Exhibit No.:	NP
Issues:	Fuel Adjustment Clause
Witness:	Jaime Haro
Type of Exhibit:	Surrebuttal Testimony
Case No.:	EO-2010-0255
Date Testimony Prepared:	December 22, 2010

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. EO-2010-0255

SURREBUTTAL TESTIMONY

OF

JAIME HARO

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

St. Louis, Missouri
December, 2010

SURREBUTTAL TESTIMONY
OF
JAIME HARO

CASE NO. EO-2010-0255

Q. Please state your name and business address.

A: My name is Jaime Haro. My business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri.

Q. Are you the same Jaime Haro who filed direct testimony in this case?

A. Yes I am.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my surrebuttal testimony is to respond to the direct/rebuttal testimony of various witnesses who argue that Ameren Missouri's power sales contracts with the American Electric Power Operating Companies ("AEP") and Wabash Valley Power Association, Inc. ("Wabash") are not excluded from the term "OSSR" as defined in the Company's Fuel and Purchased Power Adjustment Clause tariff ("FAC tariff") in effect during the period addressed in this prudence review. Essentially, these parties argue that the contracts with AEP and Wabash are not long-term partial requirements sales contracts.

Q. On page 10 of his direct/rebuttal testimony, Staff witness Dana Eaves states that you have not provided a definition of a long-term partial requirements contract. In this context, what is the definition of that term?

A. A long-term partial requirements sale is an agreement where the seller provides resources sufficient to meet part of the purchasing entity's load obligation during the term of the agreement. The demarcation between short- and long-term is one year.

Q. Are these the definitions as you understood them to be at the time that the FAC tariff was proposed, considered by the Commission, and ultimately approved by the Commission, as well as at the time that the AEP and Wabash agreements were executed?

A. Yes.

Q. Are the AEP and Wabash contracts in fact long-term partial requirements sales?

A. Yes they are. The contracts themselves, which I have attached as Schedules JH-S1 and JH-S2, have terms of 15 months (AEP) and 18 months (Wabash). Consequently they are long-term under the commonly accepted use of that term in the wholesale electric marketplace, and as the Company has consistently used that term in connection with its activities related to wholesale power marketing. The contracts also specifically provide that the firm capacity and energy sold under the contracts will be used to meet load obligations of the purchasers. This is the commonly understood meaning of a partial requirements sale, as I noted earlier, and it is how the Company has consistently used that phrase in connection with its activities relating to wholesale power marketing. The Wabash contract states: "The Buyer shall use the Product [capacity and energy] to partially meet the requirements of Citizens Electric Corporation in Missouri." The AEP contract states: "The Capacity and Energy provided by AmerenUE herein will enable AEP to partially meet load serving requirements," and the "Trade Type" is identified as "PHYSICAL Capacity and associated energy (Partial Requirements—Baseload)." As a consequence of both the contract terms and the nature of the contracts, both contracts are partial requirements sales contracts.

Q. Missouri Industrial Energy Consumers ("MIEC") witness Maurice Brubaker argues that the words in the contract have "no meaning as to the character of the service provided," and that "[c]alling these transactions requirements service does not make them so anymore [sic] than calling a dog a duck makes it quack." (Brubaker direct, p. 6, lines 13-14). Is Mr. Brubaker correct?

A. No, Mr. Brubaker is incorrect. These words constitute the terms of the service contract that define the products and services that the seller has agreed to provide and that the purchaser has agreed to purchase. In this case, Ameren Missouri agreed to provide capacity and energy to partially meet the load obligations of the purchasers, and the purchasers agreed to purchase capacity and energy in order to meet those load obligations. Including terms in a contract that define the character of the service provided is not the equivalent of calling a dog a duck.

Q. Are these contracts, in substance, partial requirements contracts?

A. Yes, they are. As indicated in the agreements, capacity and energy from the Wabash contract is to be used to partially meet the load obligations of one of its members, Citizens Electric Corporation ("Citizens"), which is a large electric cooperative that serves more than 20,000 customers in Southeast Missouri. Wabash is the not-for-profit cooperative that acquires capacity and energy on behalf of its members, including Citizens, which use that capacity and energy to meet their load obligations. Capacity and energy provided under the AEP contract is to be used to partially meet the load obligations of the AEP Operating Companies, which consist of electric utilities serving more than 5 million customers in 11 states.

Q. What is the basis for the other parties' contention that the AEP and Wabash contracts are not long-term partial requirements contracts?

A. Many of the parties rely on their interpretation of definitions for the phrases "long-term service" and "requirements service" contained on page 310 of the Federal Energy Regulatory Commission's ("FERC") Form 1, which is the annual report for electric companies used by FERC and adopted by the Missouri Public Service Commission. For reporting purposes only, this form classifies contracts as short-term (less than one year), intermediate term (1-5 years) and long-term (greater than 5 years). Form 1 also applies a definition of "requirements service" which ties to a utility's resource planning process.

Q. Is the FERC Form 1 relied upon by the wholesale electric market as a reference for contract negotiations?

A. No. In my 12 year career in wholesale power marketing and trading, I have never once heard any reference to FERC Form 1 (by those engaged in power marketing at Ameren Missouri or by other market participants), let alone the definitions found at page 310, in negotiating the terms and conditions of wholesale power contracts.

Q. Is it appropriate to use the definitions of "long-term" and "requirements service" contained in FERC Form 1 to interpret Ameren Missouri's FAC tariff?

A. No, it is not. The delineations between categories of contracts for annual reporting purposes contained in Form 1 bear no resemblance to the definitions of those terms used in the modern wholesale marketplace for electric energy, and no relationship to the common meaning of the terms "long-term" and "requirements." The FERC Form 1 contract categories date back at least to 1990, years before the modern open access market for electricity existed. I have attached as Schedule JH-S3 a copy of page 310 of Union Electric Company's 1990 Form 1 which shows the use of these terms in the reporting form has not changed over the last 20 years.

Q. Has the wholesale market for electric energy changed since the definitions of "long-term" and "requirements service" were first included in the definitions used for the Form 1 Report?

A. Yes, the wholesale market has changed dramatically since those definitions were first included. The definitions included in the Form 1 predate both the Energy Policy Act of 1992 and FERC Order 888, which fundamentally changed the wholesale market for electricity in the United States. The Energy Policy Act of 1992 laid the foundation for the eventual deregulation of the wholesale market for energy in North America by requiring utility companies to allow external entities fair access to electric transmission systems, thereby enabling large energy customers to choose their electric supplier. The FERC adopted Order 888, as well as a series of related orders, in the late 1990s to ensure the objectives of the Energy Policy Act were implemented through standards mandating fair and open access to transmission. In short, the modern wholesale market for electricity bears little resemblance to the market that existed when the definitions of "long-term" and "requirements service" were first adopted for reporting purposes in the Form 1 report.

Q. Do participants in the electric markets refer to contracts with a term of 1-5 years as "intermediate term" contracts?

A. No. In the 12 years that I have marketed and traded power, I do not recall ever hearing the phrase "intermediate term" used to describe a contract, let alone specifically one with a term duration of 1-5 years (as defined on page 310 of the FERC Form 1), until this proceeding. In the electric marketplace, the demarcation point between long-term and short-term is one year.

Q. Do other witnesses acknowledge that one year is the demarcation point between long-term and short-term power contracts in the market?

A. Yes. MIEC witnesses Brubaker and Henry Fayne both acknowledged this fact in their depositions. Mr. Brubaker stated, "[a]nd I just know that in the market today, a lot of people talk of one year as being a dividing point for long-term versus short-term." Deposition of Maurice Brubaker, p. 64, l. 6-9. Similarly, Mr. Fayne stated, "I also understand having worked with traders that a year or more is often considered long-term". Deposition of Henry Fayne, p. 40, l. 12-14.

Q. Does FERC itself use the definitions appearing on page 310 of the FERC Form 1 in differentiating between long-term and short-term contracts?

A. No. In its decisions dating back to at least 2002, FERC has completely ignored the reporting convention in its Form 1 and has consistently used one year as the demarcation between short-term and long-term contracts. The FERC made this abundantly clear in its order in Docket No. RM06-10-001, issued June 22, 2007--less than a year before Ameren Missouri's filing in Case No. ER-2008-0318 (the case in which the FAC tariff in effect during the accumulation period for this prudence review was approved)--FERC described its consistent use of this demarcation between long- and short-term contracts:

> Additionally, the Commission at the time of enactment of EPAct 2005 had for years defined long-term contracts under the OATT as one year or longer. Similarly, the Commission has treated power sales with a contract term of greater than one year to be "long-term" for reporting purposes. See, e.g., Revised Public Utility Filing Requirements, Order No. 2001, 667 FR 31043, FERC Stats.& Regs. par. 31,127 (2002), Order No. 2001-A, 100 FERC par. 61,074, reconsideration and clarification denied, Order No. 2001-B, 100 FERC par. 61, 342 (2002). ***We thus believe it is reasonable to use the convention of treating contracts of a year or more as "long-term" consistent with our longstanding practice.*** (emphasis added.)[1]

Additionally, the FERC's Electronic Quarterly Report ("EQR") data dictionary states: "Contracts with a duration of one year or greater are long-term. Contracts with shorter durations are short-term." (***Re: Revised Public Utility Filing Requirements for Electric Quarterly Reports***, "Order Revising Electric Quarterly Report Data Dictionary," 125 FERC ¶ 61,103 (2008) p. 33). All public utilities and power marketers must file EQRs for each calendar quarter. The filings must summarize contractual terms and conditions for market-based power sales, cost-based power sales, and transmission service. EQRs provide a detailed, comprehensive view of the wholesale power markets on a transaction-by-transaction basis. Unlike FERC Form 1, the information from EQR reports is regularly reviewed and utilized by wholesale power market participants. The

[1] *Re: New PURPA 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities,* 119 FERC ¶ 61,305 (2007) footnote 17, page 18-19.

Kirkwood, Kahoka, Marceline, Perry, AEP and Wabash contracts are categorized as long-term firm contracts in this report.

There are also numerous FERC orders in individual cases that reflect the common definition of one year for long-term contracts. For example, in its order in the *Mountainview Power* case, FERC stated:

> While we are conditionally accepting the PPA on the basis that it is consistent with the Commission's current policy, we will henceforth require that all affiliate ***long-term (one year or longer) power purchase agreements***, whether at cost or market, be subject to the conditions set forth in Edgar. (emphasis added.)[2]

Q. Why does FERC Form 1 continue to categorize contracts as short-term, intermediate-term and long-term when these categories are not used by FERC in other contexts?

A. I don't know why FERC chose those classifications 20 years ago. Those classifications are simply a vehicle for data collection for that particular report. FERC Form 1 could require that contracts be divided into 3 or 5 or 20 different categories, but that reporting convention would not affect what is a long-term or short-term contract in the marketplace, or how FERC uses the term in other contexts pursuant to its longstanding practice. The FERC Form 1 instructions are for the limited purpose of completing page 310 of the form. Those definitions never applied to or limited the use of the term "long-term" as it is currently used in the wholesale power market. In particular, they have never formed the basis of Ameren Missouri's understanding of the meaning of "long-term" in the wholesale marketplace.

[2] *Re: Southern California Edison Company, On Behalf of Mountainview Power Company LLC,* "Order Conditionally Accepting Proposed Rate Schedule and Revising Affiliate Policy," 106 FERC par. 61,183, paragraph 58 (2004).

Q. Is there other evidence that the standard definition of long-term is one year or longer?

A. Yes. In other areas of the electric business, one year is consistently used as the demarcation point between long-term and short-term. Both the Midwest Independent Transmission System Operator, Inc. ("MISO") tariff as well as FERC's pro forma Open Access Transmission Tariff ("OATT") define long-term point-to-point electric transmission as one year or longer. Additionally, the North American Electric Reliability Corporation ("NERC") Glossary of Terms Used In Reliability Standards defines a Resource Planner as: "The entity that develops a ***long-term (generally one year and beyond)*** plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area." (emphasis added.) See Schedule JH-S4. Even the Ameren Missouri FAC tariff at issue in this case uses one year as the demarcation point between capacity contracts whose costs are included as purchased power expense and flowed through the FAC and those whose costs are not included as purchased power expense and are thus excluded from the FAC. (See Original Sheet No. 98.3, definition of "CPP"). This is a clear recognition that one year is the appropriate demarcation between long-term and short-term capacity.

Outside the context of power sales and transmission, long-term is also regularly used to describe contracts of one year or more. For example, as Ameren Missouri witness Gary Weiss testifies, this Commission considers debt instruments with a term of one year or longer to be long-term debt in establishing the capital structures for all utilities.

Q. Notwithstanding that one year is used by wholesale power market participants, by the FERC and in other contexts as the demarcation between long-term and short-term contracts, is it possible that the FAC tariff at issue in this case was meant to incorporate the definition of long-term contracts (5 years) contained on page 310 of the FERC Form 1?

A. No, that is not possible. When Ameren Missouri originally proposed the FAC tariff, when it was being considered by the parties to Case No. ER-2008-0318, and when the Commission ultimately approved the tariff in that case, the scope of the exclusion from "OSSR" was clearly meant to be broad enough to encompass the municipal contracts with the cities of Kirkwood, Marceline, Perry and Kahoka that were in existence at the time the tariff was approved. All parties apparently agree with this because no party argues that it was improper for Ameren Missouri to exclude the revenues from those municipal contracts from OSSR for the period at issue in this prudence review proceeding. But only one of those contracts, the contract with the City of Perry, had a term of five years or longer. The contracts for Kirkwood (29 months), Marceline (36 months), and Kahoka (36 months) had significantly shorter terms.[3] The intended meaning of long-term in the FAC tariff had to be less than five years, or these contracts would not have qualified for the exclusion. Consequently it is not possible that the tariff could have been based on consideration of the definition of long-term (5 years) found on page 310 of FERC Form 1.

[3] Ameren Missouri's municipal contracts have sometimes been shorter than the AEP and Wabash contracts. For example, in October 2009, Ameren Missouri and the City of Kirkwood entered into a separate partial requirements agreement with a term of 14 months. In 2008, Ameren Missouri entered into a partial requirements contract with the City of Kahoka for a term of *22 days*.

Those who argue that the AEP and Wabash contracts are included in factor OSSR cannot have it both ways; that is, they can't claim the FERC Form 1 reporting instruction definition of five years or longer for long-term controls, but at the same time exclude contracts with terms of less than five years (29 months, 36 months and 36 months) from OSSR. This conclusively shows that the FERC Form 1 instructions had nothing to do with the meaning of the phrase "long-term full and partial requirements sales" in the FAC tariff.

