyses of potential MEPs shall happen annually, with qualifying projects approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP as part of the normal MTEP cycle. At the end of the Second Planning Area's Transition Period, the Transmission Provider shall have identified MEPs for the Second Planning Area based on the same MEP process and criteria applicable to the First Planning Area, in order to achieve comparability of the Second Planning Area's compliance with the MEP criteria, pursuant to this Attachment FF-6. This identification of projects to achieve comparability shall include MEPs that have been approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP, and also MEPs that have been determined to be a solution to meet an identified need, but have not yet been approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP by the end of the fifth year of the Second Planning Area's Transition Period, with a forecast in-service date that is no more than five (5) years after the end of the Second Planning Area's Transition Period.
3. Multi-Value Projects: The Transmission Provider will determine to what extent the Second Planning Area is not comparable in terms of the Transmission Provider's MVP criteria. When an MVP planned during the Second Planning Area's Transition Period will

terminate exclusively in one Planning Area, the Transmission Provider's benefit assessment will consider only the MVP's benefits in the Planning Area where it terminates. The Transmission Provider shall assess the comparability of the MVP portfolios that have been approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP before the Second Planning Area's Transition Period for the First Planning Area and the MVP portfolios that, during the Second Planning Area's Transition Period, have been approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP, as needed pursuant to the Attachment FF MVP criteria. Such assessment shall be made by conducting an analysis that evaluates the aggregate present value of forecast MVP benefits, spread across the combined Planning Areas, and an evaluation to determine whether such MVP benefits are roughly commensurate with the present value of the allocation of forecast costs calculated pursuant to the formulas set forth below. The cost-benefit formulas set forth below will be applied iteratively, as the Transmission Provider will evaluate alternative solutions to determine the MVP portfolio configuration that provides the most effective resolution to the identified Transmission Issues, and ensures that benefits are at least roughly commensurate with costs.

Where:

a. MVP Portfolio_1 = the portfolio of 17 MVPs approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP for the First Planning Area during MTEP10 and MTEP11 plus any other MVP portfolios planned for and exclusively benefiting the First Planning Area before the Second Planning Area's Transition Period, that are approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP before the Second Planning Area's Transition Period

b. MVP Portfolio_2 = the portfolio(s) of MVPs approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP during the Second Planning Area's Transition Period.

c. Combined MVP $_{\text{Por}}$tfolio = MVP Portfolio_1 + MVP Portfolio_2 = MVPP_{1+2}

d. LRZ = Local Resource Zone

e. Annual Benefits for a LRZ are calculated as the difference between the system including the existing topology plus MVP Portfolio_1 and the system including the existing topology plus the Combined MVP Portfolio. Annual Benefits for the Combined MVP Portfolio will be calculated using the same factors that were considered in evaluating the benefits of MVP Portfolio_1, and described in Attachment FF Section II.C.5

f. The Present Value calculations will reflect the projected cash flow streams. The costs cash flow stream will be calculated over a timeframe that includes: 1) the periods between the end of the Second Planning Area's Transition Period and the last in-service date for a project in MVP Portfolio_2, and 2) 20 years following the date that the last project in MVP Portfolio_2 goes into service. The benefits will be calculated based on the entire MVP Portfolio_2 over a timeframe that includes: 1) the periods between the end of the Second Planning Area's Transition Period and the last in-service date for a project in MVP Portfolio_2, and 2) 20 years following the date that the last project in MVP Portfolio_2 goes into service.

g. The formula in Section II.B.3 will be applied on a Local Resource Zone basis. Each Local Resource Zone in the First Planning Area must meet the test described in Section II.B.3.1 and each Local Resource Zone in the Second Planning Area must meet the test described in Section II.B.3.2 for a determination to be made that MVP benefits are roughly commensurate with the present value of the allocation of forecasted costs.

h. The present value calculation for both the annual benefits and annual costs will apply a discount rate representing the after-tax weighted average cost of capital of the Transmission Owners that make up the Transmission System.

1. First Planning Area

a. Where T = number of years of benefits and costs as described in Section II.B.3.f.

$$\sum_{i=1}^{T} PV\ MVPP_2\ Annual\ Benefits_i\ -$$

$$\left(\sum_{i=1}^{T} PV\ MVPP_1\ \ Annual\ Costs_i\ with\ Second\ Planning\ Area - \sum_{i=1}^{T} PV\ MVPP_1\ \ Annual\ Costs_i\ without\ Second\ Planning\ Area \right)$$

$$-\sum_{i=1}^{T} PV\ MVPP_2\ Annual\ Costs_i\ \geq\ 0$$

AND

2. Second Planning Area

a. Where T = number of years of benefits and costs as described in Section II.B.3.f.

$$\frac{\sum^{T}_{i=1}\ PV\ MVPP_2\ \ Annual\ Benefits_i}{\sum^{T}_{i=1}\ PV\ MVPP_{1+2}\ \ Annual\ Costs_i} \geq 1$$

III. Second Planning Area's Transition Period

A. Duration of Second Planning Area's Transition Period

Consistent with the length of the study and planning timelines required to comparably apply the Attachment FF requirements to the Second Planning Area, the Second Planning Area's Transition Period shall be a minimum five (5) years, plus the time needed to complete the MTEP approval cycle pending at the end of the fifth year of the Second Planning Area's Transition Period. The Second Planning Area's Transition Period shall commence when the first Entergy Operating Company conveys functional control of its transmission facilities to the Transmission Provider to provide Transmission Service under Module B of this Tariff, and shall not exceed six years.

B. Annual Progress Reports

At the end of the twelfth month following the commencement of the Second Planning Area's Transition Period, and every twelve months thereafter until the end of the Second Planning Area's Transition Period, the Transmission Provider shall file with the Commission an annual report on the progress in applying the MTEP planning criteria and processes to achieve comparability between the First Planning Area and the Second Planning Area. Within six (6) months before the end of the Second Planning Area's Transition Period, the Transmission Provider shall report to the Commission whether at that time there is a Combined MVP Portfolio as defined in Section II.B.3 hereof, or whether MISO's preliminary analysis indicates that a Combined MVP Portfolio as defined in Section II.B.3 hereof will be identified by the end of the Second Planning Area's Transition Period.

C. End of Second Planning Area's Transition Period

If Transmission Provider has identified a Combined MVP Portfolio as defined in Section II.B.3 hereof, the transition period shall be followed by a phase-in period of eight years for the allocation of MVP costs as described in Sections IV.B.4 and IV.B.5 of this Attachment FF-6.

In the event that a Combined MVP Portfolio as defined in Section II.B.3 cannot be identified by the conclusion of the Second Planning Area's Transition Period, the Transmission Provider shall: (1) allocate to the First Planning Area the cost of MVPs approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP before the Second Planning Area's Transition Period that terminate exclusively in the First Planning Area and were planned exclusively for the benefit of the First Planning Area prior to the Second Planning Area's Transition Period; (2) apply Attachment FF to determine whether the cost of MVPs that are approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP during the Second Planning Area's Transition Period should be shared across the two Planning Areas; and (3) use the planning process and cost allocation procedures set forth in Attachment FF as it exists at the time of project approval by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP for all future project approvals by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP. In the event that a Combined MVP Portfolio as defined in Section II.B.3 cannot be identified by the conclusion of the Second Planning Area's Transition Period, the cost of MVPs approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP during the Second Planning Area's Transition Period will only be shared across the two Planning Areas if the Transmission Provider determines that the applicable criteria of Attachment FF have been satisfied. The costs of projects other than MVPs that are approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP after the end of the Second Planning Area's Transition Period shall be allocated pursuant to Section IV.B.7 hereof.

IV. Cost Responsibility for MTEP Projects During and After the Second Planning Area's Transition Period

A. Cost Responsibility for MTEP Projects During the Second Planning Area's Transition Period

1. Projects Approved Before the Second Planning Area's Transition Period

During the Second Planning Area's Transition Period, Load and/or Pricing Zone(s) in the Second Planning Area shall not be allocated any costs of any MTEP projects (*i.e.*, BRPs, Generator Interconnection Projects ("GIP"), Transmission Delivery Service Projects ("TDSP"), MEPs, and MVPs) that were approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP before the commencement of the Second Planning Area's Transition Period.

2. Projects Approved During the Second Planning Area's Transition Period

(a) Projects Terminating in Both Planning Areas

During the Second Planning Area's Transition Period, projects (*i.e.*, BRPs, GIPs, TDSPs, MEPs, and/or MVPs) approved in any MTEP by the Transmission Provider's Board of Directors for inclusion in Appendix A during the Second Planning Area's Transition Period that terminate in both Planning Areas shall be allocated in accordance with Attachment FF.

(b) Projects Terminating Exclusively in One Planning Area

Projects approved by the Transmission Provider's Board of Directors for inclusion in any MTEP Appendix A during the Second Planning Area's Transition Period that terminate exclusively in one Planning Area shall be allocated only within such Planning Area during the Second Planning Area's Transition Period in accordance with Attachment FF, as modified by the provisions of this Attachment FF-6. For this purpose, any system-wide rate or cost allocation under the provisions of Attachment FF regarding the particular type of project shall be limited to the Planning Area where the project terminates exclusively.

i. During the Second Planning Area's Transition Period, Load and/or Pricing Zone(s) in the Second Planning Area shall not be allocated any costs of any MTEP projects (*i.e.*, BRPs, GIPs, TDSPs, MEPs, and/or MVPs) approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP during the Second Planning Area's Transition Period and terminating exclusively in the First Planning Area. Load and/or Pricing Zone(s) in the Second Planning Area shall be responsible for the applicable cost allocation of BRPs, GIPs, TDSPs, MEPs, and MVPs as set forth in Sections III.A.1.c—III.A.1.g of Attachment FF, respectively, that are approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP during the Second Planning Area's Transition Period, to the extent such projects terminate exclusively in the Second Planning Area.

ii. During the Second Planning Area's Transition Period, Load and/or Pricing Zone(s) in the First Planning Area shall not be allocated any costs of any MTEP projects (*i.e.*, BRPs, GIPs, TDSPs, MEPs, and/or MVPs) approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP, or identified, but not yet approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP, as a solution to meet an identified need and with a forecast in-service date that is no more than five (5) years after the end of the Second Planning Area's Transition Period and terminating exclusively in the Second Planning Area. Load and/or Pricing Zone(s) in the First Planning Area shall be responsible for the applicable cost allocation of MTEP projects (*i.e.*, BRPs, GIPs, TDSPs, MEPs, and MVPs) as set forth in Sections III.A.1.c—III.A.1.g of Attachment FF, respectively, that are approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP during the Second Planning Area's Transition Period, to the extent such projects terminate exclusively in the First Planning Area.

B. MTEP Project Cost Allocation After the End of the Second Planning Area's Transition Period

Notwithstanding any other provisions of this Tariff, the costs of Network Upgrades determined eligible for cost-sharing under Attachment FF, shall be allocated after the end of the Second Planning Area's Transition Period as follows:

1. Non-MVP Projects Approved Before the Second Planning Area's Transition Period

Load and/or Pricing Zone(s) in the Second Planning Area shall not be allocated any costs associated with BRPs, GIPs, TDSPs, and MEPs that were approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP before the commencement of the Second Planning Area's Transition Period. Load and/or Pricing Zone(s) in the First Planning Area shall not be allocated any costs of any projects planned and approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP in the

Second Planning Area's transmission plan prior to the commencement of the Second Planning Area's Transition Period.

2. Non-MVP Projects Approved During the Second Planning Area's Transition Period

(a) After the Second Planning Area's Transition Period, Load and/or Pricing Zone(s) in the Second Planning Area shall not be allocated any costs of any BRPs, GIPs, TDSPs or MEPs approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP during the Second Planning Area's Transition Period and terminating exclusively in the First Planning Area. Load and/or Pricing Zone(s) in the Second Planning Area shall be responsible for the applicable cost allocation of BRPs, GIPs, TDSPs, and MEPs as set forth in Sections III.A.1.c—III.A.1.g of Attachment FF, respectively, that are approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP during the Second Planning Area's Transition Period, to the extent such projects terminate exclusively in the Second Planning Area. Costs of any non-MVP projects identified, but are not yet approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP, during the Second Planning Area's Transition Period as a solution to meet a need and with a forecast in-service date no more than five (5) years after the end of the Second Planning Area's Transition Period shall also be allocated pursuant to this Attachment FF-6.

(b) During the Second Planning Area's Transition Period, Load and/or Pricing Zone(s) in the First Planning Area shall not be allocated any costs of any

BRPs, GIPs, TDSPs, or MEPs approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP during the Second Planning Area's Transition Period, or identified, but not yet approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP, during the Second Planning Area's Transition Period as a solution to meet an identified need and with a forecast in-service date that is no more than five (5) years after the end of the Second Planning Area's Transition Period and terminating exclusively in the Second Planning Area. Load and/or Pricing Zone(s) in the First Planning Area shall be responsible for the applicable cost allocation of BRPs, GIPs, TDSPs and MEPs as set forth in Sections III.A.1.c—III.A.1.g of Attachment FF, respectively, that are approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP during the Second Planning Area's Transition Period, to the extent such projects terminate exclusively in the First Planning Area.

3. First Planning Area MVPs Planned Before Second Planning Area's Transition Period, and Approved Before Second Planning Area's Transition Period

The cost of MVPs terminating exclusively in the First Planning Area, planned exclusively for the benefit of the First Planning Area prior to the Second Planning Area's Transition Period, and approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP before the Second Planning Area's Transition Period shall only be shared across the Planning Areas if the criteria set forth in Section II.B.3 of this Attachment FF-6 are satisfied, including the calculation of costs and benefits set forth therein, for the Combined MVP

Portfolio. If the criteria set forth in Section II.B.3 of this Attachment FF-6 are not satisfied, then the costs of such MVPs shall only be the responsibility of Load and/or Pricing Zones in the First Planning Area.

4. Combined MVP Portfolio MVPs Terminating Exclusively in the Second Planning Area

After the end of the Second Planning Area's Transition Period, provided that the Transmission Provider has identified a Combined MVP Portfolio as defined in Section II.B.3 of this Attachment FF-6, Load in the First Planning Area shall be responsible, pursuant to Attachment FF, for its allocation of costs associated with MVPs terminating exclusively in the Second Planning Area and approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP during the Second Planning Area's Transition Period in the following gradually increasing percentages:

First Year Following Termination of Second Planning Area's Transition Period: Twelve and one-half percent (12.5%) of the MVP Usage Rate ("MUR"),[1] for the first year following the end of the Second Planning Area's Transition Period applied to the Monthly Net Actual Energy Withdrawals. Export Schedules, and Through Schedules.

(a) **Second Year Following Termination of Second Planning Area's Transition Period:** Twenty-Five percent (25%) of the MUR for the second year following the end of the Second Planning Area's Transition Period applied to the Monthly Net Actual Energy Withdrawals, Export Schedules, and Through Schedules.

(b) **Third Year Following Termination of Second Planning Area's Transition Period:** Thirty-seven and one-half percent (37.5%) of the MUR for the third year following the end of the Second Planning Area's Transition Period applied to the Monthly Net Actual Energy Withdrawals, Export Schedules, and Through Schedules.

