ATTACHMENT B

Entergy Services, Inc.

As Agent for

Entergy Arkansas, Inc.
Entergy Gulf States, Inc.
Entergy Louisiana, Inc.
Entergy Mississippi, Inc.
Entergy New Orleans, Inc.

FERC ELECTRIC TARIFF

RATE SCHEDULE NO. 2

Entergy Services, Inc.

As Agent for

Entergy Arkansas, Inc.
Entergy Gulf States, Inc.
Entergy Louisiana, LLC
Entergy Mississippi, Inc.
Entergy New Orleans, Inc.

SYSTEM IMPACT STUDY AND FACILITIES STUDY PROCESS MANUAL

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Vice President, Transmission

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1 Introduction

1.1 Purpose

The purpose of this document is to describe Entergy's business practices for conducting System Impact Studies and Facilities Studies when evaluating requests for transmission service under Sections19 and 32 of the Entergy Open Access Transmission Tariff (Tariff).

1.2 Division of Responsibilities

The division of responsibilities between Entergy and the ICT in performing the studies described herein will be controlled by Attachment S to the Tariff, including the ICT Protocols appended to Attachment S.

1.3 Definitions

Capitalized terms used in this document and the Tariff (including Attachment S and the protocols attached thereto) will have the definition provided in the Tariff. Additional definitions are included below:

1.4 When a System Impact Study is Required

Transmission Service Requests (TSRs) must be evaluated to determine if there is sufficient transmission capability to accept the TSR and ensure reliable service for existing transmission customers. A System Impact Study is a power flow network analysis of whether a particular TSR can be reliably accommodated. To the extent a TSR cannot be reliably accommodated without the construction of additional transmission facilities, the System Impact Study will also provide a preliminary estimate of possible costs associated with the necessary facilities. The customer may also request that the System Impact Study evaluate the availability for redispatch as an alternative to transmission upgrades.

Under Attachment C to the Tariff, System Impact Studies are performed for the long-term TSRs, which include the following: (1) requests for Long-Term Firm Point-To-Point Transmission Service; (2) requests for Network Integration Transmission Service by new

Network Customers; (3) requests by existing Network Customers to designate Network Resources for a duration of one year or more; and (4) requests by existing Network Customers to designate Network Resources and obtain "rollover rights" for those Network Resources for any duration. Customers seeking to transition from service under a Grandfathered, pre-Order Nol 888 agreement to Network Service under the OATT will be treated as new Network Customers having rollover rights associated with the grandfathered service. A System Impact Study will be required for these customers consistent with Order No. 888-A, at 30,198 n.52.

System Impact Studies are generally not performed for short-term TSRs, which include the following: (1) requests for Short-Term Firm Point-To-Point Transmission Service requests; and (2) requests by existing Network Customers to designate Network Resources for a duration of less than one year without obtaining "rollover rights" for those Network Resources for any duration. These short-term TSRs are typically evaluated under Entergy's Available Flowgate Capability (AFC) Process. However, System Impact Studies will be performed for short-term TSRs under the following circumstances: (1) monthly requests for Firm Point-To-Point Transmission Service or to designate new Network Resources where the service is to take place beyond the next 18 months; (2) where the AFC process has denied a short-term TSR and the transmission customer has requested a System Impact Study to evaluate solely the potential for transmission system upgrades to increase the applicable AFC values. With respect to (2), because of the lead-time and costs associated with transmission facility construction, System Impact Studies for short-term TSRs are rarely requested or performed.

1.5 When a Facilities Study is Required

In the event that a System Impact Study indicates that transmission service cannot be reliably accommodated without the addition of transmission upgrades, the transmission customer may request a Facilities Study. The Facilities Study is a more in-depth study of the upgrades required to provide the requested transmission service, including an AC analysis of the TSR to confirm whether transmission upgrades are necessary. To the extent transmission upgrades are necessary, the Facilities Study will include a good-faith estimate of the costs and time required to complete construction of any such upgrades and an analysis of the cost allocation for those upgrades as specified under Attachment T to the Tariff. As with System Impact Studies, the customer may also request an analysis of redispatch options as an alternative to transmission upgrades.