Q. What is Staff witness Mantle's view of "long-term" in this context?

A. Ms. Mantle's view of "long-term" is a bit confusing. In her deposition, she stated that she could not say what the Commission's definition of "long-term" was when Ameren Missouri's FAC tariff took effect, but in her opinion "long-term" meant 5 years or greater at that time. Deposition of Lena Mantle, p. 30, l. 9-13. However, Ms. Mantle later opined that the definition of "long-term" has evolved since the Commission issued its order in Case No. ER-2008-0318, on January 27, 2009. She stated: "With the opening of the wholesale electric markets and the ability to buy on the spot purchase, spot market, utilities are reluctant to offer long-term contracts, and so where in the past it may have been a five year would be long term, now three years is about the longest that I've seen." Deposition of Lena Mantle, p. 31, l. 2-7. She attributes this evolution in the definition of "long-term" between January 27, 2009 and today, to "[t]he evolution of the electric market. It was still in what you might call infancy. It was emerging at that time." Deposition of Lena Mantle, p. 31, l. 17-19.

Q. What is your response to Ms. Mantle's views on the meaning of "long-term"?

A. Ms. Mantle's views of the meaning of "long-term" are completely at odds with the meaning used in the marketplace, FERC's longstanding practice and by the Staff itself in the context of this case, since the Staff has not attempted to reclassify the Kirkwood contract, which has a term of less than three years. Ms. Mantle's testimony that the marketplace was "in its infancy" in 2009 evidences a lack of understanding about the wholesale power market, which has been in existence in its modern form since the mid-1990's. Although the market continues to evolve, it was certainly no longer in its infancy by 2009. And the demarcation between short-term and long-term contracts in this market is and has consistently been one year; this demarcation is not evolving.

Q. Turning now to the debate about the definition of a "partial requirements" contract, you previously stated that this term refers to the seller's obligation to provide resources sufficient to meet part of the purchasing entity's load obligation during the term of the agreement. Is there support for this definition?

A. Yes. Based on my years of experience as a marketer and trader of power, this is the definition of a partial requirements contract that market participants use. This definition is also supported in industry publications. For example, the Electric Energy Inc. ("EEI") Glossary of Electric Industry Terms, p. 115, defines "Partial Requirements" as "a wholesale customer who purchases, or is committed to purchase, only a portion of its electric power generation need from a particular entity. There often is a specified contractual ceiling on the amount of power that a partial requirements customer can take from the entity. In contrast, a 'requirements' or 'full requirements' customer is committed to purchase all of its needs from a single entity and generally would not have a ceiling on the amount of power it can take." Similarly, the North American Energy Standards Board ("NAESB") Wholesale Electric Quadrant ("WEQ") Glossary defines "Partial Requirements" as "a sale of power to a purchaser in which the seller pledges to meet a specified part of the purchaser's requirements." Copies of the EEI and NAESB definitions are attached as Schedule JH-S5.

These definitions are intuitive. They make common sense based on the plain meaning of the words "partial" and "requirements." Webster's Dictionary defines "partial" as "of or relating to a part rather than the whole; not general or total," and it defines "requirement" as "something required; something wanted or needed; necessity; something essential to the existence or occurrence of something else." Webster's Ninth New Collegiate Dictionary. So it makes logical sense that a partial requirements power contract would be a contract that provides part of the power and energy needed by the purchasing entity to meet its load obligations.

Q. Have any of the other witnesses indicated whether they agree with this definition of partial requirements sales?

A. Yes. In her deposition, Staff witness Lena Mantle defined "long-term requirements sales" as simply "[a] contract to provide electricity. Just using the phrase long-term requirement, to me that would be three to five years, and ***there would be some requirements for providing electricity***. I don't know what may be part of that in addition. It could vary quite a bit." Deposition of Lena Mantle, p. 33, l. 1-8 (emphasis added.) When asked to define the phrase "long-term partial requirement sale" Ms. Mantle stated: "Partial can mean ***part of the person who's signing the contracts requirements, not necessarily fulfilling all their needs***," and at another point in the deposition stated: "It would be three to five years, ***anything less than full.***" Deposition of Lena Mantle, p. 35, l. 12-14; p. 42, l. 1-5 (emphasis added.) When again asked about her definition of requirements sales, Ms. Mantle admitted: "***standing on its own, it could be a contract such as what they [Ameren Missouri] signed with AEP and Wabash because you're not fulfilling all the requirements of AEP and Wabash.***" Deposition of Lena Mantle, p. 35, l. 21-p. 36, l.1 (emphasis added.) However, she then offered her opinion that the AEP and Wabash contracts at issue in this case would not qualify as <u>long-term</u> requirements sales only "because they weren't long enough." Deposition of Lena Mantle, p. 35, l. 15-p. 36, l. 5. Although Ms. Mantle takes issue with the definition of long-term, it is clear from her deposition that she supports definitions of "requirements sales" and "partial requirements sales" that are entirely consistent with my view of those terms. In fact, she specifically acknowledges that contracts such as Ameren Missouri's contracts with AEP and Wabash qualify as partial requirements contracts. Couple her admission that the AEP and Wabash contracts are partial requirements contracts with the fact that long-term means one year or longer (and must mean one year or longer given the other contracts that are excluded from OSSR) and Ms. Mantle's theory that the AEP and Wabash contracts are included in OSSR falls apart.

Q. Have other witnesses supported this definition of partial requirements?

. A. Yes. MIEC witnesses Brubaker and Fayne both provided characterizations of partial requirements in their depositions which are consistent with and support this definition. When asked what the distinction between full and partial requirements service was, Mr. Brubaker stated, "In general, full requirements service means that the selling party is the sole source of the generation to the seller or to the purchaser. ***Partial requirements would mean that there is a division of responsibility for generation. It could be either that the purchasing party has some of its own generation or that it has supply contracts with more than one seller.***" Deposition of Maurice Brubaker, p. 72, l. 1-8 (emphasis added.) Mr. Brubaker also characterized a partial requirements contract as "***something that's more bare-bones where the utility or the customer may purchase a block of power and then do hourly denominations (sic) for the difference.***" Deposition of Maurice Brubaker, p. 23, l. 20-23 (emphasis added.)

Q. What testimony did Mr. Fayne provide on this subject during his deposition?

A. Mr. Fayne also supported a common-sense definition of partial requirements sales in his deposition. Specifically, he defined "long-term partial requirements sales" as "***sales that are made to another entity that only meet part of that entity's requirements***" Deposition of Henry Fayne, p. 42, l. 10-12 (emphasis added.) He also stated that "***(r)equirement sales are any sales to either an end user, i.e. to retail customers, or to a wholesale purchaser who will resell that power or has an obligation for that power to its own customers. That is what requirements means. It's an obligation to meet some – it is a requirement to meet some obligation of load***" and "***they could also be a sale to AEP for six months helping them meet some of their pressure (sic) requirements.***" Deposition of Henry Fayne, p. 44, l. 18- p. 45, l. 4 (emphasis added.) Finally, he admitted that "***any transaction to a load-serving entity is at least a partial requirements contract regardless of duration.***" Deposition of Henry Fayne, p. 61, l. 21-23 (emphasis added.)

Q. As previously discussed, several of the witnesses in this case rely on the definition "requirements service" contained in FERC Form 1 to argue that the AEP and Wabash contracts do not qualify as long-term partial requirements service. Do you have any further comment on this?

A. Yes. First, to state the obvious, FERC Form 1 does not contain a definition for "partial requirement sales" let alone for "long-term partial requirement sale." Second, let me reiterate that the 20-year-old FERC Form 1 definition of "requirements service" is not the appropriate definition to use for purposes of classifying the AEP and Wabash contracts. It does not match the definition of requirements service commonly used in the modern marketplace, and does not comport with the plain meaning of the word "requirements" as contemplated in Ameren Missouri's tariff. Moreover, as I previously discussed, it is clear that the FERC Form 1 definitions were not being relied upon when the FAC tariff was drafted and approved. Otherwise, all but one of the Company's municipal contracts would have been reclassified because they do not meet the definition of "long-term" contained in Form 1. Since the Form 1 definition of "long-term" was not being considered when the Company's FAC tariff was developed and adopted, it is not reasonable to believe the definition of "requirements service" that appears on the same page of Form 1 was being considered. In other words, these FERC Form 1 instructions either formed the basis for the meaning of the phrase "long-term full and partial requirements sales" in the Company's FAC tariff or they did not. Neither Staff nor the other parties can pick and choose one FERC Form 1 definition (e.g., "requirements service") while ignoring the other (e.g., "long-term").

Q. What do the instructions on page 310 of FERC Form 1 provide regarding "requirements service"?

A. Form 1 states: "Requirement service is service which the supplier plans to provide on an on-going basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as or second only to the supplier's service to its own ultimate consumers."

Q. Do Ameren Missouri's contracts with AEP and Wabash meet these standards for requirements service?

A. Arguably they do. First, the load obligation represented by these agreements actually has been included in Ameren Missouri's various system resource planning efforts – including the Integrated Resource Plan ("IRP"). Secondly, these agreements were firm obligations, and thus second only to our own load in terms of reliability.

Q. Are you suggesting that these specific agreements were included in Ameren Missouri's most recent IRP?

A. No. As discussed in more detail in the surrebuttal testimony of Ameren Missouri witness Steven Wills, Ameren Missouri is required to submit an IRP to the Commission once every three years. The IRP reflects a snapshot in time that shows Ameren Missouri's resource plan at that moment. Ameren Missouri's last IRP, filed in Case No. EO-2007-0409, was submitted in February 2008 and included load projections prepared before that date – and more than two years before the AEP and Wabash contracts were consummated. The fact that it was not possible for the specific contracts with AEP and Wabash to be considered in Case No. EO-2007-0409 because they were not in existence at the time of the filing does not mean that those contracts cannot qualify as partial requirements sales. Indeed only one of the municipal contracts excluded from OSSR was in existence at the time of Ameren Missouri's last IRP filing, yet all parties to this case agree that all of the municipal contracts qualify as long-term full or partial requirements sales. Moreover, as noted by Mr. Wills in his surrebuttal testimony, the 2008 IRP did not project loads for *any* full or partial requirements customers – municipalities or otherwise - beyond December 31, 2008. In fact Ameren Missouri stopped providing service to two of those municipal customers following the expiration of their contracts on December 31, 2008.[4]

Q. Do any of the witnesses representing other parties in this case provide support for your position that a specific agreement does not need to be included in the IRP to meet the definition of a partial requirements sale or contract?

A. Yes. In his deposition, MIEC witness Brubaker was asked if "system resource planning" meant the IRP and only the IRP in his mind, or if there are other aspects of system resource planning that could be involved. In his response he stated, "I would think that they would be generally reflected in the IRP process because the IRP includes load obligations and projected loads. I wouldn't say that a specific particular agreement had to be included in an IRP at a point in time because it's a dynamic world that we live in." Deposition of Maurice Brubaker, p. 68, l. 10-18. He also agreed that "whether that particular contract or even that particular customer's load appears in the latest IRP is not necessarily determinative as to whether it is a requirements contract." Deposition of Maurice Brubaker, p. 69, l. 12-16.

[4]Ameren Missouri executed new contracts with Kirkwood, Kahoka and Marceline, but did not execute new contracts with Hannibal and Centralia.

Q. Was the load associated with the AEP and Wabash agreements in fact included in Ameren Missouri's most recently concluded IRP?

A. Yes. In his surrebuttal testimony Mr. Wills explains that the AEP and Wabash contracts simply reflect a sale of the same megawatt-hours as the Noranda load lost due to the January 2009 ice storm. The load associated with the AEP and Wabash contracts simply replaced the lost Noranda load. As noted previously, that load was included in Ameren Missouri's IRP filing in Case No. EO-2007-0409.

Q. Do you have any final observations regarding the notion that load for a specific power supply agreement must be projected in an IRP in order for that agreement to qualify as a long-term partial requirements sale?

A. Yes. As Mr. Wills explains in his surrebuttal testimony, although Ameren Missouri's 2008 IRP filing did not project load for any of the municipal agreements beyond December 31, 2008, no party has argued that Ameren Missouri's municipal agreements do not qualify as long-term full or partial requirement sales. If the fact that Ameren Missouri did not include its municipal contracts in the 2008 IRP filing does not disqualify those contracts as long-term full or partial requirements sales, then Staff and the intervenors cannot credibly argue that failure to specifically include the AEP and Wabash contracts in that same IRP filing disqualifies them as long-term full or partial requirements sales. Staff and the intervenors simply cannot have it both ways.

Q. Aside from the IRP, were the AEP and Wabash loads considered in Ameren Missouri's resource planning?

A. Absolutely. As I previously stated, the IRP merely reflects a snapshot of Ameren Missouri's resource plan at a point in time. An IRP is not the embodiment of the ongoing system resource planning process. Ameren Missouri engages in resource planning on a continuous basis, and the AEP and Wabash contracts were important considerations in that planning process. For example, the MISO requires Ameren Missouri to demonstrate on a monthly basis that it has sufficient "Planning Resource Credits" to cover its firm demand (load and sales) plus an applicable reserve margin. This demonstration must be made in a "Module E" compliance submission to the MISO. Ameren Missouri accounted for the AEP and Wabash contracts in its Module E filings. This is just one example of how Ameren Missouri engaged in system planning that accounted for both the AEP and Wabash loads. In addition, Ameren Missouri included these loads in its annual and monthly capacity position calculations, load forecasting, fuel budgeting and risk management position calculations. These are all elements of system resource planning.

Q. You also characterize the AEP and Wabash agreements as having a reliability of service second only to the service provided to Ameren Missouri's own customers. Can you explain further?

A. Yes. The Wabash contract specifically addresses this issue. Paragraph 19 of the contract states in relevant part: "Seller agrees that it will consider Buyer equivalent to Seller's native load customers and agrees that the Product that it will provide to Buyer, pursuant to this Agreement, will be System Firm power with the same quality as the electric power that the Seller provides to its firm retail customers." The AEP contract provides for the sale of "Firm LD Capacity as that term is defined in the Edison Electric Institute MISO Module E Capacity Transaction Confirmation, Version 1.0--October 20, 2008 incorporated herein by this reference and associated Firm LD

Energy." The level of service required by each of those agreements is the same as, or second only to, the service provided to Ameren Missouri's own customers.