(c) **Fourth Year Following Termination of Second Planning Area's Transition Period:** Fifty percent (50%) of the MUR for the fourth year following the end of the Second Planning Area's Transition Period, applied to the Monthly Net Actual Energy Withdrawals, Export Schedules, and Through Schedules.

(d) **Fifth Year Following Termination of Second Planning Area's Transition Period:** Sixty-two and one-half percent (62.5%) of the MUR for the fifth year following the end of the Second Planning Area's Transition Period applied to the Monthly Net Actual Energy Withdrawals, Export Schedules, and Through Schedules.

(e) **Sixth Year Following Termination of Second Planning Area's Transition Period:** Seventy-five percent (75%) of the MUR for the sixth year following the end of the Second Planning Area's Transition Period, applied to the Monthly Net Actual Energy Withdrawals, Export Schedules, and Through Schedules.

(f) **Seventh Year Following Termination of Second Planning Area's Transition Period:** Eighty-seven and one-half percent (87.5%) of the

MUR for the seventh year following the end of the Second Planning Area's Transition Period applied to the Monthly Net Actual Energy Withdrawals, Export Schedules, and Through Schedules.

(g) **Eighth Year Following Termination of Second Planning Area's Transition Period:** One-hundred percent (100%) of the MUR for the eighth year and all subsequent years following the end of the Second Planning Area's Transition Period, pursuant to Section III.A.1.g of Attachment FF, applied to the Monthly Net Actual Energy Withdrawals, Export Schedules, and Through Schedules.

5. Combined MVP Portfolio MVPs Terminating Exclusively in the First Planning Area

After the end of the Second Planning Area's Transition Period, provided that the Transmission Provider has identified a Combined MVP Portfolio as defined in Section II.B.3 of this Attachment FF-6, Load in the Second Planning Area shall be responsible for a share of the costs of MVPs terminating exclusively in the First Planning Area and approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP before or during the Second Planning Area's Transition Period in the following gradually increasing percentages:

(a) **First Year Following Termination of Second Planning Area's Transition Period:** Twelve and one-half percent (12.5%) of the MUR for the first year following the end of the Second Planning Area's Transition Period applied to the Monthly Net Actual Energy Withdrawals, Export

Schedules, and Through Schedules.

(b) Second Year Following Termination of Second Planning Area's Transition Period: Twenty-Five percent (25%) of the MUR for the second year following the end of the Second Planning Area's Transition Period applied to the Monthly Net Actual Energy Withdrawals, Export Schedules, and Through Schedules.

(c) Third Year Following Termination of Second Planning Area's Transition Period: Thirty-seven and one-half percent (37.5%) of the MUR for the third year following the end of the Second Planning Area's Transition Period applied to the Monthly Net Actual Energy Withdrawals, Export Schedules, and Through Schedules.

(d) Fourth Year Following Termination of Second Planning Area's Transition Period: Fifty percent (50%) of the MUR for the fourth year following the end of the Second Planning Area's Transition Period, applied to the Monthly Net Actual Energy Withdrawals, Export Schedules, and Through Schedules.

(e) Fifth Year Following Termination of Second Planning Area's Transition Period: Sixty-two and one-half percent (62.5%) of the MUR for the fifth year following the end of the Second Planning Area's Transition Period applied to the Monthly Net Actual Energy Withdrawals, Export Schedules, and Through Schedules.

(f) Sixth Year Following Termination of Second Planning Area's

Transition Period: Seventy-five percent (75%) of the MUR for the sixth year following the end of the Second Planning Area's Transition Period, applied to the Monthly Net Actual Energy Withdrawals, Export Schedules, and Through Schedules.

(g) Seventh Year Following Termination of Second Planning Area's Transition Period: Eighty-seven and one-half percent (87.5%) of the MUR for the seventh year following the end of the Second Planning Area's Transition Period applied to the Monthly Net Actual Energy Withdrawals, Export Schedules, and Through Schedules.

(h) Eighth Year Following Termination of Second Planning Area's Transition Period: One-hundred percent (100%) of the MUR for the eighth year and all subsequent years following the end of the Second Planning Area's Transition Period, pursuant to Section III.A.1.g of Attachment FF, applied to the Monthly Net Actual Energy Withdrawals Export Schedules, and Through Schedules.

6. Projects Approved During the Second Planning Area's Transition Period Terminating in Both Planning Areas

After the end of the Second Planning Area's Transition Period, projects (i.e., BRPs, GIPs, TDSPs, MEPs, and/or MVPs) approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP during the Second Planning Area's Transition Period that terminate in both Planning Areas shall continue to be allocated in accordance with Attachment FF.

7. Projects Approved After the End of the Second Planning Area's

Transition Period

The cost of all projects approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP after the end of the Second Planning Area's Transition Period shall be allocated across the combined First and Second Planning Areas pursuant to Attachment FF, except the cost of those non-MVP projects identified, but not yet approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP, during the Second Planning Area's Transition Period as a solution to meet an identified need and with a forecast in-service date no more than five (5) years after the end of the Second Planning Area's Transition Period and terminating exclusively in the Second Planning Area, which will not be shared with the First Planning Area, pursuant to Section IV.B.2(b) of this Attachment FF-6.

C. Withdrawal Obligations

A Member that withdraws from the Transmission Provider shall remain responsible for all financial obligations incurred pursuant to this Attachment FF-6 while a Member of the Transmission Provider, and payments applicable to time periods prior to the effective date of such withdrawal shall be honored by the Transmission Provider and the withdrawing Member, including those pertaining to Network Upgrade projects approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP after the Second Planning Area's Transition Period while the withdrawing Transmission Owner was still a Member; provided, that, with regard to Network Upgrade projects approved by the Transmission Provider's Board of Directors for inclusion in Appendix A of the MTEP before or during the Second Planning Area's Transition Period, a withdrawing Member in the First Planning Area shall not be responsible for the cost of such projects terminating exclusively in the Second Planning Area, and a withdrawing Member in the Second Planning Area shall not be responsible for the cost of such projects terminating exclusively in the First Planning Area.

[1] See Schedule 26-A.

ATTACHMENT FF-
ATCLLC

A. For those Generator Interconnection Projects for which ATCLLC will be a signatory to the Interconnection Agreement under the terms of Attachment R or Attachment X of the Tariff or any successor provision of the Tariff executed by the parties after February 5, 2006, or Generating Interconnection Projects which achieve Commercial Operation after February 5, 2006, this Attachment FF-ATCLLC shall apply in lieu of any other provision of the Tariff.

B. Generation Interconnection Projects: Network Upgrade costs of Generation Interconnection Projects that are not determined by the Transmission Provider to be Baseline Reliability Projects, or that do not result in the advancement of a Baseline Reliability Project shall be reimbursed by ATCLLC as provided below. All Network Upgrade costs of the Generation Interconnection Projects will be initially paid for by the Interconnection Customer in accordance with the terms of the Interconnection Agreement entered into pursuant to Attachment X or Attachment R of this Tariff. To the extent the Interconnection Customer demonstrates at the time of commercial operation of the generating facility that the generating facility has been designated as a Network Resource in accordance with this Tariff, or that a contractual commitment has been entered into with a Network Customer for Capacity, or in the case of an Intermittent Resource, for Energy, from the generating facility for a period of one (1) year or longer, it will receive one hundred (100%) reimbursement of reimbursable costs.

C. For all amounts to be reimbursed by ATCLLC to Interconnection Customer in accordance with this Attachment FF – ATCLLC, ATCLLC will reimburse the sums actually received from Interconnection Customer in cash in accordance with the terms of the

Interconnection Agreement together with any interest provided for under the terms of the Interconnection Agreement.

D. For all amounts that are reimbursed by ATCLLC to Interconnection Customer in accordance with this Attachment FF-ATCLLC, fifty percent (50%) of such reimbursement will be recovered by ATCLLC under its Attachment O transmission rate formula and the remaining fifty percent (50%) will be recovered in the following manner depending on the voltage class of the Network Upgrade:

i. Projects of Voltage 100 kV through 344 kV: For projects with a voltage class of 100 kV through 344 kV, 50% of the total reimbursable costs shall be allocated on a sub-regional basis to all Transmission Customers in designated pricing zones. The designated pricing zones and the subregional allocation of the Project Cost shall be determined on a case-by-case basis in accordance with a Line Outage Distribution Factor Table ("LODF Table") developed by the Transmission Provider which is similar in form to that attached hereto as Attachment FF-2. The LODF Table is based on Transmission System topology and Line-Outage Distribution Factors associated with the project under consideration and is used to determine the pricing zones to be included in the sub-regional allocation of the Project Cost. The percentage of the sub-regional allocation assigned to each designated pricing zone shall be determined based on the relative share between pricing zones of the sum of the absolute value of the product of the Line-Outage Distribution Factor on each Branch Facility in a pricing zone and the length in miles of the Branch Facility.

ii. Projects of Voltage 345 kV and Higher: For projects with a voltage class of 345 kV or higher, 10% of the total reimbursable costs shall be allocated on a system-wide basis to all Transmission Customers and recovered through a system-wide rate. The remaining 40% of the total reimbursable costs of a project with a voltage class of 345kV or higher shall be allocated on a sub-regional basis to all Transmission Customers in designated pricing zones. The designated pricing zones and the sub-regional allocation of the Project Cost shall be determined on a case-by- case basis in accordance with a Line Outage Distribution Factor Table ("LODF Table") developed by the Transmission Provider similar in form to that attached hereto as Attachment

FF-2. The LODF Table is based on Transmission System topology and Line-Outage Distribution Factors associated with the project under consideration and is used to determine the pricing zones to be included in the subregional allocation of the Project Cost. The percentage of the sub-regional allocation assigned to each designated pricing zone shall be determined based on the relative share between pricing zones of the sum of the absolute value of the product of the Line-Outage Distribution Factor on each Branch Facility in a pricing zone and the length in miles of the Branch Facility.

Attachment FF – ATCLLC Local Planning Process

I. Introduction

American Transmission Company LLC ("ATCLLC"), as a member company of the Transmission Provider, pursuant to 18 C.F. R. §37.1, *et seq.*, establishes the following as the planning requirements applicable to transmission planning activities engaged in by ATCLLC under the provisions of this Tariff effective December 7, 2007, as may from time to time thereafter be modified, changed, or amended, in accordance with the rules and requirements of the FERC or as provided in this Attachment FF-ATCLLC.

II. Applicability

The following shall apply to the transmission planning processes described below in connection with the transmission system planning required to be performed, or which in the determination of ATCLLC should be performed in fulfilling ATCLLC's obligation to provide interconnection service and open access transmission service for the benefit of all users of its Transmission Facilities under state and federal law, and to assure the availability of reliable transmission service for the use and benefit of all users of ATCLLC's Transmission Facilities.

III. Purpose

The purpose of this Attachment FF-ATCLLC is to identify and set forth, consistent with the requirements of 18 C.F. R. §37.1, *et seq*, the practices and procedures of ATCLLC associated with planning for the addition to, modification of, or extension of ATCLLC's Transmission Facilities.

There are several different planning functions set forth in this Attachment FF-ATCLLC the purpose of which is to identify those changes, modifications, additions or extensions of ATCLLC's Transmission Facilities that are reasonable and appropriate to meet the requests of and needs of ATCLLC's Transmission and Interconnection Customers and the owners of the Distribution Facilities and Transmission Facilities that are interconnected to ATCLLC's Transmission Facilities and to fulfill Public Policy Requirements. Each planning function employs different processes or procedures to arrive at the appropriate electric solution, including the construction of new or modification of existing Transmission Facilities that would meet the needs of ATCLLC's Interconnection and Transmission Customers and the owners of the Distribution Facilities and Transmission Facilities that are interconnected to ATCLLC's Transmission Facilities and fulfill Public Policy Requirements, or which will reduce the delivered cost of electric energy in the area in which ATCLLC's Transmission Facilities are located.

IV. Definitions.

The definitions set forth below shall apply to this Attachment FF-ATCLLC. Any other capitalized term not otherwise defined shall have the meaning set forth in the Transmission Provider's Tariff.

"Best Value Planning" means the consideration of, or evaluation of, one or more alternatives to the proposed construction of new, or the modification of existing, Transmission Facilities which have been identified in a planning process to determine whether an alternative or alternatives exists that may include the construction of new, or the modification of the existing, Distribution Facilities or Transmission Facilities owned by others that is/are less costly or which may provide greater enhancement to the reliability, capability or integrity of ATCLLC's Transmission Facilities and such interconnected Transmission or Distribution Facilities when compared to the estimated cost of the construction and capability of the proposed new, or the proposed modification of, ATCLLC's Transmission Facilities, while taking into account the environmental considerations, regulatory approvals and the ability to construct the proposed Distribution or Transmission Facilities in a timely and appropriate manner.

"Business Practices" means the practices developed by ATCLLC with the participation of its Interconnection and Transmission Customers relating to the manner in which certain requests, certain activities, including the compensation to be paid for certain construction-related activities, that affect the Distribution Facilities owned by others that are affected by Transmission Facilities construction are to be handled by ATCLLC and how the owners of Distribution Facilities may be compensated if the construction of Transmission Facilities necessitates the addition to or modification of Distribution Facilities.

"Common Facilities" means those facilities at a Distribution – Transmission, Transmission – Transmission or Generation – Transmission Interconnection that are used and useful to both ATCLLC and the owner of the interconnected Generating Facility or Distribution Facilities that are located at the Distribution Interconnection or Point of Interconnection. Common Facilities include, but are not limited to batteries, structures that house equipment, ground grids, fences, gravel areas, parking areas, landscaping, access roads, yard lighting, shielding, and screening. Common Facilities do not include land, land rights or Interconnection Facilities.

"Distribution Customer" –means any entity whose Distribution Facilities are directly interconnected to the Transmission Facilities of ATCLLC and who has entered into a Distribution – Transmission Interconnection Agreement with ATCLLC or will, following the Distribution Interconnection Request planning analysis, be required to enter into a Distribution – Transmission Interconnection Agreement with ATCLLC.

"Distribution Interconnection" means the point at which the Transmission Facilities owned by ATCLLC that operate at 50 kV and above interconnect to the Distribution Facilities owned by others that operate at a voltage below 50 kV which serve the purpose of distributing energy to residential, commercial and or industrial end users through one or more distribution systems, or which are intended to support or otherwise enhance the other entity's ability requesting such Distribution Interconnection to render service to one or more residential, industrial or commercial end users. Distribution Interconnection may, under certain circumstances, include the interconnection of facilities operating at greater than 50 kV if the party requesting such interconnection is a public utility, municipal utility or cooperative utility subject to the laws of the state in which such interconnection is requested, and the Distribution Interconnection is for the purpose of fulfilling their obligation to render retail transmission or distribution electric service to such residential, commercial or industrial end users under the terms of a contract or state authorized, or municipally approved retail electric service requirement.

"Distribution Facilities" –means the equipment, facilities, or associated elements, including Common Facilities, owned or operated by others that are interconnected to ATCLLC's

Transmission Facilities which are used by such other party to distribute energy to others at voltages below 50 kV, either in the form of distribution transmission service or the retail distribution of energy to residential, commercial or industrial end users.

