UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Entergy Services, Inc.	**)**	**Docket No. ER05-1065-011**
	)	**ER07-32-008**
	)	
	)	

MOTION FOR LEAVE TO FILE ANSWER
AND ANSWER OF ENTERGY SERVICES, INC.

Pursuant to Rules 212 and 213 of the Federal Energy Regulatory Commission's ("Commission" or "FERC") Rules of Practice and Procedure,[1] Entergy Services, Inc. ("Entergy"), on behalf of the Entergy Operating Companies,[2] hereby submits this Motion for Leave to File Answer and Answer in response to the May 4, 2009 Motions to Intervene, Comment and/or Protest submitted in this proceeding by various parties ("Protests").[3] These Protests concern Entergy's April 3, 2009 Revised Attachment C, D and E Compliance Filing ("April 3 Compliance Filing"),[4] which was submitted to the Commission in accordance with Order No. 890[5] and the Commission's orders in Docket Nos. EL05-52-000 and ER05-1065-000

1 18 C.F.R. §§ 385.212 and 385.213 (2008).

2 The Entergy Operating Companies are Entergy Arkansas, Inc., Entergy Gulf States Louisiana, LLC, Entergy Louisiana, LLC, Entergy Mississippi, Inc., Entergy New Orleans, Inc., and Entergy Texas, Inc.

3 Comments or Protests were filed by: (1) the Southwest Power Pool ("SPP"); (2) Union Power Partners, L.P. ("UPP"); (3) Cottonwood Energy Co. LP ("Cottonwood"); (4) Occidental Chemical Corporation ("Occidental"); (5) the Conway Corporation, the West Memphis Utilities Commission, the City of Osceola, Arkansas, the City of Benton, Arkansas, and the Hope, Water and Light Commission (collectively "Arkansas Cities"); (6) East Texas Electric Cooperative, Inc., Sam Rayburn G&T Electric Cooperative, Inc., and Tex-La Electric Cooperative of Texas, Inc. (collectively "ETEC"); and (7) Arkansas Electric Cooperative Corporation, the Lafayette Utilities System, the Louisiana Energy and Power Authority, the Municipal Energy Agency of Mississippi, the Mississippi Delta Energy Agency, the Clarksdale Public Utilities Commission, and the Public Service Commission of Yazoo City (collectively "LMA Customers"). The LMA Customers and the Arkansas Cities and filed erratas to their initial protests on May 8, 2009 and May 11, 2009, respectively.

4 *See Entergy Servs., Inc.*, Attachment C, D and E Compliance Filing, Docket No. ER05-1065-011 (Apr. 3, 2009) ("April 3 Compliance Filing").

5 *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241 (2007) ("Order No. 890"), *order on reh'g*, Order

approving Entergy's Independent Coordinator of Transmission ("ICT") (collectively, the "ICT Orders").[6] As explained below, the Commission should deny the Protests of Entergy's April 3 Compliance Filing and accept Entergy's proposed revised Attachments C, D and E as requested.

In support of this Answer, Entergy states the following:

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II EXECUTIVE SUMMARY

The Commission should deny the Protests and accept the revised Attachments C, D and E included in the April 3 Compliance Filing to be effective as requested. The transmission service criteria contained in the versions of Attachments C, D and E included with the April 3 Compliance Filing satisfy the ICT Orders and either conform to the requirements of Order No. 890's *pro forma* OATT or, where certain criteria deviate from the *pro forma* OATT, meet the Commission's "consistent with or superior to" standard. Accordingly, Attachments C, D and E should be found to be just and reasonable. No party has successfully disputed this.

No. 890-A, 73 Fed. Reg. 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007) ("Order No. 890-A"); *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008) ("Order No. 890-B"), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009) ("Order No. 890-C").

6 *Entergy Servs., Inc*., 115 FERC ¶ 61,095, *errata notice* May 4, 2006 (2006) ("April 2006 Order"); *order on reh'g*, 116 FERC ¶ 61,275 (2006) ("September 2006 Order"); *order on compliance filing*, 117 FERC ¶ 61,055 (2006); *order on clarification*, 119 FERC ¶ 61,013 (2007); *order on compliance filing*, 119 FERC ¶ 61,009 (2007) ("April 2007 Order"); *order on reh'g and compliance filing*, 119 FERC ¶ 61,187; *order on reh'g and clarification*, 122 FERC ¶ 61,216 (2008). The Commission also provided guidance regarding the ICT proposal in the March 22, 2005, May 12, 2005 and September 22, 2006 orders accepting Entergy's January 3, 2005 Petition for Declaratory Order ("Petition") in Docket No. EL05-52-000. *See Entergy Servs., Inc*. 110 FERC ¶ 61,295 ("March 2005 Guidance Order"), *order on clarification*, 111 FERC ¶ 61,222 (2005) ("May 2005 Guidance Order"), *order denying reh'g*, 116 FERC ¶ 61,269 (2006) ("September 2006 Guidance Order") (collectively, "Guidance Orders"). The Commission's orders in Docket Nos. ER05-1065 and EL05-52 are collectively referred to as the "ICT Orders."

Sections V through VIII below address Comments and/or Protests that have raised issues that are legitimately related to Attachments C, D, E and/or Entergy's request for guidance with respect to the modeling of Qualifying Facilities ("QF") and Load Serving Entities ("LSE"). While the comments all challenge a particular term or condition, the critical point is that none of them presents a material issue of fact that should require investigation or otherwise delay the Commission's acceptance of the April 3 Compliance Filing. The stakeholder process envisioned by the ICT Orders has worked as the Commission envisioned, *i.e.*, the Attachments have been thoroughly vetted through stakeholders and the ICT with the resulting Attachments representing the collective views of that group. The only issues that are legitimately related to the filing now presented to the Commission are legal, and in several instances are not issues of first impression.

As explained in the April 3 Compliance Filing, Attachments C, D and E were subject to detailed review and comments in the "AFC Stakeholder Audit Stakeholders Process," the "Near-Term Transmission Issues Working Group ("NTTIWG"), Long-Term Transmission Issues Working Group ("LTTIWG"), "Attachment Review Stakeholder Process," as well as independent review by the ICT. Entergy and the ICT have agreed to implement various ICT and stakeholder recommendations for enhancing Entergy's transmission service criteria and, where appropriate, Entergy has revised Attachments C, D and E to implement these modifications. As the ICT explained in its comments, "the ICT believes that Entergy has addressed, or established procedures for addressing, all of the ICT's recommendations concerning Entergy's AFC Process, transmission service criteria, and other commercial practices."[7] Entergy has filed Attachments C, D and E for Commission review under Section 205 of the Federal Power Act ("FPA").

While Entergy believes that the process leading up to this point has been successful, several Protesters are attempting to use this proceeding as an excuse to re-litigate issues that have

[7] *See* ICT Comments at 3.

already been resolved in the ICT Orders and are not properly related to the April 3 Compliance Filing. Primarily, these are attempts to collaterally attack: (1) the cost allocation of transmission upgrades under Entergy's Attachment T; and (2) the ICT's role in the implementation of Attachments C, D and E. These Protests fail as a matter of law and should also be summarily rejected.

Other Protests of general applicability concerning Attachments C, D and E that are legitimately subject to the Commission's review of Attachments C, D and E -- but should nevertheless be denied -- relate to Entergy's proposed use of business practices (as supported by the ICT) and requests for data beyond what Entergy already volunteers to provide above that required by FERC's regulations. With respect to business practices, the Commission should reject arguments that every business practice associated with Attachments C, D and E must be included in those Attachments and filed with FERC. Entergy (and the ICT) believe that the Commission did not intend for Entergy to incorporate all practices and protocols associated with Attachments C, D and E to be included in those Attachments. As explained by the ICT in its Comments, the "general criteria supporting Entergy's AFC calculations, study processes, and TSR review standards are captured in [Attachments C, D and E] while other more detailed material, including technical processes and procedures that the ICT believes can be improved through stakeholder processes, will be fully transparent through posted business practices."[8] Thus, Entergy (and the ICT) believe that business practices have been used as envisioned by the ICT Orders.

With respect to requests for data, the Commission should summarily deny requests for additional data beyond what Entergy has already volunteered to provide in the various stakeholder processes and what is already required under FERC's governing regulations.

[8] ICT Comments at 5-6.

Through the information that Entergy has volunteered to provide its customers, and the information that Entergy is required to provide under the Commission's regulations, Entergy satisfies the Commission's transparency requirements and provides customers ample information to make well-informed business decisions when transacting on Entergy's system. Indeed, the additional information requested by Protesters exceeds what is required under FERC's regulations and should therefore be denied. Requiring Entergy to provide additional information would undermine the bargain already struck with stakeholders.

In the end, Entergy, working through the stakeholder process, has filed revised Attachments C, D and E that satisfy all of the applicable regulatory requirements under the ICT Orders and Order No. 890. The Commission should therefore deny the Protests and accept the revised Attachments C, D and E included in the April 3 Compliance Filing to be effective as requested.

III. MOTION FOR LEAVE TO FILE ANSWER

Pursuant to Rule 212,[9] Entergy, to the extent necessary, requests leave to file an Answer to the Protests submitted in this proceeding. Generally, an Answer to a Protest is not permitted;[10] however, the Commission will permit such an Answer when it provides useful and relevant information that will assist the Commission in the decision-making process,[11] or where the Answer will clarify the issues before the Commission.[12]

This Answer corrects numerous misstatements of law and fact contained in the Protests and explains why Entergy's revised Attachments C, D and E comply with Order No. 890 and other relevant FERC policies, and why Entergy's proposed Designated Network Resource

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9 18 C.F.R. § 385.212 (2008).

10 *Id.* § 385.213(a)(2).

11 *See, e.g.*, *Cal. Indep. Sys. Operator Corp.*, 120 FERC ¶ 61,147 at P 8 (2007).

12 *See, e.g.*, *Entergy Servs. Inc.*, 91 FERC ¶ 61,348 at 62,169 (2000).

Procedures ("DNR Procedures") are consistent with or superior to Order No. 890's *pro forma* OATT. Moreover, as explained below, this Answer also identifies certain areas in which Entergy has agreed to revise Attachments C, D and E in response to concerns raised in certain Protests. Accordingly, this Answer provides useful information concerning this proceeding's disputed issues. Therefore, to the extent leave is necessary, the Commission should grant Entergy leave to file this Answer.[13]

IV. ISSUES COMMON TO ATTACHMENTS C, D AND E

While Sections V through VIII below respond to specific issues raised for each of Attachments C, D and E, several of the Protests raised concerns which implicate issues generally applicable to all of the Attachments. These concerns fall into four general categories: (1) Entergy's treatment of Base Case Overloads; (2) requests for further clarification of the ICT's role in the administration of Entergy's transmission criteria; (3) the appropriate use of business practices; and (4) requests for the addition of study-related data beyond what Entergy agreed to provide in the various stakeholder processes and what is required to be posted or provided to customers under FERC's regulations. Entergy addresses each of these general issues in this Section IV.

[13] Section 385.213(d) of FERC's regulations requires that Answers to pleading be filed with the Commission fifteen days after the relevant motion is filed with FERC. Entergy is filing this Answer sixteen days after the filing of the Protests and therefore, seeks leave to file this Answer one day out of time. Good cause exists to grant this leave because, as explained in Section III, this Answer corrects numerous issues of law and fact and will assist FERC in its decision making process. Moreover, no party's rights to participate in this proceeding or ability to raise issues or concerns with respect to Attachments C, D, and E will be negatively impacted by allowing Entergy to respond to the Protests in sixteen days as opposed to fifteen days.

A. The Protesters' "Base Case Overload" Allegations Are Not A Basis to Modify the Study Procedures under Attachment D or Cost Allocation under Attachment T.

Almost all of the Protests take issue with Entergy's procedures for mitigating post-contingent overloads in transmission models used for transmission planning, cost allocation and the evaluation of long-term transmission service requests. As discussed below, these arguments are just one example of what has become a seemingly endless series of collateral attacks on the cost allocation principles established by the Commission in the ICT Orders and embodied in Attachment T to Entergy's OATT. As it has done in the past, Entergy provides the Commission with an explanation as to why the allegations of these Protesters are simply wrong on the merits, while also demonstrating that the ultimate purpose behind these claims remains overturning the cost-allocation methodology approved by the Commission in 2006. The Commission should treat these contentions in the same manner as it has in the past, by rejecting them either on the merits or as a collateral attack on the Commission's ICT Orders.

1. Entergy's Transmission Models Comply with All Applicable NERC Reliability Standards

Many of the Protesters' complaints regarding the mitigation practices related to post-contingent overloads (referred to as "Base Case Overloads" herein) ultimately rely either implicitly or explicitly on the flawed assumption that all thermal overloads appearing in Base Case models must be mitigated by constructing new transmission upgrades to relieve those overloads. The LMA Customers, for example, claim that Entergy relies on "lax" planning criteria, operating guides, and other mitigation practices in its transmission planning models such that "Base Case Overloads are essentially 'papered over' from one year to the next, with increasingly deleterious implications for reliability."[14] Entergy has previously addressed such

[14] *See* LMA Customers' Protest at 25.

claims in its Attachment K compliance filing in Docket OA08-59 and it will do so again here.[15] The critical point is that Entergy's transmission models and mitigation practices are fully compliant with all NERC Reliability Standards as SERC has previously determined in two independent audits.

Contrary to claims of the Protesters, these mitigation practices are common on utility systems, and their presence is entirely consistent with NERC Reliability Standards. In fact, thermal overloads can exist in Base Case Models used for transmission planning purposes primarily because NERC Reliability Standards and good utility practice do not require that transmission upgrades be constructed for all post-contingent overloads (*i.e.,* N-1 overloads) that appear during the planning process. In particular, where an upgrade that relieves an N-1 overload is too costly in comparison with the potential benefits that could be realized (*i.e.,* few MW at risk, few hours at risk, probability of contingency causing constraint is small), the NERC Reliability Standards allow transmission owners to address the overload through the use of operating guides (such as switching and redispatch), local area load shedding or other mitigation procedures.

An actual example on Entergy's system in 2007 demonstrates the importance of such practices. The Jim Hill – Water Valley 161/115 kV line in Arkansas serves a peak demand of approximately 80 MW at several stations along the line. Loss of the line due to a fault will consequently interrupt all 80 MW of load during peak loading conditions. If the Water Valley end of the line is unable to be immediately restored during summer peak conditions, service from the Jim Hill end of the line will be limited to approximately 60 MW of load, leaving 20 MW unserved. Planning that considers breaker-to-breaker outages allows for the consequential load loss of the 80 MW. But if 100% of the load is required to be served from either end of the line,

15 *See e.g.,* Attachment K Compliance Filing, Docket No. OA08-59 (Dec. 7, 2007).

approximately 39 miles of 115 kV line will have to be upgraded with an estimated cost of approximately $30,000,000, or the entire route will have to be converted to 161 kV with an estimated cost of $41,000,000. Since 1991, approximately 32 MW-Hours of load was not served due to branch or section outages on the Water Valley – Jim Hill line. All load was served along the entire line section for approximately 99.97% of the time from 1991 through 2007. In light of the low probability of the loss of service, the costs of upgrading the Jim Hill-Water Valley line outweigh the benefits and relying on mitigation procedures to address any overloads that do occur does not negatively impact the reliability of the interconnected transmission system. Yet, according to the Protesters, Entergy should be prohibited from relying on such practices in its transmission planning models and, instead, should be obligated to construct $30 million in transmission upgrades to avoid the loss of 32 MW-Hours of load over an approximately 16-year period. As discussed below, such a result is not required under the NERC Reliability Standards or FERC precedent.

Entergy's treatment of N-1 overloads, which do not exist in a pre-contingency situation, is supported by Note (b) to NERC's Reliability Standard TPL-002 and by certain operating guides (including switching and redispatch). Reliability Standard TPL-002 addresses system planning related to performance under contingency conditions involving the failure of a single element. Compliance with TPL-002 ensures that the bulk-power system is planned to meet system performance requirements, with the loss of one element. Note (b) to TPL-002 states in part, "planned or controlled interruption of electrical supply to radial customers or some local Network customers, connected to or supplied by the faulted element or affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems."

SERC has previously determined that Entergy's planning practices comply with NERC's

TPL Reliability Standards, including TPL-002. As a member of SERC, Entergy demonstrates compliance through self-certification statements, data reporting, and compliance filings to SERC on a routine basis. SERC performs independent audits of Entergy's transmission planning process and transmission system on a periodic basis to further evaluate compliance with the NERC Reliability Standards, including the TPL Standards. The two most recent SERC audit reports issued in September 2004 and April 2007 make clear that Entergy's transmission planning process and transmission system are fully compliant with all applicable reliability standards.

The scope of the 2004 audit covered a number of planning measures, including those related to transmission planning assessments, system protection and controls, and system restoration. SERC's 2004 audit report concluded that Entergy "is in *full compliance* with all 2004 audited planning measures" and that "Entergy data bases, procedures and work management systems validated Entergy's self certifications."(emphasis in original). The audit report also found that there "were no concerns" with Entergy's planning process or the Entergy transmission system. Instead, there were a number of "areas that the audit team considered exceptional, and for which Entergy is to be commended."

The April 2007 audit report addressed matters similar to those addressed in the September 2004 audit report. The 2007 audit covered the post-2004 audit time period. In addition to working with Entergy personnel, the SERC audit team worked with the ICT. SERC concluded that "Entergy Transmission Planning is in compliance with the requirements of NERC's 2007 Planning Reliability Standards based on applicable items assessed." The report also concluded that "[t]here were no areas of non-compliance noted in the standards audited." Again, the SERC audit report included a number of areas the "audit team considered exceptional, and for which [Entergy] is to be commended."

To the extent the Protesters are asserting that Entergy's reliance on Note (b) or other mitigation practices is excessive, they have provided no support for such claims. Moreover, such assertions only raise the same industry-wide policy question FERC directed NERC to consider when reviewing the TPL-002, Note (b), and other aspects of the transmission planning standards in Order No. 693.[16] Specifically, in Order No. 693, FERC determined that the circumstances in which Note (b) may be applied should be addressed on an industry-wide basis though the NERC Reliability Standards development process. Among other things, FERC directed the Electric Reliability Organization ("ERO") to consider developing a ceiling on the amount and duration of consequential load loss that is acceptable.[17] In addition, FERC stated that other concerns regarding Note (b) should be addressed through the Reliability Standards development process. That process is on-going and to the extent the revised standards approved by FERC require a change in Entergy's planning practices, Entergy will comply with those requirements. That process, however, does not change the fact that Entergy is in full compliance with the current NERC Reliability Standards nor does it contemplate the complete elimination of Note (b) type mitigation practices, which will remain in place in one form or another even after the NERC review process has been completed. Thus, FERC should reject the attempt by these Protesters to mischaracterize the issue of Base Case Overloads as a failure on Entergy's part to properly develop its transmission models or otherwise construct upgrades necessary to meet NERC Reliability Standards, rather than the industry-wide policy question identified by FERC in Order No. 693.

Other stakeholders claim that the three-year planning horizon used in the context of the Construction Plan and Base Plan is also a cause of Base Case Overloads and is also inconsistent

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16 *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 118 FERC ¶ 61,218 at P 4 n.6 (2007).

17 *See* Order No. 693 at P 1795.

with Entergy's transmission planning obligations. Entergy has responded to these assertions in the context of its Attachment K compliance filing. As Entergy stated, the three-year horizon for the Construction Plan and Base Plan was approved by FERC in the ICT proceeding, and Entergy is in compliance with all applicable NERC Reliability Standards that apply to transmission planning horizons. The Commission has previously rejected these claims in the past, noting that to the extent stakeholders believe that the scope of studies and transmission plans performed pursuant to Entergy's Attachment K do not comply with NERC reliability standards, they should address those concerns in the first instance through NERC compliance procedures.[18]

2. Entergy's Mitigation Practices Do Not Violate the Comparability Standard or Otherwise Improperly Impair Transmission Access

Perhaps recognizing that the NERC Reliability Standards do not support their claim that Entergy's practices for mitigating Base Case Overloads are improper, other Protesters claim that even if Entergy is in compliance with those standards, the provisions of Attachments D and T violate FERC's comparability principles or otherwise improperly limit transmission access. Occidental leads this charge asserting that "reliability measures incorporated into the Base Plan are irrelevant to whether Entergy's transmission access policies are just, reasonable and not unduly discriminatory"[19] and that Entergy should be directed to construct facilities to eliminate Base Case Overloads even if such construction is not required under the NERC standards.[20] In fact, reliability requirements are the basis for measuring uses of the transmission system and determining available transmission capability.