Q. On pages 4 and 5 of his direct/rebuttal testimony, MIEC witness Brubaker points out that under the AEP and Wabash contracts Ameren Missouri is not providing various RTO and OATT services, and implies that this fact is relevant to whether the AEP and Wabash contracts are requirements contracts. Do you agree?

A. No. The schedules Mr. Brubaker has supplied simply show that Wabash, and not Ameren Missouri, is responsible for various RTO and OATT charges. Whether Ameren Missouri pays these charges and then bills Wabash, or Wabash pays them directly, has nothing to do with whether the contract is a partial requirements contract. More importantly, I would note again that the AEP and Wabash agreements are partial requirements sales and as such one should not expect them to provide the full scope of products and services provided under a full requirements contract.

I have attached as Schedule JH-S6 some examples of other requirements contracts where the purchaser, not the seller, is responsible for some of these RTO and OATT services, including an agreement with the City of Kirkwood, which the Commission itself has described as a full requirements wholesale customer.[5]

Q. Other parties to this case have noted that on its 2009 Form 1 report Ameren Missouri classified its municipal power supply agreements as "RQ," which indicates they are requirements service for purposes of Form 1, but did not classify

[5] *Comments of the Missouri Public Service Commission Regarding the Department of Energy's 2009 Transmission Congestion Study and the Designation of National Interest Electricity Transmission Corridors*, p. 6, footnote 2, presented at the June 18, 2008 Pre-Congestion Study Regional Workshop in Oklahoma City, Oklahoma. See Schedule JH-S7.

either the AEP or Wabash contracts the same way. Why did Ameren Missouri not classify the AEP and Wasbash agreements as RQ?

A. I am not responsible for completing FERC Form 1 but I would note that in response to Staff data request MPSC 53.1, our accounting staff stated that the AEP and Wabash contracts were not reported as "RQ" on the FERC Form 1 because they "...did not meet the definition of RQ since those transactions were not included in the supplier's (i.e. Ameren Missouri's) system resource planning since Ameren Missouri's last system resource plan was prepared prior to the loss of the Noranda load and consequently prior to entering into these contracts. Consequently, under the FERC Form 1 instructions these transactions were not "RQ" for reporting purposes, although they are requirements transactions." It is obvious to me that the standard utilized by accounting did not permit a transaction to be labeled "RQ" unless it appeared in the Company's most recent Integrated Resource Plan.

Q. Are you suggesting that the Company's accounting staff applied the wrong standard in reporting contracts as "RQ"?

A. Perhaps. The accounting department established procedures for completing page 310 of Form 1 that used a simple litmus test to determine whether contracts should be reported as "RQ": whether the customer was mentioned in the Company's most recent IRP. Although it may be logical and understandable to use such a simple litmus test in filling out a reporting form, as my testimony indicates, I believe that "system resource planning" involves more than just the IRP. If additional system resource planning activities had been taken into consideration, in my opinion the AEP and Wabash contracts would have been reported as "RQ." However, whether these contracts were reported as "RQ" or not does not change the fundamental nature of these contracts; they are requirements contracts because they serve the load obligations of the purchasers.

Q. On page 6 of her direct/rebuttal testimony, Staff witness Lena Mantle states: "To my knowledge, contracts like the AEP and Wabash contracts have never been included in the calculation of jurisdictional allocation factors in any Ameren Missouri rate case or in Ameren Missouri's resource planning process." Is Ms. Mantle correct?

A. No. As Ameren Missouri witness Gary Weiss explains in detail in his surrebuttal testimony, contracts similar to the AEP and Wabash agreements have been included in jurisdictional allocation factors in previous Ameren Missouri rate cases. For example, contracts for wholesale power sales to Missouri electric cooperatives, including Citizens, have been included in the allocation in previous rate cases. Also, contrary to Ms. Mantle's recollection, partial requirements contracts for wholesale power sales to out-of-state regulated electric utilities, such as Arkansas Power & Light Company and Illinois Power Company, have also been included in the allocation. In fact, the AEP and Wabash contracts themselves were included in the jurisdictional allocation in Ameren Missouri's filing at the beginning of its last rate case, Case No. ER-2010-0036.

Q. In her direct/rebuttal testimony in this case, Ms. Mantle claims that someone at Ameren Missouri told her the phrase "long-term full and partial requirements sales" used in the definition of "OSSR" that is at issue in this case was limited to sales to municipal utilities. Is Ms. Mantle's recollection correct?

A. No, Ms. Mantle's recollection is not correct. During her deposition Ms. Mantle was asked who from Ameren Missouri told her the phrase "long-term full and partial requirements sales" was limited to sales to municipal utilities and when the statement was made. In response, Ms. Mantle said she could not recall who made the statement or when. She also stated that she could find no notes of the alleged conversation. Deposition of Lena Mantle, p. 24, l. 18-p. 25, l. 8; p. 26, l. 3-6. I would also note that Ms. Mantle never requested that the Company modify its tariff language to include this "Missouri municipality" restriction. Making this modification would have been simple, especially if, as Ms. Mantle would have the Commission believe, the Company actually intended that restriction to apply. I can only conclude from these facts that Ms. Mantle's recollection of this alleged conversation is faulty.

Q. Does it make sense that someone from Ameren Missouri would have stated that the Company intended that the definition of requirement sales used in the FAC tariff be limited to transactions with municipalities?

A. No, it does not.

Q. Why do you believe such a statement does not make sense?

A. I believe such a statement does not make sense – and that no one from Ameren Missouri told Ms. Mantle such a limitation was intended – because Ameren Missouri has never limited its long-term requirements sales to transactions with municipalities. Certainly at the time the Company filed Case No. ER-2008-0318, the rate case in which the FAC tariff at issue in this case was approved, the only long-term requirements contracts then in effect were between Ameren Missouri and several municipalities. But as I noted previously, in the past Ameren Missouri has entered into long-term partial requirements contracts with cooperatives, such as Citizens, and other investor-owned utilities, such as Arkansas Power & Light Company and Illinois Power

Company. Given that history and the prospect that Ameren Missouri could enter into long-term requirements contracts with cooperatives or other utilities in the future, it would have made no sense for anyone from Ameren Missouri to tell Ms. Mantle that the phrase "long-term full or partial requirements sales" that was used in the company's FAC tariff was limited to sales to municipalities.

Q. Do other parties agree that long-term full or partial requirements sales are not limited to transactions between Ameren Missouri and municipal utilities?

A. Yes. During his deposition, Mr. Brubaker acknowledged that "if the transaction is structured in such a way that it's a requirements-type contract" that an agreement with a non-municipal utility could be included in the scope of the phrase "long-term full and partial requirements sales." Deposition of Maurice Brubaker, p. 51, l. 24-p.52, l. 4. At pages 3-4 of his direct/rebuttal testimony, Mr. Fayne acknowledges that "wholesale partial and full requirements contracts are long-term bilateral commitments with municipalities ***or other utilities***" (emphasis added.) He reinforced this in his deposition answering "No" when asked if "as the definition of long-term full or partial requirements sales, as it applies to Ameren, is it limited to contracts between Ameren and municipal utilities." Deposition of Henry Fayne, p. 42, l.13-16. In addition, during her deposition, Missouri Energy Group witness Billie Sue LaConte stated that a long-term full or partial requirement sale could involve an entity other than a municipal utility as long as the contract "meets the definition of long-term full or partial requirements contract." Deposition of Billie Sue Laconte, p. 55, l. 25-p. 56, l. 4.

Q. Please summarize your testimony.

A. The terms of the AEP and Wabash contracts make them long-term partial requirements sales contracts. They are long-term because their terms are greater than one year, which is the demarcation point between long-term and short-term widely used in the wholesale power markets and consistent with FERC's longstanding practice. There is really no credible support for the argument that these contracts are not long-term.

The AEP and Wabash contracts are also "partial requirements" contracts because they are firm contracts for capacity and energy that serve a portion of the load obligations of the purchaser. This meets the definition of partial requirements sales commonly used in the wholesale power markets. It is also consistent with the plain meaning of the term "partial requirements" and this definition was endorsed by the depositions of many of the witnesses in this case. Although it is not necessary to qualify as a partial requirements sale, the loads served under these contracts were also included in Ameren Missouri's system resource planning efforts, and the reliability of the service under the contracts is unquestionably the same as, or second only to, the reliability of service provided to Ameren Missouri's own ultimate customers.

Finally, it is clear that Ameren Missouri's FAC tariff could not have been based on the 20-year-old definitions of "long-term" and "requirements service" found on p. 310 of FERC Form 1, since many of the municipal contracts that all parties agree qualify as long-term requirements sales contracts do not meet these definitions.

Q. Does this conclude your surrebuttal testimony?

A. Yes it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the First Prudence Review of Costs Subject to the Commission-Approved Fuel Adjustment Clause of Union Electric Company, d/b/a AmerenUE.	))))	Case No. EO-2010-0255

AFFIDAVIT OF JAIME HARO

STATE OF MISSOURI)
) ss
CITY OF ST. LOUIS)

Jaime Haro, being first duly sworn on his oath, states:

1. My name is Jaime Haro. I work in the City of St. Louis, Missouri, and I am employed by Union Electric Company d/b/a Ameren Missouri as Director, Asset Management and Trading.

2. Attached hereto and made a part hereof for all purposes is my Surrebuttal Testimony on behalf of Ameren Missouri consisting of 26 pages, and Schedules JH-S1 through JH-S7 all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

[signature]
Jaime Haro

Subscribed and sworn to before me this 22 day of December, 2010.

Amanda Tesdall
Notary Public

My commission expires:

Amanda Tesdall - Notary Public
Notary Seal, State of
Missouri - St. Louis County
Commission #07158967
My Commission Expires 7/29/2011

Schedule JH-S1
is Highly Confidential
and has been removed in its entirety.

Schedule JH-S2
is Highly Confidential
and has been removed in its entirety.

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e. sales to purchasers other than ultimate consumers transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (pages 326-327).
2. Enter the name of the purchaser in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but less than five years.

SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means longer than one year but less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number *	Average Monthly Billing Demand (MW)	Actual Demand (MW) Average Monthly NCP Demand	Actual Demand (MW) Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Requirements Service					
2						
3						
4	Arkansas Power & Light Co	RQ	W-3	27	27	25
5		RQ	89			
6	California, MO	RQ	46 *			
7	Centralia, MO	RQ	36 *			
8	Citizens Electric Corp.	RQ	37 *			
9	Clarksville, MO	RQ	38 *			
10	Farmington, MO	RQ	39 *			
11		RQ	92			
12	Fredericktown, MO	RQ	40 *			
13	Hannibal, MO	RQ	35 *			
14	Illinois Power Co.	RQ	100			
15	Jackson, MO	RQ	W-4			
16	Kahoka, MO	RQ	48 *	2	2	2
17	Kirkwood, MO	RQ	51 *			
18	Linneus, MO	RQ	43 *	1	1	1
19	Malden, MO	RQ	W-4			
20	Marceline, MO	RQ	50 *			
21						
22						

 (Continued on Page 310A)

Schedule JH-S3

The newly approved terms are included in the shaded table rows below.

Glossary of Terms Used in Reliability Standards

February 12, 2008

Term	Acronym	Definition
Adequacy		The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
Adjacent Balancing Authority		A Balancing Authority Area that is interconnected another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
Adverse Reliability Impact		The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection.
Agreement		A contract or arrangement, either written or verbal and sometimes enforceable by law.
Altitude Correction Factor		A multiplier applied to specify distances, which adjusts the distances to account for the change in relative air density (RAD) due to altitude from the RAD used to determine the specified distance. Altitude correction factors apply to both minimum worker approach distances and to minimum vegetation clearance distances.
Ancillary Service		Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider's transmission system in accordance with good utility practice. (*From FERC order 888-A.*)
Anti-Aliasing Filter		An analog filter installed at a metering point to remove the high frequency components of the signal over the AGC sample period.
Area Control Error	ACE	The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error.
Arranged Interchange		The state where the Interchange Authority has received the Interchange information (initial or revised).
Automatic Generation Control	AGC	Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction.

Term	Acronym	Definition
Resource Planner		The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.
Response Rate		The Ramp Rate that a generating unit can achieve under normal operating conditions expressed in megawatts per minute (MW/Min).
Request for Interchange	RFI	A collection of data as defined in the NAESB RFI Datasheet, to be submitted to the Interchange Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority.
Right-of-Way (ROW)		A corridor of land on which electric lines may be located. The Transmission Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.
Scenario		Possible event.
Schedule		(Verb) To set up a plan or arrangement for an Interchange Transaction. (Noun) An Interchange Schedule.
Scheduled Frequency		60.0 Hertz, except during a time correction.
Scheduling Entity		An entity responsible for approving and implementing Interchange Schedules.
Scheduling Path		The Transmission Service arrangements reserved by the Purchasing-Selling Entity for a Transaction.
Sending Balancing Authority		The Balancing Authority exporting the Interchange.
Sink Balancing Authority		The Balancing Authority in which the load (sink) is located for an Interchange Transaction. (This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)
Source Balancing Authority		The Balancing Authority in which the generation (source) is located for an Interchange Transaction. (This will also be a Sending Balancing Authority for the resulting Interchange Schedule.)