"Distribution – Transmission Interconnection Agreement" means the agreement entered into between ATCLLC and one or more Distribution Customers, accepted by the FERC, that sets forth the terms and conditions applicable to the interconnection of one or more Distribution Systems to the Transmission Facilities of ATCLLC. A form of the Distribution

– Transmission Interconnection Agreement is set forth at Appendix B to this Attachment FF-ATCLLC. The terms and conditions of the Distribution – Transmission Interconnection Agreement set forth at Appendix B may be changed, modified or revised by ATCLLC in its judgment and determination, but such change modification or revision shall be applicable to those Distribution – Transmission Interconnection Agreements entered into prior to such change, modification or revision only upon the agreement of the parties, or after approval of the FERC. All Distribution – Transmission Interconnection Agreements entered into with new entities shall be submitted for acceptance by the FERC.

"Distribution – Transmission Interconnection Request" means the request of one or more owners of Distribution Facilities to modify or change an existing Distribution Interconnection or to interconnect proposed new Distribution Facilities at one or more locations pursuant to the terms and conditions of an existing Distribution – Transmission Interconnection Agreement or under the terms of a new Distribution – Transmission Interconnection Agreement.

"Generation – Transmission Interconnection" means the interconnection of one or more generating facilities interconnected to ATCLLC under the terms of a Generation – Transmission Interconnection Agreement, accepted by the FERC, entered into by the owner or operator of such generating facility either with ATCLLC only or in conjunction with the Transmission Provider either under the requirements of the FERC or the provisions of Attachments R or X of this Tariff.

"Generation – Transmission Interconnection Agreement" means one or more agreements entered into between ATCLLC and the owners or operators of generating facilities, or the Generator Interconnection Agreement entered into between ATCLLC, the Transmission Provider and the Interconnection Customer under the provisions of Attachment R or Attachment X of the this Tariff that set forth the terms and conditions of interconnection service relating to the interconnection of one or more generating units to ATCLLC's Transmission Facilities.   A form of the Generation – Transmission Interconnection Agreement involving ATCLLC and the Interconnection Customer only is set included at ATCLLC's external web site at: http://www.atc10yearplan.com/A6.shtml. A form of the Large Generator Interconnection Agreement employed by the Transmission Provider is set forth at Attachment X of this Tariff.   A form of the Small Generator Interconnection Agreement is set forth at Attachment R of this Tariff.   All Generation – Transmission Interconnection Agreements to which ATCLLC is a party are or have been submitted to the FERC for acceptance.

"Generation – Transmission Interconnection Request" shall have the same meaning as set forth in this Tariff and shall apply to all requests to interconnect new or increased generating capacity to ATCLLC's Transmission Facilities irrespective of whether the request is made pursuant to a Generation – Transmission Interconnection Agreement to which ATCLLC is only a party, or whether the request is made pursuant to Attachments R or X or the terms and conditions of a Small Generator Interconnection Agreement or Large Generation-Transmission Interconnection Agreement in which the Transmission Provider is also a party.

"Operating Capability" means the ability of a piece of equipment or any element of the ATCLLC's Transmission Facilities to operate at any particular level, rate or capability, notwithstanding its Physical Capacity, when operated under the then existing operating conditions in conjunction with other elements of ATCLLC's Transmission Facilities.

"Public Policy Requirements" means enacted statutes (i.e., passed by the legislature and signed by the executive) and regulations promulgated by a relevant jurisdiction, whether within a state or at the federal level, including duly enacted laws or regulations passed by a local governmental entity, such as a municipal or county government.

"Physical Capacity" means the physical ability of any piece of equipment to operate without failure based upon its physical ability or operating rating or operating limits determined by the manufacturer or otherwise calculated or determined by ATCLLC to be the physical limit of any one item or element of its Transmission Facilities and as reported by ATCLLC to the Transmission Provider in accordance with the requirements of Appendix B of the ISO Agreement.

"Regional Planning" means the planning engaged in by ATCLLC under the provisions of this Attachment FF-ATCLLC with the owners or operators of the Transmission Facilities that are interconnected with the Transmission Facilities of ATCLLC or the owners and operators of Transmission Facilities that may be affected by any modification, addition or extension of ATCLLC's Transmission Facilities and pursuant to the provisions of Appendix B of the Agreement of the Transmission Facilities Owners to Organize the Midcontinent Independent System Operator, Inc., a Delaware Non-Stock Corporation, MISO FERC Electric Tariff, First Revised Rate Schedule No. 1 and Attachment FF of this Tariff. **"Ten Year Assessment"** means the report published by ATCLLC annually setting forth the planning activities engaged in by ATCLLC relating to its Network Adequacy, which incorporates the Distribution Interconnections and Generation – Transmission Interconnections requested and studied, and the Transmission Service Requests requested by Transmission Service Customers and which identifies those provisional, projected or planned Transmission Facilities construction projects that have been identified that are reasonably believed to meet the requests of ATCLLC's Interconnection and Transmission Customers, satisfy Public Policy Requirements, and assure the necessary Network Adequacy of its Transmission Facilities to provide safe, reliable transmission service with sufficient Operating Capability and Physical Capacity to meet the needs of all users of its Transmission Facilities.

"Transmission Customer" shall have the meaning set forth at Section 1.317 of this Tariff.

"Transmission Service Request" shall mean a Transmission Service Request made by a Transmission Customer or prospective Transmission Service Customer made under Module B of this Tariff and shall be governed by the provisions of this Tariff.

"Transmission Service" shall have the meaning set forth in Section 1.327 of this Tariff and shall be provided in accordance with the terms of this Tariff.

"Transmission – Transmission Interconnection" means the interconnection of Transmission Facilities owned by parties other than ATCLLC interconnected to or which are proposed to be interconnected to the Transmission Facilities of ATCLLC, and which are operated, or when constructed, will operate at a voltage greater than 50 kV or which are used by the owner to transmit bulk quantities of energy for or on behalf of itself or its customers under the terms of this Tariff or other comparable transmission service tariff, or pursuant to a

contract or agreement and which have been classified by the owner or the appropriate state regulatory authority as Transmission Facilities in accordance with the applicable provisions of Order No. 888 (FERC's "seven-factor test").[2]

"Transmission – Transmission Interconnection Agreement" means the agreement entered

into by ATCLLC and the owners or operators of Transmission Facilities, accepted by the FERC, that sets forth the terms and conditions relating to the interconnection of their Transmission Facilities to the Transmission Facilities owned by ATCLLC.

"Transmission Facilities" means the poles, wires, structures, substations, control devices, protection methods, and other related equipment owned by ATCLLC and operated at voltages of 50 kV and above and that are used to render Interconnection Service or Transmission Service to Interconnection and Transmission Customers under the provisions of this Tariff. The term "Transmission Facilities" also refers to like facilities owned by others which are used for the purpose of carrying bulk quantities of

electric energy for others or for the ultimate distribution of such electric energy to residential, commercial or industrial end users and which have been classified by the owner or the appropriate state regulatory authority as Transmission Facilities in accordance with the applicable provisions of Order No. 888
(FERC's "seven-factor test").[3]

V. Planning Processes. Consistent with the requirements of 18 C.F. R. §37.1, *et seq.,* ATCLLC sets forth its planning processes in detail below:

A. Planning Purpose. ATCLLC hereby identifies the various planning functions engaged in by ATCLLC. The purpose of each planning function is to either meet the requested need of one or more Interconnection Customers, Transmission Customers, or interconnected entity that owns Distribution Facilities or Transmission Facilities or which are necessary in ATCLLC's reasonable judgment to insure that ATCLLC's Transmission Facilities operate in a safe, reliable manner with sufficient Physical Capacity, Operating Capability and reliability to provide adequate transmission service to meet the needs of all users of its Transmission Facilities, fulfill Public Policy Requirements, to fulfill ATCLLC's legal obligations under state, local and federal law or regulation, and/or to reduce the cost of energy in the area in which ATCLLC's Transmission Facilities are located.

B. Planning Requests; Planning Requirements. The activities associated with each planning function, together with the processes, procedures and methods employed by ATCLLC depends on the type of request made by one or more Interconnection or Transmission Customers or the owners of the Distribution or Transmission Facilities interconnected to ATCLLC's Transmission Facilities. Additionally, for the purposes of: 1) network adequacy;

2) coordination with the owners of other Transmission Facilities; or 3) coordination with the Transmission Provider and the Pennsylvania-New Jersey-Maryland Interconnect LLC (PJM), ATCLLC engages in planning that in ATCLLC's judgment and determination is necessary to ensure the safe, reliable operation of its Transmission Facilities as a whole and to assure that there is sufficient Physical Capacity, Operating Capability and reliability to render open access, nondiscriminatory Interconnection and Transmission Service to all users of its Transmission Facilities.

C. **Planning Functions.** In order to assure reliable Transmission Facilities capable of rendering reliable Interconnection and Transmission Service with sufficient Physical Capacity, operating capability or reliability to meet the needs of all Transmission and Interconnection Customers, or the needs of other Distribution Facilities or Transmission Facilities Owners whose Distribution Facilities or Transmission Facilities are interconnected with ATCLLC's Transmission Facilities and to fulfill Public Policy Requirements, ATCLLC engages in the following planning functions:

Distribution – Transmission Interconnection

Planning Generator – Transmission

Interconnection Planning Transmission –

Transmission Interconnection Planning

Transmission Service Planning

Network Adequacy Planning

Regional Coordination Planning (Transmission – Transmission; Transmission Provider

Region; PJM Region)

Economic Project

Planning

D. Applicable Planning Criteria. In carrying out each planning function, ATCLLC shall use: (1) all applicable reliability requirements established by the North American Electric Reliability Corporation (NERC) or any successor Electric Reliability Organization certified by the FERC; (2) the criteria set forth at: http://www.atc10yearplan.com/A6.shtml; or (3) any reliability requirements established by the Regional Entities approved by NERC and the FERC, and with whom ATCLLC is registered, including Midwest Reliability Organization (MRO) or Reliability*First* Corporation (RFC); (4) all Public Policy Requirements, and, more specifically, when evaluating potential needs driven by Public Policy Requirements, ATCLLC will consider relevant factors such as: (i) the effective dates, nature and magnitude of the Public Policy Requirements in applicable laws and regulations; (ii) the immediacy or other estimated timing, and extent, of the potential impact on any identified transmission needs; and (iii) the relative significance of any other issues that have been raised for consideration in ATCLLC's local planning process; and (5) such other criteria as ATCLLC may from time to time determine, provided that in the event that there is any conflict between the criteria developed or employed by ATCLLC and those of MRO, RFC or NERC, then the criteria established by MRO, RFC or NERC shall apply.

E. Controlling Planning Criteria; Modifications to Planning Criteria. In the event that there is any conflict between the reliability criteria established by MRO or RFC, then the criteria established by MRO shall apply. In the event that there is any conflict between the reliability criteria established by MRO, RFC or NERC, then the more conservative or more restrictive criteria shall be applied by ATCLLC in performing its planning functions.

ATCLLC reserves the right to change,

modify, supplement or otherwise revise the criteria employed by ATCLLC and used in connection with any planning process identified in this Attachment FFATCLLC so long as such changed, modified, supplemented or revised criteria are applicable only to planning functions, or to projects proposed, planned or constructed that were identified in such planning functions subsequent to such change, modification, supplement or revision to the criteria, and provided further that such change, modification, supplement or revision shall become applicable thirty (30) days following the posting by ATCLLC of such revised criteria at: http://www.atc10yearplan.com/A6.shtml setting forth such change, modification, supplement or revision to the reliability criteria employed in any planning function or when required by NERC, MRO or RFC.   To the extent that the criteria employed by ATCLLC are not governed by the reliability criteria of NERC, MRO, RFC, or the rules and regulations of the FERC, or state, local or federal law or regulation establishing Public Policy Requirements, ATCLLC shall employ such criteria as, in ATCLLC's judgment, will provide the more effective means of planning for reliable Transmission Facilities that can be constructed in a cost effective manner, taking into account any state, local, federal legal or regulatory requirements that may be applicable, specifically including Public Policy Requirements, while taking into account Best Value Planning associated with any project identified which is proposed to be constructed as a result of the study or studies or other assessment performed in connection with one or more of the planning functions.

F. Planning Assessment Tools. ATCLLC employs a number of planning assessment tools in order to properly assess the Distribution – Transmission Interconnection Requests, the Generation – Transmission Interconnection Requests, the Transmission – Transmission Interconnection Requests, the network adequacy of its Transmission Facilities, and the inter-relationship of the results of its transmission plans on adjoining Distribution Facilities or Transmission Facilities owners or the Transmission Provider Region or PJM Region as a whole,

particularly in connection with the evaluation of proposed transmission projects that are based upon economic factors as well as reliability, capability and safety factors. The assessment tools employed by ATCLLC are set forth at: http://www.atc10yearplan.com/A6.shtml. ATTCLLC reserves the right to discontinue the use of certain assessment tools, or to add additional assessment tools in its reasonable judgment.

To the extent that ATCLLC discontinues the use of assessment tool, or begins using an assessment tool in connection with any of the planning functions identified below, the use of such assessment tool or tools or the discontinuance of the use of any assessment tool shall be effective upon posting such discontinuance by ATCLLC on the web page: http://www.atc10yearplan.com/A6.shtml. Any interested party may request, in writing, copies of the models developed using the assessment tools employed by ATCLLC in performing any planning function or associated analysis or assessment, and ATCLLC shall provide copies of such models under appropriate confidentiality agreements, subject to the rules and regulations of the FERC. To the extent that such models are used in connection with any proprietary software, hardware or other process owned or distributed by parties other than ATCLLC,

ATCLLC will identify the items required to run the requested models, but ATCLLC makes no representation concerning the use of or availability of any proprietary software, hardware or other process necessary to operate any model or assessment tool used or employed by ATCLLC. Any costs associated with acquiring the necessary software, hardware or other process to run or operate any model employed by ATCLLC in any planning function is the responsibility of the party requesting such model or assessment tool.

VI. Descriptions of Planning Functions. The means, methods, processes and procedures associated with each planning function are set forth below:

A. Distribution – Transmission Interconnection Planning

1. Distribution Interconnection Request. Any entity that owns or operates Distribution Facilities shall be entitled to make a request to modify any existing Distribution Interconnection or to propose a new Distribution Interconnection. To the extent that the party making such request is a party to a Distribution – Transmission Interconnection Agreement, the terms and conditions of the Distribution – Transmission Interconnection Agreement shall apply. To the extent that such entity is not yet a party to a Distribution – Transmission Interconnection Agreement, ATCLLC shall perform the study or assessment provided for in this Attachment FF- ATCLLC, provided such entity enters into such Distribution – Transmission Interconnection Agreement prior to the need on the part of ATCLLC to seek any state regulatory approval for, or to engage in, the construction of any Transmission or Interconnection Facilities that are determined to be necessary as a result of the study or assessment performed. The planning associated with any new, or modified Distribution Interconnection shall be undertaken upon receipt by ATCLLC of a written request by any entity and shall be subject to the load interconnection business practice established by ATCLLC. ATCLLC shall post its load interconnection business practice on its external web site at: http://www.atc10yearplan.com/A6.shtml for review by all interested parties. ATCLLC reserves the right to amend, modify, revise or supplement its Load Interconnection Business Practice. No amendment, modification, revision or supplement shall be effective until an amended, modified, revised or supplemented load interconnection business practice is posted on ATCLLC's external web site. All Distribution Interconnections are also subject to, and governed by, the terms and conditions of the Distribution – Transmission Interconnection Agreement between ATCLLC and the owners or operators of Distribution Facilities that are interconnected to ATCLLC's Transmission Facilities.