Occidental and other Protesters claim that facilities that are overloaded prior to the queuing of a transmission service request ("TSR") should not be a limit to the TSR at all. To the

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18 *See Entergy Servs., Inc.*, 124 FERC ¶ 61,268 at P 151 (2008).

19 *See* Occidental Protest at 10.

20 *See* Occidental Protest at 8.

extent an overloaded facility has already exceeded the applicable thermal limit *prior to* simulating the TSR (*e.g.*, if the facility is loaded at 110%), the overload will not be considered a valid limit unless the TSR increases the severity of the overload. Even if the "Base Case Overload" of 10% was removed from the facility, a TSR that increases the flow over the facility still increases the severity of the overload. *In other words, the overloads do not affect TSRs to any greater extent than if the facility were loaded only to 100%.* As Entergy noted in Exhibit 1 of the April 3 Compliance Filing, this claim amounts to nothing more than the assertion that Entergy can deny a TSR when ATC is "positive" but less than the requested amount (*i.e.*, when a flowgate is loaded close to its full capacity) or when ATC is "zero" (*i.e.*, when flowgate is loaded at its full capacity), but *not* when ATC is "negative" (*i.e.*, when a flowgate is loaded above its capacity). Among other things, this assertion is inconsistent with Section 15 of the *pro forma* OATT, which provides that the transmission provider is not obligated to provide service where capacity is not available.

Finally, other Protesters claim that Entergy uses "more stringent" criteria when evaluating TSRs than when performing transmission planning analyses.[21] Cottonwood, for example, complains that the ICT does not apply the "toolbox" of operating guides, generation redispatch and load shedding used in the transmission planning process for the evaluation of TSRs.[22] According to Cottonwood, the Commission should either direct Entergy to cease using these mitigation procedures in transmission planning models or it should direct Entergy to use the same procedures uniformly and consistently across both planning and TSR processing.

These claims are based on the false premise that the Entergy OATT and Attachment D do not provide for a comparable "toolbox" for TSR processing. As noted above, NERC Reliability

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21 *See* LMA Customers' Protest at 25.

22 *See* Cottonwood at 27-28.

Standards and Entergy's Local Planning Criteria allow for the use of automatic operating guides (such as reactor switching), manual operating guides (such as system reconfiguration and generation redispatch), and local area load shedding under Note (b) to mitigate N-1 overloads in lieu of constructing transmission upgrades. Comparable, but admittedly not identical, procedures are also applied in the context of TSR processing, notwithstanding the fact that the Protesters refuse to recognize so. Section 4.4 of Attachment D provides that automatic operating guides that have been evaluated for reliability impact, level of risk, and effectiveness will be considered in the context of a System Impact Study ("SIS") as an alternative to transmission upgrades for granting additional firm transmission service. Like the *pro forma* OATT, the Entergy OATT (and Section 4.3 of Attachment D) provides that planning redispatch will also be considered in the context of a SIS as an alternative to transmission upgrades at the request of the transmission customer.

Certainly, there are differences between the "toolbox" available for TSR processing and the "toolbox" available for transmission planning under the NERC standards, but these differences are not unduly discriminatory. For example, Entergy and the ICT agree that, while certain automatic operating guides can be used in the evaluation of TSRs, manual operating guides cannot. The ICT has indicated its willingness to incorporate only automatic switching operating guides that require no manual intervention into the Base Case model that is used to evaluate transmission service, stating:

> [T]he ICT disagrees with the use of manual switching operating guides to sell long-term transmission service and generator interconnection service. The base case model used to sell transmission service should not include mitigation plans that are strictly intended for reliability purposes and that require some amount of manual intervention. For instance, a mitigation plan identified to prevent the overload of a line segment feeding more than 100 MW of consequential load may involve a manual switching guide implemented in order to restore loss of load. It is unreasonable to sell additional service based upon this operating guide because it would add loading on a line that is already assuming the loss of load. Manual operating guides are intended to protect the reliability of the transmission system

> in a real-time emergency; they are not intended to be used to grant new transmission service in a planning model.[23]

For similar reasons, Entergy and the ICT agree that, to the extent that local load shedding under Note (b) is appropriate, such a mitigation procedure cannot be applied to the evaluation of TSRs.[24]

The fact that load shedding and manual operating guides are appropriate in the context of transmission planning, but cannot be used to grant additional transmission service, is not unduly discriminatory because other comparable procedures are applied in the context of TSR processing. For example, although local load shedding under Note (b) and manual operating guides cannot be applied in the context of TSR evaluations, the availability of planning redispatch and conditional firm service provides a comparable mitigation alternative in the context of TSR processing.[25] It is important to realize that, in addition to planning redispatch, Order No. 890 established an industry-wide solution to the Protesters' underlying concern when it created conditional firm service. Conditional firm service is designed to be used, among other things, "to remedy a system condition that occurs infrequently and prevents the granting of a long-term firm point-to-point service."[26] FERC observed that conditional firm service would provide customers comparable service to native load, which employs automatic devices such as special protection systems to take resources offline during certain system conditions.[27] If a

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23 *See ICT Opinion on LTTIWG Base Case Contingency Overloads Task Force Recommendation*, at 3, April 3 Compliance Filing, Ex. 11.

24 *See id.*

25 There are other examples of procedures that avoid the need for upgrades in the context of TSR processing, but not transmission planning are also found in Attachments C and D. TSRs that have less than a 3% impact (*i.e.*, OTDF) on a particular flowgate are ignored entirely even if that impact causes the flowgate to exceed the thermal limit of the flowgate. The 3% OTDF is not used in the transmission planning process. In the AFC Process, the transmission study does not even evaluate all flowgates on the Entergy transmission system, something that is done in the context of transmission planning.

26 Order 890 at P 911.

27 *See id.* at P 924.

customer supports the construction of upgrades, it may utilize conditional firm service until the upgrades are complete. If the customer chooses not to support system upgrades for whatever reason (such as the customer decides the cost of the upgrades outweighs the benefits of "firming-up" the service), it may maintain conditional firm service subject to biennial reassessments of the conditions or hours that service may be curtailed.[28]

3. Entergy's Mitigation Practices Do Not Shift the Cost of Reliability-Related Upgrades to Transmission Customers.

The primary argument raised by all Protesters regarding Entergy's mitigation practices and the treatment of Base Case Overloads is that these practices directly assign, or otherwise shift, the cost of reliability-related upgrades to the transmission customer when such upgrades should be rolled into embedded transmission rates. These arguments wrongly suggest that the interests of transmission customers are ignored under Attachment T, when an upgrade they require is necessary for reliability purposes. Their position is incorrect.

In Exhibit 1 of the April 3 Compliance Filing, Entergy pointed out that these arguments mischaracterize the cost allocation methodology approved under Attachment T and fail to recognize that the ICT ensures that reliability-related upgrades are not directly assigned to individual customers. Under Attachment T, Entergy's Construction Plan includes all upgrades necessary for reliability reasons under Entergy's Local Planning Criteria and applicable NERC Reliability Standards. The ICT also develops its Base Plan, which includes all reliability upgrades the ICT believes are necessary for reliability reasons under any more stringent planning standards that the ICT believes are necessary. If an upgrade is included in either Entergy's Construction Plan or the ICT's Base Plan, the cost of those upgrades cannot be directly assigned to the customer and the transmission customer would pay only for any acceleration of the investment (if any acceleration is required). Attachment T further provides that, if there is an

[28] *See id.* at PP 980-81.

upgrade in the Base Plan that would cure the Base Case Overload alone (upgrade A) and an enhanced or different upgrade, not in the Base Plan, that would resolve both the overload and the transmission request (upgrade B), but no upgrade that would satisfy the transmission request alone, then the customer would pay the cost of upgrade B minus the cost of upgrade A.[29]

Although Entergy believes Attachment T adequately protects transmission customers from any improper cost-shifting, Entergy also clarified Sections 4.1 and 6.2 of Attachment D. These sections were revised to make clear that for facilities with an N-1 overload prior to simulating the TSR, the upgrades (or other mitigation options) would be "sized" based on the impact of the TSR, rather than the portion of the overload that existed prior to simulating the TSR. In practice, this means that Entergy will remove any loading on the facility in excess of 100% of the normal facility rating when developing the mitigation option.[30]

Notwithstanding the protections contained in the existing provisions of Attachment T and the additional clarification by Entergy in Attachment D, the Protesters claim that Entergy's treatment of Base Case Overloads improperly shifts the costs of reliability-related upgrades to transmission customers. Although certain arguments by the Protesters mischaracterize these provisions and incorrectly suggest (for example) that the cost of Base Plan Upgrades can be

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[29] *See* Attachment T § 3.2.2. At pages 26-27 of their Protest, the LMA Customers mistakenly claim that upgrades exceeding the cost of Base Plan Upgrades are entitled to full rolled-in treatment. This is fundamentally at odds with the Commission's pricing policy approved in the ICT Orders. If the LMA Customers were correct, then a Supplemental Upgrade costing ten times as much as the Base Plan Upgrade it eliminated would be entitled to rolled-in treatment in its entirety. Supplemental Upgrades for a particular customer cannot increase the cost of the Base Plan to other users of the transmission system.

[30] According to the LMA Customers, the Commission's view is that "pre-transfer overloads must be eliminated in a network model before a transmission provider evaluates the effect of a new service request." LMA Customers Protest at 36 (citing *Midwest Indep. Transmission Sys. Operator, Inc.,* 122 FERC ¶ 61,113 (2008)). However, the Commission's order cited by the LMA Customers did not resolve the issue. In fact, the Commission's order does not take issue with the Midwest ISO (or for that matter Entergy) "screening the base case" to prevent the customer from being assigned responsibility for any of the pre-existing study overloads. Rather, the concerns turn on application of the Midwest ISO's policy with respect to that particular interconnection request and whether the screening was implemented properly. As noted above, Sections 4.1 and 6.2 of Attachment D were revised to make clear that Entergy will remove any loading on the facility in excess of 100% of the normal facility rating when developing the mitigation option. Thus, Entergy's practices do not conflict with the Commission's MISO decision.

directly assigned to transmission customers,[31] the Protesters generally recognize that their "cost-shifting" argument focuses on transmission upgrades that alleviate a Base Case Overload but that are not included in the Base Plan because those upgrades have *not* been determined to be necessary for reliability by either Entergy or the ICT. For example, the LMA Customers complain that "[i]f an upgrade required to accommodate a TSR is not included in the ICT's Base Plan, the upgrade would be classified as Supplemental and the full cost of the upgrade directly assigned to the service-requesting customer, even if the upgrade also resolves a pre-transfer Base Case Overload."[32] Occidental likewise disputes Entergy's claim of no cost-shifting due to the fact that "not all upgrades that alleviate base case overloads are Base Plan Upgrades" and states that "there is no rational basis to allocate the cost of an upgrade that accommodates a transmission service request and alleviates a base case overload to the customer."[33]

As an initial matter, these arguments rest on the false premise that any upgrade that alleviates a Base Case Overload must be necessary for reliability reasons. As discussed in detail in section IV.A.1 above, this assumption is simply incorrect and is not supported by the NERC Reliability Standards or FERC precedent. These arguments also fail to appreciate that Attachment T contains the additional protection of the ICT to ensure that reliability-related upgrades are not directly assigned to transmission customers. In the circumstance identified by these Protesters – where an upgrade that alleviates a Base Case Overload is *not* included in the

[31] *See e.g.,* LMA Customers' Protest at 22-23 (incorrectly claiming that upgrades deemed by Entergy as supplemental end up fixing reliability concerns, when in fact the ICT (not Entergy) determines whether an upgrade is supplemental and upgrades the ICT determines to be necessary to fix reliability concerns can only be considered Base Plan Upgrades; and also incorrectly claiming that the cost of Base Plan Upgrades necessary to accommodate a TSR are borne by the TSR, when in fact Base Plan Upgrades cannot be directly assigned under Attachment T); Cottonwood Protest at 25 (incorrectly stating that operating guides or mitigation plans that avoid the need for transmission upgrades are not included in Base Case models, when Section 4 of Attachment D identifies the availability of automatic operating guides, planning redispatch and conditional firm service as alternatives to transmission upgrades).

[32] *See* LMA Customers' Protest at 23.

[33] *See* Occidental Protest at 13.

ICT's Base Plan – the ICT has determined that alleviating the Base Case Overload is *not* necessary for reliability. Put another way, the "rationale basis" that Occidental fails to see for assigning the cost of such upgrades to a transmission customer is the fact that both Entergy and the ICT have determined that the upgrade is *not* necessary for reliability and, in fact, is only necessary to accommodate that customer's TSR. Directly assigning the cost of such upgrades to the customer is required under Attachment T and is entirely appropriate.

It should also be noted that these customers completely ignore the reverse circumstance, *i.e.*, what happens when a Base Plan upgrade (or a Construction Plan upgrade) that has been determined to be necessary for reliability also happens to accommodate a subsequent TSR. Under Attachment T, the entire cost of the upgrade is rolled into transmission rates (not directly assigned to the transmission customers) because either Entergy or the ICT has determined that the upgrade was necessary for reliability. Tellingly, these Protestors do not request that FERC clarify that a portion of the costs of that upgrade should be allocated to the transmission customer.

Thus, the ICT planning process eliminates any need for an allocation of costs as advocated by UPP, the LMA Customers and other Protesters. Under the planning process, upgrades are definitively determined by the ICT to qualify either as Base Plan Upgrades or as Supplemental Upgrades, and this determination governs with respect to pricing. There is no hybridization of upgrades – upgrades are either needed for reliability, and classified as Base Plan, or they are not needed for reliability, and classified as Supplemental. They then are charged for accordingly, with the costs of reliability upgrades rolled into base transmission rates and the costs of other facilities allocated to the party that causes the costs. It should also be noted that the ICT has applied certain more stringent criteria with respect to the Base Plan. Although the NERC process for reviewing Note (b) is not yet completed, the ICT develops the

Base Plan by applying limits on the use of Note (b) – such as the 100 MW rule – that it has concluded should be used in planning for the Entergy system. The additional upgrades required by these criteria – many of which resolve Base Case Overloads – are included as Base Plan Upgrades and the costs are not directly assigned to transmission customers.

Finally, Attachment T also provides for an allocation of revenues to a transmission customer from additional service for others that is dependent on the customer's previously funded Supplemental Upgrades.[34] Such payments by Entergy include not only a share of point to point revenues, but also compensation related to long-term network resource designations, NRIS status, and service to cover load growth.[35] Thus, Attachment T properly compensates a transmission customer where an upgrade it has supported is required for service to other users of the transmission system. No modifications to the Attachment T pricing policy are needed or justified**.**

4. In Attacking Entergy's Treatment of Base Case Overloads, the Protesters Seek to Modify the Cost Allocation Principles Under Attachment T and Collaterally Attack FERC's Approval of the ICT

Almost all of the Protests take issue with the inclusion of Base Case Overloads in Entergy's modeling, particularly in the modeling for long-term transmission service under Attachment D. These arguments are an attack on the cost allocation principles established by the Commission in the ICT Orders and embodied in Attachment T to Entergy's OATT. Some Protesters are explicit in their demand for revision to the Attachment T principles, while others cloak their attack in a convoluted and erroneous interpretation of the original version of Attachment D filed (Entergy's System Impact and Facilities Study Manual ("SIS/FS Manual")) as one of Entergy's "Criteria Manual" on November 16, 2006 in Docket No. ER05-1065-004

[34] *See* Attachment T § 4.3.

[35] *See id.* at § 4.3.5.

(LMA Customers take both tacks). Yet, the cost allocation principles of Attachment T are not at issue in the April 3 Compliance Filing, and the Protesters' collateral attack on the Commission's ICT Orders must be rejected.

That each of the Protesters addressing Base Case Overloads is in fact contesting the basic cost allocation principles of Attachment T is clear from their pleadings. The LMA Customers are perhaps the most explicit. After recognizing that "no topic has received nearly as much attention in the ICT stakeholder process, or generated quite as much controversy, as the treatment of Entergy's existing Base Case Overloads,"[36] the LMA Customers assert that the '"participant funding' cost allocation method embodied in Attachment T" is a way of shifting the costs of required transmission investments to others.[37] Anticipating that Entergy will point out to the Commission the LMA Customers' collateral attack on the ICT Orders, the LMA Customers embrace the charge and respond that "the Commission nevertheless has a duty to revisit earlier decisions that relied on faulty premises."[38] The LMA Customers conclude their discussion of the issue with the assertion that "sufficient evidence now exists to make that finding [of unjustness and unreasonableness] with respect to Attachment T and the provisions of Attachments C, D and E that support Attachment T's cost allocation method."[39]

Other Protesters are somewhat more circumspect in their attack on Attachment T. For instance, ETEC argues:

> An upgrade that eliminates a base case overload may also enable a TSR without further upgrades. Allocating a portion or all of the cost of such an upgrade to the next arriving TSR creates a perverse incentive to defer upgrades, despite base case overloads, in anticipation of TSRs. This incentive arises because part or all

36 *See* LMA Customers' Protest at 19.

37 *Id.* at 20.

38 *Id.* at 21.

39 *Id.* at 36.

> of the cost of upgrading to remedy a base case overload can be unjustly and unreasonably shifted to the TSR requestor.[40]

Cottonwood asserts that "the Commission should direct Entergy to modify the Tariff to provide clear procedures and full protections to customers funding lumpy upgrades that are diverted to address preexisting BCOs,"[41] and in a footnote, argues "[i]f the terms of the Criteria Manual cannot be found just and reasonable due to conflicting terms elsewhere in the Tariff, the Commission must require further revisions to sections of the Tariff that are not directly before it."[42] Occidental likewise attacks cost allocation under Attachment T, claiming "there is simply no rationale (sic) basis to allocate the cost of an upgrade that accommodates a transmission service request and alleviates a base case overload to the customer." [43]

While it is apparent that the Protesters seek to overturn the cost allocation principles of Attachment T, it is equally clear that these principles were fundamental to the Commission's ICT Orders and the formation of the ICT. Entergy's pricing proposal, based on participant funding of transmission upgrades other than those needed for reliability, was crucial to state regulatory support for Entergy's participation in the ICT arrangement and was the cornerstone of Entergy's ICT proposal, as LMA Customers acknowledge.[44]

The Commission approved the ICT arrangement on that basis. In its September 2006 Order on Rehearing in Docket No. ER05-1065-001, the Commission summarized the pricing proposal:

> Entergy's pricing proposal is driven by a Base Plan prepared by the ICT. Base Plan Upgrade investments are investments necessary to: maintain existing long term firm point-to-point service commitments and [Network Service] commitments (including those necessary to serve load growth requirements);

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40 *See* ETEC Protest at 8.

41 *See* Cottonwood Protest at 31-32.

42 *Id.* at 32 n.46.

43 *See* Occidental Protest at 13.

44 *See id.* at 20 n.15.

> maintain applicable levels of integration of generators qualified at the Network Resource Interconnection Service (NRIS) or [Network Service] levels; meet regional safety and reliability standards; and maintain firm transmission service commitments where the ability to honor such commitments has been degraded due to events that are beyond the control of the Transmission Provider (such as increased loop flows from neighboring regions). The Base Plan upgrade costs will be recovered through Entergy's transmission rates, including Point-to-Point and [Network Service] rates under the OATT, bundled retail rates and grandfathered agreements.
>
> All other upgrades are Supplemental Upgrades, which can be constructed to accommodate a request for an "economic upgrade" or a request for specific interconnection or delivery service. Economic upgrade investments are typically designed to reduce congestion on the transmission system (*e.g.*, reduce the delivered price of power for particular loads); increase the transfer capability across, out of or into Entergy's transmission system; or to serve load at a higher level of reliability than is required by the Transmission Planning Protocol.[45]

The Commission then noted that in the April 2006 Order conditionally approving the ICT arrangement, it had "approved Entergy's pricing proposal *on a four-year basis*, subject to certain conditions."[46]

Thus, the Commission approved, for the four years of the ICT's initial term, the cost allocation mechanism that the Protesters now seek to overturn. Under that mechanism, the ICT establishes the Base Plan, to identify reliability-related upgrades with costs to be recovered through Entergy's transmission rates. All other upgrades, including those to reduce congestion or increase transfer capability, are Supplemental Upgrades, economic upgrade investments that are to be recovered from the requesting customer. Protesters now seek to re-allocate to Entergy some of the costs of these Supplemental Upgrades, engendered by their own requests for transmission service.