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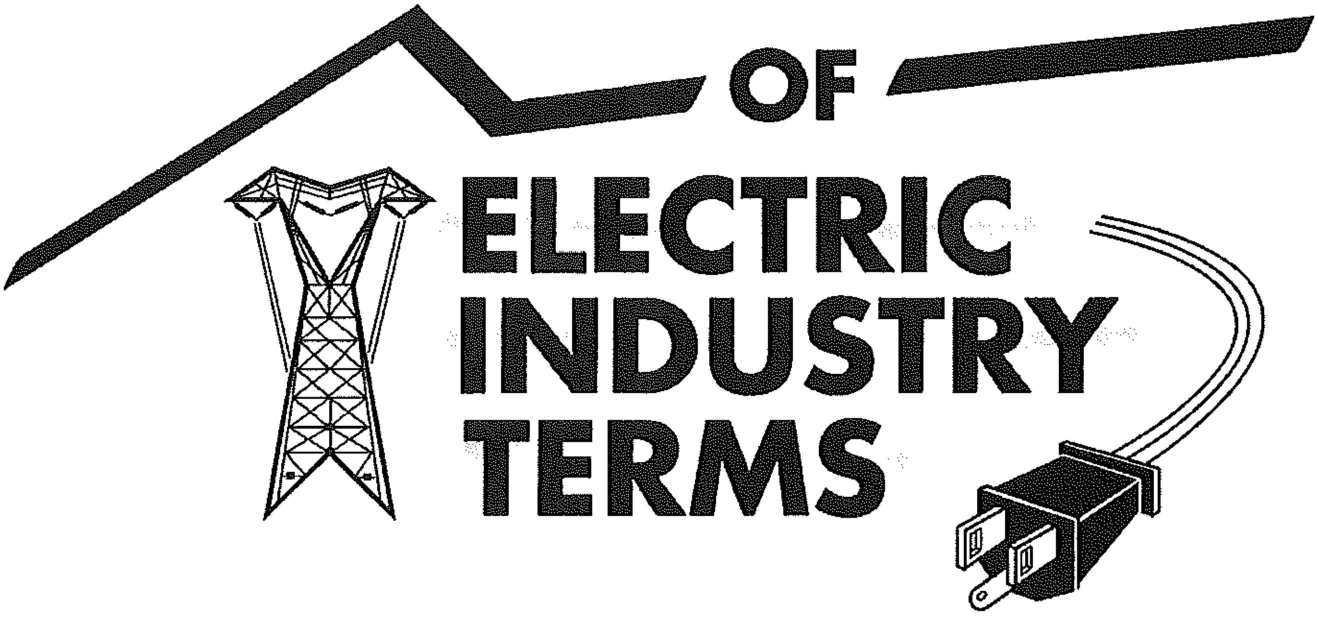

GLOSSARY OF ELECTRIC INDUSTRY TERMS

APRIL 2005

Schedule JH-S5

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ISBN: 0-931032-68-7

Published by:
Edison Electric Institute
701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
Phone: 202-508-5000
Web site: www.eei.org

Fuel Rod A long slender tube that holds fissionable material (fuel) for nuclear reactor use. Fuel rods are assembled into bundles called fuel elements or assemblies, which are loaded individually into the reactor core.

Full-Forced Outage The net capability of main generating units that is unavailable for load due to emergency reasons.

Full Requirements A wholesale customer (utility) that is committed to purchase all of its electric power generation from a single generator and generally there is not a ceiling on the amount of power purchased.

Full Service Provider A utility or company that provides both energy and delivery services of retail sales to ultimate consumers.

Fully Allocated Historical Cost An allocation of total costs (e.g., revenue requirement expenses, interest, taxes, and return) among all classes of service and jurisdictions using allocation bases reflecting demand, energy, and customer data and costs for a historical period of time. See also *Cost of Service Study*.

Fully Allocated Projected Cost Same as above, except based on future period of time.

Fume Airborne solid particles under one micron diameter, formed as vapors condense or as chemical reactions take place. The term is generally used to convey particles that are irritating, hazardous, and/or toxic.

Functional Accounts Groupings of plant and expense accounts according to the specified function or part they play in the rendition of utility service.

> **Electric Utility Plant Functional Plant Account** Includes Intangible, Production, Transmission, Distribution, and General Plant.
>
> **Operation and Maintenance Functional Expense Account** Includes Power Production, Transmission, Distribution, Customer Accounts, Customer Service and Information, Sales, and Administrative and General Expenses.

Functional Unbundling A rate design or corporate organization that offers generation, transmission, or distribution services as stand-alone services with separate charges.

Fictionalization The procedural step in a cost of service study that categorizes the supply costs related to the operating functions (e.g., generation, transmission, customer, and distribution). The next step is to classify the functionalized costs to categories reflecting cost incurrence. These categories are generally demand, energy, and customer costs.

Funded Debt The long-term debt that has arisen from the sale or assumption of debt securities with maturities of more than one year.

Funnel Sinking Fund The trustee may purchase bonds of any series outstanding under a mortgage in order to satisfy a sinking fund requirement. The requirement is stated as a percentage of the total debt outstanding in a year.

Local Distribution Utility (LDU) The utility that delivers electricity to a retail customer's home or business along the distribution poles, wires and other necessary equipment, that the LDU either owns or operates (formerly a local electric utility). See also *Default Service.*

Locational Marginal Pricing (LMP) Under the LMP proposal, the transmission provider establishes separate energy prices at each node on the transmission grid and separate prices to transmit energy between any two nodes on the grid. These prices reflect the cost of congestion and losses. The use of this congestion management system ensures that all transmission constraints are considered in developing day-ahead schedules and any congestion is reflected in the prices for energy and transmission services. See also *Standard Market Design and Structure.*

Long-Run A period of time long enough to permit the variation of all inputs to production, including capital and technological change.

Long-Run Incremental Cost (LRIC) See *Incremental Cost — Long Run (LRIC).*

Long-Run Marginal Cost (LRMC) See *Marginal Cost — Long Run (LRMC).*

Long-Term Debt Includes outstanding mortgage bonds, debentures, advances from associated companies, and notes which are due one year or more from date of issuance. The portion of such securities (inclusive of sinking fund requirements) that is due within one year from the date of the balance sheet is usually included in Current and Accrued Liabilities. Long-Term Debt to be refinanced within one year should continue to be reported under Long-Term Debt.

Long-Term Debt Due Within One Year See *Current Maturities* and *Long-Term Debt.*

Long-Term Financing Refers to the issuance and sale of debt securities with a maturity of more than one year, and preferred or common stock for the purpose of raising new capital or refunding outstanding securities.

Loop An electrical circuit that provides two sources of power to a load or substation so that if one source is de-energized the remaining source continues to provide power.

Loop Flows The unscheduled use of another utility's transmission resulting from movement of electricity along multiple paths in a grid, whereby power, in taking a path of least resistance, might be physically delivered through any of a number of possible paths that are not easily controlled. See also *Parallel Flow.*

Loss (Losses) Total electric energy losses in the electrical system. The losses consist of transmission, transformation, and distribution losses between supply sources and delivery points. Electric energy is lost primarily due to heating of transmission and distribution elements.

> **Average** The total difference in energy input and output or power input and output (due to losses) averaged over a time interval and expressed either in physical quantities or as a percentage of total input.
>
> **Demand** The kilowatts lost in the operation of an electric system at any instant.
>
> **Energy** The kilowatthours lost in the operation of an electric system.

P

Pancake Rates (Pancaking) See *Rates, Transmission Pricing — Pancake Rates.*

Paper Colloquially, refers to securities of a particular industry or sector. May also refer to commercial paper, in money market discussions.

Par (1) Price at 100%; (2) Face value assigned by a corporation to common, preferred or preference stock; (3) The principal amount or denomination at which the obligor issuing corporation contracts to redeem a debt security at maturity. This amount is stated on the face of the debt security.

Parallel Flow The flow of electricity according to the laws of physics: electricity flows on all available transmission paths between generators and points of use. The actual flow of electricity is referenced as flowing "parallel" to contractual paths (transmission paths) that are reserved for the flow of electricity, but are not actually used.

Parallel Operation (Parallel Generation) The operation of a customer-owned generator while connected to the utility's grid. Parallel operation may be required solely for the customer's operating convenience or for the purpose of delivering power to the utility's grid. This term is often used in reference to distributed generation.

Paralleling Equipment Generating and protective equipment system that interfaces and synchronizes a customer-owned generator with the distribution system facility. This term is often used in reference to distributed generation.

Partial Outage See *Outage — Partial Outage.*

Partial Requirements A wholesale customer who purchases, or is committed to purchase, only a portion of its electric power generation need from a particular entity. There often is a specified contractual ceiling on the amount of power that a partial requirements customer can take from the entity. In contrast, a "requirements" or "full requirements" customer is committed to purchase all of its needs from a single entity and generally would not have a ceiling on the amount of power it can take.

Participation Certificate (PC) A certificate representing an undivided interest in a pool of conventional mortgages. Principal and interest payments on the mortgages are passed through to the certificate holders each month. Participation certificates qualify as loans secured by an interest in real property and as qualifying real property loans with the respect to certain thrift institutions.

Particulate A particle of solid or liquid matter, also called soot, dust, and aerosols. Emissions of particulate matter are regulated by the Clean Air Act.

Payout Ratio The ratio of cash dividends on common stock to earnings available for common stock, based either on the actual dividends declared for a period or on the current indicated annual dividend rate.

PCBs (Polychlorinated biphenyls) A group of toxic, persistent chemicals used in electrical transformers and capacitors. Further sale or new use was banned in 1979 by law.

with another system or a substation where the transmission provider's transmission and distribution systems are connected to another system.

Point of Receipt A point on the electrical system where an entity receives electricity from a power supplier or wheeling entity. This point could include an interconnection with another system or generator busbar.

Point Source A stationary location where pollutants are discharged.

Point-to-Point Transmission A service that allows the customer to utilize a specified amount of transmission capacity to transmit power from designated points of receipt to designated points of delivery. A separate service agreement would be required and a separate charge generally would be paid for each pairing of a receipt point with a delivery point under this service.

Poison In reactor physics, a material other than fissionable material in the vicinity of the reactor core that will absorb neutrons to control or stop a nuclear reaction. The addition of poisons, such as control rods or boron, into the reactor is said to be an addition of negative reactivity.

Pole Miles Of Line Miles measured along the line of poles, structures, or towers carrying electric conductors regardless of the number of conductors or circuits carried. For underground lines, see *Conduit Bank Miles.*

Pollutant An impurity or contaminant emitted to the environment. It may be a solid, liquid, gas, or dissolved material. Environmental standards permit limited emissions of pollutants, because at low levels they are determined to be of negligible concern.

Pooling Company (POOLCO) An independent power pool company that operates for a group of utilities the electric transmission grid and may in some cases dispatch generating plants by buying and selling wholesale power. Although the individual utilities might continue to own portions of the transmission grid, the POOLCO would continually coordinate transmission use and may take bids from generators offering to sell electricity at specific prices. The POOLCO would then purchase the required energy and resell it to the electric distribution operations of the utilities at prices that reflect actual purchase costs that may vary by time of day.

Postage Stamp Rates See *Rates, Transmission Pricing — Postage Stamp Rates.*

Power (Electric) The time rate of generating, transferring, or using electric energy, usually expressed in kilowatts (kW).

> **Apparent** The product of the volts and amperes of a circuit. This product generally is divided by 1,000 and designated in kilovoltamperes (kVA). It comprises both real and reactive power.
>
> **Dump** See *Electric Energy — Dump.*
>
> **Firm** Power or power-producing capacity intended to be available at all times during the period covered by a commitment, even under adverse conditions.
>
> **Interruptible** Power made available under agreements that permit curtailment or cessation of delivery by the supplier. See also *Demand — Interruptible.*

Renewable Resources Any source of energy that is continually available or that can be renewed or replaced. Examples include wind, solar, geothermal, hydro, photovoltaic, wood and waste. Nonrenewable energy sources include coal, oil, and gas, that all exist in finite amounts.

Replacement Cost An estimate of the cost to replace the existing facilities either as currently structured or as redesigned to embrace new technology with facilities that will perform the same functions. This method recognizes the benefits of presently available technology in replacing the system. For example, a number of small generating units may be replaced with a single large unit at lower unit costs and greater efficiency. See also *Reproduction Cost.*

Replacement Power Power that a utility must purchase when one of its own plants (or other long-term suppliers) experiences an outage or is otherwise unavailable.

Replacements The substitution of a unit of Utility Plant for another unit generally of a like or improved character.

Repowering A means of increasing the output and efficiency of conventional thermal generating facilities. For example, adding combustion turbines to supplement or replace steam from fuel combustion used to power steam turbines.

Reprocessing See *Recycling.*

Reproduction Cost The estimated cost to reproduce existing properties in their current form and capability at current cost levels. The mechanics may involve a trending of the original cost dollars to reflect current costing factors, or they may involve a property appraisal accompanied by estimates to reconstruct the facilities. The former is most often utilized as Rate Base.

Repurchase Agreements (Repo) A means of temporarily adding to monetary reserves. The Fed buys government securities under a contract to sell them back at an agreed price and date. Generally repurchase agreements mature within one to seven days (maximum is 15 days). Dealers may usually repurchase before the maturity of the agreement if they wish. Interest rate is determined by auction.

Requirements Service Service that the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate customers.

Rerating A change in the capability of a generator due to a change in conditions such as age, upgrades, auxiliary equipment, cooling, etc.

Reregulation The design and implementation of regulatory practices to be applied to the remaining regulated entities after restructuring of the vertically-integrated electric utility. The remaining regulated entities would be those that continue to exhibit characteristics of a natural monopoly, where imperfections in the market prevent the realization of more competitive results, and where, in light of other policy considerations, competitive results are unsatisfactory in one or more respects. Regulation could employ the same of different regulatory practices as those used before restructuring.

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Schedule JH-S5

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Partial Requirements

NAESB Standard: NO **NAESB Standard Reference number:**

Source	**Definition**
McGuire Woods	A sale of power to a purchaser in which the seller pledges to meet a specified part of the purchaser's requirements.

Creation Date: 11/1/2004 **Last Revision Date:** 11/1/2004

Sections 1 and 2 of Schedule JH-S6 are Highly Confidential and have been removed.

FULL REQUIREMENTS SERVICE AGREEMENT

BETWEEN

MONONGAHELA POWER COMPANY
dba ALLEGHENY POWER

AND

COLUMBUS SOUTHERN POWER COMPANY

DATED

2372748v1

FULL REQUIREMENTS SERVICE AGREEMENT
Articles and Provisions

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EXHIBITS

FULL REQUIREMENTS SERVICE AGREEMENT

THIS FULL REQUIREMENTS SERVICE AGREEMENT ("Agreement" or "FSA") is made and entered into as of ____ ("Effective Date"), by and between Monongahela Power Company, dba Allegheny Power, hereinafter referred to as "Seller" and Columbus Southern Power Company, hereinafter referred to as "Buyer" (each hereinafter referred to individually as "Party" and collectively as "Parties").

WITNESSETH:

WHEREAS, the PUCO directed Buyer and Seller to explore the possibility of transferring the Subject Service Territory to Buyer; and

WHEREAS, Buyer and Seller have negotiated and executed an Asset Purchase Agreement dated ___, 2005 ("Asset Purchase Agreement") for the purchase of the Subject Service Territory by Buyer; and

WHEREAS, Buyer now has electric service obligations in the Subject Service Territory and desires to purchase Full Requirements Service through an Agreement with the Seller; and

WHEREAS, Seller desires to sell Full Requirements Service and Buyer desires to purchase such Full Requirements Service in the Subject Service Territory on a firm and continuous basis during the Delivery Period; and

NOW, THEREFORE, and in consideration of the foregoing, and of the mutual promises, covenants, and conditions set forth herein, and other good and valuable consideration, the Parties hereto, intending to be legally bound by the terms and conditions set forth in this Agreement, hereby agree as follows:

ARTICLE I
DEFINITIONS

In addition to terms defined elsewhere in this Agreement, the following definitions shall apply hereunder:

"Affiliate" means, with respect to any entity, any other entity that, directly or indirectly, through one or more intermediaries, controls, or is controlled by, or is under common control with, such entity. For this purpose, "control" means the direct or indirect ownership of fifty percent (50%) or more of the outstanding capital stock or other equity interests having ordinary voting power.