1.6 Queue for System Impact and Facilities Studies

Under Order No. 888, the priority of long-term TSRs is determined on a first-come, first-served basis. Long-term transmission service requests that require a System Impact Study will be placed in the System Impact Study Queue based on the date and time service is requested over OASIS. Where short-term TSRs have been denied through the AFC process and the transmission customer has requested a System Impact Study to analyze transmission upgrades, such Studies will also be placed in the System Impact Study Queue based on the date and time that service was requested through the AFC process. System Impact Studies will be performed in the order established by the queue.

The Tariff provides additional details regarding the timing and requirements associated with obtaining a System Impact Study. Refer to Sections19 and 32 of the Tariff for those details.

2 Base Case Model Development

2.1 NERC and SERC Regional Models

Consistent with Section 6 of the Transmission Service Protocol, the Base Case Models used in System Impact Studies will be based on the updated regional power flow models developed pursuant to the NERC multi-regional and SERC regional model development processes. The NERC and SERC regional models will be developed consistent with the NERC Multiregional Modeling Working Group (MMWG) Procedural Manual (or its successor), the current SERC near-term and long-term procedural manuals, and all applicable, current NERC Reliability Standards and SERC reliability criteria. The NERC models will be updated on an annual basis and will be used to develop the SERC regional models. The long-term SERC regional models will be updated on an annual basis, and the short-term SERC regional models will be updated annually with quarterly adjustments. These SERC regional models will be used to develop the seasonal/annual Base Case Models (representing a period of 10 years) and monthly Base Case Models used in System Impact Studies.

2.2 Development of Seasonal and Monthly Base Case Models

All seasonal Base Case Models used in performing System Impact Studies will be derived from the NERC and SERC regional models created as part of the regional modeling process described above. The seasonal Base Case Models will be developed by modifying the most recent SERC regional models to include a more detailed representation of the Entergy system control area and updated data inputs made available after the most recent SERC regional model was finalized. The SERC regional models will be modified on an annual basis to include the more detailed representation of the Entergy system and embedded control areas, while the updating of data inputs will occur at least on a quarterly basis. In addition to these quarterly updates, the seasonal models will be further updated by the ICT just prior to evaluating a service request as described in Section 3.1 below.

All monthly Base Case Models used in performing System Impact Studies will be derived from the seasonal base case models developed through the SERC near-term modeling procedures, as updated by Entergy and the ICT and other SERC members to include data inputs made available after the most recent near-term seasonal model was developed. The monthly Base Case Models are developed for Month 2 through Month 18 and include updated transmission system information for the Entergy Transmission System and embedded control areas. The monthly Base Case Models are also updated on a weekly basis to incorporate the most current transmission service reservation data from the Entergy OASIS site.

2.3 Data Inputs Included in Seasonal and Monthly Base Case Models

2.3.1 System Topology

All seasonal and monthly Base Case Models will include a detailed representation of the Entergy system control area and transmission system and any other control areas embedded within the Entergy control area. All other systems outside of the Entergy footprint will be retained at the level of detail contained in the SERC regional cases.

The system topology represented in the seasonal Base Case Models will be updated at least quarterly and just prior to conducting a System Impact Study. Topology changes can include recently energized construction projects (new substations/lines/transformers,

upgrades, conversions, etc.), corrections of transmission element modeling parameters (impedances, ratings, etc.), or the decommissioning of equipment.

2.3.1.1 Facilities Not In Service

Generally, transmission construction projects that have not been completed and are not currently in service will not be included in the Base Case Models used to evaluate TSRs. When transmission construction projects are completed, the system topology updates conducted prior to all System Impact Studies will capture the new facilities and include those facilities in the Base Case Models. There are three instances where transmission construction projects that are not in-service will nevertheless be included in Base Case Models:

- Where a Transmission Customer has committed to fund Supplemental Upgrades pursuant to Attachment T to the Tariff in order to obtain Network or Point-to-Point Transmission Service, those upgrades will be included in the Base Case Models starting in the season in which the service is expected to begin and for all seasons thereafter. Supplemental upgrades associated with signed block load additions are modeled in the season in which the load is expected to come in service, and all seasons beyond.

- Where an Interconnection Customer has committed to fund Supplemental Upgrades pursuant to Attachment T to the Tariff in order to obtain Interconnection Service, those upgrades will be included in the Base Case Models starting in the season in which the new generating facility is projected to be in service and for all seasons thereafter, provided that the generating facility has executed an IOA under the LGIP.