Protesters' current challenge to the cost allocation structure underlying the ICT arrangement is not their first. They opposed Entergy's pricing proposal all along the way,

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45 September 2006 Order at PP 76-77.

46 *Id.* at 78 (emphasis added).

raising the same arguments that they make again in their protests of Attachments C, D and E. For example, the LMA Customers, all of whom were members of the TDU Intervenors group, actively challenged the classification of upgrades as Base Plan or Supplemental, all the way through rehearing of the April 2006 Order in the ICT Proceeding. As the Commission noted in its September 2006 Order on rehearing:

> TDU Intervenors argue that the *April 24, 2006 ICT Order* errs in approving Entergy's pricing proposal because that proposal relies on a false distinction between reliability upgrades and economic upgrades.… TDU Intervenors argue that even if a network upgrade could be meaningfully and neatly categorized as either a Base Plan or Supplemental Upgrade at the time of construction, the upgrade's function could change over time.… TDU Intervenors state that the Commission ignored the argument that the cost assignment under Entergy's pricing proposal would result in Entergy's bearing little exposure to the cost of upgrades and that cost allocations under the ICT pricing proposal would disproportionately benefit Entergy's retail load.[47]

The Commission rejected these contentions in the September 2006 Order, and it likewise should reject the LMA Customers' and other Protesters' very similar current attack on the ICT arrangement.

The treatment of Base Case Overloads is governed by the cost allocation mechanism approved by the Commission in the ICT Orders. Under this approach, the ICT determines what investments are required for reliability purposes, including some that may alleviate Base Case Overloads. As the Commission noted, "if the ICT believes that a particular investment is required for reliability purposes and comports with the Planning Criteria, it would be considered a Base Plan Upgrade under the Transmission Planning Protocol for pricing purposes."[48] The costs of such upgrades, whether built pursuant to Entergy's Construction Plan or to a service request by a transmission customer, would be rolled in. The Commission also noted, importantly:

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[47] *Id.* at PP 93-95.

[48] *Id.* at P 117.

> While the ICT must use the criteria proposed by Entergy in determining what is a Base Plan or Supplemental Upgrade, it is the ICT that makes the ultimate determination. Further, we accepted the criteria used to determine cost allocation after considering extensive comments.[49]

The cost allocation criteria, incorporated in Attachment T, are not properly at issue in the filing of Attachments C, D and E. Attachments C, D and E identify the processes by which transmission requests are made and evaluated; they do not address cost allocation. Indeed, the ICT recognized this very point in rejecting a portion of the Stakeholder Policy Committee's July 11, 2007 recommendation on Base Case Overloads. While the ICT indicated that it was "not opposed to the concept of a specific cost sharing alternative" for addressing the impact of Base Case Overloads, it concluded:

> Attachment D provides the process for studying long term transmission service requests while Attachment T contains provision for cost allocation and recovery.[50]

It is Attachment D and the processes for obtaining transmission service that are at issue here, and not the cost allocation provisions of Attachment T.

This conclusion is further supported by the Commission's September 18, 2008 Order addressing Entergy's proposed transmission planning procedures in Attachment K.[51] In that proceeding, certain commenters, including UPP, argued that Entergy's development of Attachment K "started with the flawed premise that Attachment K must be derived from Attachment T of Entergy's OATT and pre-Order No. 890 Commission orders. . . ."[52] Rejecting UPP's attempt to challenge Entergy's cost allocation methodology set forth in Attachment T, the Commission stated that in Order No. 890, "it did not intend to modify existing mechanisms to

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[49] *Id.* at P 115.

[50] *See* April 3 Compliance Filing, Ex. 11 at 4.

[51] *See Entergy Servs., Inc.*, 124 FERC ¶ 61,268 at PP 151-52 (2008).

[52] *Id.* at P 140.

allocate costs for projects that are constructed by a single transmission owner and billed under existing rate structures."[53]

This point was underscored by the Commission in its March 4, 2009 Order in Docket No. OA07-32-004.[54] In that order, the Commission ruled that prohibiting any comments on Attachment T when Entergy filed its revised criteria manuals in Attachments C, D and E would not be appropriate, "since portions of the criteria manuals are directly related to Attachment T. Though Attachment T relates primarily to Entergy's transmission facility pricing provisions, it contains numerous references to provisions in the criteria manuals."[55] While both the LMA Customers and Cottonwood cite to this order as support for their ability to attack participant funding and the ICT pricing mechanism in this docket, they fail to note the Commission's specific caveat in allowing some comments on Attachment T:

> [W]e agree that Entergy's filing of the revised criteria manuals shall not be an open season for parties to relitigate issues previously decided by the Commission to establish the ICT and the criteria for base plan and supplemental upgrades.[56]

Protesters' challenge to the cost allocation principles of Attachment T plainly runs afoul of this prohibition. Entergy's and the ICT's treatment of Base Case Overloads fully comports with Attachment T pricing principles and is not legitimately at issue in this proceeding.

5. The Original Version of Attachment D Does not Provide for an Allocation of Upgrade Costs

In their efforts to overturn the Commission's acceptance of Entergy's pricing proposal, both UPP and the LMA Customers offer an interpretation of the original version of Attachment D, predecessor to the SIS/FS Manual, filed on November 16, 2006 in Docket No. ER05-1065-004, to argue that upgrades that cure Base Case Overloads, as well as provide for new service,

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53 *Id.* at P 151.

54 *Entergy Services, Inc.*, 126 FERC ¶ 61,194 (2009).

55 *See id.* at P 8.

56 *Id.* at P 9.

were always intended to be allocated; *i.e.*, that upgrade costs were to be split between Entergy and the customer requesting new service. UPP devotes thirteen pages of its pleading to its interpretation of the SIS/FS Manual, as establishing cost allocation principles separate from and different than the cost allocation under Attachment T. The LMA Customers chase this illusion as well, and charge that Entergy is violating its OATT "by disregarding the still-effective language of § 6.2 of Attachment D that required an allocation of upgrade costs between overload remediation and new transmission service."[57] According to both UPP and the LMA Customers, Entergy and the ICT have failed to abide by the lawful terms of the Entergy OATT and Entergy is now trying to modify its OATT to eliminate this allocation.

There is no support for this position in the pleadings leading to the Commission's approval of Entergy's pricing policy in its April 2006 and September 2006 Orders in the ICT proceeding, nor in the Orders themselves, and the Protesters point to none. Indeed, this position conflicts with the rest of the LMA Customers' argument, which plainly and directly calls for the Commission to modify the pricing policy: see, for example, the concluding paragraph of their "Treatment of Existing Base Case Overloads" argument at page 37 of their Protest, where LMA Customers assert that "continuing this element of the experiment simply would be unwise…. The Commission, therefore, should direct Entergy to participate in an ICT-led process to develop an alternative method for allocating transmission upgrade costs."

UPP's and the LMA Customers' claim that upgrade costs already are subject to an allocation, rather than qualifying either as Base Plan or Supplemental Upgrades, derives from language in Section 6.2 of the SIS/FS Manual. This language, while not a model of clarity, in fact, does not support the interpretation of UPP and the LMA Customers, as is apparent when it is read in conjunction with the next provision of the manual, Section 6.3. During the stakeholder

[57] *See* LMA Customers' Protest at 30.

review process, Entergy clarified this provision. UPP and the LMA Customers now argue that this clarification is a tariff change that is not yet effective, and that if upgrade costs are not now being allocated, then Entergy is in violation of its tariff.

A review of the original language of sections 6.2 and 6.3 of the SIS/FS Manual, together with Entergy's modifications in Attachment D to clarify that language, will demonstrate that there is no support for the LMA Customers' and UPP's position, and that Attachment T alone governs who bears cost responsibility for upgrades.

a. The Original Language of Section 6.2 and 6.3 Does Not Allocate Upgrade Costs

As explained previously, Attachment T of the Entergy OATT describes: (1) the process where the ICT classifies upgrades as Base Plan or Supplemental; (2) "higher of" pricing; and (3) the financial rights that those funding Supplemental Upgrades have when other entities subsequently use the upgrade. Under Attachment T, Supplemental Upgrades are funded initially by the party requesting the service that requires the upgrade, with that customer receiving payments where subsequent service (including service to cover load growth) depends on the previously funded upgrade. Attachment T further describes the calculations that would determine the amount of such payments.

In arguing for a different policy, where the cost of upgrades that resolve Base Case Overloads would be apportioned at the outset between the customer requesting the upgrade and all customers taking service, UPP and the LMA Customers point to the language found in Section 6.2 of the SIS/FS Manual (Original Sheet No. 22), which states, "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."

Any suggestion, however, that upgrade costs are to be divided initially between Supplemental Upgrades and Base Case improvements, is belied by the very next sentence of the manual, which constitutes the entirety of section 6.3, Cost Allocation of Transmission Upgrades. Section 6.3 states:

> 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.

Thus, Section 6.3 of the original SIS/FS Manual removes any doubt as to the application of Attachment T to a situation in which an upgrade resolves Base Case Overloads while allowing for new service. This classification of an upgrade as Base Plan or Supplemental (and not some combination of the two) is consistent with the basic pricing mechanisms approved by the Commission in the ICT Orders and with the fundamental structure of the tariff, in which Attachment T -- not Attachment D -- has controlled the pricing of transmission upgrades. *The SIS/FS Manual/Attachment D only constitutes the procedures used by Entergy when studying upgrades that will eventually be subject to Attachment T's pricing policies.* These pricing policies are what both the FERC and the Louisiana Public Service Commission ("LPSC") approved when allowing the establishment of the ICT -- not SIS/FS procedures included in Attachment D.[58]

Accordingly, not only does Entergy believe that UPP and the LMA Customers are misinterpreting the role of Attachment D, neither Entergy nor the ICT has the authority to implement their interpretation. To the extent UPP and the LMA Customers request as much, they are asking Entergy and the ICT to depart from the proposal originally approved by FERC and the LPSC.

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58 *See Entergy Louisiana, Inc.*, Docket No. U-28155, La. Pub. Serv. Comm'n at 5,9,11, 14 (Jul. 12, 2006); *Entergy Louisiana, Inc.*, Final Recommendation of the Administrative Law Judge, Docket No. U-28155, La. Pub. Serv. Comm'n at 29, 38 (Jun. 28, 2006).

b. Entergy's Attempt to Clarify the Language in Section 6.2 of Attachment D

UPP and the LMA Customers further claim that Entergy improperly clarified the application of Sections 6.2 and 6.3 in its July 13, 2007 Order No. 890 Compliance filing. They argue that the original language of Sections 6.2 and 6.3, found in the SIS/FS Manual, is currently in effect, and that unless Entergy allocates upgrades between Base Plan and Supplemental, it is in violation of its tariff. These assertions are invalid, as a review of the various filings by Entergy demonstrates.

In the April 2006 Order, the Commission conditionally approved Entergy's enhanced ICT proposal, while calling, *inter alia*, for Entergy and the ICT to work with stakeholders to further develop what would become Entergy's Criteria Manuals. After notice to and comment from stakeholders, Entergy filed the revised Criteria Manuals on November 16, 2006, in Docket No. ER05-1065-004. On April 4, 2007, the Commission accepted the Criteria Manuals but required Entergy to resubmit the Criteria Manuals as attachments to its OATT, rather than as independent rate schedules.[59] The Commission also required Entergy to vet the Criteria Manuals through an additional stakeholder process. This latter process culminated in the April 3 Compliance Filing now before the Commission.

Entergy made a compliance filing on May 18, 2007, revising the Criteria Manuals to clarify the ICT's role in implementing the Criteria Manuals. Entergy explained that, in order to minimize confusion and facilitate a coherent approach to amending its OATT, Entergy was going to re-file the Criteria Manuals as Attachments C, D and E to the Entergy OATT in Entergy's upcoming July 13, 2007 Order No. 890 compliance filing. Entergy made its Order No. 890 Compliance Filing on July 13, 2007 and explained that the Criteria Manuals (by that time,

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59 *Entergy Services, Inc.*, 119 FERC ¶ 61,009 ('2007") ("April 2007 Order").

Attachments C, D and E) were being filed subject to the outcome of the stakeholder process required by the April 26 Order and April 4 Order.

In its July 13, 2007 Order No. 890 Compliance Filing, Entergy clarified the language of Sections 6.2 and 6.3, now found in Attachment D, in response to questions, first by UPP, in the stakeholder process about the meaning of Section 6.2. In Order No. 890,[60] as clarified on April 11, 2007, the Commission explained that Order No. 890's revisions to the *pro forma* OATT were to become effective July 13, 2007. Accordingly, the revisions included in Entergy's July 13, 2007 Order No. 890 compliance filing became effective upon their submission, and now represent the effective version of the Entergy OATT, including Attachments C, D and E.

Entergy recognizes that the ICT believes that Entergy should not have modified the language in Section 6.2 as part of its Order No. 890 compliance filing. However, and significantly, the ICT also concluded that "the inclusion or removal of this specific language in Entergy's tariff does not, and should not, alter the way the ICT currently performs its analysis on the cost responsibility for upgrade facilities" because Attachment T, not Attachment D, governs the allocation of upgrade costs.

Entergy submits that the currently-effective version of Attachment D and Section 6.2 is that contained in its July 13, 2007 Order No. 890 Compliance Filing. In any event, whether that filing is currently in effect or the previous May 18, 2007, compliance filing is effective, the result is the same, as the ICT concluded – Attachment T, not Attachment D, governs cost allocation.

60 *See* Order No. 890 at PP 139-41.

2. No Further Clarification of the ICT Role with Respect to Attachments C, D and E is Required

Section 1 in each of Attachments C, D and E addresses the general division of responsibilities between Entergy and the ICT. A number of the Protests focus on this division of responsibility, seeking further clarification of the ICT's review and validation role.[61] The arguments raised by Protesters are similar to those raised by stakeholders in response to Entergy's May 18, 2007 compliance filing currently pending in Docket No. ER05-1065-008.

As stated in the April 3 Compliance Filing, Entergy believes that the existing language in Attachments C, D and E continues to comply with the requirements of the Commission's April 2007 Order in the ICT Proceeding.[62] The ICT developed the necessary revisions to ensure appropriate language that Entergy included in its compliance filing. As a further safeguard, specific language was included in Attachments C, D and E providing that the terms and conditions of Attachment S and/or the ICT Protocols included in Attachment S would control.

Thus, not only has Entergy included language on the division of responsibilities that was specifically developed by the ICT, it has included a catch-all provision in Attachments C, D and E that prevents provisions in Attachment C, D or E from displacing the division of rights and responsibilities between Entergy and the ICT set forth in Attachment S. Entergy and the ICT believe that this approach will provide more clarity, not less.

UPP's arguments on this issue reveal the intent of its proposed changes. UPP takes issue with the ICT's statements that it is bound by Entergy's FERC-filed tariff, including Attachment S.[63] Rather than clarification, UPP seeks to relitigate the ICT's *authority* as accepted by the Commission in the ICT Orders. Likewise, Cottonwood argues that the ICT should be given full

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[61] *See* Arkansas Cities Protest at 5 and 7; ETEC Protest at 2-3; Cottonwood Protest at 9-11; UPP Protest at 8-12; LMA Customers' Protest at 8-12, 17 and 38.

[62] *See* April 3 Compliance Filing at 4-5.

[63] *See* UPP Protest at 10.

control over the AFC models, SISs and Facilities Studies ("FSs").[64] Again, these issues have been addressed by the Commission, and that division of responsibility regarding control over the models and the performance of SISs and FSs is clearly set forth in the Entergy tariff and was approved by the Commission.[65]

Furthermore, the ICT is not without recourse on the issues highlighted by Protesters. The ICT's options when a dispute arises are clearly set forth in the ICT Orders.[66] These options are stated in Attachment S and authorize the ICT to institute specified dispute resolution procedures when disputes arise over data or models. More importantly, it must be noted that, in many cases, the ICT's position prevails pending resolution of the dispute. Still, the Commission has made clear that the ICT lacks filing rights under Section 205 of the FPA and cannot directly propose changes to criteria, standards or policies under the Entergy OATT to the Commission.[67] As well, the ICT does not have authority to compel Entergy to change the transmission criteria.[68]

The Commission also denied requests that would have allowed the ICT to unilaterally implement its recommendations concerning the AFC Process, stating that if Entergy declines to follow an ICT recommendation, the appropriate recourse is for the ICT to submit a protest when the revised process is filed.[69] The Commission observed that, in terms of seeking a change in the transmission service criteria under the Entergy OATT, the ICT essentially stood in the same posture as any other interested party with the ability to pursue such change through formal

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64 *See* Cottonwood Protest at 9-11, 23; *see also* LMA Protest at 39-40.

65 *See* Attachment S, Original Sheet Nos. 574-83.

66 *See* March 2005 Guidance Order, 110 FERC ¶ 61,295, *order on clarification*, 111 FERC ¶ 61,222**,** *order denying reh'g*, 116 FERC ¶ 61,269.

67 *See* September 2006 Order at P 21 (2006).

68 *See* Entergy OATT, Attachment S, §§ 4.3 and 6.1; Attachment S, Transmission Services Protocol §§ 5.3 and 8.3.

69 *Id.* at P 23.

complaint or protest procedures.[70] Thus, the scope of the ICTs authority has already been decided by the Commission and Protesters should not be allowed to use this proceeding to relitigate those issues.

Entergy does not believe that any of the proposed changes to Attachments C, D and E warrant any change to the division of responsibilities language currently set forth in the Attachments. The ICT has not recommended that Entergy modify this language further. The Commission should accept the language as filed.

3. Attachments C, D, and E Provide More Than Adequate Detail and Meet the Commission's Rule of Reason Approach; Thus There Is No Justification for Requiring Additional Detail More Properly Included in Business Practices

Cottonwood seeks additional information in Attachments C and D that has been proposed for inclusion in the business practices.[71] Other Protests seek to develop a timeline to review and comment on proposed business practices.[72]

As discussed in the April 3 Compliance Filing, during the stakeholder review process, certain stakeholders argued that *every* business practice associated with Attachments C, D and E must be included in those Attachments and filed under Section 205 of the FPA.[73] Entergy and the ICT disagreed with this position, believing that the Commission did not intend for Entergy to include all such practices within the scope of the transmission service criteria required to be filed under the ICT Orders. Now, Cottonwood seeks to renew this issue with claims for additional tariff language that is better suited for the business practices. Cottonwood and UPP make similar

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70 *Id.* at P 21.

71 *See* Cottonwood Protest at 16-21, 34-35.

72 *See* UPP Protest at 12-14; LMA Customers' Protest at 5-8; ETEC Protest at 7.

73 *See* April 3 Compliance Filing, Ex. 3, Cmt. 261; Ex. 5, Cmt. Nos. 70.3 and 331.

arguments regarding inclusion of additional information that they deem to be necessary in the SIS to review TSRs evaluations.[74]

As Entergy stated in its April 3 Compliance Filing, Attachments C, D and E provide significant detail; in fact, Entergy's Attachments contain more detail than many of the Attachments C and D currently on file with the Commission, a conclusion with which the ICT agrees. As explained by the ICT, the "general criteria supporting Entergy's AFC calculations, study processes, and TSR review standards are captured in [Attachments C, D and E] while other more detailed material, including technical processes and procedures that the ICT believes can be improved through stakeholder processes, will be fully transparent through posted business practices."[75] To the extent that the information is sought by customers to review TSR evaluations, Commission regulations already provide a process for review of denied TSRs.[76]

Entergy's approach complies with Order No. 890 and the ICT Orders, none of which requires that all practices, policies, or procedures related to the OATT be filed as part of an OATT. Moreover, in Order No. 890, the Commission upheld its traditional "rule of reason" approach and rejected requests to require all business practices related to the *pro forma* OATT or

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74 *See* Cottonwood Protest at 33-34 (SIS should include: (i) identification of all Base Case Overload facilities, including the preexisting overloaded MW amount and incremental MW loading that constrain the TSR; (ii) response factors of the TSR on all identified constrained facilities; (iii) whether incremental loading can be mitigated by breaker-to-breaker modeling and associated load shedding or an existing operating guide; and (iv) if requested by the customer, the full power flow models used to evaluate the TSR); UPP Protest at 57-58 (ATC values in the SIS should be identified in positive and negative amounts, and where the SIS does not accept the full amount of the TSR, "the information provided in the [SIS] should also include (i) pre-transfer flow on the limiting element, (ii) post-transfer flow on the limiting element, (iii) response factor on the limiting element, and (iv) rating on the limiting element"; Cottonwood at 28 (Entergy and the ICT should be required to file with the Commission their local planning criteria and criteria for identifying Base Plan Upgrades, respectively). Section IV.4 below explains why Cottonwood's and UPP's request for this additional information should be denied.