2. **Distribution Interconnection Study Request Queue.** Distribution Interconnection requests are studied or assessed by ATCLLC primarily upon a first come, first served basis. ATCLLC maintains a queue of Distribution Interconnection requests made by those entities owning Distribution Facilities that are interconnected to ATCLLC's Transmission Facilities. Each request is studied in the order in which such request was received, unless the requested date for in-service of the modification of an existing Distribution Interconnection or the establishment of a new Distribution Interconnection requires that ATCLLC study a Distribution Interconnection request prior to other earlier received requests, or the party requesting such Distribution Interconnection identifies such other circumstances, including but not limited to, loss of load, low voltage, or potential emergency circumstances that, in ATCLLC's judgment and determination, require that a later received request should be studied prior to earlier received requests, but which have a later in-service date or which do not involve any exigent circumstances. Subject to the forgoing, upon receipt of a written load interconnection request pursuant to the load interconnection business practice from an entity with whom ATCLLC has entered into a Distribution – Transmission Interconnection Agreement, or the same or similar request from any entity not currently a party to a Distribution – Transmission Interconnection Agreement, ATCLLC shall conduct the appropriate evaluation of its Transmission Facilities employing such models and such assessment tools as are appropriate in order to determine what if any modification, addition, or extension of its existing Transmission Facilities may be required in order to accommodate the new or modified Distribution Interconnection.

3. **Communication; Information.** ATCLLC shall communicate with the entity making such Distribution Interconnection request consistent with the load interconnection request business practice, and consistent with the requirements of 18 C.F.R. §358.1, *et seq*4. As frequently as is necessary to insure that the request of the Distribution Facilities' owner is appropriately addressed and that ATCLLC has sufficient information in order to properly assess the impact of the modification of the existing Distribution Interconnection or the proposed new Distribution Interconnection upon ATCLLC's Transmission Facilities. The entity making the written Distribution Interconnection request, in addition to the information required under the load interconnection business practice, shall, at the request of ATCLLC, provide such other information to ATCLLC as ATCLLC reasonably believes necessary, including but not limited to any studies performed by such entity, the estimated costs determined by such entity, and such other information as

ATCLLC in its reasonable judgment shall determine. To the extent that such Distribution Interconnection request is received from an entity not currently a party to a Distribution – Transmission Interconnection Agreement, ATCLLC shall commence and continue the study of such modification or new Distribution Interconnection, provided such entity agrees to enter into a Distribution – Transmission Interconnection Agreement and enters into such agreement prior to ATCLLC being required to seek regulatory approval for the construction of any Transmission Facilities determined to be necessary as a result of such study. In the event that no regulatory approval is required prior to the construction of any Transmission Facilities determined to be necessary, then the parties shall enter into such Distribution – Transmission Interconnection Agreement prior to the commencement of construction of any Transmission Facilities.

4. **Distribution Interconnection Planning Meetings.** In addition to specific Distribution Interconnection requests, ATCLLC shall, at periodic intervals, hold meetings with individual owners of Distribution Facilities, either collectively, individually, or in small groups of similarly situated or electrically inter-related Distribution Facilities in order to assess the need for specific load interconnection requests and to assess whether the current load interconnection requests are appropriate to meet the needs of an owner of such Distribution Facilities. Such meetings will also provide an opportunity for ATCCLLC to obtain such other information, or to validate previously received information, and to discuss with such Distribution Facility owners whether the studies or assessments then being performed or which are to be performed, are appropriate to meet their respective needs, and to determine whether the study models or assessment tools are appropriate for the particular Distribution Interconnection or Distribution Facilities owner's requirements.

ATCLLC shall conduct meetings regularly and involve those owners of Distribution Facilities whose distribution systems are, or based on ATCLLC's initial assessment, may be affected by a proposed Distribution Interconnection or which may be experiencing significant change, modification or revision. ATCLLC shall organize such meetings, and solicit information for the agenda for such meetings. Meetings may be telephonic or may be located at the offices of one of the owners in Distribution Facilities or one of the offices of ATCLLC depending on the location of the principal offices of the owner of the Distribution Facilities.

5. Study Results. Upon completion of its study or assessment, ATCLLC shall, consistent with the rules and regulations of the FERC relating to Standards of Conduct and Critical Energy Infrastructure Information (CEII), provide to the party requesting the Distribution Interconnection the results of its study or assessment, and shall identify the Transmission Facilities that, based on its study, have been determined to be necessary to permit the modification of the existing Distribution Interconnection or to interconnect the proposed new Distribution Interconnection together with a preliminary estimate of the costs associated with the regulatory approval of, if any, and the estimated cost of constructing such Transmission Facilities.

6. Best Value Planning. In addition, ATCLLC and the party requesting such

Distribution Interconnection, shall engage in Best Value Planning to determine whether there are

other distribution system modifications, additions or extensions that may provide the same or greater benefit to facilitate the modification to the existing Distribution Interconnection or which will support the proposed new Distribution Interconnection at a lower estimated cost, or which, for a greater estimated cost, could provide a greater benefit to both the Distribution Facilities and the Transmission Facilities. The entity requesting such Distribution Interconnection shall provide such additional information, as ATCLLC may reasonably request including the estimated cost of constructing such alternatives to the Transmission Facilities identified in ATCLLC's study or studies or other assessment.

7. Effect on other Transmission or Distribution Systems. To the extent that a Distribution Interconnection Request is determined to have, an impact on the Distribution or Transmission Facilities owned by others or Public Policy Requirements, ATCLLC shall provide the information necessary or the results of its study or assessment to the owner or owners of such other Distribution or Transmission Facilities subject to the rules and regulations of the FERC relating to Standards of Conduct and CEII. To the extent appropriate, ATCLLC, the party requesting the Distribution Interconnection and the party or parties owning such affected Distribution or Transmission Facilities shall engage in such further planning and assessment, including such meetings (whether telephonic or in person), including Best Value Planning to determine what Distribution or Transmission Facilities may be required to fulfill the Distribution Interconnection request, giving consideration to the impact of such interconnection on the Transmission Facilities of ATCLLC and the impact of such Distribution Interconnection request on the Distribution or Transmission Facilities of such other party or parties.

8. Inclusion of Distribution Interconnection Request Study Results in other

Planning Functions. To the extent necessary and appropriate, ATCLLC shall incorporate the results of the studies or assessments performed for any and all Distribution Interconnection requests in its network assessment. ATCLLC shall reflect such modifications to existing Distribution Interconnections or proposed new Distribution Interconnections in any Generation – Transmission Interconnection study or assessment or in any other Distribution Interconnection study or assessment that may be electrically affected by the Distribution Interconnection request, and the Transmission Facilities that are determined to be necessary as a result of such study or studies or other assessment shall be incorporated into such other planning function, including but not limited to, other Distribution Interconnection requests, Generation Interconnection requests, Transmission Service Request, network assessment, regional plans, or the MISO Transmission Expansion Plan ("MTEP"), to the extent necessary or appropriate to reflect the effect of such request or the Transmission Facilities determined necessary to fulfill such request on the configuration or ATCLLC's Transmission Facilities, and shall be incorporated in any models or assessment tools utilized in such other planning functions.

9. Cost Allocation of Transmission Facilities Required to Fulfill a Distribution Interconnection Request. The allocation of the costs of any Transmission Facilities constructed by ATCLLC determined to be necessary to fulfill any Distribution Interconnection request shall be handled in the following manner:

A. To the extent that such Transmission Facilities are necessary to permit ATCLLC to render adequate service under the terms of the Distribution – Transmission Interconnection Agreement, the costs associated with the construction of such Transmission Facilities shall be paid for by ATCLLC and those costs incurred shall be recovered in accordance with the provisions of Attachment O of this Tariff, or as otherwise may be recovered under the provisions of Attachment FF of this Tariff, or any successor provisions of this Tariff that permit

ATCLLC to recover its capital costs and revenue requirement associated with rendering Transmission and other services.

B. To the extent that any portion of the costs associated with the Distribution – Transmission Interconnection are governed by the business practices adopted by ATCLLC, then the responsibility for the payment of such costs shall be initially allocated between the Distribution Customer and ATCLLC in accordance with such business practices.

C. To the extent that any Transmission Facilities required to meet the needs of any Distribution Interconnection Request qualifies as a Baseline Reliability Project or to fulfill any Public Policy Requirement under the provisions of Attachment FF of this Tariff, then the costs associated with such Transmission Facilities shall be allocated in accordance with the provisions of Attachment FF of this Tariff.

B. Generator – Transmission Interconnection Planning

1. Generator Interconnection Requests. Requests received to interconnect new generating facilities or to modify existing Generator – Transmission Interconnections, to the extent that such request involves new generating capacity or an increase in the generating capacity currently interconnected to ATCLLC's Transmission Facilities at a Generation Interconnection are governed under the terms of Attachments R and X of this Tariff.

All requests to interconnect new or to increase the generating capacity of existing generating facilities shall be made to the Transmission Provider pursuant to either Attachment R or Attachment X of this Tariff. All studies required to assess the impact of such new or increased generating capacity shall be performed in accordance with Attachment R or Attachment X of this Tariff. The results of such studies, together with the Transmission Facilities that are determined to be required to interconnect such new or increased generating capacity shall be reflected in either an amendment to the existing Generation – Transmission Interconnection Agreement between ATCLLC and the Interconnection Customer, or where appropriate, between ATCLLC, the Interconnection Customer and the Transmission Provider, or a new Large Generator Interconnection Agreement or Small Generator Interconnection Agreement entered into pursuant to Attachment X or Attachment R of this Tariff.

2. Requests to Modify Existing Generation – Transmission Interconnections That Do Not Involve an Increase in Generating Capacity. Any Interconnection Customer may request, in writing, that ATCLLC perform any necessary studies or assessment of the impact of proposed modifications, additions, or supplemental Interconnection Facilities or auxiliary facilities to be installed by the Interconnection Customer at the existing Generation Interconnection with ATCLLC's Transmission Facilities or any Common Facilities located at the Point of Interconnection. In addition to the requirements set forth in this Attachment FF-ATCLLC, the results of such studies, together with the Transmission Facilities that are determined to be required to accommodate such modifications or additions may be reflected, if necessary, in an amendment to the existing Generation – Transmission Interconnection Agreement between ATCLLC and the Interconnection Customer pursuant to Attachment X or Attachment R of this Tariff.

3. Generation – Interconnection Request. Upon receipt by the Transmission Provider of a request under either Attachments R or X of this Tariff, the studies required under this Tariff shall be performed at the direction of the Transmission Provider. If the request does not involve new generating capacity or an increase in the generating capacity at an existing Point of Interconnection, then ATCLLC shall study or assess the impact on ATCLLC's Transmission Facilities of any modification, addition or supplement to the Interconnection Facilities, Common Facilities, or auxiliary facilities of the Interconnection Customer. ATCLLC shall perform such studies or assessment using such models or assessment tools as ATCLLC shall determine. ATCLLC shall perform such study or assessment in a reasonable period of time following receipt of such request. ATCLLC shall complete such study or assessment not more than ninety (90) days following receipt by ATCLLC of sufficient information from the Interconnection Customer to permit ATCLLC to perform the appropriate study or assessment of the impact of such addition, modification or supplement to the Interconnection Facilities, Common Facilities, or auxiliary facilities located at the Generation – Transmission Interconnection.

4. Generation – Transmission Interconnection Information; Communication. The Interconnection Customer shall provide ATCLLC with sufficient information in order to permit ATCLLC to perform such studies or assessments necessary to determine the impact of the addition, modification or supplement to the Interconnection Facilities, Common Facilities, or auxiliary facilities may have on ATCLLC's Transmission Facilities. The information that the Interconnection Customer shall supply shall include, but not be limited to information consistent with Attachments R and X of this Tariff, and such other information ATCLLC reasonably determines to be required to permit ATCLLC to perform the assessment or analysis. The Interconnection Customer and ATCLLC shall communicate as frequently as necessary in order to insure that ATCLLC has sufficient information to appropriately study or assess the impact of the change, modification, addition or supplement to the Interconnection Facilities, Common Facilities, or auxiliary facilities at the Generation – Transmission Interconnection.

5. Study Results; Completion. Upon receipt of the necessary information, ATCLLC shall, within a reasonable period of time not to exceed ninety (90) days following receipt of sufficient information from the Interconnection Customer, complete the study or studies or make such other appropriate assessment of the impact of the change, modification, addition or supplement

to the Interconnection Facilities, Common Facilities or auxiliary facilities at the Generation – Transmission Interconnection. Upon completion of the study or studies or other assessment, ATCLLC shall post on ATCLLC's external web site a copy of such study or studies or other assessment to the Interconnection Customer which shall identify the modifications, additions or extensions of ATCLLC's Transmission Facilities, together with the preliminary estimated costs, that ATCLLC has determined are required as a result of the change, modification, addition or supplement at the Generation – Transmission Interconnection.

6. Impact on Other Systems. To the extent that the impact of the change, modification, addition or supplement of the Interconnection Facilities, Common Facilities or auxiliary facilities at the Generation – Transmission Interconnection, based on ATCLLC's study or assessment, may have an impact on the Distribution or Transmission Facilities owned by others or Public Policy Requirements, ATCLLC shall so advise the Interconnection Customer. To the extent permitted and authorized in writing by the Interconnection Customer, ATCLLC will make a copy of its study or studies or other assessment available to the owners of the Distribution or Transmission Facilities that may be affected by the change, modification, addition or supplement to the Generation – Transmission Interconnection. To the extent authorized, ATCLLC, the Interconnection Customer and the owner or owners of the Distribution Facilities or Transmission Facilities that are affected by the change, modification, addition or supplement at the Generation – Transmission Interconnection shall engage in Best Value Planning to determine if there are other, less costly, or more appropriate solutions, other than the changes, modifications, additions or extensions of ATCLLC's Transmission Facilities in order to meet the Interconnection Customer's request, taking into account the environmental concerns, regulatory concerns (including Public Policy Requirements), and the estimated cost of such alternative or alternatives. Upon completion of any Best Value Planning, ATCLLC shall provide the Interconnection Customer with the results of such Best Value Planning study or assessment.

7. Inclusion of Generation Interconnection Studies in Other Planning Functions. The results of all studies or assessment of Generation Interconnections, whether performed pursuant to Attachments R or X of this Tariff, or the provisions of this Attachment FF-ATCLLC, shall be included by ATCLLC in any other planning function, and the Transmission Facilities that are determined to be necessary as a result of such study or studies or other assessment shall be incorporated into such other planning function, including but not limited to, other Generation Interconnection requests, Network Assessment, Regional Plans, or the MTEP, to the extent necessary or appropriate to reflect the effect of such change on the configuration or ATCLLC's Transmission Facilities, and shall be incorporated in any models or assessment tools utilized in all affected planning functions.