- Where the Transmission Provider has committed to fund an upgrade in the Construction Plan, those upgrades will be included in the Base Case Models starting in the season in which facilities are expected to be complete and for all seasons thereafter.

Any TSR that is accepted and confirmed based on the assumption that a Supplemental Upgrade or an upgrade in the Construction Plan will be in service at a future date, transmission service will be conditional until that upgrade actually goes into service. If the funding customer reneges on the funding commitment and the upgrade is necessary to accommodate the TSR, acceptance of the TSR may be retracted unless the Transmission Customer agrees to the fund the cancelled or delayed upgrade.

2.3.1.2 Transmission Facility Ratings

Transmission facility ratings for System Impact Studies will be determined in the same manner as for the calculation of Available Flowgate Capability (AFC) values and in accordance with the procedures specified in the AFC Manual. These procedures will be filed with SERC in accordance with NERC Reliability Standard FAC-008.

2.3.1.3 TRM

Transmission Reliability Margin (TRM) is the amount of transmission transfer capability needed to provide a reasonable level of assurance that the system will remain reliable. TRM accounts for the inherent uncertainty in system conditions and its associated effects on transfer capability evaluations (such as System Impact Studies) and the need for operating flexibility to ensure reliable system operation as system conditions change.

The current value of TRM used in seasonal Base Case Models beyond the next eighteen months is five percent (5%). Because the need for applied margins decreases as analysis time approaches real-time, the current TRM value used in monthly Base Case Models is zero.

2.3.2 Existing Transmission Commitments and Rollover Rights

All confirmed long-term firm transmission service reservations (including service to Native and Network Load, and for Point-to-Point and Grandfathered customers) will be modeled in Base Case Models for the full term of service. To the extent long-term firm transmission service is entitled to rollover rights, that service will be modeled in Base Case Models for periods beyond the term of service, unless: (1) the transmission service agreement specifies that rollover rights are not available for the applicable period; or (2) the customer has failed to exercise its rollover rights by the specified deadline. Non-firm transmission service reservations (including Non-Firm Point-to-Point Service, Secondary "Network" Service) and Qualifying Facility (QF) PURPA "Puts" that do not obtain Tariff Service will not be included in Base Case Models. Long-Term Firm Point-to-Point Service will be modeled by dispatching the generating unit sourcing the reservation to the full amount specified in the reservation. The modeling of long-term firm service to Native Load, Network Load and grandfathered customers will be achieved by economically dispatching the resources that have obtained firm transmission service to a level sufficient to meet the load forecast for that customer. This process is described below under Load and Resource Forecasts.

The modeling of Long-Term and Short-Term TSRs will comply with the capacity rights established in the Tariff. TSRs in study mode (SIS or Facilities Study) will only be simulated in the evaluation of subsequent TSRs and only to the extent necessary to protect the superior capacity rights of the first-in-time TSRs. Specifically, Long-Term TSRs in study mode are included as prior transactions. To the extent that firm Short-Term TSRs are included in Base Case Models, a secondary analysis will be performed as necessary to determine if the Long-Term TSR can be accepted by "bumping" conditional firm Short-Term TSRs.

2.3.3 Load Forecasts

2.3.3.1 Seasonal/Annual Models

The load forecasts for the Entergy System peak load contained in the NERC and SERC regional models are based on the most recent full calendar year (January-December) coincident System peak demand. The most recent peak demand provided by LSEs is used because it reasonably reflects load adjustments (e.g., losses, load growth, load reductions, cogeneration) that would have occurred prior to the peak load period. If there are significant load changes (additions or reductions) that occurred within the System after the summer peak, the load forecast will be adjusted to take these changes into consideration. The LSEs, or their agents, are required to provide a load forecast annually to the Transmission Provider, preferably submitted in the Transmission Provider's Load and Resource Forecast Template. The types of loads represented in these load forecasts includes the loads of the following customer types: retail, wholesale (including wholesale load under the Tariff and grandfathered, pre-Order No. 888 agreements), industrial, nuclear generating facility, and cogenerating facility. To create power flow models of the off-peak seasons, Entergy applies monthly scaling factors to load forecasts that are based on historical load data. Additionally, the peak load forecasts may be non-coincident peak to account for the large geographic footprint of the Entergy system. Forecasted loads are adjusted according to actual peak for the year, weather normalization, block load changes and growth trending.