75 ICT Comments at 5-6.

76 UPP also states that it is unclear whether the provision of power flow models are included in the categories of information posted on OASIS or supplied upon request, and FERC should direct Entergy to revise Section 8 of Attachment D accordingly. *See* UPP Protest at 59-60. Entergy, however, has committed to develop a business practice that describes the SIS and FS data available to customers. *See* April 3 Compliance Filing, Ex. 1 at 41.

its attachment be filed as part of the OATT.[77] The Commission's ICT Orders clarify the scope of what practices, policies and standards need to be included in the transmission service criteria and do not require that every business practice be filed under Section 205 of the FPA.[78] Entergy [and the ICT] believes that it has appropriately addressed the Commission's requirements in Order No. 890 and the ICT Orders and included the necessary detail in the proposed tariff language and requests that the Commission deny the Protesters' request for inclusion of additional detail.

Further, the Commission should refuse to accept requests to include information in Attachments C, D and E that are subject to, and governed by North American Electric Reliability Corporation ("NERC") Reliability Standards. For example, the LMA Customers argue that if provisions addressing facility ratings remain in the business practices, then the ICT should be allowed to, "at a minimum, (i) verify that the ratings provisions of the business practices are identical to the ratings methodology used to demonstrate compliance with NERC Standards FAC-008 and FAC-009, and (ii) that the business practices have been properly applied in establishing the facility ratings used for the impact studies."[79] Cottonwood urges the Commission to require Entergy to include its line rating methodology in Attachment D.[80]

The applicable Reliability Standards require Transmission Owners and Generation Owners to establish a facility ratings methodology and to establish and communicate those ratings to certain entities. Thus, under those Reliability Standards as currently written, Entergy is under no obligation to seek verification from the ICT of its facility ratings or file its methodology with the Commission. The LMA Customers and Cottonwood have offered no

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77 *See* Order No. 890 at P 1633.

78 *See, e.g.*, September 2006 Order at PP 34-35.

79 *See* LMA Customers' Protest at 40.

80 *See* Cottonwood Protest at 34.

justification for why the current requirements of the Reliability Standards are not sufficient. Accordingly, the Commission should deny their requests in this aspect.

As for an implementation timeline for business practices, Entergy stated in its April 3 Compliance Filing that some of the business practices are subject to further development activities to take place in the future through the ICT's stakeholder process. Entergy has committed to submit a follow-up informational filing in these dockets that includes the Entergy's business practices as revised to address stakeholder comments.

4. The Commission Should Reject Requests That Entergy Provide Additional Data Beyond That Agreed-Upon In The Stakeholder Process and Required By The Governing FERC Regulations

In their Protests, certain stakeholders request that the Commission require Entergy to provide additional AFC-related, SIS-related and FS-related data beyond that which was already agreed-to in the Stakeholder process and required under the Commission's regulations. The Commission should deny these requests.

As a preliminary matter when considering this issue, Entergy believes that it is important for the Commission to realize the full scope of information that Entergy already provides its customers voluntarily because the scope of such information sharing already significantly exceeds what is required under Section 37.6 of the Commission's regulations. In large part, this additional information is provided to customers as a direct result of compromises reached during the various Stakeholder processes concerning Attachments C, D and E and, therefore, is meant to balance Entergy's interest of offering non-discriminatory service in the most efficient manner possible with customers' interests in being able to make sound business decisions when transacting business on Entergy's system. Requiring Entergy to provide additional information beyond what it has already agreed-to would undermine the bargain struck in those discussions.

For example, with respect to the AFC Process, in addition to what Entergy must provide under Section 37.6, Entergy has agreed to post the following data in the various Stakeholder processes:

- Four hourly models for each day for the Day 1-7 time frame
- A daily peak model for each day of the Day 1-31 time frame[81]
- A monthly peak model for each month of the Month 2-18 time frame[82]
- Subsystem files that define all sources and sinks used to calculate Study Horizon AFC values
- Monitored element file containing the Flowgate definitions used to calculate Study Horizon AFC values
- A file containing Response Factors of up to the top 15 Flowgates per path and base flows for each Flowgate for the Study Horizon
- A file containing Response Factors of up to the top 15 Flowgates per path and base flows for each Flowgate for the Operating and Planning Horizons
- Files containing the Hourly Effective ATC values, Daily Effective ATC values, Weekly Effective ATC values, and Monthly Effective ATC. Each of these is updated every 15 minutes resulting in Entergy posting 384 of these files on a daily basis
- A file containing the list of generators that define the Entergy control area sink for response factor calculation. The file also lists the participation factors for these generators.
- On a one time basis (March 4, 2009), the most limiting component of a limiting element (e.g., specific transmission line and substation equipment).
- A revision log documenting all changes made to the AFC Master List of Flowgates (“Master List”)
- List of AFC Sources located external to the Entergy area
- List of AFC Sources listed by zone

Entergy has exceeded the level of transparency required by Order No. 890 and FERC’s regulations by providing the above information. In light of the fact that Entergy has already

[81] These models are updated every time the AFC Process recalculates base flows and Response Factors. Based on the number of updates on a given day, Entergy posts approximately 258 hourly models and approximately 96 daily peak models making it a total of approximately 354 models posted daily. This translates to Entergy posting approximately 129,000 models daily peak models on a yearly basis.

[82] In a December 3, 2003 Technical Conference, Entergy volunteered to post daily peak models and monthly peak models on OASIS. *See* Transcript of December 8, 2003 Technical Conference, Docket No. ER03-1272 at 158-60 (2003). In its February 11, 2004 Order, FERC accepted Entergy’s offer, and directed Entergy to provide the information on OASIS. *See Entergy Servs., Inc.*, 106 FERC ¶ 61,115 at P 34 (2004). In a subsequent compliance filing submitted March 19, 2004, Entergy stated its commitment to posting both the daily and monthly peak models in its proposed AFC Manual. *See* Informational Filing of Entergy Services, Inc., Docket No. ER03-1272 (Mar. 19, 2004).

exceeded its regulatory obligations, the Protesters' requests that Entergy provide additional information are inappropriate and should be denied.

A perfect example of a request for additional information that should be denied comes from the LMA Customers, which request that Entergy be required to provide the reasons for a denied "proxy" TSR submitted through the AFC Scenario Analyzer.[83] Using Entergy's Scenario Analyzer, parties can submit "proxy" TSRs to evaluate the availability of short-term firm and non-firm transmission service on Entergy's system, and so to determine the likely action a TSR would obtain. While it is not expressly stated, Entergy presumes the information that the LMA Customers are seeking is the information that Entergy must provide to a transmission customer under 18 CFR § 37.6(e)(2)(i)-(ii) when a TSR is denied.[84]

The Commission should deny the LMA Customers' request. First and foremost, Section 37.6(e)(2)(i)-(ii) only applies to "real" TSRs. It does not apply to proxy TSRs submitted over the Scenario Analyzer and, consequently, the LMA Customers' request is beyond what is required by FERC's regulations. Based on the Scenario Analyzer, Entergy has received a waiver from the Section 37.6 requirement to convert AFC values into ATC values; however, that waiver does not exempt Entergy from the obligation to provide the reasons for a denied TSR under Section 37.6(e)(2)(1)-(ii).[85] Accordingly, the LMA Customers' attempt to argue that Entergy should be required to provide this additional information because Entergy has a waiver to post converted AFC values should be rejected. Indeed, the information that the LMA Customers seeks has no

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83 *See* LMA Customers' Protest at 14-15.

84 *See* April 3 Compliance Filing, Ex. 3, Cmt. 35.2. Section 37.6(e)(2)(1)-(ii) states:

> (i) When a request for service is denied, the Responsible Party must provide the reason for that denial as part of any response to the request.
>
> (ii) Information to support the reason for the denial, including the operating status of the relevant facilities, must be maintained for five years and provided, upon request, to the potential Transmission Customer and the Commission's Staff.

85 *See* LMA Customers' Protest at 14-15.

relationship to data posting obligations satisfied by the Scenario Analyzer. Further, as discussed above, Entergy voluntarily posts effective ATC values and the underlying models for use by its customers. Therefore, Entergy's customers have numerous tools to utilize in evaluating the availability of AFC, and the information requested by the LMA Customers would convey no benefits to customers that are not already available to them.

Second, the LMA Customers have not explained how this information, when taken in the context of all of the other information that Entergy already provides, is needed. To the extent that a customer submits a real TSR and that request is denied, then the data required under Section 37.6(e)(2)(i)-(ii) will be provided to the LMA Customers. There is not a legitimate need for this information to be provided for the vast array of proxy TSRs.

The Commission should deny similar requests made by UPP and Cottonwood for additional information that implicate Entergy's long-term study processes. In their Protests, UPP and Cottonwood ask that Entergy provide: (1) ATC included in an SIS in both positive and negative amounts;[86] (2) pre-transfer flow on a limiting element;[87] (3) post-transfer flow on a limiting element;[88] (4) response factors on a limiting element;[89] (5) facility rating on a limiting element;[90] (6) identification of all Base Case Overload facilities that constrain the TSR, and the preexisting overloaded MW amount on the Base Case Overload facility and the incremental MW loading;[91] (7) information concerning whether breaker-to-breaker modeling and associated load

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86 *See* UPP Protest at 57; *see also* April 3 Compliance Filing, Ex. 3, Cmt. 321.

87 *See* UPP Protest at 58; *see also* April 3 Compliance Filing, Ex. 3, Cmt. 322.

88 *See* UPP Protest at 58; *see also* April 3 Compliance Filing, Ex. 3, Cmt. 322.

89 *See* UPP Protest at 58; *see also* April 3 Compliance Filing, Ex. 3, Cmt. 322.

90 *See* UPP Protest at 58; *see also* April 3 Compliance Filing, Ex. 3, Cmt. 322; Cottonwood Protest at 33.

91 *See* Cottonwood Protest at 33.

shedding or an operating guide can mitigate the incremental loading; and (8) if requested by the customer, the full SIS/FS power flow models used to evaluate the relevant TSR. [92]

There is no regulatory obligation to provide any of the information included in items (1) – (7). Moreover, the information in items (2) – (4) above can already be extracted from the full power flow models that Entergy provides its customers under 18 CFR § 37.6(b)(2)(iii), and there is no regulatory obligation for Entergy to manipulate the power flow model as requested.[93] Because these requests exceed Entergy's regulatory obligation with respect to the provision of SIS-related and FS-related information, they should be denied.

With respect to item (8) above, Entergy already provides the full power flow models underlying its SIS and FS process under 18 CFR § 37.6(b)(2)(iii) when they are requested, and this commitment will be stated in the TSR Business Practice referenced in Section 8 of Attachment D.[94] Because Entergy provides this information under 18 CFR § 37.6(b)(2)(iii), there is no need to revise Section 8 of Attachment D as requested by UPP.

Finally, UPP requests that material changes between the SIS Report and FS Report be identified in the FS Report. UPP's request that material changes in the SIS and FS be identified is not required by FERC regulations. Between the information that Entergy must provide under FERC's regulations when a TSR is denied (including information available upon request) and the provision for the power flow models underlying the SIS and FS, Entergy provides customers more than enough information to evaluate the costs and benefits of moving forward with a TSR. The additional step of identifying differences between the SIS and FS is not necessary and should be denied.

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[92] UPP Protest at 60; *see* April 3 Compliance Filing, Ex. 5, Cmt. 322 (stating, "if the customer wants additional information regarding a denied TSR the power flow model can be requested and this information can be extracted from the model").

[93] *See* April 3 Compliance Filing, Ex. 1, at 24-25, 41.

[94] *See* April 3 Compliance Filing, at Ex. 1, 22-23, 41, Ex. 5, Cmt. 322.

V. ATTACHMENT C COMMENTS

Stakeholders raise two general categories of Protests with respect to Attachment C. The first category effectively requires the implementation of NERC and North American Energy Standards Board ("NAESB") standards that are not yet in effect. The second category requires that Entergy make miscellaneous revisions to different sections of Attachment C and/or include study-related information (as discussed in Section IV above) in Attachment C that exceeds that required by Order No. 890 or other governing ATC/AFC regulations. All of these Protests should be denied.

A. The Commission Should Summarily Deny Protests Effectively Demanding Early Implementation of Pending NERC and NAESB Standards

1. The Commission Should Reject UPP's Claim That Entergy Is Required To "Benchmark" its AFC Models Pursuant to Order No. 890 Before The Finalization of the Relevant NERC and NAESB Standards

UPP's Protests concerning Entergy's obligation to "benchmark" are contradictory (at best) and ignore Order No. 890's Attachment C implementation procedures. On the one hand, UPP admits that it: "appreciates that because the NERC standards and NAESB business practices have not yet been approved by the Commission and therefore cannot be included in the current version of revised Attachment C."[95] On the other hand, UPP argues:

> [R]ather than recognizing that its models should already be benchmarked against actual events and adjusted as necessary to reflect transmission system conditions expected at the time service is to be provided, Entergy inappropriately seeks to defer correcting this deficiency. The Commission should direct Entergy to benchmark its current modeling and not defer benchmarking to some point in the future.[96]

Accordingly, even though UPP expressly recognizes that there are no currently effective NERC or NAESB benchmarking standards that can be incorporated into Entergy's Attachment

95 *See* UPP Protest at 22.

96 *Id.* at 20.

C, UPP nevertheless argues that the Commission should direct Entergy to benchmark its current modeling based on this yet-to-be effective standard rather than defer such benchmarking until the resolution of the NERC and NAESB processes.

As an initial matter, Entergy wants to emphasize that while Entergy and the ICT have agreed to work together to pursue additional software enhancements/recommendations[97] to improve the AFC Process in certain areas (*e.g.*, net interchange and external control areas) and have Commission guidance in other areas (*e.g.*, QFs and LSE shortfalls), Entergy's current AFC Process is fully compliant with Order No. 890.[98] Accordingly, while Entergy agrees that its current AFC modeling processes could be enhanced in certain areas, Entergy disagrees with UPP's blanket statement that Entergy's AFC models do not reflect actual system topology and do not comply with Order No. 890.

UPP's assertion that Entergy is currently obligated to implement the type of benchmarking required by Order No. 890 ignores that Order's two-step compliance filing process for ATC/AFC related criteria. "Step one" required the submission of an "intermediate" Attachment C which was to be filed to become effective September 11, 2007.[99] FERC has explained that "the intermediate" Attachment C filing was supposed to be "no more than a documentation of existing practices."[100] In other words, transmission providers were just required to revise their Attachment C's to memorialize their existing ATC/AFC methodologies. They were not required to implement any ATC/AFC procedures or protocols subject to a NERC

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97 As the ICT explained, "some ICT-recommended changes to the current processes, such as improvements to the dispatch assumptions used for external generation and calculating net interchange, were determined to require software modifications; for these changes, Entergy and the ICT agreed to further development discussions to explore changes to the software." ICT Comments at 3.

98 *See* April 3 Compliance Filing at 32-37; *see also infra* Part III.E.

99 As Entergy explained in the April 3 Compliance Filing, Entergy's "intermediate" Attachment C was the version filed on July 13, 2007 in Entergy's Order No. 890 Compliance Filing , as superseded by the version of Attachment C included in the April 3 Compliance Filing.

100 *See* Order No. 890-A at P 112.

or NAESB standard mandated by Order No. 890. "Step two," however, will include a further revised Attachment C reflecting amendments necessary to comply with Order No. 890's required revisions to NERC and NAESB standards. The second compliance filing must be submitted to FERC no later than 60 days after the Commission approves the relevant NERC standard or NAESB practice.[101]

Entergy presumes that the benchmarking requested by UPP is that required in Paragraph 290 of Order No. 890, which is a "step two" ATC/AFC requirement. Paragraph 290 of Order 890 mandated that NERC revise reliability standards MOD-10 through MOD-025 for periodic review and modifications for: (1) the calculation of ATC/AFC; (2) the exchange of data and coordination among providers for the purposes of modeling and to support consistency in the determination of ATC; and (3) benchmarking to actual events load flow base cases, short circuit data, and transient and dynamic stability simulation data.[102] These standards, however, have not yet been finalized by NERC and filed with the Commission and therefore are not yet in effect.[103]

Entergy's "intermediate" Attachment C was the version included in Entergy's Order No. 890 Compliance Filing, as superseded by the version of Attachment C included in the April 3 Compliance Filing. UPP provides no legal support, and there is none, for its position that Entergy is obligated to implement the type of "step two" benchmarking required by Paragraph 290 before the resolution of the NERC and NAESB processes. Therefore, UPP's position that Entergy is required to benchmark now must be denied.

101 *See id.* at PP 16, 290, 325.

102 *See* Order No. 890 at P 290.

103 When submitting revised MOD-001, 008, 028, 029 and 030, on August 29, 2008, NERC explained that the benchmarking required Paragraph 290 of Order No. 890 "is outside the scope of the NERC ATC standard drafting team effort. To respond to this directive, NERC has included these standards in its *Reliability Standards Development Plan: 2008-2010* as part of projects 2009-04 –Modeling Data and 2009-05 – Demand Data. This modeling activity requires a different skillset and expertise than that required for developing ATC methodologies and is best addressed through a separate project and standard drafting team." Accordingly, NERC currently anticipates establishing its benchmarking standards as part of its 2009 work plan. *See* NERC Compliance Filing, Docket No. RM05-17 at 98 (Aug. 29, 2008).

As explained in the April 3 Compliance Filing, Entergy and the ICT have already agreed to revise Entergy's AFC Process upon the conclusion of the NERC and NAESB processes. Under these procedures, Entergy and the ICT will identify the necessary revisions to Attachment C once the NERC and NAESB processes are complete. These revisions will be vetted through stakeholders and then filed with the Commission. If UPP has concerns regarding those revisions when they are vetted through stakeholders and filed with the Commission, then UPP can raise those concerns at that time.

2. The Commission Should Reject Cottonwood's Accusation That Entergy Does Not Satisfy Its Existing Obligation to Coordinate With Its Neighboring Utilities

Cottonwood argues that Entergy "simply engages in no coordination with neighboring utilities for AFC purposes in the Operating and Planning Horizons"[104] and requests that the Commission direct Entergy and the ICT to establish a process "for the exchange of AFC models and data for the Operating and Planning Horizons with neighboring control areas on a frequent and consistent basis." Based on its conclusion that Entergy currently does not coordinate with other control areas, Cottonwood also asks that the Commission order Entergy to modify its Energy Management System ("EMS") to accurately reflect external control areas. Cottonwood has misconstrued Section 8 of Entergy's Attachment C and, therefore, its Protest should be summarily denied.

First, Cottonwood's allegation that Entergy does not coordinate with neighboring controls areas in the Operating and Planning Horizons ignores the plain text of Section 15 of Attachment C (Regional Coordination). Therein, Entergy has described the type of data exchanges it implements for the Planning and Operating Horizons. Section 15 states:

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104 *See* Cottonwood Protest at 14.

> For the EMS-Based Models used in the *Operating and Planning Horizons*, transmission facility outages for External Control Areas are derived from NERC SDX outage data provided by those Control Areas. Load data for External Control Areas is based on data supplied by the SPP RTO or the NERC SDX. Additional updates to data for External Control Areas is described in Section 7.4.[105]

Accordingly, Section 8 of Entergy's Attachment C expressly provides for Entergy to exchange both facility outage data and load data through the NERC SDX.

Section 7.4 of Attachment C describes Entergy's processes for calculating Net Interchange and its modeling of External Control Areas in the Operating and Planning Horizons, and how Entergy uses information from External Control Areas when determining AFC values. While the April 3 Compliance Filing explained that Entergy is currently working with the ICT to improve Entergy's treatment of Net Interchange and External Control Areas, Cottonwood's accusation that Entergy does not coordinate with other control areas at all with respect to the calculation of AFC values in the Operating and Planning Horizons is just incorrect.[106]

Second, the Commission should deny Cottonwood's Protest to the extent that it is requesting Entergy to exchange ATC-related data as required in Order No. 890. Presently, FERC has issued a Notice of Proposed Rulemaking that would approve NERC's revised MOD-001, which would impose, as directed by Order No. 890, a requirement that entities exchange AFC data.[107] For all of the reasons that Entergy should not be required to implement the benchmarking requested by UPP, Entergy also should not be required to implement those AFC data exchange standards until they are approved. Once those standards are final, Entergy will revise Attachment C as necessary.