"ALM Operating Reserve Adjustment" shall have the meaning ascribed to it in Section 4.2(c) (Load Response Programs).

"Ancillary Services" shall have the meaning ascribed thereto in the PJM Agreements.

"Auction Revenue Rights" or "ARR" means entitlements allocated annually by PJM to firm transmission service customers under the PJM OATT that entitle the holder to receive an allocation of the revenues from PJM's annual FTR auction.

"Bankrupt" means, with respect to any entity, such entity: (i) voluntarily files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy, insolvency, reorganization or similar law; (ii) has any such petition filed or commenced against it by its creditors and such petition is not dismissed within sixty (60) calendar days of the filing or commencement; (iii) makes an assignment or any general arrangement for the benefit of creditors; (iv) otherwise becomes insolvent, however evidenced; (v) has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets; or (vi) is generally unable to pay its debts as they fall due.

"Business Day" means any day except a Saturday, Sunday or a day that PJM declares to be a holiday, as posted on the PJM website. A Business Day shall open at 8:00 a.m. and close at 5:00 p.m. Eastern Prevailing Time ("EPT").

"Capacity" means "Unforced Capacity" as set forth in the PJM Agreements, or any successor measurement of the capacity obligation of a Load Serving Entity as may be employed in PJM (whether set forth in the PJM Agreements or elsewhere).

"Closing" will have the meaning given to that term by the Asset Purchase Agreement.

"Congestion Revenue Rights" or "CRR" means the current or any successor congestion management mechanism or mechanisms as may be employed by PJM (whether set forth in the PJM Tariff or elsewhere) for the purpose of allocating financial congestion hedges.

"Costs" means, with respect to the Non-Defaulting Party, brokerage fees, commissions, PJM charges, and other similar third party transaction costs and expenses reasonably incurred by such Party either in terminating any arrangement pursuant to which it has hedged its DS Load obligations or entering into new arrangements that replace the Transaction upon termination; and all reasonable attorneys' fees and expenses incurred by the Non-Defaulting Party in connection with the termination of the Transaction.

"Default Service Load" or "DS Load" means the metered total sales adjusted to the generator level, plus Unaccounted For Energy, expressed in MWh for retail customers being served by Buyer in the Subject Service Territory, as such sales vary from hour to hour, as such territory exists on the Effective Date. For purposes of clarification, DS Load shall not include changes in the above mentioned service territory that occur as a result of a merger, consolidation, or acquisition of another entity or a result of a significant franchise territory swap with another entity.

"Delivery Period" means the period of delivery of the Full Requirements Service under this Agreement, beginning at the Effective Time and ending at 11:59 EPT on May 31, 2007.

"Delivery Point" means (i) prior to the "Delivery Point Aggregation Date," the LMP points in the PJM Control Area that make up the aggregate APS Zone, or any successor, superceding or amended aggregates for the APS Zone as defined by PJM over the term of this Agreement and (ii) from and after the Delivery Point Aggregation Date, the LMP points in the PJM Control Area that make up the aggregate AEP Zone or any successor, superceding or amended aggregates for the AEP Zone as defined by PJM over the term of this Agreement.

"Delivery Point Aggregation Date" means the date on which the LMP points associated with the Subject Service Territory are assimilated by PJM into the AEP Zone from the APS Zone.

"Eastern Prevailing Time" or "EPT" means Eastern Standard Time or Eastern Daylight Savings Time, whichever is in effect on any particular date.

"Effective Time" will have the meaning given to that term by the Asset Purchase Agreement.

"Emergency Energy" shall have the meaning ascribed to it in the PJM Agreements.

"Energy" means three-phase, 60-cycle alternating current electric energy, expressed in units of kilowatt-hours or megawatt-hours.

"Equitable Defenses" means any bankruptcy, insolvency, reorganization and other laws affecting creditors' rights generally, and with regard to equitable remedies, the discretion of the court before which proceedings to obtain same may be pending.

"FERC" means the Federal Energy Regulatory Commission or its successor.

"Financial Transmission Right" or "FTR" means a financial instrument that entitles the holder to receive compensation from PJM for certain congestion-related transmission charges that arise when the grid is congested and differences in locational marginal prices result from the redispatch of generators out of merit order to relieve congestion in the PJM day-ahead market.

"Firm Energy" means Energy that Seller shall sell and deliver and Buyer shall purchase and receive unless relieved of their respective obligations without liability by Force Majeure, but only to the extent that, and for the period during which, either Party's performance is prevented by Force Majeure.

"Force Majeure" means an event or circumstance that prevents one Party from performing its obligations under the Transaction, which event or circumstance was not foreseen as of the date the Transaction is entered into, which is not within the reasonable control of, or the result of the negligence of, the affected Party and which, by the exercise of due diligence, the Party is unable to mitigate or avoid or cause to be avoided. Notwithstanding the foregoing, under no circumstance shall an event of Force Majeure be based on: (i) the loss or failure of Seller's supply; (ii) Seller's ability to sell the Full Requirements Service at a price greater than that received under the Transaction; (iii) curtailment by a Transmitting Utility; or (iv) Buyer's ability to purchase the Full Requirements Service at a price lower than paid under the Transaction.

"Full Requirements Service" means Seller shall supply Firm Energy to the Delivery Point, as the same may fluctuate in real time to serve Retail Load, limited in any hour to the DS Load in the Subject Service Territory during the applicable billing period and capacity credits, congestion costs, and losses, all as set forth in Exhibit A and elsewhere in this Agreement.

"Gains" means, with respect to any Party, an amount equal to the present value of the economic benefit to it, if any (exclusive of Costs), resulting from the termination of the Transaction, determined in a commercially reasonable manner.

"Governmental Authority" means any federal, state, local, municipal or other governmental entity, authority or agency, department, board, court, tribunal, regulatory commission, or other body, whether legislative, judicial or executive, together or individually, exercising or entitled to exercise any administrative, executive, judicial, legislative, policy, regulatory or taxing authority or power over a Party or this Agreement.

"Interest Rate" means, for any date, the lesser of: (i) the per annum rate of interest equal to the prime lending rate as may from time to time be published in *The Wall Street Journal* under "Money Rates" on such day (or if not published on such day on the most recent preceding day on which published), plus two percent (2%); and (ii) the maximum rate permitted by applicable law.

"Load Serving Entity" or "LSE" shall have the meaning ascribed to it in the PJM Agreements.

"Locational Marginal Price" or "LMP" means the hourly integrated market clearing marginal price for energy at the location the energy is delivered or received.

"Losses" means, with respect to any Party, an amount equal to the present value of the economic loss to it, if any (exclusive of Costs), resulting from the termination of the Transaction, determined in a commercially reasonable manner.

"Monthly Settlement Amount" means with respect to any calendar month during the Delivery Period, the product of the Settlement Price and Monthly Settlement Load and any other adjustments as set forth in this Agreement.

"Monthly Settlement Date" means, with respect to any calendar month of the Delivery Period, the date determined to be the PJM Settlement Date pursuant to the PJM Agreements.

"Monthly Settlement Load" means, with respect to any calendar month during the Delivery Period, DS Load.

"MWh" means one megawatt of electric power used over a period of one hour, which shall be rounded in a manner consistent with standards in the PJM Agreements. The current rounding standards are to the nearest one-thousandth of a megawatt hour.

"NERC" means the North American Electric Reliability Council or any successor organization thereto.

"Network Integration Transmission Service" shall have the meaning ascribed to it in the PJM Agreements.

"Non-Performance Damages" means any direct damages, calculated in a commercially reasonable manner, that a Party incurs as a result of the other Party's failure to schedule and deliver or receive, as applicable, the Full Requirements Service. Direct damages may include, but are not limited to: (i) the positive difference (if any) between the price of Full Requirements Service hereunder and the price at which the Buyer or Seller is able to purchase or sell (as applicable) Full Requirements Service (or any components of Full Requirements Service it is able to purchase or sell) from or to third parties, including PJM; (ii) Emergency Energy charges; and (iii) additional transmission or congestion costs incurred to purchase or sell Full Requirements Service.

"Operating Reserve" shall have the meaning ascribed to it in the PJM Agreements.

"PUCO" means the Public Utility Commission of Ohio.

"PJM" means the PJM Interconnection, LLC or any successor organization thereto.

"PJM Active Load Management" shall have the meaning ascribed to it in the PJM Agreements.

"PJM Agreements" means the PJM OATT, PJM Operating Agreement, PJM RAA, PJM West RAA, and any other applicable PJM manuals, market rules, procedures or documents, or any successor, superceding or amended versions that may take effect from time to time.

"PJM Control Area" shall have the meaning ascribed to it in the PJM Agreements.

"PJM OATT" or "PJM Tariff" means the Open Access Transmission Tariff of PJM or the successor, superceding or amended versions of the Open Access Transmission Tariff that may take effect from time to time.

"PJM Operating Agreement" means the Operating Agreement of PJM or the successor, superceding or amended versions of the Operating Agreement that may take effect from time to time.

"PJM Planning Period" shall have the meaning ascribed to it in the PJM Agreements. Currently, the PJM Planning Period is the twelve month period beginning June 1 and extending through May 31 of the following year.

"PJM RAA" means the PJM Reliability Assurance Agreement or any successor, superceding or amended versions of the PJM Reliability Assurance Agreement that may take effect from time to time.

"PJM Settlement Date" means the date on which payments are due to PJM for services provided by PJM in accordance with the PJM Agreements. Such date currently occurs on the first Business Day after the nineteenth (19th) calendar day of the month following service.

"PJM West RAA" means the PJM West Reliability Assurance Agreement or the successor, superceding or amended versions of the PJM West Reliability Assurance Agreement that may take effect from time to time.

"Settlement Amount" means, with respect to the Transaction and the Non-Defaulting Party, the Losses or Gains, and Costs, expressed in U.S. Dollars, which such Party incurs as a result of the liquidation of the Transaction pursuant to Article 12 (Events of Default – Remedies). The calculation of a Settlement Amount for the Transaction shall exclude any Non-Performance Damages calculated pursuant to Section 12.2(b)(ii) (Remedies) for the Transaction. For the purposes of calculating the Termination Payment, the Settlement Amount shall be considered an amount due to the Non-Defaulting Party under this Agreement if the total of the Losses and Costs exceeds the Gains, and shall be considered an amount due to the Defaulting Party under this Agreement if the Gains exceed the total of the Losses and Costs.

"Settlement Price" means the following amount during the following period:

1/1/2006 – 5/31/2007	$45/MWh.

"Subject Service Territory" means the "Certified Territory" (as defined by Section 4933.81(G) of the Ohio Rev. Code) of Seller in Ohio on file with the PUCO as of the execution date of the Asset Purchase Agreement.

"Transaction" means the purchase by Buyer and the sale by Seller of the Full Requirements Service pursuant to this Agreement.

"Transmitting Utility" means the utility or utilities and their respective control area operators and their successors, transmitting Full Requirements Service.

"Unaccounted For Energy" means the difference between the Buyer's hourly system load and the sum of: (i) the estimated hourly customer loads (interval metered and profiled); and (ii) electrical losses, as such Unaccounted For Energy is determined in the Buyer's retail load settlement process.

"Zone" means an area within the PJM Control Area, as set forth in the PJM OATT, the PJM RAA and the PJM West RAA.

ARTICLE II
TERMS AND CONDITIONS OF FULL REQUIREMENTS SERVICE

2.1 Seller's Obligation To Provide Service. From and after the Effective Time, Seller shall provide Full Requirements Service on a firm and continuous basis such that the Full Requirements Service is supplied during the Delivery Period.

2.2 Buyer's Obligation to Take Service. From and after the Effective Time, Buyer shall accept Full Requirements Service as provided by Seller pursuant to Section 2.1 (Seller's Obligation to Provide Service), and shall pay Seller the Monthly Settlement Amounts for the Full Requirements Service on the applicable Monthly Settlement Date in accordance with Section 7.3 (Payments of the Invoice).

2.3 Network Integration Transmission Service and Distribution Service. Buyer shall be responsible, at its sole cost and expense, for the provision of Network Integration Transmission Service within PJM and distribution service from the Delivery Point necessary to serve the DS Load. With respect to the DS Load, Buyer is responsible, at its sole cost and expense, for future PJM charges assessed to network transmission customers for PJM-required transmission system enhancements pursuant to the PJM Regional Transmission Expansion Plan, and for future PJM charges assessed to network transmission customers for transition costs related to the elimination of through-and-out transmission rates.

2.4 Other Changes in PJM Charges. Except for charges specifically allocated to Buyer pursuant to Section 2.3, any new charges implemented by PJM during the term hereunder will be allocated as between Seller and Buyer in a manner similar to the current PJM charges as illustrated on Exhibit A and elsewhere in this agreement.

2.5 Status of Seller. Seller, for purposes of providing the Full Requirements Service to Buyer hereunder, is agent, pursuant to the PJM Agreements, for Buyer who is the Load Serving Entity as that term is defined in the PJM Agreements. Prior to the Closing, Buyer and Seller shall execute and submit to PJM a PJM Declaration of Authority for this Agreement.

2.6 Sales for Resale. All Full Requirements Service provided by Seller to Buyer shall be sales for resale, with Buyer reselling such Full Requirements Service to DS Load customers.

2.7 Governing Terms. This Agreement, including all exhibits hereto, shall form a single integrated agreement between Buyer and Seller.

ARTICLE III
SCHEDULING, FORECASTING, AND INFORMATION SHARING

3.1 Scheduling. Seller shall schedule the Full Requirements Service pursuant to the PJM Agreements. Buyer will provide to PJM all information required by PJM, for the purpose of calculating Seller's Full Requirements Service obligations.

3.2 Load Forecasting. Buyer shall provide to Seller a daily, twenty-four hour, hour-by-hour estimated load schedule for Seller's Full Requirements Service for the Transaction hereunder by no later than 9:00 a.m. EPT at least one Business Day prior to the delivery day. Buyer shall provide annually a load forecast for each month of the year no later than November 1 of prior year or, if the Closing occurs after November 1, 2005, within thirty (30) days of the Closing. Furthermore, Buyer shall promptly notify Seller if Buyer's load forecast for a month varies by more than five percent of the total Energy shown for such month from the annual load forecast for such month. Buyer will prepare and submit all such information to Seller in good faith, but makes no warranty as to its accuracy. Buyer will have no liability for any inaccuracy in such information.