2.3.3.2 Monthly Models

The derivation of load forecasts used in the monthly Base Case Models is described in Section 3.1.1.2 of the AFC Process Manual.

2.3.4 Resource Forecasts and Generation Dispatch

2.3.4.1 Seasonal Models

The resource forecasts and generation dispatch levels represented in the monthly and seasonal Base Case Models will be based on the generation data included in the NERC and SERC regional models. This generation data is in turn based on the resource plans of the load-serving entities (LSEs) taking transmission service over Entergy Transmission System. These LSEs include the Entergy Operating Companies (i.e., EAI, EMI, ELL, EGSI, and ENOI), wholesale Tariff customers, and wholesale grandfathered contract customers. These LSEs, or their agents, are required to provide a resource plan annually to the Transmission Provider, preferably submitted in the Transmission Provider's Load and Resource Forecast Template. The resource plan should include adequate generation resources to serve the LSE's projected peak load for the coming seasons. If an LSE fails to provide or update its resource plan, the last resource plan submitted by that LSE will be used in conjunction with OASIS data regarding long-term Network Resources if available. The resources identified in the various LSE resource plans will be dispatched on an economic basis to the extent the LSE provides sufficient cost information. Any generating resource having a Long-Term Firm Point-to-Point Reservation will be dispatched to the level of that reservation, which will not be attributable to serving any load other than the Point-to-Point load.

Should any LSE submit a resource plan that fails to provide sufficient generation to meet forecasted load, the forecasted load will be met by dispatching uncommitted generating resources interconnected to the Entergy Transmission System to serve the shortfall, including resources that have not reserved long-term firm transmission service to a specific sink or otherwise been included in the long-term resource plans of an LSE. Resources used to serve the shortfall in this manner will be dispatched according to the following priority:

a. Generating resources that have obtained NRIS under the LGIP, but have not obtained long-term firm transmission service (either Point-to-Point or Network) to a specific sink will be dispatched first. The dispatch level will be based on a uniform dispatch up to their uncommitted capacity (*i.e.,* the difference between their reserved service and the maximum output of the units).

b. Generating resources that are owned by LSEs but are designated as non-firm will be dispatched second. The dispatch level will be based on a uniform dispatch up to their uncommitted capacity (*i.e.,* the difference between their reserved service and the maximum output of the units).

c. Generating resources that have only obtained ERIS under the LGIP (or its equivalent under pre-Order No. 2003 interconnection agreements) will be dispatched third. To the extent that all NRIS resources are at their maximum output in the model, then any remaining shortfall between an LSE's load and the resources used to serve that load will be met by using a uniform dispatch of the uncommitted capacity of these ERIS resources.

The resource forecasts and generation dispatch levels contained in the SERC regional models is updated when converting those models to the seasonal Base Case Models used in System Impact Studies. These updates will incorporate additional information provided by LSEs, as well as new TSRs confirmed on OASIS.

2.3.4.2 Monthly Models

The derivation of resource forecasts and generation dispatch levels used in the monthly Base Case Models is described in Section 3.1.1.2 of the AFC Process Manual addressing the off-line monthly AFC models.

2.3.5 CBM

Capacity Benefit Margin (CBM) is not currently used the seasonal or monthly Base Case Models applied to TSRs.

3 Performing the System Impact Study

In order to determine if there is sufficient capability to accept the TSR and ensure reliable service for existing transmission customers, a full network, load flow analysis will be performed for each Long-Term TSR an each Short-Term TSR that falls outside of the model horizon for the AFC process. The load flow analysis component of a System Impact Study consists of the following steps: (1) selecting and updating Base Case Models; (2) simulating the proposed transfer; and (3) evaluating the impact of the proposed transfer against applicable reliability criteria.

3.1 Selecting and Updating the Base Case Models

Seasonal Base Case Models exist for each season for a ten-year horizon and monthly Base Case Models exist for each month for an eighteen-month horizon. Seasonal Base Case Models will be applied to all TSRs (or any portions thereof) that extend beyond the horizon for which monthly Base Case Models are available. Monthly Base Case Models will be applied to all TSRs (or any portions thereof) that fall within the horizon for which monthly Base Case Models are available. Seasonal Base Case Models will be applied to all TSRs (or any portions thereof) that fall outside of the horizon for which monthly Base Case Models are available.