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105 *See* April 3 Compliance Filing, Ex. 3, First Revised Sheet No. 227 (emphasis added).

106 *See* April 3 Compliance Filing at 18.

107 *See* Order No. 890 at P 310. In a March 13, 2008 letter to WEQ members, NAESB determined that the NERC reliability standards addressed all of FERC's concerns regarding data exchange, and thus no new business practices needed to be developed. *See* March 13, 2008 Letter to Wholesale Electric Quadrant Members and Interested Industry Participants, *available at* http://www.naesb.org/pdf3/weq_2008_ap_2bv2_rec.doc.

B. Other Protests Regarding Attachment C That Should Be Rejected

1. Section 1.2: Definitions

a. Definition of "AFC Process"

The Arkansas Cities argue that the definition of "AFC Process" "does not limit the AFC calculation period for evaluation of TSRs to the Operating, Planning and Study Horizons."[108] The Arkansas Cities had requested that Entergy make this revision during the stakeholder process and, in response, Entergy revised the definition of AFC Process to read "[t]he software, data inputs, assumptions and flow-based study methodology used to calculate AFC values and evaluate TSRs in the *Operating, Planning and Study Horizons*."[109] Accordingly, Entergy has already addressed the Arkansas Cities' concerns on this issue.

b. Definition of "Most Limiting Flowgates"

The Arkansas Cities argue that the use of the term "significantly impacted flowgate" in the definition of "Most Limiting Flowgates" provides Entergy "excess discretion in determining what flowgates need decrement for AFC calculations."[110] The Commission should deny the Arkansas Cities Protest because "significantly impacted flowgate" does not appear in the definition of "Most Limiting Flowgates." The Most Limiting Flowgates are defined as, "for each transfer path, the Flowgates used to evaluate a TSR pursuant to Section 10.1." Section 10.1 of Attachment C describes the flowgates used to evaluate TSRs under the AFC Process. To the extent that the Arkansas Cities are arguing that "significantly impacted flowgates" is not a defined term in Attachment C at all, that argument should also be rejected. Section 1.2 defines a "Significantly Impacted Flowgate" as "for a particular TSR, any Flowgate for which the TSR has

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108 *See* Arkansas Cities Protest at 3.

109 *See* April 3 Compliance Filing, Ex. 2, First Revised Sheet No. 197 (emphasis added).

110 *See* Arkansas Cities Protest at 3.

a Response Factor equal to or greater than the three percent (3%) Response Factor threshold specified in Section 9.2" of Attachment C.

2. Section 2.1: Criteria for Initial Selection of Flowgates

The Arkansas Cities argue that a reference to Section 7.3 of Entergy's Local Area Criteria in Section 2.1 of Attachment C creates an inconsistency with respect to Entergy's nominal voltage thresholds when initially selecting monitored flowgates. Section 2.1 includes no such reference to Entergy's Local Planning Criteria. The Arkansas Cities' Protest on this issue should be denied.

The Arkansas Cities also take issue with language stating that, when initially selecting flowgates to monitor, Entergy considered the frequency and severity of occurrences when a particular facility exceeded 100% of its rating in real-time operating conditions.[111] In Arkansas Cities' view, the reliance on real-time operating conditions is improper because if a flowgate exceeds its limit in real-time and that limit is also the System Operating Limit, the facilities should automatically be monitored. If a flowgate is automatically monitored, there is no need for Entergy to consider the frequency and severity of such occurrences to begin with.[112] This Protest should be denied.

As explained in the April 3 Compliance Filing, the procedure set forth in Section 2.1 of Attachment C is a historical one-time analysis that was performed in 2004 to establish Entergy's initial list of flowgates,[113] and was inserted into Entergy's tariff at the Commission's direction when Entergy first proposed the AFC Process.[114] Thus, because this was a "one-time" process, it is no longer used by Entergy when adding new flowgates. Instead, Section 2.2.1 of Attachment C

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111 *See id.* at 3-4.

112 *Id.* at 4.

113 *See, e.g.*, April 3 Compliance Filing, Ex. 3, Cmt. 158, 192, 193.

114 *See* Entergy Servs., Inc., Compliance Filing, Docket No. ER03-1272 (Aug. 13, 2004).

identifies the current set of criteria applied to adding or removing flowgates from the Master List and these criteria do not include the reliance on real-time system conditions that appears to concern Arkansas Cities. Therefore, to the extent that Arkansas Cities are arguing that Entergy's reliance on real-time system information to add or remove flowgates is improper, Arkansas Cities have misconstrued Section 2.2.1 because Entergy does not rely on such data when adding or removing flowgates. Alternatively, to the extent that Arkansas Cities are arguing that the historical analysis allows Entergy to avoid monitoring certain facilities, such an argument is incorrect. Entergy is meeting and will continue to meet effective NERC standards. The Commission should deny Arkansas Cities' comments on Section 2.1 of Attachment C.

3. Section 2.2.1: Adding New Flowgates

The Arkansas Cities argue that there is a discrepancy between the criteria used when Entergy originally selected its monitored flowgates under Section 2.1 and Entergy's criteria for adding flowgates under Section 2.2.1. Specifically, the Arkansas Cities argue that a 92%-96% criteria is established for 230 kV facilities for the initial selection of flowgates and the criteria changes to 96% for 230 kV and above facilities for adding new flowgates in Section 2.2.1.[115] Once again, Arkansas Cities' are far off the mark. Section 2.2.1 (nor any other section discussing the addition of new flowgates) does not include the 96% threshold referenced by the Arkansas Cities. This Protest should be denied.

4. Section 2.2.1 (ii): Flowgates on Third-Party Transmission Systems

ETEC and the Arkansas Cities argue that Section 2.2.1(ii) of Attachment C should be revised to describe how flowgates on third-party transmission systems are added to the Master List of Flowgates.[116] These Protests should be denied. Section 2.2.1 already states that facilities

115 Arkansas Cities Protest at 4.

116 *See* ETEC Protest at 4; *see also* Arkansas Cities Protest at 4.

on third-party transmission systems may also be included on the Master List "to be monitored consistent with the applicable NERC Reliability Standards." That standard is MOD-030. Once the currently pending version of MOD-030 is effective, it will govern the process by which neighboring control areas will coordinate when adding flowgates and therefore the process for which ETEC seeks clarification will be subject to an industry standard and does not need to be stated in Section 2.2.1(ii). Moreover, to the extent that a party has a question concerning the addition of an external flowgate, that question can be addressed in the stakeholder process.[117]

5. Section 3.6: Posting of Reasons For Most Recent AFC Resynchronization

The Commission should deny UPP's argument that Entergy should be required to post the reason for any delay in a resynchronization of AFC values undertaken under Section 3.6 of Attachment C.[118] There is no obligation to post the reason for any delay in resynchronizations, to the extent that they occur. If a stakeholder believes that a resynchronization has been delayed and is curious about the reason, then the stakeholder should make an inquiry through the stakeholder process.[119]

6. Sections 4.2 and 5.1: Adjustments to Facility Ratings Based on Adjustments To TRM

The Commission should deny ETEC's Protest that any adjustment that Entergy makes to its treatment of TRM should be paired with a corresponding adjustment to its facility ratings.[120] Attachment C defines Transmission Reliability Margin ("TRM") as, "[t]he 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

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117 *See* April 3 Compliance Filing, Ex. 3, Cmt. 191.

118 *See* UPP Protest at 23-24.

119 *See* April 3 Compliance Filing, Ex. 3, Cmt. 208.

120 *See* ETEC Protest at 5.

associated effects on transfer capability evaluations and the need for operating flexibility to ensure reliable system operation as system conditions change."[121] Accordingly, when calculating AFC values, TRM is subtracted from Total Flowgate Capability ("TFC") in order to calculate non-firm and firm AFC values. TRM, however, has no relationship whatsoever with facility ratings. Consequently, there is no reason to adjust facility ratings if Entergy's TRM methodology is revised.

7. Section 4.2: Re-rating of "Vintage" Transmission Facilities

The Commission should summarily reject UPP's general request that Entergy re-rate "vintage" transmission facilities (defined by Entergy to be pre-1991-1994)[122] when they comprise a flowgate, as well as the LMA Customers' narrower, but equally inappropriate, request to allow transmission customers to request that certain vintage facilities be selectively re-rated.[123]

As explained in the April 3 Compliance Filing and on numerous occasions to stakeholders, the power industry standard is to treat vintage facilities pursuant to the standards that were effective at the time the facilities were installed, and for vintage facilities not to be re-rated until they are significantly modified or replaced.[124] Accordingly, Entergy's practice consistent with National Electric Safety Code ("NESC") guidelines, is that, vintage transmission facilities are required to meet the NESC standards that were in effect at the time the facility was installed. The re-rating requested by UPP and the LMA Customers would be unnecessarily

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121 *See* April 3 Compliance Filing, Ex. 3 at First Revised Sheet No. 202.

122 *See* April 3 Compliance Filing, Ex. 3 at Cmt. Nos. 162, 163, and 218. As explained in the April 3 Compliance Filing, Entergy transferred certain functions relating to transmission facilities ratings from its operating companies to its service company. Because the installation and rating of facilities prior to this transfer period were managed independently by each operating company, Entergy uses the 1991 - 1994 timeframe as the threshold to classify a facility as vintage.

123 *See* UPP Protest at 24-27; LMA Customers' Protest at 13-14.

124 *See*, *e.g.*, NESC Rule 13B2 (specifying that older facilities need not be modified or updated to comply with current safety rules if they comply with the rules in effect at the time they were installed).

expensive, overly burdensome and could very well result in Entergy continually re-rating literally thousands of miles of transmission facilities with no guaranteed benefit.[125] If a TSR is denied (or counter-offered) and a customer has concerns regarding the rating of a particular facility, then Order No. 890 allows the customer to request information regarding that facility.[126]

8. Section 7.1.2: Service to Network/Transmission Provider's Native Load Customers (Study Horizon)

The Arkansas Cities argue that Section 7.1.2 "does not provide any details on how Firm Network Resource Reservations are to be handled in the Study Horizon" and that Entergy is relying on a business practice to provide this detail.[127] While it is not clear, Entergy believes that the Arkansas Cities may be commenting upon Entergy's modeling of Network Resources when a customer does not provide a dispatch priority.[128] In fact, Section 7.1.2 of the Attachment C included in the April 3 Compliance Filing details Entergy's treatment of Network Resources in the Study Horizon when an LSE fails to inform Entergy of its priority dispatch for designated resources. Accordingly, the Arkansas Cities' Protest on this issue should be denied.

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125 UPP points to Paragraph 114 of FERC's March 19, 2009 Notice of Proposed Rulemaking addressing NERC's proposed Reliability Standards and argues that Entergy should be required to re-rate "vintage" facilities. *See Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the Bulk-Power System*, 126 FERC ¶ 61,249, at P 114 (2009) ("ATC NOPR"). Paragraph 114 of the ATC is discussing Total Transfer Capability ("TTC") as calculated under proposed MOD-029. Entergy, however, uses an AFC Process and uses TFC calculated under MOD-030. Therefore, Paragraph 114 would not apply to Entergy's facilities used in Entergy's AFC Process.

126 *See* Order No. 890-A at P 148; 18 CFR § 37.6(e)(2).

127 *See* Arkansas Cities Protest at 6.

128 Entergy is making this assumption because the Arkansas Cities have raised this concern on prior drafts of Attachment C. The Arkansas Cities also protest Entergy's supposed reference to Entergy's use of "other resources" to "meet the deficiency between Firm Network Resources and forecasted load." Section 7.1.2 of the Attachment C included in the April 3 Compliance Filing includes no such reference.

9. Section 9.1: Assumptions Underlying Response Factors

UPP has requested that Entergy revise Section 9.1 of Attachment C to describe in detail Entergy's underlying assumptions when applying Response Factors in the Operating, Planning and Study Horizons. Specifically, UPP requests that Entergy explain: (1) what ways the assumptions and evaluations differ; (2) the difference between the AFC Process for evaluating TSRs and the subsequent off-line process to include confirmed TSRs in the AFC monthly models; (3) the rationale for the discrepancies; (4) whether the Response Factors in the different horizons are benchmarked against actual dispatch/operation of the transmission system; and (5) all other information from which Entergy concludes that there is no negative impact to TSRs and that the differences inherent in the various horizons are reasonable.[129]

The Commission should deny UPP's requested revisions to Section 9.1 of Attachment C. Neither Order No. 890 nor any NERC standards require that (1) through (5) above be included in transmission providers' Attachment C. Instead, Entergy's obligation to describe its treatment of Response Factors is governed by FERC's February 11, 2004 order in the original AFC Proceeding in Docket No. ER03-1272-000.[130] Therein, FERC required Entergy to file revised tariff sheets that "provide more specific details regarding the following aspects of its AFC proposal . . . (4) the response factor threshold and the criteria for modifications to the threshold."[131] The order also required Entergy to "describe any operating and reliability assumptions that influence its modeling [including] any transmission margins existing in AFC power flow cases."[132] Section 9 of Entergy's Attachment C provides this information. Accordingly, to the extent that UPP seeks to include additional information in Section 9, that

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[129] *See* UPP Protest at 32.

[130] *See Entergy Servs.*, 106 FERC ¶ 61,115 at P 33.

[131] *Id.* at P 33.

[132] *Id.* at P 35.

request goes beyond the requirements established by Order No. 890, applicable NERC standards and FERC's orders in the original AFC proceeding and should be rejected.

10. Section 8: Counterflows

The LMA Customers request that the Commission require Entergy to revise Section 8 of Attachment C to require Entergy to model counterflows for accepted and counter-offered TSRs.[133] The Commission should deny the LMA Customers' request for Entergy to account for counterflows associated with accepted or counteroffered TSRs, as well as the LMA Customers' claim that Entergy has not explained this discrepancy. Entergy has previously explained to both stakeholders and FERC why it does not account for accepted and counter-offered TSRs when modeling counterflows.[134] Counterflow associated with a TSR cannot be considered by Entergy's AFC software unless such TSR is modeled as a discrete injection and withdrawal. Entergy stopped modeling counter-offered and accepted TSRs as discrete injections and withdrawals in the Operating Horizon and Planning Horizon as part of the revised generation and load dispatch process presented to, and accepted by, stakeholders in the SPP Audit Stakeholder Process that lead to Entergy's May 24, 2007 filing in Docket No. ER07-935-000, as accepted by the Commission on July 13, 2007.[135] In that filing, Entergy explained:

> the original [AFC] dispatch process modeled new OASIS reservations that had been accepted by Entergy, but had not yet been confirmed by the customer. The inclusion of accepted-unconfirmed reservations in the base case models placed additional loading on all transmission facilities impacted by such reservations, even though many of these reservations were never ultimately confirmed by customers. *Under the new dispatch process, accepted-unconfirmed reservations will be algebraically decremented against the top fifteen flowgates, but will not be modeled in the AFC base case models.*[136]

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[133] *See* LMA Customers' Protest at 15.

[134] *See* April 3 Compliance Filing, Ex. 1 at 17-18, Ex. 3, Cmt. 263.

[135] Entergy applies the same criteria to the Study Horizon to ensue consistency of the modeling of base flows in all three of the AFC horizons.

[136] *See* Letter from Gregory W. Camet to the Honorable Kimberly D. Bose, Docket No. ER07-935-000, at 7 (filed May 24, 2007)(emphasis added). Section 4.2.2.4 (Modeling Unconfirmed Reservations) of the AFC

This filing was not opposed by any stakeholder and was accepted by the Commission nearly two years ago. Moreover, importantly, Entergy did not change its treatment of counterflows when it submitted its revised Attachment C in its Order No. 890 Compliance Filing, as superseded by the Attachment C included in the April 3 Compliance Filing.

If the LMA Customers opposed Entergy's treatment of counterflows, then they should have raised those concerns when Entergy originally filed its revised generation and load dispatch process with FERC in Docket No. ER07-935-000.[137] The LMA Customers, however, did not dispute Entergy's treatment of accepted and counteroffered TSRs at that time and should not now be allowed to collaterally attack Entergy's treatment of counterflows as it has already been approved by stakeholders and FERC.[138]

C. Revisions that Entergy Agrees to Make In A Compliance Filing

Certain commenters requested revisions to Attachment C which, if ordered by the Commission, Entergy will make. These comments are as follows: (1) ETEC's request that Entergy revise Sections 6 and 7 of Attachment C so that references to LSEs reflect that on

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Manual included in that filing also explained that accepted and counter-offered TSRs will not be modeled. It explained:

> Reservations (both Point-to-Point and new Network Resources) that *are in accepted mode and counteroffered will not be modeled in base flows after resynchronization*. Reservations that are in accepted or counter offer mode will be algebraically decremented against the two proxy flowgates (PMAX and TIECAP) and the remaining top-thirteen flowgates until such time as they are withdrawn, rejected or confirmed. All reservations that are in study mode will be algebraically decremented against the two proxy flowgates (PMAX and TIECAP) and the remaining top-thirteen flowgates. Once an accepted request is confirmed, it will only be modeled if included in the customer's dispatch files or until such time as RFcalc requires modeling of those reservations to meet the customer's load. When an accepted request is confirmed in between resynchronizations, it will continue to be decremented against the two proxy flowgates (PMAX and TIECAP) and the remaining top-thirteen flowgates until such time there is an RFCalc and OASIS Automation resync. Confirmed reservation for network resources that are not modeled by RFcalc will be treated as Excess Reservations and will be decremented against the two proxy flowgates (PMAX and TIECAP) but not the remaining top-fifteen flowgates. (emphasis added).

137 *See* Attachment C § 7.3.1.

138 Entergy notes that it currently provides for 100% counter flow under its AFC Process and believes that this treatment is more liberal than other transmission providers that typically provide 100% counterflows for TSRs.

occasion, designated agents will submit certain data (e.g. load forecasts and generation) on behalf of the LSE;[139] (2) UPP's request that Entergy clarify that when it serves as an LSE, Entergy is subject to Sections 6.2.1 and 6.3.1 of Attachment C, which requires LSEs to submit certain data;[140] and (3) Arkansas Cities' requested clarification regarding whether Remaining Existing Transmission Commitments ("ETCs") "have any counterflow associated with them."[141]

VI. ATTACHMENT D COMMENTS

A. Cottonwood's Arguments Regarding Reliability Upgrades Ignore the Structure Established Under the ICT Orders and Are Unnecessary Under the Pricing Provisions of Attachment T

Cottonwood argues that Entergy and the ICT, in developing the Construction and Base Plans, should be required to identify reliability upgrades for a planning horizon of 10 years. According to Cottonwood, the current three-year period of the Construction Plan is too limited, and fails to provide the long-term horizon needed for system planning. In addition, the three-year period improperly results in assignment of costs for system reliability upgrades to individual TSRs that extend beyond that period.[142]

Cottonwood's arguments regarding the horizon lengths of the Base Plan and Construction Plan – as well as the process for identifying Base Plan and Supplemental Upgrades – have been addressed in the Commission's ICT Orders. Entergy's Attachment T provides that the ICT will assess whether a proposed upgrade should be considered a Base Plan Upgrade or Supplemental Upgrade. For purposes of identifying upgrades as Base Plan or Supplemental Upgrades, the ICT will consider only upgrades in the then-current Base Plan for which construction is to be initiated

139 *See* ETEC Protest at 5-6.

140 *See* UPP Protest at 28.

141 *See* Arkansas Cities Protest at 5; *See also* April 3 Compliance Filing, Ex. 3, Cmt. 204.

142 *See* Cottonwood Protest at 26-27.

within the next 3 years."[143] The Commission's April 2006 Order accepted this approach to the assignment of upgrade costs.[144]

This approach had been originally filed with the Commission on April 1, 2004 in Docket No. ER04-699-000. In that filing, Entergy explained that "[i]n order to ensure comparable treatment of interconnection and transmission customers, the ICT will independently determine whether an upgrade should be included in the Base Plan. In so doing, the ICT will consider all Base Plan upgrades that are to be initiated within the next three years."[145] Although commenters protested this approach,[146] the Commission never rejected it. Cottonwood's argument is an attempt to relitigate those established time frames and should be rejected.