ARTICLE IV
SPECIAL TERMS AND CONDITIONS

4.1 Congestion and Congestion Management.

(a) Seller will be responsible for any congestion charges incurred to supply the Full Requirements Service to the DS Load during the Delivery Period, both before and after any Delivery Point Aggregation Date(s). For the avoidance of doubt, this obligation shall terminate upon the termination of this Agreement as set forth in Section 5.1.

(b) Notwithstanding Section 2.5 (Status of Seller), Buyer shall transfer or assign to Seller, Buyer's rights to CRRs, including the right to nominate such CRRs, for the Delivery Period to which Buyer is entitled as an LSE for the DS Load pursuant to the PJM Agreements, provided that with respect to the 2005/2006 PJM Planning Period, Buyer will not be required to transfer to Seller any CRRs in excess of the CRRs transferred by Seller to Buyer under the Asset Purchase Agreement relating to that period. All rights and obligations associated with such CRRs will accrue to the Seller through the transfer or assignment from Buyer to Seller. The allocation of CRRs associated with the DS Load will be in accordance with the PJM Agreements.

(c) Notwithstanding any assimilation of the LMP points associated with the Subject Service Territory into the AEP Zone for other purposes, Buyer agrees that it will not request or take any other actions to cause PJM to modify the set of generation resources on which the CRR allocation for the Subject Service Territory is based from the set of generation resources associated by PJM with the APS Zone to the set of generation resources historically associated by PJM with the AEP Zone effective earlier than June 1, 2007 without the written consent of Seller to an earlier effective date.

4.2 Load Response Programs. Buyer will manage its load response programs in accordance with the provisions of its applicable riders and retail electric service tariffs, as amended and approved by the PUCO from time to time or distribution utility customer contracts, as amended by the distribution utility from time to time.

(a) Buyer shall be responsible for complying with all PJM Active Load Management program operating rules (including resource nominations, compliance reports, load drop estimates, and special studies) and any penalties assessed in accordance with the PJM Agreements for failure to implement its load response programs when so requested by PJM. Buyer shall be responsible for maintaining and operating any equipment currently relied upon to operate existing load response programs.

(b) Buyer shall retain all of the benefits associated with its load response programs and shall be responsible for all customer incentive payments.

(c) Buyer shall reimburse Seller for real time Operating Reserve costs incurred by Seller as a result of Buyer's operation of its load response programs, which reimbursement shall be equal to the product of the: (i) estimated hourly load reduction, (ii) the real time Operating Reserve charge; and (iii) 100%, such reimbursement to be referred to as the "ALM Operating Reserve Adjustment."

(d) The obligations addressed in 4.2 (a), (b) and (c) above do not apply to any load reduction initiated by a DS Load customer through the PJM Economic Load Response Program or PJM Emergency Load Response Program. Responsibility for any subsequent PJM charges associated with the PJM Economic Load Response Program or PJM Emergency Load Response Program will be allocated as between Seller and Buyer in a manner similar to the current PJM charges as illustrated on Exhibit A or elsewhere herein.

4.3 Load Management. Buyer covenants with respect to the DS Load that: (i) Buyer shall purchase the Full Requirements Service from Seller for the purpose of fulfilling Buyer's retail supply obligation to the DS Load in the Subject Service Territory only; (ii) Buyer shall enforce those contractual and tariff provisions with respect to its retail service customers that comprise part of the DS Load and that affect the total of the retail supply amount of the DS Load; (iii) Buyer shall participate in load response and demand-side management initiatives to the extent required by

Buyer's retail tariffs applicable to the DS Load. If Buyer enters into any special contract offering discounted rates where the effect of such special contract offering is to increase the retail supply amount of the DS Load with respect to the customer receiving such special contract, Buyer will be responsible for the cost of serving the increased DS Load of that customer. A change in the retail tariff rate schedule under which a customer takes service from Buyer to a different tariff rate schedule and/or any increase in the load of a customer taking service from Buyer under a retail tariff rate schedule, will not constitute an increase in supply under a special contract.

4.4 PJM E-Accounts. Buyer and Seller shall work with PJM to establish any PJM E-Accounts necessary for Seller to provide Full Requirements Service.

4.5 Title Transfer. Title to, possession of, and risk of loss (except for electrical system transmission and distribution losses) of Full Requirements Service scheduled and received or delivered hereunder shall transfer from Seller to Buyer at the Delivery Point. Seller warrants that Seller shall have good title to the Full Requirements Service sold and delivered hereunder, and that Seller shall have the right to sell such Full Requirements Service to Buyer, free and clear of all liens, security interests, claims and encumbrances thereto or therein by any person. Nothing contained in this Agreement is intended to create or increase any liability of Buyer to any third party beyond any such liability, if any, that would otherwise exist under the PJM Agreements or under applicable law if Buyer had not taken title and/or if title had remained with Seller.

4.6 Reliability Guidelines. Each Party agrees to adhere to the applicable operating policies, criteria and/or guidelines of the NERC, PJM, their successors, and any regional or sub regional requirements.

4.7 PJM Membership.For the period of time that this Agreement is in effect, Seller shall be: (i) a member in good standing of PJM; and (ii) qualified as a PJM "Market Buyer" and "Market Seller" pursuant to the PJM Agreements. For the period of time that this Agreement is in effect, Buyer shall be: (i) a member in good standing of PJM; and (ii) qualified as a PJM "Load Serving Entity" pursuant to the PJM Agreements.

4.8 FERC Authorization.For the period of time that this Agreement is in effect, Seller shall have FERC authorization to make sales of energy, capacity and ancillary services at market based rates.

4.9 Remedy for Seller's Failure to Deliver. If Seller fails to schedule and deliver all or part of the Full Requirements Service, and such failure is not excused by Force Majeure or by Buyer's failure to perform, then in addition to any other remedies available under law or in equity to Buyer or under Article 12, Seller will pay Buyer, on the date that payment would otherwise be due for the month in which the failure occurred, an amount for such deficiency equal to positive amount, if any, of Buyer's Non-Performance Damages.

4.10 Remedy for Buyer's Failure to Receive. If Buyer fails to receive all or part of the Full Requirements Service, and such failure is not excused by Force Majeure or by Seller's failure to perform, then in addition to any other remedies available under law or in equity to Seller or under Article 12, Buyer will pay Seller, on the date that payment would otherwise be due for the month in which the failure occurred, an amount for such deficiency equal to positive amount, if any, of Seller's Non-Performance Damages.

ARTICLE V
TERM AND SURVIVAL

5.1 Term. Unless this Agreement is terminated prematurely pursuant to Article 12 of this Agreement and unless otherwise agreed upon by Buyer and Seller, this Agreement shall continue in full force and effect from the Effective Date until May 31, 2007, at which time this Agreement shall terminate automatically without the need for action by either Party; provided, however, that if the Asset Purchase Agreement is terminated without the closing of the sale of the Subject Service Territory having occurred, then this Agreement shall terminate without further obligation or liability for either Party. Neither Party shall have any rights to extend the term of this Agreement.

5.2 Survival. All provisions of this Agreement that must, in order to give full force and effect to the rights and obligations of the Parties hereto, survive termination or expiration of this Agreement, shall so survive, including, without limitation, Articles 9, 10, 12 and 13.

ARTICLE VI
DETERMINATION OF DELIVERED QUANTITIES

6.1 Monthly Settlement Load. The amount of Monthly Settlement Load with respect to any calendar month during the Delivery Period shall be determined in terms of megawatt-hours (MWh) of Energy.

The MWh of Energy shall be equivalent to the amount of Energy reported as the Seller's Full Requirements Service obligation by Buyer to PJM, at the generator level, in accordance with Buyer's initial and subsequent retail load settlement processes. Such Energy reported by Buyer to PJM for the subsequent retail load settlement process shall include Energy adjustments associated with Buyer's operation of its load response programs as necessary to ensure that Seller is credited with energy deliveries equal to the amount by which load was reduced due to Buyer's operation of its load response programs, as determined by Buyer. If required by PJM, Seller shall confirm such adjustments.

ARTICLE VII
BILLING AND SETTLEMENT

7.1 Billing. Unless otherwise agreed to by the Parties, on or before the sixth (6^{th}) Business Day of each month, Buyer shall deliver to Seller, via electronic transmission or other means agreed to by the Parties, an invoice ("Invoice") that sets forth the total amount due for the previous calendar month for the Transaction. The Invoice shall detail the following:

(a) Monthly Settlement Load
(b) Settlement Price
(c) Monthly Settlement Amount
(d) PJM billing adjustments
(e) ALM Operating Reserve Adjustment
(f) Any other adjustments set forth in this Agreement

7.2 PJM Billing. Buyer and Seller shall direct PJM to invoice Seller and Buyer for charges and credits relating to Seller's and Buyer's rights and obligations under this Agreement as set forth in Exhibit A attached hereto and made a part hereof. If PJM is unable to invoice charges or credits in accordance with Exhibit A, Buyer shall rectify such PJM invoice discrepancy in the Invoice sent pursuant to Section 7.1 (Billing). To the extent that either Party pays or is required to pay for any service or charge that is the responsibility of the other Party, then the paying Party shall be reimbursed for such costs by the responsible Party either through cash payment or by credit against other amounts owed to the responsible Party by the paying Party in accordance with this Section.

(b) The Parties agree that the PJM bill may change from time to time. Allocation of any charges that are reflected in a PJM bill that are not included on or are inconsistent with Exhibit A will be determined pursuant to Sections 2.3 (Network Integration Transmission Service and Distribution Service), 2.4 (Other Changes in PJM Charges), and 15.11 (PJM Agreement Modifications) of this Agreement.

(c) The Parties shall work with PJM to adjust the billing determinants upon which SECA charges and credits are allocated among PJM Zones to ensure that the aggregate SECA charges and credits for each Party will not be altered by the transfer of customers in the Subject Service Territory from the Seller to Buyer.

7.3 Payments of the Invoice. On the Monthly Settlement Date, Buyer will pay to Seller the total amount due as shown in the applicable Invoice. All payments shall be made by "Electronic Funds Transfer" (EFT) via "Automated Clearing House" (ACH), to the bank designated by Seller on Exhibit B. Buyer will execute (transmit to its banks) an ACH request to transfer funds to Seller's designated bank account on the Monthly Settlement Date. Payment of Invoices shall not relieve the paying Party from any other responsibilities or obligations it has under this Agreement (other than the obligation to make such payment), nor shall such payment constitute a waiver of any claims arising hereunder.

7.4 Netting of Payments. Buyer and Seller shall discharge mutual debts and payment obligations due and owing to each other under this Agreement, as of the Monthly Settlement Date, such that all amounts owed by each Party to the other Party shall be reflected in a single amount due to be paid by the Party who owes it and received by the other Party, provided that the calculation of the net amount shall not include any disputed amounts being withheld pursuant to Section 7.5 (Billing Disputes and Adjustment of Invoices).

7.5 Billing Disputes and Adjustments of Invoices. Within twelve (12) months of the date on which an Invoice is issued, Buyer may, in good faith, adjust the Invoice to correct any errors, provided that Buyer has paid by the Monthly Settlement Date any portion of an Invoice that is not adjusted. The adjustment shall include interest calculated at the Interest Rate from the original due date to the date of payment. Buyer shall provide Seller a written explanation of the basis for the adjustment.

(a) Within twelve (12) months of the date on which an Invoice is issued or an Invoice is adjusted pursuant to Section 7.5(a) (Billing Disputes and Adjustment of Invoices), Seller may, in good faith, dispute the correctness of such Invoice or adjustment, pursuant to the provisions of Article 13 (Dispute Resolution), provided that Seller has paid by the Monthly Settlement Date any portion of an Invoice that is not disputed. Seller will provide Buyer a written explanation of the basis for the dispute.

(b) Within twelve (12) months of the date on which a PJM bill is issued, Buyer or Seller may, in good faith, dispute the correctness of any such PJM bill, pursuant to the provisions of Article 13 (Dispute Resolution), provided that the disputing Party has paid by the Monthly Settlement Date any portion of an Invoice that is not disputed.

7.6 Interest on Unpaid Balances. Interest on delinquent amounts, other than amounts in dispute as described in Section 7.5 (Billing Disputes and Adjustment of Invoices), shall be calculated at the Interest Rate from the original due date to the date of payment.

ARTICLE VIII
TAXES

8.1 Cooperation. Each Party shall use reasonable efforts to implement the provisions of and administer this Agreement in accordance with the intent of the Parties to minimize taxes, so long as neither Party is materially adversely affected by such efforts.

8.2 Taxes. As between the Parties: (i) Seller is responsible for the payment of all taxes imposed by any Governmental Authority on the wholesale sales of Full Requirements Service under this Agreement; and (ii) Buyer is responsible for the payment of all taxes imposed by any Governmental Authority on retail sales of Full Requirements Service under this Agreement.

(a) Any Party paying taxes that should have been paid by the other Party pursuant to Section 8.2(a) (Taxes), shall be reimbursed by such other Party in the next invoice issued pursuant to Section 7.1 (Billing).

ARTICLE IX
INDEMNIFICATION

9.1 Seller's Indemnification for Third-Party Claims. Seller shall indemnify, hold harmless, and defend Buyer and its Affiliates, and their respective officers, directors, shareholders, partners, members, employees, agents, contractors, subcontractors, invitees, successors, representatives and permitted assigns (collectively, "Buyer's Indemnitees") from and against any and all claims, demands or suits (by any person), liabilities, costs, losses, damages, obligations, payments and expenses including reasonable attorney and expert fees, disbursements actually incurred, and any penalties or fines imposed by Government Authorities in any action or proceeding between Buyer and a third party or Seller for damage to property of unaffiliated third parties, injury to or death of any person, including Buyer's employees or any third parties, to the extent directly caused by the gross negligence or willful misconduct of Seller and/or its officers, directors, employees, agents, contractors, subcontractors or invitees arising out of or connected with Seller's performance under this Agreement, Seller's exercise of rights under this Agreement, or Seller's breach of this Agreement.