When selecting the Base Case Models applicable to a particular TSR, the most recent version of each model will be used to ensure that the Base Case Models include updated data inputs as described in Section 2 above. As described in Section 7.2.1 of the Transmission Service Protocol, before performing a specific System Impact Study, the applicable Base Case Models will be further updated to reflect additional information regarding Long-Term TSRs and changes in system topology, including transmission and generation outages. Additionally, any preempted TSRs will be removed from the Base Case Model. The updated Base Case Models will be subject to a final review to confirm that the updating process was performed correctly.

3.2 Simulating the Proposed Transfer

Once the appropriate Base Case Models have been selected and updated, load flow simulations will be performed. In general, where specific source/sink information is provided by the customer, the transfer will be simulated between the source/sink pair; where such information is not provided by the customer, the transfer will be simulated as described below.

3.2.1 Request for Point-to-Point Service

For Point-to-Point TSRs that are considered "imports" (*i.e.,* TSRs that are sourced from external control areas and that sink "into" the Entergy Control Area) a transfer will be simulated in one of two ways:

> If the source is located in a "first–tier" control area (*i.e.,* a neighboring control area with direct ties to the Entergy Control Area) and the specific generating unit sourcing the TSR is known, that specific generating unit will be scaled up to simulate the transfer into the Entergy Control Area. If no generator is specified (*i.e.*, the source is specified as the whole control area), the Study will be performed assuming generation will be scaled up from the most constraining

generator on the limiting element identified to effect the transfer into the Entergy Control Area. The generation of the customer submitting the TSR will be ramped down based on the customer's specified dispatch or, if the customer does not provide such a dispatch, based on a *pro rata* scale down of the requesting customer's existing resources within the Entergy Control Area.

If the source located in a "second–tier" control area (*i.e.,* a control area with no direct ties to the Entergy Control Area), the Study will be performed by proportionally increasing all generation in the source control area to effect the transfer into the Entergy Control Area. The generation of the customer submitting the TSR will be ramped down based on the customer's specified dispatch or, if the customer does not provide such a dispatch, based on a *pro rata* scale down of the requesting customer's existing resources within the Entergy Control Area.

For Point-to-Point TSRs that are considered "exports" (*i.e.,* TSRs that are sourced from inside the Entergy Control Area and that sink outside of the Entergy Control Area), the Tariff requires that specific generating unit be identified. Therefore, the transfer will be simulated by increasing the dispatch of that generating unit. If a designated source is modeled online in the base case at a level that does not allow for transfer (i.e., generator at or close to maximum generation amount), then the generator at the designated resource will be scaled down and other units inside the designated control area will be scaled up economically in an equivalent amount. The generation within the sink control area will be ramped down proportionately.

For Point-to-Point TSRs that are considered "through" transactions (*i.e.,* TSRs that both source and sink outside the Entergy control area), one transfer will be simulated using the same method for "imports" and another transfer will be simulated using the method for "exports."

3.2.2 Requests to Designate New Network Resources

In accordance with Sections 28, 30 and 32 of the Tariff, existing Network Customers may designate new Network Resources and undesignate existing Network Resources. Under Entergy's Transmission Business Practices Manual, there are two different methods for simulating a transfer associated with the designation of a new Network Resource: (1) incremental; and (2) displacement/delisting. At least initially, all requests to designate a new Network Resource will be studied through the incremental method. Existing Network Customers will also have the option of requesting the Study include the delisting/displacement method in the event that service cannot be accepted without

transmission upgrades or redispatch under the incremental method.

The requirements and business practices associated with Delisting/Displacement option are discussed more fully in Entergy's Transmission Business Practices Manual and will not be repeated here. For purposes of this System Impact Study Manual, the essential distinction between the two options lies in the manner in which the transfer is simulated. All other Base Case Model data, assumptions and criteria are the same. The exact method for simulating transfers under each of these two options is described below.