Furthermore, the cost allocation provisions of Attachment T render Cottonwood's arguments moot because, under Attachment T, the costs of Supplemental Upgrades can be recovered if they eliminate a Base Plan Upgrade set forth in the Base Plan. Attachment T, Section 3.2.3 states: "[i]f the ICT determines that a proposed upgrade represents an acceleration of a Base Plan Upgrade, then the cost of accelerating the Base Plan Upgrade will be recovered as a Supplemental Upgrade[.]"

Moreover, as previously noted, Attachment T also provides for an allocation of revenues to a transmission customer from additional service for others that is dependent on the customer's previously funded Supplemental Upgrades.[147] Such payments by Entergy include not only a share of point to point revenues, but also compensation related to long-term network resource

143 *See* Attachment T, § 3.2.

144 *See* April 2006 Order at PP 159-68.

145 *See* Letter from Kimberly H. Despeaux to the Hon. Magalie R. Salas, Docket No. ER04-699-000, at 21 (filed Apr. 1, 2004).

146 S*ee, e.g.*, Protest of the NRG Companies in Docket No. ER04-699 (June 3, 2004); Protest of the Southeast Electricity Consumers Association in Docket No. ER05-1065 (Aug. 5, 2005).

147 *See* Attachment T § 4.3.

designations, NRIS status, and service to cover load growth.[148] To the extent that a Supplemental Upgrade funded by a transmission customer outside of the horizon of the Construction Plan and Base Plan is used to serve load growth, the funding customer will receive payments under those provisions.

B. Contrary to Certain Protests, it is Not Appropriate to Use the Breaker-to-Breaker Methodology in the SIS

Cottonwood argues that Entergy and the ICT should be required to use consistent methodologies and assumptions, including the use of breaker-to-breaker assessments, for planning, reliability assessment, and evaluation of TSRs. Thus, breaker-to-breaker assessments should be conducted in the SIS.[149] UPP also argues that Entergy should use a breaker-to-breaker methodology in the SIS rather than just in the FS.[150]

As Entergy explained to stakeholders, it conducts the breaker-to-breaker analysis in the FS but not the SIS. The bus-to-bus methodology is used in the SIS to provide a high-level estimate of the upgrade costs that are further refined in the FS through the breaker-to-breaker analysis. This approach is in keeping with the difference between the SIS and the FS, generally. The SIS is a more general review of impacts to the system and a high-level estimate of the potential costs of upgrades. If the transmission customer chooses to proceed to the FS stage, a more detailed analysis of the costs is performed. UPP and Cottonwood's arguments ignore the Commission's requirements to target completion of SISs and FSs within defined timeframes. The Commission also requires the posting of metrics on OASIS related to the performance of these studies and whether they were performed within the targeted timeframe.[151] Entergy and the ICT must balance the need for efficiency with the desire for greater detail. Entergy believes

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148 *See id.* at § 4.3.5.

149 *See* Cottonwood Protest at 29-30.

150 *See* UPP Protest at 44-45.

151 *See* 18 C.F.R. § 37.6(h).

the process set forth in Attachment D strikes that balance, and no further changes are necessary. The Commission should deny requests to use breaker-to-breaker methodology in the SIS.

C. No Further Clarification Regarding Performance of Affected System Studies is Required

Cottonwood argues that Entergy and the ICT should be required to explain the criteria under which they will conduct Affected System Studies, as well as whether, and under what procedures, they will grant TSRs that impact neighboring control areas.[152]

Cottonwood's request for additional modifications should be rejected for two reasons. First, the Commission's orders, including Order No. 890, do not require the filing of criteria under which transmission providers conduct Affected System Studies. In Order No. 890, the Commission stated that "*pro forma* OATT section 21.2, 'Coordination of Third-Party System Additions,' provides for certain rights for transmission providers to coordinate construction of facilities on their systems associated with point-to-point customer requests and related construction on a third-party transmission system, *but imposes no obligation on transmission providers*."[153]

Section 21.2 provides only that the transmission provider receiving the request for service has the right to coordinate construction on its own system with the construction on affected systems. Furthermore, the Commission allows the transmission provider to defer construction of its new transmission facilities, if the new transmission facilities on another system cannot be completed in a timely manner. The Transmission Customer may challenge the decision in accordance with the dispute resolution procedures pursuant to Section 12 of the tariff or it may refer the dispute to the Commission for resolution. Thus, there is no obligation on Entergy to perform or conduct Affected System Studies.

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152 *See* Cottonwood Protest at 32.

153 *See* Order No. 890 at P 420 n.227 (emphasis added).

Second, Attachment K sets forth the process for coordination of certain "regional optimization opportunities" with affected systems. As part of that process, the ICT will identify any opportunities for regional optimization of Entergy's Construction Plan with the construction plans of those adjoining transmission owners.[154] The ICT will review such optimization opportunities with Entergy, other affected transmission owners, state regulators, and stakeholders. If Entergy determines that it will proceed with a regional optimization opportunity or regional economic upgrade, Entergy will enter into negotiations with other affected transmission owners for a binding agreement governing the allocation of construction costs and responsibility for the coordinated set of upgrades.[155] Therefore, even though Entergy has no obligation to perform Affected System Studies, it has developed provisions, set forth in Attachment K, that provide a process for identifying opportunities to coordinate with affected systems. No further clarification is required by Order No. 890, and Cottonwood's arguments should be rejected.

D. Section 2.1: Entergy Will Clarify Section 2.1 With a Reference to its Attachment K

In Attachment D, Section 2.1 states that the ICT participates in the regional model development process for the SERC region with Entergy. UPP requests that Section 2.1 be revised to indicate: (i) whether the ICT's participation in the SERC regional model development process is a reference to the process under Entergy's Attachment K; or (ii) the scope of the ICT's participation if it is different than the process set forth in Attachment K.[156] Under Attachment K, "[t]he ICT and the [Entergy] shall participate in the regional model development process for the

154 *See* Attachment K § 13.1.5.

155 *Id.*

156 *See id.* at 45.

SERC region."[157] In order to provide additional clarity, Entergy commits to revise Section 2.1 to state that the ICT will participate in the regional model development process as set forth in Attachment K.

E. Section 2.2.2: Inter-regional Coordination Between SPP and Entergy is Set Forth in Their Letter Agreement; Thus no Further Amendment to 2.2.2 is Necessary

In section 2.2.2, Attachment D states that Entergy coordinates with Southern Company and Tennessee Valley Authority on a monthly basis to update the Seasonal Base Case Models and develop Monthly Base Case Models. UPP requests that the Commission require Entergy to revise Section 2.2.2 to reflect that the monthly coordination include SPP, in its role as RTO.[158]

Section 2.2.2 does not require further clarification because the additional detail sought by UPP is either already reflected in Attachment K and the Letter Agreement on seams issues ("Letter Agreement") between the SPP RTO and Entergy or is still being developed in ongoing discussions between Entergy and the SPP RTO on seams and coordination issues. The Letter Agreement sets forth the responsibilities related to inter-regional coordination related to transmission planning between the SPP RTO and Entergy.[159] The Letter Agreement also obligates the Parties to engage in coordinated transmission system planning in accordance with certain Principles Governing Regional Planning ("Principles"). The Principles establish that the Parties will, as required by Order Nos. 890 and 890-A and other applicable Commission orders: (1) share system plans to ensure that they are simultaneously feasible and otherwise share and use consistent assumptions and data in the development of such plans; and (2) identify system enhancements that could relieve congestion or integrate new resources. Among other things, the Principles also provide for sharing of data necessary to engage in coordinated transmission

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157 *See* Attachment K § 13.3.

158 *See* UPP Protest at 46.

159 *See Southwest Power Pool, Inc.*, 127 FERC ¶ 61,032 (2009).

system planning, govern cost allocation for the cost of studies performed and upgrades identified by the Parties under the Principles, and provide for stakeholder involvement in the inter-regional planning process. As noted in Entergy's December 7, 2007 compliance filing in Docket No. OA08-59, Entergy and the SPP RTO are in the process of evaluating additional coordination on transmission planning and service request evaluations. Rather than include this detail in Attachment D, it is more appropriate to allow Entergy and the SPP to coordinate that process through any seams arrangements between them. No further clarification is required here. The Commission should deny UPP's request.

F. Section 2.3.1.1: The Provisional Upgrade Provisions Will Be Applied to Entergy in the Same Manner that They are Applied to other Transmission Customers

The criteria in Section 2.3.1.1 for designating upgrades as Provisional Upgrades are intended to capture circumstances where the upgrades have become sufficiently certain that transmission service can be reasonably granted and where disruption is minimized if a construction project is delayed or cancelled. For upgrades to be included in Base Case Models as Provisional Upgrades, these criteria require either that: (1) the upgrades being constructed have been determined necessary to accommodate a transmission or interconnection service reservation that is subject to an executed transmission or interconnection service agreement; or (2) the upgrades are being constructed for reliability reasons and have been approved for funding. Sections 1.4 and 2.3.1.1 address customer options for confirming service that is dependent on future construction projects and obtaining new studies when such Provisional Upgrades are delayed or cancelled.

UPP is unclear how Section 2.3.1.1 applies to Entergy when it requests transmission service. UPP further states that the provisions, as currently written, present a situation where Entergy's required upgrades beyond the three-year term of construction will not be considered when evaluating long-term transmission service even though the upgrades of OATT customers for the period beyond the three-year term will be used in determining transmission availability pursuant to the Provisional Upgrade provisions.[160] UPP misunderstands the scope and purpose of the Provisional Upgrades provisions as they apply to Entergy. Simply put, the provisions apply to Entergy as they apply to any transmission customer. Any transmission or interconnection service granted to serve Entergy's native load customers that requires a transmission upgrade will be documented in a form of service agreement that will be filed with the Commission. Further, the upgrades will be included after execution of that agreement rather than dependent on the funding status of the project as part of Entergy's Construction Plan. In this way, UPP's concerns regarding differing treatment will be addressed, and UPP's arguments for further clarification should be rejected.

G. Section 3.2.1: Reference to "Proportional Basis" in Scaling for Simulation

During the stakeholder process, certain stakeholders requested that Entergy modify its existing process for simulating TSRs where the source is located in a first-tier (*i.e.*, adjacent) external control area. Entergy's existing process would simulate the PTP transaction by ramping up the generating facility that was identified as the source of the transaction. However, where a first-tier control area was identified as the source of a transaction and the customer chose not to identify the specific generating facility, Entergy would simulate the transaction from the generating facility that had the largest impact on the limiting element for that transfer (*i.e.*, the most constraining facility).

Some stakeholders requested that Entergy modify this policy so that TSRs from first-tier external control areas are studied the same as other non-adjacent external control area (*i.e.*, so that TSRs from first-tier control areas are studied by ramping up all generating facilities in the

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[160] *See* UPP Protest at 46-53.

external control area on a *pro rata* basis). As discussed in its April 3 Compliance Filing, Entergy does not believe the *pro rata* dispatch method is appropriate in all circumstances but proposed changes to Section 3.2.1 to address stakeholders' concerns.[161] Section 3.2.1 has been modified to require identification of the specific generating facility only if the customer wants the ability to schedule from a facility that qualifies as a "border generating facility" under the AFC Process as described in Attachment C to the Entergy OATT. If the specific generating facility has not been identified, the SIS will simulate the transfer by "proportionally increasing all generation in the Control Area."

ETEC and UPP request clarification that "proportional basis" is the same as "*pro rata*" scaling for simulation purposes.[162] Entergy clarifies that "proportional basis," as used in this here, is not the same as "*pro rata*." The SIS will simulate a transfer by ramping up all non-firm generation in the external control area on a proportional basis relative to a calculated reserve capacity within the external control area.

Also, in Section 3.2.1, UPP seeks clarification that to the extent there is economic data available for imports, the section should be revised to allow scaling for imports on an economic basis.[163] Entergy clarifies that the ICT will use the customer-provided economic dispatch data and it will determine if a dispatch is feasible based on that provided data. If the dispatch is not feasible, then the ICT will seek additional clarification from the customer.

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161 *See* April 3 Compliance Filing, Appendix 1 at 33.

162 *See* ETEC Protest at 7-8; UPP Protest at 54.

163 *See* UPP Protest at 54.

H. Section 3.2.2: Designation/Undesignation Procedures Are Consistent with Order No. 890 and Should Not Be Modified

Section 3.2.2 of Attachment D describes the methods used to simulate requests to designate Network Resources. Section 3.2.2 reflects two procedures: one for studying a stand-alone request to designate a new Network Resource (Section 3.2.2.1) and another procedure for studying a request to designate a new Network Resource that is submitted simultaneously with a request to undesignate an existing Network Resource (Section 3.2.2.2). The primary difference between the two procedures is that simultaneously submitted requests to designate a new Network Resource and requests to undesignate an existing Network Resource are studied together in a cluster study.[164]

As described in Section 3.2.2.2, the cluster study is performed by simultaneously ramping up the new Network Resource and ramping down by an equal amount the subset of the Network Customer's existing Network Resources identified as eligible for undesignation. Additional procedures related to cluster studies are included in Section 7. Entergy modified Section 3.2.2.2 to specify that simultaneously submitted requests would take into account any competing TSRs of higher priority and that confirmation of the requests may result in undesignated capacity being released to the market (either permanently or temporarily). In response to stakeholder requests for additional detail regarding how the undesignation process works, Entergy initially attempted to provide that detail in a subsequent draft of Attachment D provided to stakeholders, but ultimately realized that these provisions were premature, because the NAESB process required by FERC to address these matters is ongoing.[165]

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164 *See* Order No. 890-B at P 189.

165 In Order No. 890, the Commission recognized that simultaneous requests to designate new Network Resources and undesignate existing Network Resources could be studied in clusters and directed NAESB to develop standards for processing "concomitant evaluations of transmissions requests and temporary terminations [of Network Resources.]" *See* Order 890 at P 1541. The Commission stated that the NERC/NAESB standards process should also address the proper modeling of undesignation requests and

Regarding simultaneous designation and undesignation, LMA Customers argue that, as drafted, a customer bears the burden of required capacity in the event a simultaneous undesignation does not cover the capacity required by a designation. However, if the undesignation creates excess capacity, Entergy is free to sell the capacity. According to LMA Customers, this transmission provider advantage requires "a more even-handed approach."[166] Arkansas Cities make similar arguments, essentially taking issue with the fact that capacity freed up through a simultaneous designation and undesignation will be made available to those first in the queue.[167]

The issues raised by LMA Customers and Arkansas Cities are not issues with Entergy or its Attachment D, but rather reflect their concern with the Commission policy on designation and undesignation of network resources as set forth in Order No. 890. The Commission clearly stated in Order No. 890, when a transmission provider evaluates an undesignation request with a concomitant TSR evaluation, the evaluation of the TSR should be processed taking proper account of all competing requests of higher priority.[168]

The Commission clarified in Order No. 890-B that if a transmission customer "wishes for the transmission provider to take into consideration the effect of a request to terminate a network resource on a concomitant request to designate another network resource, it may request the transmission provider to cluster the requests." This allows the transmission provider to cluster

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the impact undesignation requests have on ATC. *See* Order No. 890-B at PP 207, 241; *see also* Order No. 693, at P 1041. The Commission also clarified that prior to implementation of the NAESB standards, transmission providers need not implement OASIS functionality for undesignating network resources or business practices relating to the procedures for submitting and processing requests for concomitant evaluations of transmission requests and temporary terminations. *See* Order 890 at P 1543. Presently, the applicable NAESB business practices are undergoing development, and are anticipated to be complete in 2009. *See*, Report of the North American Energy Standards Board, Docket Nos. RM05-17-000 and RM05-5-000 at 11, 145 (dated Aug. 29, 2008).

166 *See* LMA Customers' Protest at 40-41.

167 *See* Arkansas Cities Protest at 8-10.

168 *See* Order No. 890 at P 1541.

study the impacts of the undesignation with the request for a new resource; however, if additional capacity is made available after the new network resource has been accepted, it is made available to the customer first in the queue. Contrary to LMA Customers' assertions, the Commission's approach does not "advantage" the transmission provider, which is indifferent as to who receives service released to the market as a result of excess capacity created by an undesignation. The LMA Customers' and Arkansas Cities' concerns clearly lie not with Entergy or its revisions to Attachment D, but with the Commission's policy, which has been decided in Order No. 890 and its progeny. Arguments here should be rejected by the Commission as an impermissible collateral attack on previous Commission orders.

I. Section 3.2.2.1: No Further Revisions to Section 3.2.2.1 Are Necessary Because Attachment D Already Provides Appropriate Detail to Customers

Under Section 3.2.2.1, Network Resource TSRs that are submitted without a simultaneous undesignation request are modeled as an additional Network Resource above and beyond the existing Network Resources for that Network Customer. The analysis simulates the transfer in two ways: generation-to-generation and generation-to-load. UPP argues that Section 3.2.2.1 should "be revised to describe how the results for each of the analyses are used in granting service, counter-offering of service, or denial of service".[169] In Section 5 of Attachment D, Entergy has clearly set forth the information contained in the SIS. Entergy does not believe that further information beyond the detail set forth in Section 5 is necessary or required by the ICT Orders or Order No. 890.

[169] *See* UPP Protest at 55.

J. Section 3.2.4.1 and 3.2.4.2: Rollover Rights and Grandfathered Customers

Certain stakeholders requested that Entergy clarify its rollover policies, including when a "grandfathered" customer transitions from a pre-Order No. 888 contract to OATT service. Consistent with Order Nos. 888 and 890, Section 3.2.4.2 specifies that a grandfathered customer's transition to OATT service will be studied when the transitioning customer requests additional or different resources or loads than are included in the existing contract. If the SIS indicates that the change in resources or loads substantially changes power flows, the customer's right to continue taking service may be affected by transmission constraints.[170]

Arkansas Cities argue that Attachment D should protect grandfathered customers through a "capacity credit" from having to pay for transmission upgrades when transitioning to OATT service and selecting a new power supplier.[171] Arkansas Cities further argue that such an approach is appropriate even where the customer changes power suppliers, because the grandfathered load and capacity requirements would not change.[172]

Entergy does not agree that Attachment D should be modified to allow grandfathered customers the ability to designate new or additional resources or loads, other than those included in the existing contract, without any study performed at all. To do so would be inconsistent with Order Nos. 888 and 890. Where a grandfathered customer's load and capacity requirements remain the same, but the customer changes power suppliers, thereby designating different resources (and in different locations) than those included in the existing contract, the request

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170 *See Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilitie*s, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036, at 31,665 n.176 (1996) ("Order No. 888), *order on reh'g*, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048, at 30,198 n.52 (1997) ("Order No. 888-A"), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

171 *See* Arkansas Cities at 11-13.

172 *See id*. at 11.

must be studied to determine whether the new resources involve substantial changes to power flows, such that the Customer's right to continue taking service is affected by transmission constraints.[173] Moreover, the Commission re-confirmed its requirements in this circumstance in its recent acceptance of Entergy's Settlement Agreement in Docket No. ER06-1555. In fact, the Commission's approval of the settlement agreement is notable as it required that Entergy revise its OATT and business practices to acknowledge when it would and would not perform a SIS for renewal by a Network Customer. What happens when a Network Customer modifies power flows was specifically addressed in that docket, and the disputed language required a revision. Arkansas Cities' arguments must therefore be rejected as inconsistent with Order Nos. 888 and 890 and Commission practice.

UPP also raises issues associated with rollover rights related to network service. UPP argues that Section 3.2.4.1 is overbroad by not requiring a SIS in some circumstances, and should be revised to provide for consideration in a change in operations that could result in a substantial change in power flows.[174] UPP posits the hypothetical whereby two entities are under a joint operating agreement and are also under a single Network Service Agreement. The joint operating agreement ends, and each entity individually seeks to roll over service based on the same load and same resources. According to UPP, under Section 3.2.4.1, each entity would be designating a mutually exclusive subset of resources and separate load. However, without the joint operating agreement the dispatch of the generation would change. After reviewing UPP's hypothetical, Entergy would be willing to amend 3.2.4.1 to address the specific situation that UPP presents, *i.e.* termination of a joint operating agreement that results in two separate entities seeking to become network customers with a subset of the previously designated resources and

173 *See* Order No. 888, at 31,665 n.176; Order No. 888-A at 30,198 n.52; Order No. 890-B at PP 148, 150.