9.2 Buyer's Indemnification for Third-Party Claims. Buyer shall indemnify, hold harmless, and defend Seller and its Affiliates, and their respective officers, directors, shareholders, partners, members, employees, agents, contractors, subcontractors, invitees, successors, representatives and permitted assigns (collectively, "Seller's Indemnitees") from and against any and all claims, demands or suits (by any person) liabilities, costs, losses, damages, obligations, payments and expenses including reasonable attorney and expert fees, disbursements actually incurred, and any penalties or fines imposed by Government Authorities in any action or proceeding between Seller and a third party or Buyer for damage to property of unaffiliated third parties, injury to or death of any person, including Seller's employees or any third parties, to the extent directly caused by the gross negligence or willful misconduct of Buyer and/or its officers, directors, employees, agents, contractors, subcontractors or invitees arising out of or connected with Buyer's performance under this Agreement, Buyer's exercise of rights under this Agreement, or Buyer's breach of this Agreement.

9.3 Indemnification Procedures. If either Party intends to seek indemnification under Sections 9.1 (Seller's Indemnification for Third-Party Claims) or 9.2 (Buyers Indemnification for Third-Party Claims), as applicable, from the other Party, the Party seeking indemnification shall give the other Party notice of such claim within ninety (90) days of the later of the commencement of, or the Party's actual knowledge of, such claim or action. Such notice shall describe the claim in reasonable detail, and shall indicate the amount, estimated if necessary, of the claim that has been, or may be, sustained by said Party. To the extent that the other Party will have been actually and materially prejudiced as a result of the failure to provide such notice, such notice will be a condition precedent to any liability of the other Party under the provisions for indemnification contained in this Agreement. Neither Party may settle or compromise any claim without the prior consent of the other Party; provided, however, said consent shall not be unreasonably withheld or delayed.

ARTICLE X
LIMITATIONS ON LIABILITY

10.1 Limitation of Remedies, Liability and Damages. EXCEPT AS SET FORTH IN THIS AGREEMENT, THERE IS NO WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, AND ANY AND ALL IMPLIED WARRANTIES ARE DISCLAIMED. THE PARTIES CONFIRM THAT THE EXPRESS REMEDIES AND MEASURES OF DAMAGES PROVIDED IN THIS AGREEMENT SATISFY THE ESSENTIAL PURPOSES HEREOF. FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY, THE OBLIGOR'S LIABILITY SHALL BE LIMITED AS SET FORTH IN SUCH PROVISION AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY PROVIDED HEREIN, THE OBLIGOR'S LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY, SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. UNLESS EXPRESSLY HEREIN PROVIDED, NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE

LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OR OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT AND THE DAMAGES CALCULATED HEREUNDER CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

ARTICLE XI
FORCE MAJEURE

11.1 Force Majeure. The Parties shall be excused from performing their respective obligations under this Agreement (other than the obligation to make payments with respect to performance prior to the event of Force Majeure) and shall not be liable for damages or otherwise due to their failure to perform, during any period that one Party is unable to perform due to an event of Force Majeure, provided that the Party declaring an event of Force Majeure shall: (i) act expeditiously to resume performance; (ii) exercise all commercially reasonable efforts to mitigate or limit damages to the other Party; and (iii) fulfill the requirements set forth in Section 11.2 (Notification).

11.2 Notification. A Party unable to perform under this Agreement due to an event of Force Majeure shall: (i) provide prompt written notice of such event of Force Majeure to the other Party, which shall include an estimate of the expected duration of the Party's inability to perform due to the event of Force Majeure; and (ii) provide prompt notice to the other Party when performance resumes.

ARTICLE XII
EVENTS OF DEFAULT; REMEDIES

12.1 Events of Default. An "Event of Default" shall mean, with respect to a Party ("Defaulting Party"), the occurrence of any of the following:

(a) the failure to make, when due, any payment required pursuant to this Agreement if such failure is not remedied within two (2) Business Days after written notice;

(b) any representation or warranty made by such Party herein is false or misleading in any material respect when made or when deemed made or repeated;

(c) the failure of a Party to comply with the requirements of Sections 4.6 (PJM Membership) and 4.7 (FERC Authorization) if such failure is not remedied within three (3) Business Days after written notice;

(d) PJM has declared a Party to be in default of any provision of any PJM Agreement, which default prevents a Party's performance hereunder if such failure is not remedied within three (3) Business Days after written notice;

(e) the failure to perform any material covenant or obligation set forth in this Agreement (except to the extent constituting a separate Event of Default) if such failure is not remedied within three (3) Business Days after written notice;

(f) such Party becomes Bankrupt;

(g) such Party consolidates with, or merges with or into, or transfers all or substantially all of its assets to, another entity, or assigns the Agreement or any rights, interests, or obligations hereunder, and, at the time of such consolidation, merger, transfer or assign, the resulting, surviving, transferee, or assigned entity fails to assume all the obligations of such Party under this Agreement to which it or its predecessor was a party by operation of law or pursuant to an agreement reasonably satisfactory to the other Party, such agreement not to be unreasonably withheld.

(h) the occurrence and continuation of: (i) a default, event of default or other similar condition or event in respect of such Party under one or more agreements or instruments, individually or collectively, relating to indebtedness for borrowed money in an aggregate amount of not less than 50,000,000 (Fifty Million Dollars) with respect to Buyer or $25,000,000 (Twenty-Five Million Dollars) with respect to Seller, which results in such indebtedness becoming immediately due and payable or; (ii) a default by such Party in making on the due date therefore one or more payments, individually or collectively, in an aggregate amount of not less than 50,000,000 (Fifty Million Dollars) with respect to Buyer or $25,000,000 (Twenty-Five Million Dollars) with respect to Seller.

12.2 Remedies. If an Event of Default with respect to a Defaulting Party shall have occurred and be continuing, the other Party (the "Non-Defaulting Party"), shall provide written notice to the Defaulting Party and shall have the right to temporarily suspend performance pursuant to Section 12.2(a) or implement all remedies pursuant to Section 12.2(b):

(a) If an Event of Default has occurred and is continuing, the Non-Defaulting Party shall have the right to suspend performance, provided that such suspension shall not continue for longer than ten (10) Business Days. At any time during or subsequent to the temporary suspension of performance, the Non-Defaulting Party may proceed with the steps outlined in Section 12.2(b). If, by the end of the ten (10) Business Day period of suspension, the Non-Defaulting Party has not commenced the implementation of the remedies pursuant to Section 12.2(b), then the Non-Defaulting Party must resume performance of its obligations under this Agreement.

(b) In addition to any other remedies available at law or in equity to the Non-Defaulting Party, if an Event of Default has occurred and is continuing, the Non-Defaulting Party shall have the right to implement all, but not less than all, the following remedies:

i. designate a day, in such notice, no earlier than the day such notice is effective and no later than twenty (20) (calendar) days after such notice is effective, as an early termination date ("Early Termination Date") for the purposes of determining the Settlement Amount;

ii. calculate and receive from the Defaulting Party, payment for any Non-Performance Damages and Costs the Non-Defaulting Party incurs as of, or has incurred prior to, the date of the event giving rise to the Event of Default, and from such date until the earlier of: (i) the Early Termination Date (if applicable); or (ii) the Event of Default has been cured by the Defaulting Party; or (iii) the Non-Defaulting Party waives such Event of Default;

iii. withhold any payments due to the Defaulting Party under this Agreement as an offset to any Non-Performance Damages or Termination Payment, as defined in Section 12.3 (Calculation and Net Out of Settlement Amounts); and

iv. permanently suspend performance.

12.3 Calculation and Net Out of Settlement Amounts.

(a) The Non-Defaulting Party shall calculate, in a commercially reasonable manner, a Settlement Amount for the Transaction as of the Early Termination Date or, to the extent that in the reasonable opinion of the Non-Defaulting Party the Transaction is commercially impracticable to liquidate and terminate or may not be liquidated and terminated under applicable law on the Early Termination Date, as soon thereafter as is reasonably practicable. The Non-Defaulting Party shall aggregate all Settlement Amounts into a single liquidated amount (the "Termination Payment") by netting out: (i) all Settlement Amounts that are due to the Defaulting Party, plus, at the option of the Non-Defaulting Party, any or all other amounts due to the Defaulting Party under this Agreement; against (ii) all Settlement Amounts that are due to the Non-Defaulting Party plus any or all other amounts due to the Non-Defaulting Party, including but not limited to Non-Performance Damages, under this Agreement. The Termination Payment shall be due to or due from the Non-Defaulting Party as appropriate.

(b) In order to avoid doubt regarding a commercially reasonable calculation for the purposes of calculating the Settlement Amount by the Non-Defaulting Party, the quantity of amounts of Energy, Capacity and other services to have been provided under the Agreement for the period following the Early Termination Date (the "*Termination Quantity*") shall be deemed those quantity amounts that would have been delivered on an hourly basis had the Agreement been in effect during the previous calendar year, adjusted for such DS Load changes as have occurred since the previous calendar year. This paragraph will not be construed to limit Buyer's rights when Seller is the Defaulting Party to replace Seller's obligation to provide the Full Requirements Service.

12.4 Notice of Termination Payment. As soon as practicable after an Early Termination Date is declared, the Non-Defaulting Party shall provide written notice to the Defaulting Party of the amount of the Termination Payment and whether the Termination Payment is due to or due from the Non-Defaulting Party. The notice shall include a written statement explaining in reasonable detail the calculation of such amount. The owing Party shall make the Termination Payment within five (5) Business Days after such notice is effective.

12.5 Disputes With Respect to Termination Payment. If the Defaulting Party disputes the Non-Defaulting Party's calculation of the Termination Payment, in whole or in part, the Defaulting Party shall, within five (5) Business Days of receipt of Non-Defaulting Party's calculation of the Termination Payment, provide to the Non-Defaulting Party a notice that it intends to dispute the calculation of the Termination Payment ("Termination Payment Dispute Notice"), pursuant to the provisions of Article 13 (Dispute Resolution), and provided, however, that if the Termination Payment is due from the Defaulting Party, the Defaulting Party shall first transfer collateral to the Non-Defaulting Party in an amount equal to the Termination Payment, such collateral to be in a form acceptable to the Non-Defaulting Party by the Termination Payment Date.

12.6 Closeout Setoffs.After calculation of a Termination Payment in accordance with Section 12.3 (Calculation and Net Out of Settlement Amounts) if the Defaulting Party would be owed the Termination Payment, the Non-Defaulting Party shall be entitled, at its option and in its discretion, to: (i) set off against such Termination Payment any amounts payable by the Defaulting Party to the Non-Defaulting Party under any other agreements, instruments or undertakings between the Defaulting Party and the Non-Defaulting Party; and/or (ii) to the extent the Transaction is not yet liquidated in accordance with Section 12.3 (a), withhold payment of the Termination Payment to the Defaulting Party. The remedy provided for in this Article shall be without prejudice and in addition to any right of setoff, combination of accounts, lien or other right to which any Party is at any time otherwise entitled (whether by operation of law, contract or otherwise). If any obligation is unascertained, the Non-Defaulting Party may in good faith estimate that obligation and set-off in respect of the estimate, subject to the Non-Defaulting Party accounting to the Defaulting Party when the obligation is ascertained.

12.7 Duty to Mitigate. Each Party agrees that it has a duty to mitigate damages and covenants that it will use commercially reasonable efforts to minimize any damages it may incur as a result of the other Party's failure to perform pursuant to this Agreement.

ARTICLE XIII
DISPUTE RESOLUTION

13.1 Arbitration. This Section shall apply to any dispute, claim, or controversy arising out of or relating to this Agreement (a "Dispute").

In the event of a Dispute, the party alleging such Dispute shall provide written notice thereof to the other party. The parties shall negotiate in good faith to resolve the Dispute for a period of up to thirty (30) days from the date of the written notice. If the parties do not resolve the Dispute within such thirty (30) day period, then upon written notice by either party the Dispute shall be determined as provided herein by binding arbitration administered by the American Arbitration Association ("AAA") under its Commercial Arbitration Rules, and judgment on the award rendered by the arbitrator may be entered in any court having jurisdiction thereof. One arbitrator shall be selected from the AAA's Roster of Neutrals using the AAA's listing process; provided that he/she shall be a member of the bar of the District of Columbia or of a state of the United States and shall have actively engaged in the practice of law for at least fifteen (15) years. The parties shall return their respective strikes and preferences to the AAA within twenty (20) days of receipt of the list. If a party fails to timely return its strikes and preferences, an arbitrator will be invited to serve based solely on the strikes and preferences timely provided by the other party. All proceedings in arbitration, including all conferences and hearings, will be held in Washington, D.C. unless otherwise agreed between the parties. Consistent with the expedited nature of arbitration, each party will, upon the written request of the other party, promptly provide the other with copies of documents on which the producing party intends to rely in support of or in opposition to any disputed item. Any dispute regarding discovery, or the relevance or scope thereof, shall be determined by the arbitrator, which determination shall be conclusive. At the request of a party, the arbitrator shall have the discretion to order examination by deposition of witnesses to the extent the arbitrator deems such additional discovery relevant and appropriate. All objections are reserved for the arbitration hearing except for objections based on privilege and proprietary or confidential information. All discovery shall be conducted in accordance with the AAA rules of procedure. A schedule for completing discovery shall be agreed to between the parties within twenty-one (21) days of the appointment of the arbitrator and submitted to the arbitrator for his/her approval. In the event the parties are unable to agree to a schedule for completing discovery, they shall each submit their discovery proposals to the arbitrator within thirty (30) days of his/her appointment. The arbitrator shall issue a discovery scheduling order within ten (10) days after the parties submit their competing proposals. All discovery shall be completed within one hundred eighty (180) days following the appointment of the arbitrator. Hearing on the merits will be scheduled by the arbitrator on not less than thirty (30) days' notice to each party. The arbitrator shall award to the prevailing party, if any, as determined by the arbitrator, all of the prevailing party's costs and fees. "Costs and fees" mean all reasonable pre-award expenses of the arbitration, including the arbitrator's fees, administrative fees, travel expenses, out-of-pocket expenses such as copying and telephone, court costs, witness fees, and attorneys' fees. The award shall be in writing, shall be accompanied by a reasoned opinion, and shall be signed by the arbitrator.

The submission of any dispute to Arbitration shall not impair any party's right to seek or obtain from a court of competent jurisdiction a temporary restraining order and other preliminary injunctive relief to preserve the status quo or to seek or obtain another available extraordinary remedy while any such Arbitration is pending or is being appealed or reviewed. Any such action seeking temporary or preliminary equitable relief must be filed in a court of competent jurisdiction located within Franklin County, Ohio and each party expressly submits to personal jurisdiction of any such court located within Franklin County, Ohio.