3.2.2.1 Incremental Method

Under the incremental method, the proposed Network Resource is modeled as an additional Network Resource above and beyond the existing Network Resources for that customer. This allows the new Network Resource to be designated without terminating an existing Network Resource. The incremental method involves simulating the transfer associated with the new Network Resource by first reducing the Network Load by the same MW amount requested for the new Network Resource designation (except that the load will never go below zero) and then next simultaneously ramping up both the new Network Resource and the Network Load to the level requested for the new Network Resource. This evaluation is simulated in two ways, generation to generation and generation to load. The transfer to generation will be from the study unit to the customer's existing designated Network Resources. The transfer to load will be from the study unit to the Network Customer's load. It will be performed by first reducing the Network Customer's load by the requested amount and economically dispatching the existing Network Resources to the new load level. The transfer will then be simulated from the study generator to the Network Customer's load. These different analyses are performed to differentiate the constraints used to serve the load and the constraints caused by the new generator.

3.2.2.2 Delisting/Displacement Method

Under the delisting/displacement method, the proposed Network Resource is modeled as a delisting/displacement of some subset of the Network Customer's existing Network Resources. This allows the new Network Resource to be designated only if the capacity rights of the displaced/delisted Network Resources are surrendered. The delisting/displacement method involves simulating the transfer associated with the new Network Resource by simultaneously ramping up the new Network Resource and ramping down some subset of the Network Customer's existing Network Resources. In

selecting which existing Network Resources will be ramped down and to what extent, all Network Resources for which the Customer has firm network service and shall study the most cost effective mix of resources for delisting/displacement based on estimated variable production costs for those Network Resources. Alternatively, the Network Customer can choose to supply a list of the specific generating units that may be considered, including cost information to be used in the Study.

3.2.3 Requests to Initiate Network Service

A request to initiate Network Service involves a "first-time" request for Network Service, including: (1) an existing Network Customer that is seeking Network Service for a new Network Load under a new Service Agreement; (2) a requesting customer that was previously taking service under a grandfathered, pre-Order No. 888 agreement; and (3) a requesting customer is otherwise not currently a Network Customer under the Tariff.

All requests to initiate Network Service will be studied by first removing the power flow impact of prior service to that load included in the Base Case Models (if any) and then by simulating the transfer using the incremental method described above in Section 3.2.2.1.

3.2.4 Requests to Designate PPAs As Network Resources

Network Customers may designate power purchase agreements as Network Resources pursuant to the Tariff and related business practices. The request is made over OASIS in the the same manner as other requests for designating Network Resources. These TSRs will be performed using the same methods described above in Sections 3.2.2.1 and/or 3.2.2.2. If the Customer seeks to designate a "Liquidated Damages" contract or "Slice of the System" contract as a Network Resource, the customer must provide sufficient information so that the request may be studied. If the generator supplying the power purchase is located on the Entergy Transmission System, the Customer must identify the bus bar location of the generator. If the specific generator supplying the power purchase agreement is unknown far in advance of real-time operations, the power purchase agreement may still be designated as a Network Resource, but the Customer will have to obtain a specific System Impact Study or AFC analysis that confirms that the deliverability of the specific generator prior to scheduling service under the Power Purchase Agreement. If the the generator is off the Entergy Transmission System, the control area in which the generator is located and the interface over which energy will flow will be sufficient.

3.3 Evaluating the Reliability Impact of the Proposed Transfer

Once the impact of the proposed transfer is simulated in the Base Case Model, the resulting "change" case will be evaluated to determine if allowing the proposed transfer is consistent with all applicable reliability criteria and standards, including the following:

- NERC Reliability Standards
- SERC reliability criteria
- Thermal Limits specified in Section 3.3.1
- Contract path limits

These standards establish three general types of limits that restrict the ability of the Transmission System to reliably accommodate power transfers: thermal, voltage and stability. The System Impact Study will analyze thermal limits pursuant to these criteria and standards and, to the extent thermal limits are identified, an analysis of voltage issues will be conducted. Short-circuit and stability issues will only be analyzed as part of the Facilities Study process.

3.3.1 Thermal Analysis

As part of the System Impact Study, a Direct Current (DC) contingency analysis will be performed. This flow-based analysis will consider the impact of single transmission element contingencies on all monitored elements. The analysis will be conducted using a full monitored element list and a full contingent element list. The monitored and contingent element list will include all transmission facilities at 115kV or higher. If the proposed transfer involves generating unit that is located on the 69kV transmission system, the monitored and contingent element list will also include all transmission facilities at 69kV and greater. The thermal violation thresholds are the same as those specified for the NERC Reliability Standard TPL-001 and 002 contingency evaluations in which facility loadings must be within their normal rating (RATE A).