174 UPP makes the same argument regarding Section 3.2.4.2. *See* UPP Protest at 57.

load. Otherwise, Entergy believes the language as currently written, tied to the designation of new resources or loads, is the appropriate triggering mechanism for an SIS.

K. Section 4.3: Entergy Does Not Consider Voltage In an SIS, So It Is Unnecessary To Consider It For Mitigation Purposes

ETEC argues that Entergy does not consider the issue of voltage violations in its use of redispatch and requests that Section 4.3 should add "and/or voltage limit violations" after the phrase "thermal overloads" to address situations where service is denied due to voltage violations.[175]

Entergy addressed this issue during the stakeholder process. Once the impact of the proposed transfer is simulated in the Base Case Model, Section 3.3 of Attachment D provides that the resulting power flows are evaluated to determine if allowing the proposed transaction is consistent with the thermal limits established in NERC Reliability Standards, SERC reliability criteria and Local Planning Criteria. Under this section, if a proposed transaction imposes an impact of three percent (3%) or greater and causes the facility/flowgate to exceed its rating, the facility/flowgate is considered a valid limit.

In response to stakeholder comments regarding these provisions and the consideration of voltage limits, Entergy clarified the applicable reliability criteria and specified that only thermal limits are considered at the SIS stage. Because only thermal limits are considered at the SIS stage, in accordance with the reliability criteria, it is inappropriate to consider such voltage limits when evaluating redispatch options. ETEC's argument should be rejected.

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175 *See* ETEC Protest at 9.

L. Section 4.4: The ICT Has Determined that The Use of Manual Operating Guides to Grant TSRs is Inappropriate and Requests for the Commission to Reconsider This Issue Should be Denied

ETEC argues that Entergy's failure to grant transmission service, through the use of manual operating guides in Section 4.4, is arbitrary, unjust and unreasonable.[176] ETEC's Protest fails to note, however, that this issue was presented to the ICT for resolution and the ICT found that manual operating guides should not be used to grant TSRs. The ICT has indicated its willingness to incorporate only automatic switching operating guides that require no manual intervention into the Base Case model that is used to evaluate transmission service, stating:

> [T]he ICT disagrees with the use of manual switching operating guides to sell long-term transmission service and generator interconnection service. The base case model used to sell transmission service should not include mitigation plans that are strictly intended for reliability purposes and that require some amount of manual intervention. For instance, a mitigation plan identified to prevent the overload of a line segment feeding more than 100 MW of consequential load may involve a manual switching guide implemented in order to restore loss of load. It is unreasonable to sell additional service based upon this operating guide because it would add loading on a line that is already assuming the loss of load. Manual operating guides are intended to protect the reliability of the transmission system in a real-time emergency; they are not intended to be used to grant new transmission service in a planning model.[177]

Entergy agrees with the ICT's opinion, and the Commission should reject ETEC's arguments to the contrary.

M. Section 6: No Further Revision to Section 6 is Required

UPP renews its position that if a FS results in a material change in the transmission upgrades identified in the SIS, the FS should address such change.[178] Entergy has responded to UPP previously on this issue. As UPP points out in its Protest, Entergy believes that the FS does not need to address such differences, but customers that have questions in this regard can request

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176 *See id.* at 9-10.

177 *See ICT Opinion on LTTIWG Base Case Contingency Overloads Task Force Recommendation*, at 3, April 3 Compliance Filing, Ex. 11.

178 *See id.* at 59.

the information from the ICT. Entergy is subject to a performance metric related to its studies, and it must balance the need for information with the requirements to complete studies within identified timeframes. The Commission has not required other transmission providers to provide the type of information requested by UPP, and it should not require Entergy to do so here. The Commission should deny UPP's request.

VII. ATTACHMENT E COMMENTS

Stakeholders generally protested three aspects of Attachment E: (1) Entergy's revised DNR Procedures; (2) Entergy's proposal to grant rollover rights to specific Network Resources that are designated during the term of a NITSA (as opposed only to those resources designated when a NITSA terminates); and (3) Entergy's use of rounding to the next highest megawatt when calculating losses. Entergy will respond to these Protests below.

A. The Commission Should Reject UPP's Protest of Entergy's Proposed DNR Procedures

UPP's Protest of Sections 7.5.3, 7.5.5, 7.6.2.1, 7.6.2.2 and 7.6.3 of Entergy's proposed DNR Procedures should be summarily denied. As explained in the April 3 Compliance Filing, Entergy's proposed DNR Procedures are meant to balance the conflicting interests of Network Customers/LSEs and PTP Customers/generators in light of the *pro forma* OATT's transmission service "bumping" priorities. These procedures balance the interests of Entergy's customers, more closely reflect the commercial practices of buying and selling capacity in energy markets, and provide added flexibility, speed, and security to wholesale power transactions. Entergy's revised DNR Procedures are consistent with or superior to the *pro forma* OATT and should be accepted to be effective as requested in the April 3 Compliance Filing.

1. The History of Entergy's Proposed DNR Procedures

Energy believes that it is necessary to provide a brief reiteration of the history and scope of its revised DNR Procedures. Under Section 13.2 of the OATT and governing FERC precedent, requests for DNRs have a higher bumping priority than requests for shorter-term and non-firm PTP Service.[179] This bumping priority, however, is subject to the *pro forma* OATT's DNR Procedures which, among other things, require that requests to designate Network Resources be accompanied by the *pro forma* OATT's attestation.

During the stakeholder process, Entergy received two general categories of comments on Attachment E's DNR Procedures.[180] LSEs and Network Customers generally wanted the maximum level of flexibility when designating Network Resources to serve their respective Network Loads. More specifically, they wanted revised DNR Procedures that maximized their ability: (1) to designate new Network Resources with enough "lead time" to negotiate and to finalize PPAs; (2) to arrange necessary off-system transmission paths for off-system DNRs while minimizing the risk of unnecessary "sunk" costs; and (3) to attest to their requested DNRs as

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179 For purposes of determining preemption rights under Section 13.2, the Commission has held that all requests to designate Network Resources are considered to be "long-term." *See Madison Gas & Elec. Co.*, 80 FERC ¶ 61,331, at 62,103 n.4 (1997), *reh'g order*, 82 FERC ¶ 61,099, at 61,373 (1998). The practical effect is that a request to designate a Network Resource can preempt a previously-approved reservation for short-term PTP Service, even though the PTP Service is requested for a longer period of time than the network resource (*i.e.*, a Network Resource request for one day can preempt, for example, a PTP request for three months).

180 Entergy's notes that UPP's characterization of Entergy's attempt to introduce this issue during the last round of comments on Attachment E ignores the fact that this issue has been discussed among Stakeholders for quite some time before Entergy submitted the April 3 Compliance Filing. It was debated at the January 2008 Attachment Review Stakeholder meetings in Little Rock, Arkansas. Entergy included proposed DNR language in the version of Attachment E circulated on September 4, 2008 and again on February 18, 2009 for discussion during a February 26, 2009 conference call. As noted by UPP, Entergy highlighted theses changes during that call. A representative from UPP was present on that call but did not raise issues on Entergy's proposed DNR Procedures at that time. All parties were informed that they could contact Entergy with questions, if such questions arose. UPP did not contact Entergy. Accordingly, Entergy strongly disagrees with UPP's implication that UPP was not provided a fair opportunity to review drafts of Entergy's proposed DNR Procedures before they were included in the April 3 Compliance Filing. *See* UPP Protest at 60 n.208.

required under Order No. 890 without sacrificing an unreasonable amount of flexibility in accomplishing (1) and (2).

Conversely, PTP Service Customers and generators wanted to minimize their risk of being bumped by requests for DNRs. Therefore, they requested that Entergy revise its TSR evaluation process to prevent Network Resource requests from bumping PTP Service reservations, unless the Network Resource request was Confirmed or submitted "Pre-Confirmed."[181] Alternatively, PTP Service Customers and generators requested that Entergy adopt procedures that would limit Entergy's DNR process so that Network Customers could not attest to the validity of a proposed DNR unless that customer already had finalized the necessary PPAs (*i.e.*, it was executed) and, with respect to an off-system DNR, had confirmed firm off-system transmission paths. PTP Customers and generators that requested these changes wanted to minimize the risk that they would be bumped by "speculative" DNRs.

Based on these conflicting concerns and in order to balance stakeholder interests, Entergy proposed the following deviations to the *pro forma* OATT's DNR Procedures in its April 3 Compliance Filing:

- **<u>Section 7.4 (Deadline for Submission of Attestation):</u>** Entergy revised Section 7.4 of Attachment E to require that the attestation required by Section 30.2 of the *pro forma* OATT be submitted with a Network Customer's initial TSR.[182] In Order No. 890-B, the Commission indicated that the attestation should be submitted when a DNR is confirmed.[183]

- **<u>Section 7.6 (Network Resources Contingent Upon Transmission Service):</u>** In Section 7.6.2.1 of Attachment E, Entergy allowed: (1) binding oral contracts (recorded in audio format); (2) written, unexecuted contracts for the purchase that, if executed, would meet the requirements

[181] *See*, *e.g.*, April 3 Compliance Filing, Ex. 7, Cmt. 344.

[182] *See* April 3 Compliance Filing, Ex. 6, First Revised Sheet Nos. 267-68.

[183] *See* Order No. 890-B at P 183.

to be designated as a Network Resource under the Entergy OATT; and (3) draft contracts or terms sheets for one or more potential purchases being developed as part of a formal Request for Proposals ("RFP") process to qualify as a DNR for purposes of providing the attestation required by Section 29.2(viii) and 30.2 and to confirm its TSR. Under Section 7.6.2.2, all of these arrangements may be finalized and executed (for oral contracts, reduced to writing) by certain deadlines.[184] With respect to UPP's Protest,[185] a final contract satisfying the OATT's DNR requirements must be executed by the following deadlines: for monthly Network Resources, the contract must be executed the earlier of five days prior to the commencement of service or fifteen days after the Network Customer confirms the TSR; for yearly Network Resources, the contract must be executed the earlier of thirty days prior to the commencement of service or forty-five days after the confirmation of the TSR.[186] If not, the Customer must notify the ICT by certain deadlines, and the ICT will terminate the relevant TSR under Section 7.6.3.[187]

- **Section 7.5.3 (Off-system Transmission Arrangements for Off-System Network Resources):** Entergy proposed to give Network Customers additional flexibility when securing off-system transmission arrangements necessary for off-system DNRs by allowing the off-system transmission requests to be confirmed *after* the customer submits its request to designate the off-system DNR. While a Network Customer must still provide OASIS numbers corresponding to external transmission arrangements when submitting its TSR, these requests

184 *See* April 3 Compliance Filing, Ex. 6 at § 7.6.

185 *See* UPP Protest at 67.

186 *See id.* § 7.6.2.2.

187 *See* April 3 Compliance Filing, Ex. 6, First Revised Sheet Nos. 270-71.

may be in accepted, counter-offered, or study mode.[188] The off-system path, however, must be confirmed prior to the commencement of Network Service.[189]

2. The Commission Should Reject UPP's Protests of Entergy's Proposed DNR Procedures

a. UPP's Protest Should be Denied Because UPP Asks the Commission to Apply the Wrong Legal Standard To Entergy's Proposed Deviations to the *Pro Forma* OATT

While UPP supports Entergy's proposal to require that Network Customers' attestations be submitted when their requests to designate a resource are queued, UPP protests Entergy's proposed Sections 7.5.3 (off-system transmission paths), 7.5.5 (notification of status for off-system paths), 7.6.2.1 (unexecuted contracts), 7.6.2.2 (unexecuted contract deadlines) and 7.6.3 (notification procedures). The Commission should summarily deny UPP's Protest of all of these provisions because UPP effectively has asked the Commission to apply the wrong legal standard of review. UPP does not argue that Entergy has failed to establish that Entergy's proposed deviations are consistent with or superior to the *pro forma* OATT. Instead, UPP argues that Entergy's proposed DNR Procedures are different from what is established by Order No. 890 and, solely because of those differences, Entergy's proposed DNR Procedures should be denied.

188 Despite UPP's statement otherwise, Entergy requires that any OASIS numbers provided pursuant to Section 7.5.3 must correspond to the off-system transmission arrangements. *See* UPP Protest at 65.

189 *See* April 3 Compliance Filing, Ex. 6, First Revised Sheet No. 268. Entergy notes that it believes that, at least in part, UPP has misconstrued Section 7.5.3's DNR Procedures. In the its Protest, UPP indicates that Entergy "permits the OASIS numbers provided pursuant to Sections 7.5.1 and 7.5.2 with the request to designate a Network Resource that does correspond with the numbers of the service actually used to provide the off-system transmission service." UPP Protest at 65. This interpretation of Section 7.5.1 and 7.5.2 is not correct. Customers must provide the OASIS reservation numbers corresponding to the off-system path used to deliver the off-system DNR to Entergy's system. UPP has also raised questions over Entergy's use of the terms "Confirmed Firm" and "Conditional Firm" in Section 7.5.3. These are not separate terms. If ordered to by the Commission, Entergy agrees to revise Section 7.5.3 to use the terms "Confirmed, Firm" and "Conditional, Firm" so that Section 7.5.3 reads, "The OASIS numbers provided pursuant to Sections 7.5.1 and 7.5.2 do not have to correspond to Confirmed**,** Firm or Conditional**,** Firm Reservations at the time the Customer submits or Confirms the TSR to designate the Off-System Resource as a Network Resource."

With respect to Entergy's proposal to allow requests for off-system DNRs to be queued before the relevant off-system path has been confirmed (Section 7.5.3), UPP argues that Entergy's proposal should be denied because:

> [t]he Order No. 890 OATT requires that the [off-system] Network Customer include, among other things, a description of the transmission arrangements on the external transmission system(s) for each off-system Network Resource . . . if a Network Customer has a request for Firm Point-To-Point Transmission Service off-system that is accepted or confirmed, then it has transmission service sufficient to make the required attestation. However, if that service is in study mode or counter-offered and the Network Service Customer may have to withdraw its request because of the off-system transmission arrangements, the attestation requirements of Section 29.2(viii) cannot be met.[190]

With respect to Entergy's proposal to expand the types of contracts that qualify for attestation (Section 7.6.2.1), UPP argues that Entergy's proposal should be denied because:

> [t]he attestation in Section 29.2(viii) of the Order No. 890 OATT requires either executed contracts (*i.e.,* written and signed) or unexecuted contracts subject to the availability of transmission service under Part III of the OATT. The electronically recorded terms and conditions for the purchase falls into neither category. An unexecuted contract without the transmission service under Part III of the OATT contingency similarly does not satisfy the Order No. 890 attestation requirement. And the third category, the RFP, is the worst of the lot. This category does not satisfy the Commission's attestation requirement and, in contrast to the first two categories, it is not even expected.[191]

With respect to Entergy's extended deadlines for finalizing and executing PPAs that were contingent upon transmission service (Section 7.6.2.2 and 7.6.3), UPP argues that Entergy's proposal should be denied because:

> [t]he time frames by which a written contract must be executed for monthly and annual Network Resources extend well past what would otherwise be required for submittal of the attestation under Order No. 890.[192]

Accordingly, instead of evaluating whether Entergy's proposed deviations are consistent with or superior to the *pro forma* OATT, UPP is asking for the Commission simply to focus on

[190] UPP Protest at 63-64.

[191] *Id.* at 66.

[192] *Id.* at 67. Entergy believes UPP is referring to confirmation of a relevant TSR when making this point.

the fact Entergy's proposed Sections 7.5.3, 7.5.5, 7.6.2.1, 7.6.2.2, and 7.6.3 differ from the DNR Procedures promulgated in Order No. 890. Based on those differences alone, UPP asks the Commission to reject Entergy's proposal.

This argument neglects to address the critical issue. As explained in the April 3 Compliance Filing, there is no question that Entergy's proposed DNR Procedures vary from Order No. 890. The legal question for the Commission to decide, however, is whether Entergy's attempt to balance the conflicting interests discussed above results in DNR Procedures that are consistent with or superior to the *pro forma* OATT.

Entergy has satisfied this legal standard. While Entergy required Network Customers to include the *pro forma* OATT attestation with a TSR when it is queued over OASIS, Entergy broadly defined what qualifies as a DNR, and proposes to give customers additional time to execute a contract after it confirms its TSR. This compromise was intended to reduce "speculative" DNRs, thereby decreasing the risk that PTP Service customers and generators could be bumped unnecessarily. At the same time, the packaging of the broad standards for qualifying as a DNR and the extended deadline for DNR contracts provides LSEs and Network Customers greater flexibility when serving their respective loads and better reflects power industry timelines for negotiating a power supply arrangement. Finally, requiring Network Customers to submit their attestations when they queue their TSRs while also allowing Network Customers and LSEs to have more flexibility when designating off-system resources, not only protects PTP Service Customers and generators but also decreases the likelihood that Network Customers and LSEs will be subject to unnecessary sunk costs and enables them to secure less expensive resources than what may be available on-system.

Accordingly, Entergy's revised Sections 7.5.3, 7.5.5., 7.6.2.1, 7.6.2.2, and 7.6.3 are consistent with or superior to the *pro forma* OATT. These procedures balance the interests of

Entergy's customers, more closely reflect the commercial practices of buying and selling capacity in energy markets, and provide added flexibility, speed, and security to Network Customers' and LSEs' wholesale power transactions. Other than stating that Entergy's revised DNR Procedures deviate from the *pro forma* OATT, UPP has not explained why Entergy's proposals should not be accepted as filed. The Commission should deny UPP's request.

b. The Commission Should Reject UPP's Protest of Entergy's Revised DNR Procedures Because They Rest on Incorrect Assumptions Concerning the *Pro Forma* OATT's Attestation Requirements

UPP's Protest of Sections 7.5.3, 7.5.5., 7.6.2.1, 7.6.2.2, and 7.6.3 must be denied because UPP has fundamentally misconstrued the *pro forma* OATT's DNR attestation requirements. Central to UPP's position is the false assumption that "[o]nce the attestation is submitted, an unexecuted contract may be contingent *only* on Network Service for the Network Resource being granted by Entergy."[193] Based on this assumption, UPP argues that there are only two types of PPAs that can satisfy the *pro forma* OATT's attestation requirements: (1) executed PPAs; or (2) unexecuted PPAs where the *only* remaining condition precedent to execution is the acquisition of transmission service. This is a misreading of Section 29.2(viii) of the *pro forma* OATT, which governs Network Customers' attestation requirements.

Section 29.2(viii) requires that Network Resources

> …. satisfy the following conditions: (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation *where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff …* (emphasis added)

Accordingly, while executed contracts clearly satisfy the attestation requirements, Section 29.2(viii) also allows unexecuted PPAs contingent upon transmission service to qualify as

[193] *See id.* at 65 (emphasis added).

DNRs. UPP, however, is going one step beyond the clear text of Section 29.2(viii) by asking the Commission to read Section 29.2(viii) so that a PPA can only qualify as a DNR if the *only* remaining condition precedent to execution of the PPA is the acquisition of transmission. In other words, UPP effectively asks the Commission to read Section 29.2(viii) to require that all DNRs:

> satisfy the following conditions: (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation *where execution of a contract is* ***[only]*** *contingent upon the availability of transmission service under Part III of the Tariff* …..[194]

When interpreting tariff language, however, FERC "looks first to the four corners of the entire tariff, considers the entire instrument as a whole, giving effect so far as possible to every word, clause and sentence, *and attributes to the words used the meaning which is generally used, understood, and accepted.*"[195] When applying this rule, the Commission will decline to read limiting language "into" a tariff where such language does not exist.[196] Rather, a tariff should be construed based on its plain text.[197]

Therefore, the Commission should reject UPP's interpretation of Section 29.2(viii) because that construction reads limiting language into Section 29.2(viii) when it does not exist. Section 29.2(viii)'s plain text allows other conditions precedent to be satisfied before a PPA can qualify as a DNR. For example, the execution of a PPA could be contingent upon the satisfaction of, among many other things, a regulatory approval clause, the completion of a SIS or FS, or the acquisition of "rights of way" and still qualify as a DNR.

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194 *Id.* at 62 (emphasis added).

195 *See Columbia Gas Transmission Corp.*, 27 FERC ¶ 61,089, at 61,166 (1984) (emphasis added).