8. Allocation of Generation – Transmission Facilities Costs. To the extent that ATCLLC constructs any Transmission Facilities to fulfill any Generation Interconnection Request, the costs associated with such Transmission Facilities shall be allocated to the extent such Generation Interconnection Request is governed by the provisions of Attachment R or Attachment X of this Tariff. Then the costs associated with the construction of any Transmission Facilities required in connection with fulfilling such Generation Interconnection Request shall be allocated in accordance with the provisions of Attachment R or Attachment X, the provisions of the Small Generator Interconnection Agreement, the provisions of the Large Generator Interconnection Agreement, or the provisions of Attachment FF of this Tariff as applicable.

C. Transmission Service Planning

1. Transmission Service Requests. Transmission Service Requests shall be governed by the terms of this Tariff. Any request for Network Integration Transmission Service, Firm Point-to-Point Transmission Service, Interruptible Transmission Service or any other transmission-related service, including but not limited to, the change to any receipt or delivery point under any existing Transmission Service Agreement, or the receipt of any ancillary services, shall be made to the Transmission Provider and shall be governed by the provisions of this Tariff. The results of any studies or assessments performed in connection with any Transmission Service Request shall be included in any other planning function that may be affected by such Transmission Service Request, including but not limited to Distribution Interconnection Requests, Generation Interconnection Requests, Network Assessment, Public Policy Requirements, or Regional Planning, or the MTEP, to the extent necessary or required.

2. Allocation of Transmission Facilities Costs Related to Transmission Service Requests. To the extent that the study or assessment of any Transmission Service Request results in the construction of any Transmission Facilities, the costs associated with the construction of such Transmission Facilities shall be allocated in accordance with the provisions of this Tariff and the provisions of ATCLLC's Attachment O to this Tariff. To the extent that the Transmission Facilities are determined to be a Baseline Reliability Project, or Market Efficiency Project, or necessary to fulfill a Public Policy Requirement, then the costs associated with the construction of such Transmission Facilities shall be allocated in accordance with Attachment FF of this Tariff.

D. Network Adequacy Planning

1. Network Assessment; Ten Year Assessment. In addition to assessments made in connection with any requests made by any Interconnection or Transmission Customers, or the owners of any Distribution or Transmission Facilities interconnected with ATCLLC's Transmission Facilities, ATCLLC performs an assessment of the need to modify, extend, or construct

new Transmission Facilities to provide, safe, reliable, Interconnection and Transmission Service and to insure that its Transmission Facilities are capable of providing and have the Physical Capacity and Operating Capability to reliably provide adequate Transmission Service to meet the needs of all users of its Transmission Facilities and to fulfill all Public Policy Requirements. Each year, ATCLLC shall perform such studies and assessments of various attributes and elements of its Transmission Facilities in order to determine whether any change, modification, extension or addition to its Transmission Facilities is required over the next ten (10) year period. The results of such studies and assessments shall be published as ATCLLC's *Ten Year Assessment* (TYA). As described in more detail below, the TYA shall make an assessment of the Transmission Facility construction projects over a ten year planning horizon, and shall determine whether such projects are provisional, proposed or planned. For the purposes of this Attachment FF-ATCLLC and the TYA, a provisional project is one that has been identified, based on an initial assessment of one or more needs of ATCLLC's Transmission Facilities, either from a reliability, Physical Capacity, maintenance, Operating Capability or, Public Policy Requirement or economic requirement. However, the information available to support the need determination is either not yet sufficient or warrants further evaluation before the need can be adequately determined. For the purposes of this Attachment FF-ATCLLC and the TYA, a proposed project is one for which the electrical need has been sufficiently determined from a reliability, Physical Capacity, maintenance, Operating Capability, Public Policy Requirement or economic requirement, but for which there are more than one electrical solutions that could result in changes, additions, modifications or extensions to one or more elements of ATCLLC's Transmission Facilities. For the purposes of this Attachment FF-ATCLLC and the TYA, a planned project is one that is sufficiently justifiable on the basis of the electrical need to support the reliability, Operating Capability, maintenance, Physical Capacity, Public Policy Requirement or economic requirements of ATCLLC's

Transmission Facilities and that all other electrical solution alternatives have been considered and the planned projects determined to be the Transmission Facilities construction project that will meet the needs of ATCLLC and its Transmission and Interconnection Customers, and the needs of the owners of the Distribution and Transmission Facilities that are interconnected to ATCLLC's Transmission System.

2. Participation in and Information Gathering For the Network Assessment and the TYA. For the purposes of the TYA and the general Network Assessment, ATCLLC, not less frequently than annually, shall solicit information from all Interconnection Customers, Transmission Customers and the owners of all Distribution Facilities that are interconnected to ATCLLC's Transmission System, and other stakeholders, specifically including information relating to Public Policy Requirements. Each party shall be contacted by using the form letters included on ATCLLC's web page at: http://www.atc10yearplan.com/A6.shtmlpage, which request the supply of certain information concerning each recipient's current and projected use of ATCLLC's Transmission Facilities or the needs of their respective Interconnection or Distribution Facilities. Additionally, ATCLLC shall post on its web page a solicitation for information from stakeholders including federal, state, and local regulators regarding needs driven by Public Policy Requirements and potential Transmission Facilities to address those needs. The information set forth in such letters or received in response to such web page posting, shall be collected and compiled and taken into account in any models and assessment tools that ATCLLC uses to study and make its assessment of its Transmission Facilities requirements. In addition to the information solicited from all interconnected entities, federal, state and local regulators and other stakeholders as provided in this paragraph, ATCLLC shall contact such interconnected parties or other stakeholders as it deems necessary or appropriate to obtain all additional information, including, but not limited to load forecasts, generation requirements, generation retirements, generation outage schedules, demand response availability, including any demand response resources available to reduce demand for any interconnected entity that is interconnected to the facilities of ATCLLC or any entity that is interconnected to ATCLLC's facilities, and distribution construction programs, and Public Policy Requirements. ATCLLC shall incorporate or otherwise take into account the information provided by all Distribution Facilities owners, and shall incorporate or otherwise take into account all Distribution, Generation Interconnection and Transmission Service Requests previously studied or assessed by either ATCLLC or the Transmission Provider in conducting its studies and assessment of its Transmission Facilities needs. Furthermore, ATCLLC shall affirmatively conduct its own reasonable inquiries, if deemed necessary by ATCLLC, in an effort to ascertain the existence of any relevant Public Policy Requirements not identified through other means (*i.e.*, identified to ATCLLC by stakeholders), and ATCLLC shall incorporate or otherwise take into account all relevant information regarding Public Policy Requirements, without regard to whether such information was obtained from a stakeholder or resulted from ATCLLC's affirmative inquiry.

3. Information Verification. ATCLLC shall communicate with any party supplying information to be incorporated in or otherwise taken into account in performing the studies or assessments associated with the TYA. Such communication may be individually with the entity supplying such information, or may be with more than one owner of Distribution Facilities to the extent that their respective systems are electrically interrelated or otherwise have an impact or effect on their respective use or interconnection to

ATCLLC's Transmission Facilities. To obtain information, or to verify information that has been supplied, ATCLLC may:

A. Meet individually with the entity supplying the information, including Public Policy Requirement information. To the extent of such meeting, ATCLLC shall coordinate the date, time and location of such meeting or meetings, whether such meetings are to be telephonic or in person, and shall coordinate the determination of the agenda. Any such meetings shall be conducted in accordance with the requirements of ATCLLC's Standards of Conduct Agreements, the FERC's Standards of Conduct, and shall take into account the requirements of the FERC in connection with CEII.

B. Communicate telephonically or electronically with representatives of such entity supplying information requested or received by ATCLLC in connection with the TYA. Any meetings or communications shall be as frequent as the party supplying the information may request or as ATCLLC may determine to assure itself that the information supplied by such entity is complete, accurate and sufficient to permit ATCLLC to incorporate such information in the studies or assessments associated with the TYA. To the extent that ATCLLC has affirmatively identified relevant Public Policy Requirements, as referenced in V.D.2, above, ATLLC shall make inquiries, or take any other action, necessary to assure itself that the information regarding the Public Policy Requirement is complete, accurate, and sufficient to incorporate such information in the studies or assessments associated with the TYA.

4. **Information Review/Feedback by Stakeholders.** Following the verification of the data provided by interconnection customers, Transmission Customers and

the owners of all Distribution Facilities that are interconnected to ATCLLC's Transmission System, ATCLLC shall hold one or more meeting with customers and stakeholders to discuss the assumptions set forth for inclusion in the TYA and the models and assessment tools that will be used to perform the assessment, including the Public Policy Requirements. The meeting or meetings to discuss the TYA shall be held by ATCLLC at such locations and at such times as may be convenient for customers and other stakeholders. ATCLLC shall establish the date, time, and place for such meeting or meetings and ATCLLC shall post notice of such meeting or meetings on its external web site to provide notice to all parties in advance of such meeting or meetings. Information regarding assumptions and models, including Public Policy Requirements, shall be posted on ATCLLC's external web site. ATCLLC shall post on its web site an explanation of which transmission needs driven by Public Policy Requirements that will be considered in study assumptions, as well as any suggested Public Policy Requirements that will not be considered in study assumptions. ATCLLC shall also post on its web site an explanation as to why relevant transmission needs driven by Public Policy Requirements were, or were not, considered by ATCLLC in its study assumptions.

Any interconnection customer, Transmission Customer, owner of Distribution Facilities or Transmission Facilities, as well as any other stakeholder, including state regulators, local, state and federal governmental officials, and members of interested community organizations shall be entitled to participate in such meeting or meetings held to discuss assumptions and models, specifically including a discussion of ATCLLC's decision to include in, or exclude from, its proposed models any transmission needs driven by Public Policy Requirements. Participants in such meetings, or thereafter, shall be entitled to comment on, provide additional information associated with, or otherwise offer suggested revisions, changes, modifications or additions to the assumptions that will be used in performing the studies required by the TYA, specifically including ATCLLC's decision to include in or exclude from proposed models any transmission needs driven by Public Policy Requirements . Furthermore, Stakeholders may comment on the inputs provided to ATCLLC. Such comments, provided they are predicated on relevant facts, information not available during the study, or evaluation of the Network requirements, shall be considered by ATCLLC, and to the extent appropriate, included in the evaluation of the Network requirements, and may be included in the TYA analysis.

5. Studies and Assessments. ATCLLC shall perform such studies or assessments of its Network requirements employing the assessment tools set forth on ATCLLC's external web page at: http://www.atc10yearplan.com/A6.shtml as ATCLLC determines are appropriate or necessary, given the information supplied by the entities interconnected to its Transmission Facilities and interested stakeholders (specifically including, without limitation, identification by such stakeholders of 1) needs driven by Public Policy Requirements and/or 2) potential Transmission Facilities to address those needs) , or resulting from ATCLLC's own inquiries. ATCLLC reserves the right to verify the information supplied by others, or to make such additional assessments of the needs, systems or utilization of ATCLLC's Transmission Facilities as ATCLLC determines are appropriate in order to assure itself that the information utilized in any such model or assessment tool is as accurate and complete as necessary to permit ATCLLC to perform an appropriate assessment of its Network requirements. Further, ATCLLC shall, to the extent necessary, obtain from the Transmission Provider any information that the Transmission Provider may have, including Public Policy

Requirements, or employ any models developed by the Transmission Provider which will facilitate or otherwise permit ATCLLC to make an appropriate evaluation or assessment of the Network requirements for its Transmission Facilities.

6. Network Assessment Study Results. Upon the completion of its assessment of its Network requirements, ATCLLC shall publish and distribute to all parties wishing to receive a copy, its TYA. The TYA shall set forth the information obtained, the assumptions used in making such evaluation of is network requirements, including all Public Policy Requirements and shall identify the Transmission Facilities construction projects, including all Distribution Interconnections, Generation Interconnections, and other construction projects that ATCLLC has determined will meet the needs of its Interconnection Customers, Transmission Customers and the owners of the distribution systems interconnected to ATCLLC's Transmission Facilities and fulfill Public Policy Requirements over the next ten (10) year period. In determining the Transmission Facilities to be included in the TYA, ATCLLC shall include those Transmission Facilities that provide the most benefit to meet the needs of its Distribution Customers, Transmission Customers and all other parties whether interconnected to ATCLLC's Transmission Facilities or not, taking into account Public Policy Requirements and the effect of any demand response resource on overall network requirements and Public Policy Requirements. ATCLLC will determine the Transmission Facilities to be included in the TYA based upon a comparison of the reasonably estimated costs of construction of the Transmission Facilities and the reasonably estimated costs of any other transmission, generation or demand response resources proposed by others (provided the estimated costs are provided by the party proposing such other transmission, generation or demand response resource) based upon the ability of such alternatives to meet Public Policy Requirements and the anticipated needs of ATCLLC's Distribution Customers, Transmission Customers, and all other parties whether interconnected to ATCLLC's Transmission Facilities or not. The Transmission Facilities construction projects shall be identified as provisional, proposed, and planned, as defined in the TYA and this Attachment FF-ATCLLC. With respect to identified transmission needs driven by Public Policy Requirements, ATCLLC will provide in the TYA a written explanation of ATCLLC's decision to include in the TYA, or to exclude from the TYA, Transmission Facilities that would satisfy such transmission needs.

7. TYA Distribution. ATCLLC shall publish the TYA annually on its external web site and shall inform all entities that are interconnected to its Transmission Facilities, all state utility regulators in the states in which ATCLLC owns Transmission Facilities, and all other
stakeholders of the availability of the TYA.

8. TYA Evaluation. Following the publication of the TYA on its external web site and its dissemination of the notice to interconnected parties and other stakeholders, ATCLLC shall hold one or more meeting(s) with customers, state regulators and other stakeholders to discuss the conclusions set forth in the TYA, and the Transmission Facilities identified as provisional, proposed or planned solutions to meet the needs of ATCLLC's transmission system as a whole , specifically including any solutions intended to satisfy Public Policy Requirements and ATCLLC's decision to include in the TYA, or not to include in the TYA. Transmission Facilities that would satisfy identified transmission needs driven by Public

Policy Requirements. The meeting or meetings to discuss the TYA shall be held by ATCLLC at such locations and at such times as may be convenient for customers and other stakeholders. ATCLLC shall establish the date, time, place for such meeting or meetings following the publication of the TYA and shall post notice of such meeting or meetings on its external Web site to provide notice to all parties. Any interconnection customer, Transmission Customer, owner of Distribution Facilities or Transmission Facilities, as well as any other stakeholder, including state regulators, local, state and federal governmental officials, and members of interested community organizations shall be entitled to participate in such meeting or meetings held to discuss the TYA. Participants in such meetings, or thereafter, shall be entitled to comment on, provide additional information associated with, or otherwise offer suggested revisions, changes, modifications or additions to the conclusions reached in the TYA, and the identification of Transmission Facilities construction projects as set forth in the TYA, specifically including Transmission Facilities identified by ATCLLC as being necessary to meet a need driven by Public Policy Requirements. Such comments, provided they are predicated on relevant facts, information not available during the study or evaluation of the network requirements shall be considered, and to the extent appropriate, included in the next evaluation of the Network requirements, and may be included in succeeding TYA. With respect to any ATCLLC decision regarding Transmission Facilities identified by ATCLLC as being potentially necessary to meet a need driven by a Public Policy Requirement: ATCLLC reserves the right to reconsider its decision regarding such Transmission Facilities following receipt of additional information or comments from stakeholders, as discussed herein, or following further review of the TYA unilaterally initiated by ATLLC; and to, time permitting, revise the

TYA for the relevant year to address ATCLLC's revised decision regarding such Transmission Facilities.