The DC contingency analysis will identify any monitored transmission facility that exceeds the thermal limits. An Outage Transfer Distribution Factor ("OTDF") of 3% will be used so that facilities with an OTDF below the 3% threshold will not be considered a valid limit. If the OTDF for a particular facility is equal to or greater than the 3% threshold, then the facility will be considered a valid limit to the transfer. To the extent an overloaded facility had already exceeded the applicable thermal limit *prior* to simulating

the proposed transfer, the overload will not be considered a valid limit unless the proposed transfer *increases* the level/severity of the overload.

All valid thermal limits identified by the System Impact Study will be examined to determine whether: (1) non-coincident generation or transmission outages are contributing to the overload; or (2) the dispatch assumptions designed to make up for the short-fall in an LSEs resource plan under Section 2.3.4 above are contributing to the overload. With respect to outages, the applicable seasonal or monthly model may be divided into smaller models to evaluate the whether the proposed transfer produces the same or similar overloads when the non-coincident outages are modeled separately. If it does not, then the limit may not be valid. With respect to short-falls in an LSEs resource plan, the NRIS, non-firm and ERIS resources dispatched on a *pro rata* basis under Section 2.3.4.1 will be preempted (i.e., the dispatch will be modified) to eliminate the impact of those resources on the elements limiting the proposed transfer.

3.3.2 Voltage and Short-Circuit and Stability Analyses

Voltage, short-circuit and stability issues will only be analyzed as part of the Facilities Study process.

4 Developing Mitigation Plans

To the extent the System Impact Study identifies violation of thermal or voltage reliability limits, the Study will also consider mitigation options that would eliminate the violations and allow for the service to be accepted.

4.1 Evaluating Transmission Upgrade Options

Each System Impact Study that identifies a limiting element that constrains the proposed transfer will also provide a high-level cost estimate of transmission upgrades necessary to mitigate the loading on the identified transmission element. Because of the time frames involved in conducting System Impact Studies, the estimated costs of transmission upgrades will be based on: (1) to the extent available, any previous System Impact Study or Facilities Study that estimated the cost of the upgrade in question; or (2) a dollar per mile cost estimate where new transmission lines are required. *The upgrade*

costs identified in System Impact Studies are planning estimates only and should be expected to change during the more detailed Facilities Study process.

4.2 Evaluating Redispatch Options

If requested by the Transmission Customer, the System Impact Study for a Long-Term TSR will also contain an evaluation of redispatch options for alleviating thermal overloads associated with the proposed transfer. The System Impact Study will consider the availability of the Transmission Provider's resources to provide redispatch. Redispatch of the Transmission Provider's resources will not be available during periods when the forecasted Native Load requirements exceed the Transmission Provider's currently available Network Resources. The System Impact Study process will examine Network Resources over which the Transmission Provider has operational control, but will not evaluate the opportunity to provide redispatch by making additional purchases for that purpose.

Although there is no requirement under the Tariff to identify redispatch options from resources for which the Transmission Provider does not currently have rights or from resources of other Network Customers, the Transmission Provider does allow Network Customers to request an analysis of the Customer's ability to redispatch its own Network Resources in a manner that will allow for the new transmission service without the need to construct transmission upgrades. If redispatch is available for only a portion of the requested service period, the TSR will be granted conditionally based on the Network Customer's obligation to obtain additional resources to continue the redispatch in later years. To the extent that the overload necessitating the redispatch existed in the Base Case Model before the proposed transfer was simulated and was only exacerbated by the transfer, the System Impact Study will only require redispatch sufficient to mitigate the incremental portion of the overload attributable to the proposed transfer.

4.3 Operating Guides

Operating Guides are not used in the evaluation of Transmission Service Requests, with some exceptions. Those Operating Guides that are implemented automatically (with no operator intervention) will be used. These Operating Guides will be posted on OASIS.