196 *See Northwest Pipeline Corp*., 65 FERC ¶ 61,046, 61,430 (1993), *aff'd*, *Northwest Pipeline Corp.*, 61 F.3d 1479, 1486 , (10th Cir. 1995) (refusing to read limiting language into a tariff and determining that the phrase "total annual volumes" in a tariff is applicable to *all* volumes of natural gas transported rather than *only* unbundled volumes of natural gas transported).

197 *See Columbia Gas Transmission Corp.*, 27 FERC at 61,166.

Entergy's proposed DNR Procedures are the type of additional conditions precedent for a PPA to qualify as a DNR allowed under Section 29.2(viii). Section 7.5.3 allows an off-system resource to qualify as a DNR for purposes of submitting an initial TSR while off-system paths are still pending, but conditions the ultimate validity of the DNR on the path being confirmed before the deadlines in Section 7.5.5. Section 7.6.2.1 broadens the types of contractual arrangements that may qualify as DNRs for purposes of submitting an initial TSR subject to the execution deadlines delineated in Section 7.6.2.2 and the notification requirements in Section 7.6.3. All of these additional contingencies are consistent with or superior to the *pro forma* OATT for the reasons discussed in the April 3 Compliance Filing and above.

In the end, UPP argues that Entergy's proposed deviations from the *pro forma* OATT should be denied because Entergy's proposal "does not provide any relief to the displacement of Point-to-Point Transmission Service, but ties up transmission by enabling the speculative designation of Network Resources." [198] Based on this statement, it appears as though UPP's fundamental complaint is really that short-term PTP TSRs are bumped by requests for DNRs. This is codified by the incorporation of the WEQ-001 into the Commission's regulations at 18 CFR §38.2 and will, therefore, occur regardless of the DNR Procedures that Entergy implements. Accordingly, UPP's issues are actually with the Commission's regulations; this proceeding is not the correct forum to address UPP's concern. Indeed, Entergy believes that it is important to emphasize that if UPP is granted the relief that it seems to desire (*i.e.*, that the *pro forma* OATT's DNR Procedures apply), then UPP will be subject to an even *higher* risk of being bumped by speculative DNRs. Under the *pro forma* procedures, *a Network Customer can go through the entire TSR evaluation process without a valid DNR and then withdraw its request*

[198] *See* UPP Protest at 68.

right before confirmation. In comparison to its proposals to balance stakeholder interest, Entergy fails to see how this would better serve UPP's interests.

Accordingly, UPP's Protest of Entergy's revised DNR Procedures must be denied. UPP is effectively asking the Commission to apply the wrong standard of review, and incorrectly assumes the faulty premise that contracts can only satisfy the OATT's contingency attestation requirement if their execution (in the literal sense) is subject only to the acquisition of transmission service. This position is not supported by the language of the OATT. While the OATT certainly indicates that one contingency of DNR status may be the acquisition of transmission service, the OATT does not preclude other conditions for a contract to satisfy the OATT's DNR requirements. Entergy's proposed DNR Procedures recognize such additional contingencies and provide commercially reasonable procedures to balance Stakeholders interests in a manner that is consistent with or superior to the *pro forma* OATT.

B. Contrary to UPP's Assertions, Entergy's Rollover Rights Provisions are Consistent with or Superior to" the Order No. 890 OATT and Should be Accepted

Entergy has included its DNR rollover procedures in Section 7.9 of Attachment E, and consistent with the Commission's clarification in Order No. 890-B, Entergy has tied the entitlement to rollover rights to the duration of the relevant customer's NITSA. Accordingly, NITSAs that are at least five years in duration are entitled to rollover rights under Section 2.2 of Entergy's OATT. Under the *pro forma* OATT, only those Network Resources that remain designated at the time the NITSA expires are entitled to rollover rights.[199] In Section 7.9.2, however, Entergy has taken its rollover policy one step further and is also proposing to grant rollover rights to any Network Resource designated by the customer for a period of five years or

199 *See* Order No. 890-B at PP 148-52.

longer, even if the Network Resource terminates prior to the expiration of the relevant NITSA. These rollover rights are subject to the SIS conducted when the particular resource is designated.

UPP, however, objects to Entergy's proposal to grant rollover rights to any Network Resource designated by the customer for a period of five years or longer, even if the Network Resource terminates prior to the expiration of the relevant NITSA.[200] UPP objects to Section 7.9.2 because it enhances "Network Customers' rights by adding service taken previously."[201] According to UPP, the Entergy approach was rejected by the Commission because it has "rejected the concept of providing rollover rights to undesignated resources."[202]

UPP misunderstands the Entergy proposal. Entergy does not propose to provide "rollover rights to undesignated resources." Rather, Section 7.9.2 allows a Network Customer to receive rollover rights for any network resource designated by the customer for five years or longer, so that at the end of the five years, it may rollover the resource if it so wishes. For example, if a customer has a 20-year NITSA and during year three of its NITSA, it submits a request to designate a Network Resource for five years, Entergy would study the resource for rollover rights. The customer could then rollover that resource *at the end of the five-year period*. However, UPP seems to contemplate a situation whereby at the end of the 20-year NITSA, the customer would have rollover rights for any five-year Network Resource that it designated during the term of the NITSA even if the customer had not used the resource for a number of years. Section 7.9.2 does not provide the type of flexibility UPP fears. Instead, the provision simply allows a network customer that seeks to designate a Network Resource for five years to have the ability to study the resource for rollover rights, so that at the end of the five years, it may redesignate the Network Resource and maintain its status without further study. Such an

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200 *See* UPP Protest at 69-70.

201 *Id.* at 70.

202 *Id.*

approach is one step beyond the Commission's approach in the *pro forma* OATT. It provides more commercial certainty to Network Customers and Entergy as the transmission provider and provides greater comparability of service between PTP Customers and Network Customers. Thus, for the reasons explained in the April 3 Compliance Filing, the Commission should find Section 7.9.2 to be consistent with or superior to the *pro forma* OATT.[203]

C. The Commission Should Reject the Arkansas Cities' Protest of Entergy's Loss Compensation Procedures

The Arkansas Cities argue that for the purposes of calculating loss compensation service, Entergy should round up or down to the nearest megawatt depending on where the breaking point of .5 occurs.[204] Under such an arrangement, if the breaking point is at .5 (or less), Entergy would round down.[205] This Protest should be rejected.

As proposed in Section 3 of Attachment E, Entergy rounds up to the next MW. Entergy reiterates its position explained in the April 3 Compliance Filing that losses can only be provided in whole MW.[206] Accordingly, Arkansas Cities' proposal would prevent Entergy from collecting the appropriate loss amount because Entergy would be forced to round down in some circumstances, and each circumstance would result in Entergy collecting less than the required loss amount.[207] Ultimately, this approach could result in Entergy being prevented from collecting a significant amount of losses.

Furthermore, Entergy believes that Arkansas Cities' proposal would allow customers to intentionally circumvent the loss compensation provisions in Section 3 of Attachment E by submitting multiple identical tags with capacities such that they would not be required to provide

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203 *See* April 3 Compliance Filing at 27.

204 *See* Arkansas Cities Protest at 13-14.

205 *See id.* at 14.

206 *See* April 3 Compliance Filing, Ex. 7. Cmt. 337.

207 *See id.*

losses. For example, in a scenario where a customer would submit one tag with 103 MW received and 100 MW delivered, a customer under Arkansas Cities' proposal could instead submit six identical 16 MW tags and one 4 MW tag and not be required to provide any losses.

VIII. ENTERGY'S REQUESTS FOR COMMISSION GUIDANCE

A. Modeling of QF "Puts"

In the April 3 Compliance Filing, Entergy sought guidance from the Commission on the two related, but distinct issues concerning the appropriateness of the incorporation of QF "put" transactions in AFC Base Case models (through historical data or "non-binding" schedules) in light of the "physical rights" transmission capacity allocation priorities in the *pro forma* OATT notwithstanding the fact that QFs do not qualify as DNRs.[208] As a corollary, Entergy also asked the Commission for guidance on the separate legal issue of whether the inclusion of QF puts into Entergy's AFC Base Case models would also necessitate the inclusion of QF output in long-term transmission models used in SISs or transmission planning models.[209]

UPP, Occidental and the LMA Customers commented on Entergy's request for guidance. UPP argues that the guidance that Entergy seeks is not necessary in light of Paragraph 290 of Order No. 890 requiring that NERC implement benchmarking standards as discussed in Section IV above. While Occidental supports the incorporation of QF puts into Entergy's transmission models (presumably, Entergy's AFC models, SIS models and planning models), Occidental "strenuously opposes the alternative proposal" of using non-binding schedules. Finally, the LMA Customers do not oppose Entergy's request for guidance on the modeling of QFs and suggest that, to the extent that historical information must be used, Entergy can "mine" at least some of the relevant QF data from Reliability Standards TOP-002-2 (Normal Operations Planning); TOP-

208 *See* April 3 Compliance Filing at 32.

209 *See id.* at 34.

003-0 (Planned Outage Coordination); TOP-006-1 (Monitoring System Conditions) and VAR-002-1 (Generator Operation for Maintaining Network Voltage). Entergy will address each of these comments in this Section IX.

1. The Commission Must Still Provide the Legal Guidance Requested By Entergy Despite the Fact That NERC Has Been Ordered to Establish Benchmarking Standards

Despite UPP's assertions otherwise, the Commission must still provide Entergy the guidance concerning QFs sought in the April 3 Compliance Filing despite the fact that Paragraph 290 of Order No. 890 required that NERC revise MOD-10 through MOD-25 to develop benchmarking standards. As Entergy explained in Section IV above, these NERC standards have not yet been approved by FERC. Therefore, UPP is simply incorrect to the extent that UPP is arguing that Entergy is currently obligated to benchmark models to reflect QF puts.

Even assuming that these standards were effective, however, the Commission would still need to resolve the two issues for which Entergy has sought guidance. As explained in the April 3 Compliance Filing, Order No. 890 distinguished between "long-term" AFC calculations (which Entergy construes to be "transmission planning" models) and "short-term" AFC calculations (which Entergy construes to be "operational planning" models).[210] Moreover, FERC appeared to limit "short-term" AFC calculations to AFC values calculated during the current-day and next-day horizons for which unscheduled firm is released.[211] Entergy then explained that while NERC is still developing standards that address consistency between ATC calculations and transmission planning activities, Order No. 890's apparent distinction between short-term and long-term AFC models raised additional questions concerning the inclusion of QF "put" transactions in AFC base case models.

[210] *See* Order No. 890 at P 280.

[211] *See id.* at P 244.

Based on this ambiguity, Entergy sought guidance on whether: (1) it was appropriate to include QF puts in its AFC Base Case models; and (2) to the extent the former was permissible, whether it was also appropriate to include QF puts in Entergy's SIS and transmission planning studies. With respect to UPP's Protest, this means that even if NERC establishes benchmarking standards that require the incorporation of QFs into short-term models, the Commission must still clarify Entergy's second legal question of whether the incorporation of QFs into short-term models means that QF puts must also be incorporated into long-term models, (*i.e.*, SISs and transmission planning studies). Thus, FERC approval of establishing benchmarking standards for AFC Base Case models only gets you halfway to resolving both of the legal issues for which Entergy has sought guidance.

2. If the Commission Finds That QFs Are Not Required to Provide Non-binding Schedules to Entergy, the Commission Should Also Clarify That Entergy Is Not Obligated To Incorporate QF Puts Into Its Transmission Models

As explained above, the reason that Entergy sought guidance on whether it would be appropriate to incorporate QF puts into its AFC Base Case models through historical data or non-binding schedules is that it is not clear that such a practice would be consistent with the *pro forma* OATT's "physical rights," "first-come, first-served" transmission capacity allocation process. Entergy explained that the incorporation of QF puts into Entergy's Base Case models through the use of non-binding schedules had been discussed in the past, and that certain QFs refused to participate with such a practice. Occidental objects to being forced to submit non-binding schedules.

Entergy has no preference to whether historical data or non-binding schedules are used to model QFs and, therefore, does not oppose Occidental's Protest.[212] Entergy, however, believes

[212] Entergy notes, however, that Energy's request to use non-binding schedules in order to improve the accuracy of its transmission models is consistent with Order No. 890's requirement that Network

that the Commission cannot separate Entergy's requested use of non-binding schedules to predict QF puts from the obligation to model QFs in the first place (unless, of course, FERC requires the use of historical data). Accordingly, to the extent that the Commission rejects Entergy's alternative proposal to require QFs to provide Entergy non-binding schedules, Entergy should not be obligated to include QFs in its transmission models.

3. If Used At All, the Type of Historical Data Used To Predict QF Puts Will be Vetted Through Stakeholders

LMA Customers do not oppose Entergy's request for guidance on the incorporation of QF puts into Entergy's transmission models and request that the Commission revise Attachment C and the AFC Process "to incorporate reasonable assumptions with respect to the volumes of 'put' energy… based upon historical patterns."[213] The LMA Customers argue that Entergy can collect this information from data collected pursuant to Reliability Standards TOP-002-2 (Normal Operations Planning); TOP-003-0 (Planned Outage Coordination); TOP-006-1 (Monitoring System Conditions) and VAR-002-1 (Generator Operation for Maintaining Network Voltage). Accordingly, while the LMA Customers do not necessarily address the legal issues for which Entergy seeks guidance, they seem to support the use of historical data to the extent that QF puts are incorporated into Entergy's transmission models.

While these standards may be relevant in trying to identify historical QF activity (and the LMA Customers have not explained how they are), Entergy believes that any methodology that would be used to evaluate the inputs used to forecast QF puts may be subject to pending NERC and NAESB standards and would need to be vetted through stakeholders. Entergy, therefore, does not believe that the Commission needs to resolve the type of information that Entergy

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Customers be required to provide information on their project loads and resources to transmission providers to assist transmission providers in their transmission planning. *See* Order No. 890 at PP 480, 486; Order No. 890-A at P 206.

213 LMA Customers Protest at 16.

would rely upon to incorporate QF puts into its models at this time. Instead, Entergy is only seeking guidance on whether the incorporation of such information into Entergy's transmission models would be consistent with the *pro forma* OATT. The actual data that may (or may not) be used to project QF dispatch is better resolved in a stakeholder process.

B. Entergy's Request for Guidance on the Modeling of LSE Shortfalls.

In the April 3 Compliance Filing, Entergy requested Commission guidance on the appropriate modeling procedures to apply to the Study Horizon of the AFC process when an LSE fails to designate sufficient Network Resources to serve its designated Network Loads.[214] While Entergy explained that neither option is optimal, Entergy proposed two alternative modeling solutions that had been discussed by both Entergy and the ICT. The first approach is supported by Entergy. The second is supported by the ICT.

Under the first approach, Entergy proposed to rely on generating facilities within the Entergy control area that have obtained Energy Resource Interconnection Service ("ERIS") and that are currently running at some level in the Base Case model. The dispatch of these resources would be increased on a *pro rata* basis to meet any remaining shortfall between the resource plan and the load requirements for a particular LSE. Entergy explained that the approach is similar to Entergy's treatment of resource short-falls in its long-term Base Case models under Section 2.3.4.1 of Attachment D. Without knowledge of the actual resource(s) that will be committed in future timeframes to meet these load requirements, *pro rata* dispatch ensures that resources with interconnection service and the ability to inject power into the grid are utilized.

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[214] *See* April 3 Compliance Filing at 35. In the April 3 Compliance Filing, Entergy explained that the modeling of LSE shortfalls may implicate both the Planning Horizon and Study Horizon but really is more of a Study Horizon issue because customers usually designate sufficient resources during the first thirty days of the AFC Process to serve their loads. To the extent the issue does occur in Operating and Planning Horizon the imbalance is met by using the approach discussed in section 7.1.1.4 of Attachment C. Further, the AFC Process uses specific scheduling data in the Operating Horizon rather than reservation data to commit and dispatch generating resources. Accordingly, the discussion surrounding Entergy's request for guidance in the April 3 Compliance Filing and in this Answer focuses on Study Horizon modeling issues.

Under the second approach, the AFC software would model a "pseudo" resource that would be located at the relevant load bus so that any resource short-fall for a particular LSE would be covered by the pseudo resource, rather than other uncommitted resources as in the first approach.

In its comments, the ICT advocates for the pseudo generator approach. Entergy disagrees that this approach is preferable to the *pro rata* dispatch approach. As Entergy explained in the April 3 Compliance Filing, Paragraph 296 of Order No. 890 directed NERC to modify MOD-001 to specify that "base generation dispatch will model: (1) all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run and (2) uncommitted resources that are deliverable within the control area, economically dispatched as necessary to meet balancing requirements."[215] The fundamental problem with the ICT's approach is that, in relying on a pseudo generation resource that does not exist, it fails to satisfy (1) and (2) above once the revised MOD-001 becomes effective.

In addition to the fact that the pseudo resource approach is inconsistent with Paragraph 296 of Order No. 890 because it does not model actual resources as they are expected to run or uncommitted resources that are deliverable within the Entergy Operating Companies' control area**,** Entergy believes that implementation of the second approach may mask certain transmission constraints associated with the deliverability to LSEs and will be technically and administratively burdensome to implement. For instance, many (if not most) LSEs and Network Customers do not notify Entergy of their projected use of future resources to serve their respective loads; however, the "firmness" of that load and the fact that Entergy's Transmission System must be used to serve those loads remain unchanged. Entergy believes that both the placement and dispatch of a "pseudo" generating facility at a certain bus -- either located within

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215 *See* Order No. 890 at P 296.

the load balancing authority area or at a load delivery point bus -- entirely ignores potential limitations on the availability of transmission service otherwise necessary to serve the load.

Furthermore, in response to the ICT,[216] Entergy disagrees that the use of resources with ERIS status in the Entergy control area on a *pro rata* basis creates"pseudo" transmission service. To the contrary, the utilization of all generating resources with ERIS status that are available for dispatch minimizes the impact to flows on the transmission system from constraints associated with generation deliverability. In addition, the use of existing resources located within the Entergy Operating Companies' control area most accurately reflects the impact that transmission service to network load customers may have since (1) actual generating resources are utilized; and (2) the impact of the load is recognized and accounted for.

In fact, Entergy believes that the pseudo resource approach is more likely to cause phantom congestion or mask transmission system constraints associated with the deliverability of the load. While power flows will be impacted under both approaches, because of the concentrated nature of the assumed resource in the pseudo generator approach (*i.e.*, one "pseudo" generator injecting at one delivery point versus multiple ERIS generating facilities), the magnitude of impact to certain transmission facilities will be greater. For example, assume that a Network Customer with 300 MW of load distributed among several transmission delivery points fails to submit a resource plan for a future time frame. Under the pseudo generator option, a fictional generating unit will be added to the model at one of the delivery points and dispatched to 300 MW (plus loss requirements). Because this generator is not real, the transmission system may not be able to accommodate the pseudo generation and phantom transmission constraints may occur.

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[216] *See* ICT Comments at 9.

If the *pro rata* dispatch process is utilized and an LSE with one load delivery point fails to submit an adequate resource plan, then a generating resource is added to the power flow model at the only load delivery point to account for the load serving requirements. The net impact to the Base Flows in the power flow model is that the impact of the load is removed or negated. No other adverse effects will be observed to other customers, but the impact of the load serving requirement to the transmission system is not preserved. Thus, consideration of the transmission system topology and the impact of load serving requirements to the transmission system flows are most accurately preserved under the *pro rata* approach.

The advantage of the *pro rata* dispatch option is that it is consistent with Entergy's modeling of resource short-falls in its long-term Base Case models under Section 2.3.4.1 of Attachment D pursuant to which Entergy mitigates resource shortfalls by dispatching ERIS resources on a *pro rata* basis. Other obvious benefits of Entergy's *pro rata* dispatch of available resources are that it provides the largest possible pool of resources to serve affected loads and is consistent with Paragraph 296 of Order No. 890's base generation dispatch policies.[217] The use of *pro rata* dispatch aligns with the utilization of designated Network Resources (and other resources) that are committed to run and uncommitted resources that could be delivered to the relevant Network Customer's load. In Entergy's view, these facts support the utilization of the *pro rata* dispatch approach to meet any LSE capacity shortfalls.

[217] *See* Order No. 890 at P 296.

IX. CONCLUSION

For the foregoing reasons, Entergy requests that the Commission reject the Protests, and accept Entergy's April 3 Compliance Filing, subject to the revisions that Entergy commits to make herein, to be effective 30 days after a FERC order accepting them, as requested.

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon those designated on the official service list compiled by the Secretary in this proceeding.

Dated this 20th day of May, 2009.

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