9. Customer Evaluation Committee. In accordance with the Settlement entered into in Docket No. ER04-108-000 as approved by the FERC5, ATCLLC shall, by October 1 of each year, provide information to its Interconnection and Transmission Customers concerning the

Transmission Facilities construction projects that it intends to engage in during the next succeeding year, together with the estimated costs associated with such Transmission Facilities construction projects. ATCLLC shall post its proposed Revenue Requirement, including its forecasted costs to be recovered for any Transmission Facilities construction project to be engaged in during the succeeding year on its external web site. Thereafter, Interconnection and Transmission Customers shall be entitled to comment on the planned construction projects and such revenue requirement and costs associated with any or all planned Transmission Facilities construction project to be engaged in by ATCLLC during the succeeding year.

10. Inclusion in the MTEP. ATCLLC shall, consistent with Appendix B of the ISO Agreement and in accordance with the provisions of the Attachment FF of this Tariff, upon completion of the analysis of any proposed Transmission Facilities project, or upon the completion of the evaluation of its network adequacy, identify to the Transmission Provider those provisional, proposed or planned projects that ATCLLC, in its judgment, has determined should be constructed to meet the needs of its Interconnection and Transmission Customers in order to fulfill ATCLLC's obligation to provide interconnection service and open access transmission service for the benefit of all users of its Transmission Facilities.

E. Transmission – Transmission Interconnection Planning

1. Transmission – Transmission Interconnection and System Coordination. ATCLLC shall coordinate its Transmission Facilities assessment and any proposed Transmission Facilities construction with the owners of Transmission Facilities that are interconnected to ATCLLC's Transmission Facilities. The purpose of such coordination is to develop a coordinated assessment of the respective Transmission Facilities of the participating entities in order to identify any alternatives to any provisional, proposed or planned Transmission Facilities construction project identified in ATCLLC's TYA, or which may have been identified by one or more of the owners of those interconnected Transmission Facilities as a Transmission Facilities construction project to be engaged in by such other Transmission Facilities owner for which one or more provisional, proposed or planned Transmission Facilities construction projects identified by ATCLLC could be an alternative, or which, in accordance with the provisions of Attachment FF of this Tariff, or Appendix B of the ISO Agreement, may be determined by the Transmission Provider, in its regional planning coordination responsibilities, be combined with the provisional, proposed or planned project of one or more other transmission owners to provide a project that produces more appropriate reliability or economic benefits or is less costly in the aggregate.

2. Transmission Coordination Meetings. To the extent not provided for under Attachment FF of this Tariff relating to sub-regional planning meetings (SPM), Meetings of the owners of Transmission Facilities that are interconnected to ATCLLC's Transmission Facilities shall be held no less frequently than annually, and may be held more frequently as the circumstances may require or as the needs of the respective Transmission systems may warrant.

The meetings shall include ATCLLC and the representatives of at least one entity that owns Transmission Facilities that are interconnected to ATCLLC's Transmission Facilities. The meetings may be held in such locations, and at such time and place as ATCLLC and such owner or owners that intend to participate shall determine.

3. Information Exchange. ATCLLC and the owners of interconnected Transmission Facilities, in advance of such meeting or meetings, shall provide each other with the following information:

A. Any current Network assessment for the owners' respective Transmission Facilities.

B. The transmission or distribution construction plans of any owner of Distribution Facilities or other combined Transmission and Distribution Facilities that are interconnected to their respective systems, to the extent that such information can be provided consistent with the confidential nature of such information, and subject to the FERC's Standards of Conduct; such other information as is necessary or appropriate in order to determine the proposed Transmission Facilities Construction plans proposed by such other entity and the information used to arrive at such conclusion or assessment, including information regarding any Public Policy Requirements about which such other transmission owner may be aware.

4. Purpose. The purpose of such regional coordination of the assessment of the needs of the respective Transmission Facilities is to:

A. Identify Transmission System constraints or constrained interfaces between the respective Transmission systems.

B. Identify the problems of any load serving entity interconnected to the respective Transmission Facilities based upon the NERC mandatory planning requirements, regional requirements of the MRO or RFC, or the identified planning criteria of the respective owners of the Transmission Facilities, whichever is more conservative or restrictive.

C. Compare the respective needs of their Transmission systems and assess the provisional, proposed or planned Transmission Facilities construction projects of ATCLLC and such proposed projects identified by others to meet their respective needs, including Public Policy Requirement needs and develop such studies or assessments that will assist in determining whether there are other alternatives that could be considered that could achieve the same or greater electrical result either by alleviating one or more constraints on the respective Transmission systems or by providing greater Physical Capacity or Operating Capability or enhanced reliability or fulfilling any Public Policy Requirements at the same or lesser cost than the provisional, proposed or planned Transmission Facilities construction projects of ATCLLC or the proposed projects of such Transmission Facilities' owner or owners.

D. To the extent that the parties have made assessments of their respective Transmission Facilities and have determined that there are one or more provisional, proposed or planned Transmission Facilities construction projects that warrants further study to determine whether a coordinated solution may be more appropriate, the parties shall agree upon the model or assessment tool to be used, and shall supply sufficient information to permit both parties to perform the evaluation or assessment of their respective systems in order to determine whether there is a coordinated Transmission Facilities construction project, or one or more alternatives to one or more provisional, proposed or planned Transmission Facilities construction projects proposed in such Transmission Facilities assessment that could be constructed, either by one or the other, or jointly, that would provide the same or greater Transmission system benefit at a lower cost, or a greater benefit to both Transmission systems.

E. In connection with any assessment performed, the parties shall agree upon the criteria to be employed or otherwise incorporated in the evaluation, study or other assessment to be performed. In no event shall the criteria to be used be contrary to the mandatory reliability requirements of NERC, MRO, or RFC, but such criteria may be more restrictive or more conservative than the reliability requirements of NERC, MRO or RFC and shall include any Public Policy Requirements identified.

5. Study Results. The results of each party's assessment or the output of any model or assessment tool shall be shared with the other party or parties participating in such assessment, evaluation or analysis and have arrived at different results or different conclusions, the parties shall:

A. Determine if the results are a result of differing model characteristics, input information, assumptions or criteria used. To the extent possible, such differences shall be removed, or minimized, and to the greatest extent possible, the differences in such information, assumptions, model characteristics or criteria shall be eliminated. The comparative results of such evaluations, assessments or analyses shall be shared with all parties participating in the Transmission
– Transmission coordination.

B. The results of such comparative analyses, joint evaluations or assessment of the respective Transmission system requirements shall be included by ATCLLC in the next succeeding TYA following the conclusion of the study, assessment or other analysis performed the results of which have been jointly concurred in by all parties participating in such evaluation, assessment or analysis, and shall be incorporated, to the extent appropriate, in the Regional Plan of the Transmission Provider or PJM.

6. Transmission Facilities Construction and Cost Allocation. The costs associated with any Transmission Facilities construction project determined by such Transmission – Transmission Planning to be reasonably necessary shall be allocated in accordance with the requirements of any applicable state regulatory authority having jurisdiction over the siting of some or all of the construction, and, to the extent governed by the Transmission Provider or PJM transmission tariffs, in accordance with the provisions of the respective tariffs, or as otherwise may be agreed to by the Transmission Owners proposing the construction of such Transmission Facilities construction project.

7. Coordination with the Transmission Provider's Attachment FF SPM requirements. Upon the development by ATCLLC of any local transmission plans that set forth any provisional, proposed or planned transmission projects as provided for in this Attachment FF- ATCLLC, ATCLLC shall provide such provisional, proposed or planned projects to the Transmission Provider for consideration in accordance with the requirements of Appendix B of the ISO Agreement. ATCLLC may participate in any SPM process of the Transmission Provider in which the Transmission Provider is determining its regional planning requirements as a result of the local planning requirements determined by any other Transmission Owner under the provisions of Attachment FF of this Tariff.

F. Economic Project Planning.

1. Economic Evaluations. ATCLLC, at the request of one or more parties, irrespective of whether they are a Distribution Customer, Transmission Customer or interconnected in any manner to ATCLLC's Transmission Facilities, or upon its own determination, may make an assessment of its Transmission Facilities to determine whether the construction, modification, addition or extension of ATCLLC's Transmission Facilities or other potential transmission, generation or demand resources identified by any other party can provide economic benefits when compared to the cost of constructing the proposed Transmission Facilities or other transmission, generation or demand resources (provided the estimated costs are provided by the party proposing such other transmission, generation or demand response resource).

2. Request for Economic Evaluations. Any party, whether Interconnection Customer or Transmission Customer or not, may, by March 1 of any year, request that ATCLLC perform such study, assessment or analysis for any proposed Economic Project, including potential Transmission Facilities to address needs driven by Public Policy Requirements. By no later than April 15 of each year, ATCLLC shall determine the two proposed Economic Projects that, based on a preliminary assessment, could provide an economic benefit greater than the costs of constructing any required Transmission Facilities.

3. Economic Project Information. In order for ATCLLC to consider any proposed Economic Project, the party requesting that such evaluation, study or analysis be done, shall provide the following information:

A. Identification of the constrained element of ATCLLC's Transmission Facilities, or the designation of the node within the Transmission Provider region in which a constraint may exist.

B. A list of the elements of ATCLLC's Transmission Facilities that would be affected by such constraint.

4. Economic Project Posting. ATCLLC, by April 15 of each year, shall post on its external Web site all proposed Economic Projects, and shall post on its web site which two Economic Projects that ATCLLC has determined to perform. By no later than April 30 of each year, any Interconnection or Transmission Customer, state regulator or other stakeholder, may comment on the proposed Economic Projects and on the two identified by ATCLLC for further study or evaluation, specifically including Transmission Facilities identified to meet a need driven by Public Policy Requirements. ATCLLC shall post all comments received relating to the proposed Economic Projects. In the event that ATCLLC receives comments on the two Economic Projects that it proposes to study, ATCLLC may revise its determination on the Economic Projects to be evaluated. If ATCLLC changes its determination, ATCLLC shall, by no later than May 15, post the revised Economic Projects to be studied or evaluated.

5. Economic Project Selection Criteria. Annually, ATCLLC shall select the two Economic Projects for study based on the preliminary determination that the proposed

Economic Projects have the potential to provide the greatest economic value by reducing the delivered cost of energy or reducing Congestion Costs, for Interconnection and Transmission Customers, and interconnected parties when compared to the preliminarily estimated Transmission Facilities construction cost.

6. Economic Project Selection. ATCLLC shall set forth its reasons for selecting the Economic Projects that it intends to evaluate, study or otherwise analyze in sufficient detail to permit interested parties to determine the basis upon which the selections were made.

7. Economic Project Assessment Costs. The evaluation, assessment or analysis associated with the two economic projects selected by ATCLLC shall be performed at no cost to the party recommending that such economic project be evaluated, studied or assessed.

8. Time To Perform Such Economic Assessment, Study or Analysis.

To the extent possible, ATCLLC shall perform the necessary evaluation, assessment or study of such proposed economic projects within One Hundred and Eighty (180) days of the posting of the selection of the economic projects. However, ATCLLC expressly reserves the right to delay the completion of any economic project analysis in order to permit ATCLLC to conduct an appropriate analysis, evaluation or assessment. If ATCLLC is unable to provide the results of its evaluation, assessment or analysis of the economic projects within the 180-day period, ATCLLC shall post on its web site an interim report indicating the nature of the evaluation, analysis or assessment completed, and the amount of such evaluation, analysis or assessment remaining, together with an estimated date when such economic project evaluation, analysis or assessment is to be completed.

9. Economic Project Study Models and Assumptions. The Party recommending the economic project may suggest the study models or assumptions to be used by ATCLLC. ATCLLC will use all reasonable effort to incorporate the proposed assumptions or models suggested by such parties, including consideration of Public Policy Requirements. ATCLLC by April 15 shall post the assumptions, study models and assessment tools on its web site and customers, state regulators and other stakeholders shall have until April 30, to comment on the assumptions, study models and assessment tools. ATCLLC shall post on its web site an explanation of which transmission needs driven by Public Policy Requirements that will be considered in study assumptions, as well as any suggested Public Policy Requirements that will not be considered in study assumptions. ATCLLC shall also post on its web site an explanation as to why relevant transmission needs driven by Public Policy Requirements were, or were not, considered by ATCLLC in its study assumptions. ATCLLC reserves the right to employ such models or assessment tools as it deems appropriate to evaluate, analyze or assess such proposed economic project. The Party or other stakeholders recommending the economic project may suggest assumptions to be used by ATCLLC in the analysis; however, ATCLLC reserves the right to employ such assumptions as it deems appropriate to evaluate, analyze or assess such proposed Economic Project.

10. Additional Economic Projects. To the extent that ATCLLC has the ability to do so, ATCLLC may conduct such other economic project evaluation, analysis or assessment as possible, given the planning resources available to perform such evaluation, analysis or assessment. Any party requesting that ATCLLC perform the evaluation, analysis or assessment of any other economic project other than those identified by ATCLLC that it will perform must agree to pay the costs associated with such evaluation, analysis or assessment, which may be performed by others, but which must be performed under the control of, and at the direction of ATCLLC in order to incorporate such evaluation, analysis or assessment in ATCLLC's TYA. Any party requesting that ATCLLC perform the evaluation, analysis or assessment of any other economic project other than those identified by ATCLLC that it will perform must agree to publicly post the results of the study if ATCLLC determines this is appropriate to meet FERC Standards of Conduct or CEII regulations. For those economic studies requested by one or more Parties to be paid for by such party requesting such study or studies, ATCLLC shall estimate the time necessary to perform such study or studies and the estimated costs associated with performing such study or studies, and shall provide the estimated time and costs to the party or parties requesting such study or studies. The costs estimated shall be paid to ATCLLC prior to ATCLLC commencing such study or studies. Upon receipt of the estimated amount, ATCLLC shall commence performance of the study or studies. In the event that the estimated time or costs are determined by ATCLLC to be insufficient to complete the study or studies, ATCLLC shall provide written notification of such additional time or increased costs to the party or parties responsible for paying for such study or studies. Within thirty (30) days following receipt of such notice, such party or parties shall acknowledge in writing the increased time and shall, to the extent applicable, pay the revised estimated amount. However, if a party or parities dispute the revised amount of time or estimated costs, then such dispute shall be resolved in accordance with Section VI. B. below. In the event that the actual cost incurred by ATCLLC in performing any economic study or studies is (are) less than the amount estimated by ATCLLC, then ATCLLC shall refund to such party or parties any excess amount received by ATCLLC within thirty (30) days following the posting of such economic study or studies.

11. Economic Project Study Results. The results of such Economic Project evaluation, analysis or assessment shall be posted on ATCLLC's web site upon completion.