5 The System Impact Study Report

All System Impact Study Reports will be made available to requesting customers as required under the Commission's OASIS regulations. Although these regulations do not require posting the actual studies on OASIS, Entergy's business practice is to post all System Impact Studies on OASIS for downloading by customers. All System Impact Study Reports will contain the following information at a minimum:

- the transaction data associated with the TSR, *i.e.,* OASIS ID number, POR, POD, direction, amount requested and time period requested;
- the Base Case Models and power flow software used to evaluate the TSR;
- a general description of the updated data inputs included in the Base Case Models;
- the confirmed and unconfirmed transactions with a higher priority that were included in the Base Case Models;
- the method used to simulate the proposed transfer;
- the results of any redispatch analysis requested by the Customer if redispatch was necessary to accept the request;
- whether the Transmission Customer is required to match the term of a competing request to obtain the service ;
- whether the acceptance of the TSR is conditional due to the fact that the service is dependent upon a transmission facility that is not currently in-service as described in Section 2.3.1.1; and
- whether there was sufficient Available Transfer Capability (ATC) to grant the request and the amount of ATC that was determined to be available.

Additionally, if the System Impact Study does not accept the full amount of the TSR, the System Impact Study Report will also include the following information:

- the limiting elements that prevented the request from being accepted in full; and

- the high-level, planning estimate of the costs associated with constructing the necessary upgrades to make service available.

6 Facilities Studies

The Transmission Customer may request a Facilities Study be conducted if the System Impact Study finds that additional transmission upgrades are necessary before the TSR can be accepted. The Facilities Study is an in-depth study of the upgrades required to reliably accommodate the TSR and will include a good faith estimate of the costs and time required to complete construction and initiate service. Facilities Studies are subject to the procedures and requirements set forth in sections 19, 20 and 32 of the Tariff, as well as the Study practices described in this Manual.

6.1 Scope of a Facilities Study

A Facilities Study is performed pursuant to the request of a Transmission Customer whose Long-Term or Short-Term TSR cannot be accommodated without the addition of transmission upgrades. The results of such a study provide the customer with a list of necessary facilities, the estimated cost of those facilities, and the time required to provide the facilities needed to accommodate the requested transmission service.

The Facilities Study will include a "Project Execution Plan" comprised of the following elements:

- The work scope of the project, including:
    - Safety requirements
    - Rebuilding, reconductoring or new construction of transmission lines
    - Substation additions, modification and/or new substation construction
    - Equipment addition, replacement, and/or modifications
    - Relay modifications on Entergy's system
    - Supervisory Control and Data Acquisition (SCADA) requirements

- Metering requirements
- Telecommunications requirements
- AGC requirements

- A list of assumptions used in developing the scope
- An estimated project schedule
- An estimated cost of the project, including equipment, engineering, procurement and construction work costs
- A risk assessment

6.2 Evaluating the Scope of Necessary Upgrades

When determining the scope of upgrades necessary to accommodate the TSR, the Facilities Study will examine the thermal and voltage requirements contained in the NERC Reliability Standards, SERC reliability criteria, and the Thermal Limits described in Sections 3.3.1 and the voltage limits specified for the NERC Reliability Standard TPL-001 and 002 contingency evaluations in which transmission bus voltages must remain within +/- 5% for TPL-001 and within +5% / -8% for TPL-002. Additionally, the impact of any new transmission facilities on stability and short circuit issues will also be evaluated. The Facilities Study will use the same Base Case Models as used for System Impact Studies, except that the most recent versions of those models will be used to the extent available.

As part of the reliability analysis, the Facilities Study will include an Alternating Current (AC) analysis of the Transmission System. Because of the nature of the AC analysis, TRM will not be used to determine the need for transmission upgrades during the Facilities Study stage. Redispatch alternatives described in Section 4.2 of this Manual may also be considered to the extent not requested in the System Impact Study process. If after taking into account updates to the Base Case Models, the AC analysis, the elimination of TRM, and/or redispatch options, the TSR can be accepted without constructing upgrades, the TSR will be accepted over OASIS and the Customer will be notified.

To the extent that transmission upgrades are still necessary, the design of all necessary facilities will comply with the NERC Reliability Standards, SERC reliability criteria and the Thermal Limit described in Sections 3.3.1 and the Voltage Limit described in this section. To the extent that the overload necessitating the upgrades existed in the Base Case Model before the proposed transfer was simulated and was only exacerbated by the transfer, the Facilities Study will identify the portion of the cost of the upgrade attributable to the new TSR.

6.3 Cost Allocation of Transmission Upgrades

The final Facility Study Report will contain an analysis of whether the necessary upgrades qualify as Base Plan or Supplemental Upgrades under Attachment T to the Tariff and the cost allocation of such upgrades.