12. Transmission Facilities Construction Cost. To the extent that any Economic Project evaluation, analysis or assessment concludes that modifications, additions, expansions or extensions to ATCLLC's Transmission Facilities are appropriate and should be constructed, the costs once constructed shall be recovered pursuant to the provisions of Attachment FF of this Tariff provided such meet the definition of "Market Efficiency Project" under the provisions of Attachment FF of this Tariff. However, ATCLLC acknowledges that all Transmission Facilities construction projects that are Economic Projects, and which may produce appropriate economic benefits when compared to the cost of constructing such Transmission Facilities may not be entitled to treatment as Market Efficiency Projects under the provisions of Attachment FF of this Tariff. In such event, ATCLLC, if such Transmission Facilities are constructed and are not treated as a Market Efficiency Project under Attachment FF, shall collect the costs associated with the construction of such Transmission Facilities pursuant to Attachment O of this Tariff.

VII. Dispute Resolution.

In the event that a dispute arises between ATCLLC and the owner of any Distribution Facilities, Transmission Facilities, or an Interconnection Customer, Transmission Customer or other stakeholder in connection with any planning process set forth above, the following dispute resolution provisions shall apply:

A. Disputes Arising Under Any Generation Interconnection Request or Transmission Service Request. All disputes arising under any Generation Interconnection Request or Transmission Service Request shall be handled in accordance with Article 12 and Attachment HH of this Tariff, provided however, that to the extent that such Generation Interconnection dispute arises in connection with any Generation Interconnection planning associated with a Generation Interconnection request that does not involve a new generating facility or the increase in the capacity of any existing generating capacity, then such dispute shall be handled under the provisions of the applicable Generation – Transmission Interconnection Agreement.

B. Disputes Arising in Connection with the Network Assessment or Evaluation of Economic Projects. All disputes arising between ATCLLC and any interconnected entity, Interconnection Customer, Transmission Customer or other interested stakeholder in connection with ATCLLC's Network Assessment or its TYA, shall be handled in accordance with the provisions of Appendix B of the ATCLLC Operating Agreement.

C. Disputes Arising in Connection with Distribution Interconnection Requests. Any dispute arising between ATCLLC and any party making a Distribution Interconnection request shall be handled in accordance with the provisions of the Distribution – Transmission Interconnection Agreement entered into between ATCLLC and such party. If no Distribution –

Transmission Interconnection Agreement has been entered into, then any dispute shall be resolved as if the parties had entered into a Distribution – Transmission Interconnection Agreement.

D. Disputes Arising in Connection with Public Policy Requirements.

Any dispute arising between ATCLLC and any interested party respecting the applicability of any Public Policy Requirement, ATCLLC's decision to include or exclude certain Public Policy Requirements in ATCLLC's TYA study assumptions, or ATCLLC's decision to include in, or exclude from, the TYA Transmission Facilities identified to address transmission needs driven by Public Policy Requirements, shall be handled in accordance with Article 12 and Attachment HH of this Tariff.

VIII. Planning Costs

The costs incurred by ATCLLC in connection with performing the planning functions set forth above will be collected by ATCLLC through Attachment O of the MISO Tariff as annual operating expense. Any planning costs incurred pursuant to Generator-Transmission Interconnections are determined in accordance with Attachments R and X of this Tariff and are collected pursuant to those Attachments.

[1] Transformer voltage is defined by the voltage of the low-side of the transformer for these purposes.

[2] *See* Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996) at 31,771.

[3] *See Order No. 888 at* 31,771.

[4]

ATCLLC has entered into a number of Distribution – Transmission Interconnection Agreements with Affiliates as that term is used in 18 C.F.R. §358.1, *et seq.* Pursuant to ATCLLC's Compliance Plan, the communication between ATCLLC and its affiliates in connection with Distribution Interconnections is only with those distribution system planners of such affiliates and is governed by the terms of the Confidential Data Access Agreement (CDAA) entered into between ATCLLC and such Affiliate. ATCLLC's Compliance Plan and the companion CDAA was reviewed by the FERC in Docket No. TS04-76-000. *See Standards of Conduct for Transmission Providers, Docket No. RM0110-000, Order No. 2004 Compliance Filing, American Transmission Company LLC* (Docket No. TS04-76-000) (February 9, 2004). Also see *Request of American Transmission Company LLC for Limited Waiver and Clarification of the Standards of Conduct* (Docket No. TS04-76-001) (July 8, 2004).

[5] *American Transmission Company LLC,* 107 FERC ¶61,117 (2004).

ATTACHMENT FF – MIDAMERICAN

LOCAL TRANSMISSION PLANNING PROCESS

I. Introduction

MidAmerican Energy Company ("MidAmerican"), as a member company of the Transmission Provider, pursuant to 18 C.F. R. §37.1, *et seq.*, engages in local system planning in order to carry out its responsibilities for meeting its respective transmission needs in collaboration with the Transmission Provider subject to the requirements of applicable state law or regulatory authority. In meeting its responsibilities under the ISO Agreement, MidAmerican may, as appropriate, develop and propose plans involving modifications to any of MidAmerican's transmission facilities which are part of the Transmission System.
The following provides the planning requirements applicable to MidAmerican's local system planning process engaged in by MidAmerican under the provisions of this Tariff, as may from time to time thereafter be modified, changed, or amended, in accordance with the rules and requirements of the FERC or as provided in this Attachment FF-MidAmerican. MidAmerican sets forth its local transmission planning processes in detail below to meet the nine planning principles set forth in FERC Order No. 890.

II. Definitions

The definitions set forth below shall apply to this Attachment FF-MidAmerican. Any other capitalized term not otherwise defined shall have the meaning set forth in the Transmission Provider's Tariff or in FERC's rules and regulations.

“MidAmerican Local Transmission Planning Process” means the process conducted by MidAmerican for Local Transmission Planning as described in the Transmission Provider’s Tariff.

“MidAmerican” means MidAmerican Energy Company.

“Registered Stakeholder” means a stakeholder which has registered its intent to participate in the MidAmerican Local Transmission Planning Process with the MidAmerican Transmission Planning Process Technical Contact or a stakeholder that MidAmerican transmission planners have registered as representatives of the stakeholders listed in Section V that follows.

III. Scope

The MidAmerican Local Transmission Planning Process described in this Attachment FF-MidAmerican covers MidAmerican’s portion of the Transmission System under the Tariff. The purpose of the MidAmerican Local Transmission Planning Process is to conduct local long- term planning for transmission facilities consistent with the Transmission Provider’s planning cycle with assessments to serve MidAmerican’s native end-use load and the Transmission Provider’s firm transmission commitments. The MidAmerican Local Transmission Planning Process does not extend to specific retail or wholesale customer service requests. The process provides comparable long-term transmission system planning for similarly-situated wholesale customers. The process provides long-term reliability and economic planning of transmission facilities for MidAmerican’s portion of the Transmission System for firm commitments (e.g., point-to-point service of five years duration or longer with rollover rights) and Network Customers under the Tariff which are served from MidAmerican’s portion of the Transmission System, which includes MidAmerican’s native end-use load. The process provides long-term economic planning of facilities on MidAmerican’s portion of the Transmission System for third-party generators connected to MidAmerican’s portion of the Transmission System that is comparable to the long-term economic planning for MidAmerican generators connected to MidAmerican's portion of the Transmission System as detailed in Section XI.8 of the Tariff. This is done by modeling from the generation to the Transmission Provider's Network Load on the MidAmerican portion of the Transmission System.

IV. Responsibilities

MidAmerican will be responsible for the development of the transmission plans that result from the MidAmerican Local Transmission Planning Process. The MidAmerican Local Transmission Planning Process will allow timely and meaningful stakeholder input and participation in the development of these transmission plans. The MidAmerican Local Transmission Planning Process will follow regional planning procedures provided in this Attachment FF-MidAmerican. The transmission plans and studies resulting from the MidAmerican Local Transmission Planning Process which are to be included in the Transmission Provider's Transmission Expansion Plan will be submitted to the Transmission Provider in accordance with the regional planning process as established by the Transmission Provider consistent with this Attachment FF, and the Transmission Planning Business Practices of the Transmission Provider.

In addition to developing transmission plans to be provided to the Transmission Provider for regional coordinated planning, the MidAmerican Local Transmission Planning Process will develop plans to address local MidAmerican transmission issues, such as transmission facility uprates that do not significantly change network system flows. MidAmerican will select transmission issues, including but not limited to those involving transmission needs driven by public policy requirements, to be considered in the planning process for which transmission solutions will be evaluated based on the scope of planning studies to be undertaken, the development of future scenarios to be modeled and analyzed in long-term planning studies, and the development of suitable models and assumptions to support such studies. MidAmerican

will evaluate transmission needs driven by public policy requirements in accordance with Section XII. of this Attachment FF - MidAmerican. The plans will be provided in reports with executive summaries that are brief and designed to be understandable to stakeholders.

The MidAmerican Local Transmission Planning Process does not apply to System Impact Studies or Facilities Studies associated with specific Generator Interconnection Requests or Transmission Service Requests.

With the limited exception of certain transitional studies completed by MidAmerican with Transmission Provider oversight, such studies are performed by the Transmission Provider under the terms of the Tariff. In the event of a conflict between this MidAmerican Local Transmission Planning Process and the Transmission Provider's Tariff, the Transmission Provider's Tariff shall control.

V. Openness and Coordination

1.) MidAmerican will hold at least two face-to-face stakeholder meetings per year to discuss local transmission planning, including local transmission issues. Additional meetings will be held as needed.

The stakeholder meetings will be open to the Transmission Provider's transmission service customers, MidAmerican's marketing and energy affiliates, generation interconnection customers, neighboring transmission owners, neighboring transmission providers, the Transmission Provider affected state and federal authorities, regional planning groups, and any other interested entities.

2.) MidAmerican will hold an additional stakeholder meeting within 60 days after receipt of a written request from registered stakeholders from ten or more different organizations, companies, Eligible Customers, regulatory agencies, municipal utility associations or wind generator associations to hold such a meeting; however, MidAmerican is not required to hold more than two additional stakeholder meetings per year as a result of such registered stakeholder requests.

3.) MidAmerican will invite representatives from affected and interested stakeholders, including the Midcontinent Independent System Operator, Inc., to stakeholder meetings.

4.) A meeting notice with a draft meeting agenda will be sent out by email to stakeholders and posted at least thirty days in advance of each meeting unless exception or emergency situations require less notice, such as resolution of imminent unreliable conditions or customer needs, or to meet required regulatory or statutory requirements.

5.) To ensure meaningful dialogue at the stakeholder meeting, available information related to the proposed draft agenda will be distributed with meeting notices. This information may include, for example, identified system constraints, significant and recurring congestion, and proposed solutions or new projects. Stakeholders may submit questions or comments, including other suggested system constraints or problems and suggested solutions thereto, in advance of, at, or up to 30 days after the semi-annual meeting.

6.) MidAmerican will develop and maintain an updated email list of registered stakeholders that have attended prior meetings, as well as key participants that should be invited regardless of attendance at prior meetings, for example, affected state authorities will be included on the registered stakeholder list regardless of attendance at prior meetings. Stakeholders will be provided the opportunity to register at any of the stakeholder meetings. Stakeholders may also register by providing an email or written notification to the MidAmerican Local Transmission Planning Process

Technical Contact listed in Section XIII of this Attachment FF - MidAmerican Registered stakeholders wishing to be removed from the registered stakeholder list may do so through email or written notification to the MidAmerican Local Transmission Planning Process Technical Contact.

7.) MidAmerican Local Transmission Planning Process meetings may include activities such as discussion of new proposed facilities for MidAmerican's portion of the Transmission System; review of constrained facilities on MidAmerican's portion of the Transmission System; discussion of recently completed and ongoing studies of MidAmerican's Transmission System upgrades to meet MidAmerican, regional, and NERC planning criteria and/or reliability standards; discussion of completed and ongoing studies of upgrades to MidAmerican's portion of the Transmission System to meet reliability standards and economic benefit criteria; discussion of NERC, regional, and MidAmerican transmission planning criteria, criteria application, and comparability; discussion of operating guides, operating guide application, and comparability on MidAmerican's portion of the Transmission System; open forum for discussion of proposed upgrades of MidAmerican's portion of the Transmission System from transmission service users and neighboring transmission systems; discussion of the MidAmerican Local Transmission Planning Process including process issues and other stakeholder issues related to the process or the results of the process; and comments from affected state authorities.

8.) MidAmerican will retain ultimate responsibility for the transmission studies and transmission plans developed under the MidAmerican Local Transmission Planning Process. MidAmerican will request and consider stakeholder input provided during the stakeholder process. The MidAmerican Local Transmission Planning stakeholder process will not be a voting forum.

9.) Milestones of MidAmerican's planning cycle are expected to be set so as to coordinate with the Transmission Provider's planning cycle.

Milestones to MidAmerican's planning cycle typically will include the following:

a. Request for model and other data from customers, as described in Section VII.1 below;
b. Information on significant and recurring congestion provided to customers;
c. Initial stakeholder meeting per Section V.1;
d. Submit regional model data information to the region;
e. Begin work on planning studies initiated as part of the MidAmerican Local Transmission Planning Process;
f. New regional models available;
g. Second stakeholder meeting per Section V.1; and
h. Complete planning studies initiated as part of the MidAmerican Local Transmission Planning Process.

10.) MidAmerican will provide non-disclosure agreements, password-protected access to information, and other procedures in order to maintain the confidentiality of information and to protect Critical Energy Infrastructure Information ("CEII"). The procedures for protection of and access to CEII are to be posted on the MidAmerican's Open Access Same Time Information System ("OASIS") page. Definitions for CEII are provided in 18 C.F.R. §388.113(c).

11.) Information containing confidential/CEII may include but is not limited to physical maps of electric facilities that do not just give the general location; system electric diagrams or switching diagrams and data bases that provide facility locations, ratings, and/or system connectivity; power flow cases; and evaluations of electric system performance. Confidential information supplied by stakeholders as part of the MidAmerican Local Transmission Planning Process will be treated confidentially and comparably to MidAmerican confidential information.

12.) A working group is established to receive information and provide comment on planning issues that are the subject of the MidAmerican Local Transmission Planning Process that arise between stakeholder meetings. MidAmerican will provide (subject to confidentiality, CEII and Standards of Conduct requirements):

a. the initial assumptions used in developing the annual local planning process transmission assessment and will provide an opportunity for feedback.

b. the models used for local planning process transmission planning.

c. information regarding the status of local planning process transmission upgrades and how such upgrades are reflected in future local planning process transmission plan development.

d. the draft study scope for those studies conducted by the working group as part of the local planning process, which will include or provide references to the basic assumptions for the study, the model or models used in the working group study including information regarding significant changes in the model.

e. the draft transmission report for those studies conducted by the working group as part of the local planning process, as prepared by MidAmerican or MidAmerican's designate.

Stakeholders who do not participate on the working group will be given the opportunity to comment on the draft report after MidAmerican has considered the comments of the working group. The report will include an executive summary that is brief and is designed to be understandable to stakeholders.

f. draft transmission plans that result from the MidAmerican Local Transmission Planning Process before they are distributed to stakeholders pursuant to the stakeholder meeting process described in Section V above.

g. Ad hoc study groups will be formed by MidAmerican if a need is determined by MidAmerican Transmission or due to significant registered stakeholder interest in the details of a local problem requiring a planning study as indicated by registered stakeholders at ten or more different organizations, companies, Eligible Customers, regulatory agencies, municipal utility associations or wind generator associations. However, no more than two ad hoc study groups are required at any given time. In addition, if no more than three registered stakeholders from the requesting organizations or companies attend an ad hoc study group meeting, MidAmerican retains the right to discontinue the activities of an ad hoc study group.

i. An email notice of MidAmerican intent to form an ad hoc study group will be distributed to the registered stakeholders prior to MidAmerican forming an ad hoc study group.

ii. The ad hoc study group will be formed considering the responses to the email notification and a separate mailing list will be established for that ad hoc group. Additional participants will be allowed throughout the ad hoc group study process; however, the addition of new participants shall not impede progress already completed by the ad hoc group.

iii. In order to facilitate the efficient collection of input from stakeholders on transmission studies and plans, MidAmerican may combine multiple transmission problems and/or studies for consultation with a single ad hoc study group; or may separate problems and/or studies for consultation with multiple ad hoc study groups.

iv. MidAmerican will determine when each ad hoc study group process is complete which typically will follow completion of the final report. The final report will be distributed to the registered stakeholders, subject to CEII and Standards of Conduct requirements. The report will include an executive summary that is brief and is designed to be understandable to stakeholders.

h. Working group and ad hoc study group meetings will be established by

MidAmerican on an as needed basis. Working group meetings will also be established if need is expressed by 10 members of the respective working group; however, MidAmerican will not be required to hold meetings of the working group more than on a semi-annual basis. Meetings will typically be conference calls and/or web casts, but face-to-face meetings may be called if necessary. Meeting notices will be distributed via email to the respective study group mailing list. Meeting materials may be distributed via email respecting email size limitations and CEII and Standards of Conduct requirements. A password protected FTP site or internet may be used to transmit study models or large amounts of data.

i. MidAmerican will chair and provide leadership to the working group and ad hoc groups, including facilitating the group meetings.

j. Input from the working group and ad hoc study group members will be considered in the local planning process. Comments will generally be expected via email or during working group or ad hoc study group meetings. Comments will be solicited within the defined comment periods of the study group process.

VI. Transparency

In addition, the MidAmerican Local Transmission Planning Process will be open and transparent to facilitate comment and exchange of information (subject to CEII and Standards of Conduct requirements) as described below:

1.) MidAmerican will make available the basic criteria that underlie its transmission system plans by posting MidAmerican's transmission planning criteria for facilities covered by this Attachment FF-MidAmerican on MidAmerican's OASIS page on the Transmission Provider's OASIS node.

2.) MidAmerican will make available to Registered Stakeholders the basic criteria, assumptions, and data that underlie its transmission system plans. For this purpose, MidAmerican will make its FERC Form 715 available in a way that maintains confidentiality and complies with CEII requirements.

3.) MidAmerican will provide information on the location of applicable NERC/MISO/Midwest Reliability Organization ("MRO") planning criteria, reliability standards, regional power flow models, or other pertinent information, as available.

4.) MidAmerican will provide its regional planning model submittal in accordance with Section V of this Attachment FF-MidAmerican.

5.) MidAmerican will set the planning study horizons and study frequencies considering NERC and or regional entity standards and the Transmission Provider's planning cycle.

6.) MidAmerican will simultaneously disclose transmission planning information where appropriate in order to alleviate concerns regarding the disclosure of information with respect to the FERC Standards of Conduct.

7.) MidAmerican will consider customer demand response resources in the MidAmerican Local Transmission Planning Process on a comparable basis with generation resources in developing transmission plans provided that 1) such resources are capable of providing measurable transmission system support needed to correct transmission system problems assessed in the MidAmerican Local Transmission Planning Process, 2) such resources can be relied upon on a long-term basis, 3) such resources meet NERC Reliability Standards and applicable laws, rules, and regulations, and 4) the inclusion of such resources in corrective action plans are permitted by the NERC Reliability Standards.

VII. Information Exchange

Certain information exchanges associated with the stakeholder process and the local study group process are described in Sections V and VI in this Attachment FF-MidAmerican. In addition, information exchange for base regional model development will take place as follows:

1.) MidAmerican participates in the annual development of the regional base case power flow and stability models currently for the PSS™E computer application. These regional models provide the basis for studies of transmission service requests, generator interconnection requests, local planning studies and regional planning studies. To assist in the development of accurate base case regional models and thereby develop appropriate local transmission plans for the MidAmerican system, MidAmerican will request at a minimum the following data of the Transmission Provider's Transmission Customers connected to MidAmerican's portion of the transmission system:

   a. Existing loads and future loads for the horizon of the regional base case models for each of its load points. Information for firm loads will be separated from information for interruptible loads.

   b. A list of all existing and proposed new demand response resources including behind the meter generation or load curtailment;

c. the MW impacts on peak load.

d. the historical and expected future operating practice of the demand response resources such as the conditions under which the customer intends to initiate each resource, and whether each resource is available for use in providing measurable transmission system support to correct problems assessed in the MidAmerican Local Transmission System Planning Process, as well as, other information required to consider such resources as provided in Section VI.7. The Transmission Provider's Transmission Customers will be requested to provide updates of this information when substantive changes occur.

e. A list of existing and proposed new generation resources and historical and expected future dispatch practices such as the load level at which the customer plans to start each generating unit and plant, and whether each generation resource is available for use in providing measurable transmission system support to correct problems assessed in the MidAmerican Local Transmission System Planning Process, as well as, other information required to consider such resources as provided in Section VI.7. The Transmission Provider's Transmission Customers will be requested to provide updates of this information when substantive changes occur.

f. Projections of quantifiable transmission service needs over the planning horizon, including applicable receipt and delivery points and the transmission service reservations anticipated to be scheduled.

g. Sponsors of all types of resources, including transmission, generation, and demand resources, can provide information to MidAmerican for use in developing the base-line assumptions and models used in the MidAmerican Local Transmission Planning Process.

h. Additional modeling data will be requested as necessary to conform to the requirements of FERC, NERC, Transmission Provider and the regional entity.

2.) The data submitted by the Transmission Provider's Transmission Customers will be included to the extent appropriate in the base case model.

3.) The MidAmerican data request will be sent annually in coordination with the regional data request. MidAmerican will send a data request to the Transmission Provider's Transmission Customers located in MidAmerican's Load Balancing Area typically prior to expected transmittal of the regional data request.

4.) Responses to the data request will be accepted in forms such as PSS™E raw data format or in spreadsheet format with appropriately labeled headings.

5.) Each of the Transmission Provider's Transmission Customers within the MidAmerican Local Balancing Authority Area will be responsible for providing MidAmerican with an email address of its data modeling contact. MidAmerican will send the annual data request to these contacts via email.

6.) The MidAmerican data response will be made available subject to CEII and Standards of Conduct restrictions upon request to Registered Stakeholders.

VIII. Comparability

1.) MidAmerican will plan its portion of the Transmission System to treat similarly-situated customers comparably in the MidAmerican Local Transmission Planning Process.

2.) MidAmerican will consider alternative proposed solutions to identified system needs in the MidAmerican Local Transmission Planning Process. Such alternatives may include transmission, generation and demand-side resources. MidAmerican will review and evaluate such alternatives on a comparable basis in developing transmission plans, provided that:

a. such resources are capable of providing the measurable transmission system support needed to correct transmission system problems assessed in the MidAmerican Local Transmission Planning Process,
b. such resources can be relied upon on a long-term basis,
c. such resources meet applicable NERC Reliability Standards and applicable laws, rules, and regulations, and
d. the inclusion of such resources in corrective action plans are permitted by the NERC Reliability Standards.

3.) MidAmerican will use a combination of technical analysis and engineering judgment to determine the preferred solution when competing solutions are proposed to meet system needs. Technical analysis can include, but is not limited to, power flow studies, dynamic stability studies and voltage stability studies, while engineering judgment can take into account such factors as the extent to which proposed alternative solutions meet applicable planning criteria and other regulatory requirements, estimated project costs and projected environmental impacts.

4.) MidAmerican shall select proposed project(s) for inclusion in MidAmerican's transmission plan.

IX. Dispute Resolution

Consistent with Attachment HH of this Tariff and Appendix D to the ISO Agreement, the

Transmission Provider shall resolve disputes concerning MidAmerican Local Transmission Planning issues. The first step will be for designated representatives of MidAmerican and other affected parties to work together to resolve the relevant issues in a manner that is acceptable to all parties.

If the first step is unsuccessful, each affected party shall designate an officer who shall review disputes involving them that their designated representatives are unable to resolve. The applicable officers of the parties involved in such dispute shall work together to resolve the disputes so referred in a manner that meets the interests of such parties, either until such agreement is reached, or until an impasse is declared by any party to such dispute.

If such officers are unable to satisfactorily resolve the issues, the matter shall be referred to mediation, in accordance with the procedures described in Appendix D to the ISO Agreement. Parties that are not satisfied with the dispute resolution procedures may only file a complaint with the Commission during the negotiation or mediation steps. If a matter remains unresolved, the affected parties may pursue arbitration pursuant to Appendix D of the ISO Agreement.

X. Regional Participation

Consistent with Sections I and II of Attachment FF to the Tariff, MidAmerican will participate in the Transmission Provider's regional transmission planning process as a Transmission Owner member. Such participation shall include participation in the development of the Transmission Owner's Transmission Expansion Plan and participation on the Planning Advisory Committee, the Planning Subcommittee, Sub-regional Planning Meetings and focus study groups, as appropriate. Such participation shall be carried out to the extent that such activities apply to the planning of MidAmerican's portion of the Transmission System.

XI. Economic Planning Studies

As part of the MidAmerican Local Transmission Planning Process, MidAmerican will implement an Economic Planning Study Procedure. This procedure will include the following:

1.) Each year, during the notice period prior to the first stakeholder meeting of the year and at the first stakeholder meeting, stakeholders may request MidAmerican to perform Economic Planning Studies to evaluate potential upgrades or other improvements to MidAmerican's portion of the Transmission System that could reduce congestion or integrate new resources and loads on an aggregated basis.

2.) The scope of such studies will primarily include studies to resolve continuing congestion on MidAmerican transmission facilities and/or to review the integration of large levels of proposed generation facilities to MidAmerican's portion of the Transmission System without identification of generation ownership.

3.) Stakeholders may submit requests for MidAmerican to study potential upgrades or other investments necessary to integrate any resource, whether transmission, generation or demand resources, identified by the stakeholder. MidAmerican will either determine which facilities on the MidAmerican Transmission System have experienced significant and recurring congestion or which facilities on the MidAmerican Transmission System are expected to experience significant and recurring congestion. Pursuant to Section V.5 above, such information shall be provided to registered stakeholders prior or with the notice of the first stakeholder meeting subject to CEII and Standards of Conduct restrictions.

4.) Based upon Registered Stakeholder input, MidAmerican will determine the high priority studies to be started that year based upon a ranking in order of priority from indications of Registered Stakeholder support. MidAmerican will facilitate a registered stakeholder discussion of proposed Economic Planning Studies to determine which stakeholder study requests provide the greatest value to stakeholders. Based on this discussion, MidAmerican will determine the high priority studies to be conducted that year. The studies will be ranked in order of priority based upon indications of registered stakeholder support. The method of ranking study priority will be based upon registered stakeholder input.

5.) MidAmerican may propose Economic Planning Studies to be conducted, but MidAmerican will be a facilitator and not a participant in ranking the priority of requested studies. Registered Stakeholders, including the MidAmerican marketing and energy affiliates, may be participants in ranking the priority of requested studies.

6.) MidAmerican, in consultation with its registered stakeholders, will be allowed to cluster or batch requests for Economic Planning Studies, or if a particular request is excessively broad in scope it may be appropriate to separate the request into two or more studies so that MidAmerican can perform the studies in the most efficient manner.

7.) Generally, Economic Planning Studies are not to be the subject of an ongoing local or regional study, an ongoing System Impact Study or Facilities Study, or an ongoing joint study. Each Economic Planning

Study is to be scoped broadly enough to represent the interests of a number of stakeholders.

8.) MidAmerican will study the cost of congestion only to the extent it has the information required to perform such study. If stakeholders request a particular congested area be studied, the requesting stakeholders must supply relevant data for calculations of the level of congestion costs occurring, or likely to occur in the near future. MidAmerican will make reasonable efforts to assist stakeholders in obtaining the information to the extent it is not readily available.

9.) Economic Planning Studies performed by MidAmerican will include sensitivity analyses as appropriate; however, MidAmerican shall conduct such sensitivity analyses only to the extent it has information to conduct such analyses. MidAmerican will make reasonable efforts in obtaining the information to the extent it is not readily available.

10.) Economic Planning Studies performed by MidAmerican will identify the projected benefits of proposed facility upgrades by typically comparing one or more of the following factors: Control Area generation production costs, redispatch costs and the costs of transmission losses with and without the proposed facility upgrades.

11.) MidAmerican shall select the project(s), if any, proposed as a result of Economic Planning Studies performed by MidAmerican for inclusion in MidAmerican's transmission plan.

XII. Transmission Needs Due to Public Policy Requirements

As part of the MidAmerican Local Transmission Planning Process, MidAmerican will consider transmission issues driven by public policy requirements. Public policy requirements are meant to include requirements established by applicable local, state or federal laws or regulations. MidAmerican will select transmission issues involving transmission needs driven by public policy requirements to be considered in the planning process for which transmission solutions will be evaluated.

The process for selecting public policy requirements, out of the larger set of public policy requirements that stakeholders may propose, to be included in the selected transmission issue(s) for which transmission solutions will be evaluated, shall be as follows:

- Stakeholders may submit to MidAmerican proposals to consider transmission needs driven by public policy requirements as part of the transmission issues. MidAmerican may also submit proposals to consider transmission needs driven by public policy requirements as part of the transmission issues.
- Proposals to consider transmission needs driven by public policy requirements will be discussed at a stakeholder meeting.
- MidAmerican will consolidate all such proposals, including proposals submitted by MidAmerican, into a list that will be posted on its website for stakeholder review and comment and will notify stakeholders of such posting by email notification.
- MidAmerican will assess such proposals, consider stakeholder feedback, and select the public policy requirements that will be further studied in the MidAmerican Local Transmission Planning Process. This selection will be based on: (i) the effective

dates, nature and magnitude of the public policy requirements in applicable laws and regulations; (ii) the immediacy or other estimated timing, and extent, of the potential impact on the identified transmission needs; (iii) the availability of the resources, and any limitations thereto, that would be required by consideration of such transmission needs driven by public policy requirements; (iv) the relative significance of other transmission issues that have been raised for consideration; and (v) other appropriate factors that can aid the prioritization of transmission issues to be considered in the MidAmerican Local Transmission Planning Process.

- MidAmerican will post on its website an explanation of which transmission needs driven by public policy requirements will be evaluated for potential solutions in the MidAmerican Local Transmission Planning Process, as well as an explanation of why other suggested potential transmission needs will not be evaluated.

XIII. Cost Allocation for New Projects

The Transmission Provider will designate and assign cost responsibility for identified Network Upgrades within MidAmerican's portion of the Transmission System according to the terms and provisions of Section III of Attachment FF to the Tariff. The cost allocation methodology set forth in Section III of Attachment FF to the Tariff shall not supersede joint-investment obligations to which MidAmerican may be subject.

XIV. Technical Contact

The technical contact for the MidAmerican Local Transmission Planning Process shall be:

Manager - Electric System Planning
MidAmerican Energy Company

One RiverCenter Place
106 East Second Street
P. O. Box 4350
Davenport, Iowa 52808