ARTICLE XIV
REPRESENTATIONS AND WARRANTIES

14.1 Representations and Warranties. On the Effective Date and throughout the term of this Agreement, each Party represents and warrants to the other Party that:

(a) it is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation;

(b) it has all regulatory authorizations necessary for it to legally perform its obligations under this Agreement and the Transaction;

(c) the execution, delivery and performance of this Agreement and the Transaction are within its powers, have been duly authorized by all necessary action and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any law, rule, regulation, order or the like applicable to it;

(d) this Agreement and the Transaction constitutes its legally valid and binding obligation enforceable against it in accordance with its terms; subject to any Equitable Defenses;

(e) it is not Bankrupt and there are no proceedings pending or being contemplated by it or, to its knowledge, threatened against it which would result in it becoming Bankrupt;

(f) there are no pending, or to its knowledge threatened, actions, suits or proceedings before any Governmental Authority against it or any of its Affiliates that could materially adversely affect its ability to perform its obligations under this Agreement or the Transaction;

(g) no Event of Default with respect to it has occurred and is continuing and no such event or circumstance would occur as a result of its entering into or performing its obligations under this Agreement or the Transaction;

(h) it is not relying upon the advice or recommendations of the other Party in entering into this Agreement, it is capable of understanding, understands and accepts the terms, conditions and risks of this Agreement and the Transaction, and the other Party is not acting as a fiduciary for or advisor to it in respect of this Agreement;

(i) it is a "forward contract merchant" within the meaning of the United States Bankruptcy Code;

(j) it has entered into this Agreement and the Transaction in connection with the conduct of its business and it has the capacity or ability to provide or take delivery of the Full Requirements Service; and

(k) it is an "eligible contract participant" as defined in Section 1a(12) of the Commodity Exchange Act.

14.2 Additional Understandings. This Agreement is for the purchase and sale of Full Requirements Service that will be delivered in quantities expected to be used or sold over the Delivery Period in the normal course of business, and it is the intention at the inception and throughout the term of this Agreement and the Transaction hereunder that the Agreement will result in physical delivery and not financial settlement, and the quantity of Full Requirements Service that Seller must deliver and Buyer must receive will be determined by the requirements of the DS Load served by Buyer, and, as such, the Agreement does not provide for an option by either Party with respect to the quantity of Full Requirements Service to be delivered or received during performance of the Agreement. This Agreement has been drafted to effectuate Buyer's and Seller's specific intent so that in accordance with Financial Accounting Standards Board Statement No. 133 ("FAS 133"), as amended, Buyer would be able to elect to use accrual accounting for its purchases under this Agreement, while Seller would be able to elect to use either accrual or mark-to-market accounting for its sales under the Agreement. If either Buyer or Seller determines, in good faith, that the intended accounting treatment has become jeopardized, due to a change in interpretations of FAS 133, as amended, or otherwise, then Buyer and Seller agree to meet and use their best efforts to reform the Agreement so that, with the minimum changes possible, the Agreement again qualifies for the intended accounting treatments.

ARTICLE XV
MISCELLANEOUS

15.1 Notices. Unless otherwise specified herein, all notices shall be in writing and delivered by hand delivery, overnight mail service or facsimile. Notice by facsimile or hand delivery shall be effective at the close of business on the day actually received, if received during business hours on a Business Day, and otherwise shall be effective at the close of business on the next Business Day. Notice by overnight mail service shall be effective on the next Business Day after it was sent. A Party may change its address by providing notice of the same in accordance with this Section 15.1. Notice information for Buyer and Seller is shown on Exhibit B.

15.2 General. This Agreement shall be considered for all purposes as prepared through the joint efforts of the Parties and shall not be construed against one Party or the other as a result of the preparation, substitution, submission or other event of negotiation, drafting or execution hereof. Each Party further agrees that it will not assert, or defend itself, on the basis that any applicable tariff is inconsistent with this Agreement. This Agreement shall not impart any rights enforceable by any third party other than a permitted successor or assignee bound to this Agreement or the Transaction. Any provision declared or rendered unlawful will not otherwise affect the remaining lawful obligations that arise under this Agreement or the Transaction; provided that in such event the Parties shall use commercially reasonable efforts to amend this Agreement or the Transaction in order to give effect to the original intention of the Parties.

15.3 Rules of Interpretation. The following principles shall be observed in the interpretation and construction of this Agreement:

(a) unless otherwise stated, the terms "include" and "including" when used in this Agreement shall be interpreted to mean by way of example only and shall not be considered limiting in any way;

(b) all titles and headings used herein are for convenience and reference purposes only, do not constitute a part of this Agreement and shall be ignored in construing or interpreting the obligations of the parties under this Agreement;

(c) references to the singular include the plural and vice versa;

(d) references to Articles, Sections, Clauses and the Preamble are, unless the context indicates otherwise, references to Articles, Sections, Clauses and the Preamble of this Agreement;

(e) in carrying out its rights, obligations and duties under this Agreement, each Party shall have an obligation of good faith and fair dealing.

15.4 Audit. Each Party has the right on at least three (3) Business Days prior written notice, at its sole expense and during normal working hours, to examine the records of the other Party to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to this Agreement. If any such examination reveals any inaccuracy in any statement, the necessary adjustments in such statement and the payments thereof will be made in accordance with Sections 7.1 (Billing) and 7.6 (Interest on Unpaid Balances).

15.5 Successors. This Agreement and all of the provisions hereof are binding upon, and inure to the benefit of, the Parties and their respective successors and permitted assigns.

15.6 Assignment/Change in Corporate Identity. Neither Party shall assign this Agreement, its rights or obligations hereunder without the prior written consent of the other Party, which consent may not be unreasonably withheld; provided, however, either Party may, without the consent of the other Party (and without relieving itself from liability hereunder),

(a) transfer, sell, pledge, encumber or assign this Agreement or the accounts, revenues or proceeds hereof in connection with any financing or other financial arrangements,

(b) transfer or assign this Agreement to an Affiliate of such Party if such Affiliates' creditworthiness is equal to or higher than that of such Party,

(c) transfer or assign this Agreement to any person or entity succeeding to all or substantially all of the assets whose creditworthiness is equal to or higher than that of such Party,

(d) provided, however, that in each such case, any such assignee shall agree in writing to be bound by the terms and conditions hereof and so long as the transferring Party delivers such tax and enforceability assurance as the non-transferring Party may reasonably request.

15.7 Governing Law. THIS AGREEMENT AND THE RIGHTS AND OBLIGATIONS OF THE PARTIES HEREUNDER SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF OHIO, WITHOUT REGARD TO PRINCIPLES OF CONFLICTS OF LAW.

15.8 Waiver of Jury Trial EACH OF THE PARTIES HERETO HEREBY IRREVOCABLY WAIVES, TO THE FULLEST EXTENT PERMITTED BY LAW, ANY AND ALL RIGHT TO TRIAL BY JURY IN ANY LEGAL PROCEEDING ARISING OUT OF OR RELATING TO THIS AGREEMENT OR THE TRANSACTION CONTEMPLATED HEREBY.

15.9 Amendments. Except as provided in Section 15.10 (PJM Agreement Modifications), this Agreement and the Transaction shall not be amended, modified, terminated, discharged or supplemented, nor any provision hereof waived, unless mutually agreed, in writing, by the Parties. Except as provided in Section 15.10 (PJM Agreement Modifications), the rates, terms and conditions contained in this Agreement and the Transaction are not subject to change under Sections 205 or 206 of the Federal Power Act absent the mutual written agreement of the Parties. Absent the agreement of all parties to the proposed change, the standard of review for changes to this Agreement proposed by a Party, a non-Party or the FERC acting *sua sponte* shall be the "public interest" standard of review set forth in *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956), and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U. S. 348 (1956) (the "*Mobile-Sierra*" doctrine).

15.10 PJM Agreement Modifications. If the PJM Agreements are amended or modified so that any schedule or section references herein to such agreements is changed, such schedule or section references herein shall be deemed to automatically (and without any further action by the Parties) refer to the new or successive schedule or section in the PJM Agreements which replaces that originally referred to in this Agreement.

(a) If the applicable provisions of the PJM Agreements referenced herein, or any other PJM rules relating to the implementation of this Agreement, are changed materially from those in effect on the Effective Date, both Parties shall cooperate to make conforming changes to this Agreement to fulfill the purposes of this Agreement; provided that no such changes shall alter the economic benefits of this Agreement between the Parties.

15.11 Delay and Waiver.Except as otherwise provided in this Agreement, no delay or omission to exercise any right, power or remedy accruing to the respective Parties hereto upon any breach or default of any other Party under this Agreement shall impair any such right, power or remedy, nor shall it be construed to be a waiver of any similar breach or default thereafter occurring; nor shall any waiver of any single breach or default be deemed a waiver of any other breach or default theretofore or thereafter occurring. Any waiver, permit, consent or approval of any kind or character of any breach or default under this Agreement, or any waiver of any provision or condition of this Agreement, must be in writing and shall be effective only to the extent specifically set forth in such writing.

15.12 Regulatory Approvals. The Parties agree to cooperate, to the fullest extent necessary, to obtain and maintain in effect any and all required State, Federal or other regulatory approvals for this Agreement.

15.13 Counterparts. This Agreement may be executed in two or more counterparts, each of which will be considered an original, and all of which together will constitute one and the same instrument.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their duly authorized representative as of the date first set forth above.

Columbus Southern Power Company	Monongahela Power Company dba Allegheny Power
By: ______________	By: ______________
Name: ______________	Name: ______________
Title: ______________	Title: ______________

EXHIBIT A

ALLOCATION OF RESPONSIBILITY FOR PJM CHARGES AS BETWEEN SELLER AND BUYER

FINAL BILLING STATEMENT ISSUED ON: MM/DD/YYYY
FOR PERIOD: MM/DD/YYYY TO MM/DD/YYYY

OPERATING AGREEMENT OF PJM INTERCONNECTION, L.L.C.:	Day-ahead	Balancing	Total
Charges:			
Spot Market Energy	Seller	Seller	Seller
Transmission Congestion	Seller	Seller	Seller
Transmission Losses (Point-to-Point)	Seller	Seller	Seller
Regulation			Seller
Spinning Reserve			Seller
Operating Reserves	Seller	Seller	Seller
Synchronous Condensing			Seller
Capacity Credit Market			Seller
Reconciliation for Spot Market			Seller
Reconciliation for Regulation			Seller
Reconciliation for Operating Reserves			Seller
Emergency Energy			Seller
FTR Auction			Seller
Meter Error Correction			Seller
PJM Economic & Emergency Load Response Programs			Seller
Credits:			
Spot Market Energy	Seller	Seller	Seller
Transmission Congestion			
Hourly			Seller
Annual			Seller
Transmission Losses (Point-to-Point)			Buyer
Regulation			Seller
Spinning Reserve			Seller
Operating Reserves	Seller	Seller	Seller
Synchronous Condensing			Seller
Capacity Credit Market			Seller
Reconciliation for Transmission Losses			Buyer
Emergency Energy			Seller
Auction Revenue Rights			Seller

FINAL BILLING STATEMENT ISSUED ON: MM/DD/YYYY
FOR PERIOD: MM/DD/YYYY TO MM/DD/YYYY

PJM OPEN ACCESS TRANSMISSION TARIFF:	
	Total
Charges:	
PJM Scheduling, System Control and Dispatch Service	Buyer
Transmission Owner Scheduling, System Control and Dispatch Service	Buyer
Reactive Supply and Voltage Control from Generation Sources Service	Buyer
Black Start Service	Buyer
Network Integration Transmission Service	Buyer
Network Transmission Service Offset Charges	Buyer
Firm Point-to-Point Transmission Service	Seller
Non-Firm Point-to-Point Transmission Service	Seller
Mid-Atlantic Area Council (MAAC)	Buyer
Transitional Market Expansion Charges (Transmission Customer Charge Only)	Buyer
Reconciliation for PJM Scheduling, System Control and Dispatch Service	Buyer
Reconciliation for Transmission Owner Scheduling, System Control and Dispatch Service	Buyer
Seams Elimination Charges	Buyer
Credits:	
Non-Firm Point-to-Point Transmission Service	Buyer
Other Supporting Facilities	Buyer
Seams Elimination Credits	Buyer
Energy Imbalance Credits	Seller

Reliability Assurance Agreement Among Load Serving Entities in the PJM Control Area:	
	Total
Charges:	
Capacity Deficiency	Seller
Credits:	
Capacity Excess	Seller

COMMENTS OF THE MISSOURI PUBLIC SERVICE MISSOURI COMMISSION

REGARDING THE DEPARTMENT OF ENERGY'S 2009 TRANSMISSION CONGESTION STUDY AND THE DESIGNATION OF NATIONAL INTEREST ELECTRICITY TRANSMISSION CORRIDORS

I. Introduction

A. Major Concern of the Missouri Public Service Missouri Commission

At the outset, the Missouri Public Service Commission (Missouri Commission) wants to thank the Department of Energy (DOE) for the opportunity to provide input on its process for establishing National Interest Electricity Transmission Corridors (NIETCs). While cost allocation is not within the purview of the DOE under the 2005 Energy Policy Act, it is important for DOE to understand that the Missouri Commission's major concern is being allocated cost without commensurate benefits for the citizens of Missouri. The Missouri Commission has the obligation to ensure that charges paid by Missouri ratepayers whose rates fall under its jurisdiction are just and reasonable. In this regard, the Missouri Commission does not regard rate increases for transmission upgrades that provide little or no benefit to those ratepayers as being just and reasonable.

B. Summary of the Comments

These comments are organized to give DOE a perspective of the current situation in Missouri in regard to congestion. Section II gives the Missouri Commission's understanding of the purpose for the DOE's transmission congestion studies, including a brief summary of the DOE's findings in its 2006 Transmission Congestion Study. Notably, no NIETC areas were specified in this study for the Midwest, and the only congestion concerns that appeared in the study for the Midwest area were potential future issues related to exporting wind from the Dakotas – Minnesota area and the Oklahoma – Kansas area.

Currently the DOE is also funding a wind integration study that involves most of the Eastern Interconnection. The results of that study will not be available until June 2009. In addition, these studies appear to be based on an assumed National Renewable Portfolio Standard, which is not yet a component of our nation's energy policy. The Missouri Commission does not believe that this is the time for DOE to specify areas as qualifying for NIETC designation for transmission that might be needed at an unspecified future time for a nation-wide requirement for renewable resources. This does not mean that planning for such needs should not be performed today. Instead, until there is a clearly determined need for transmission to export electricity from committed wind power resources, and a clear understanding of the operational issues and cost involved in the introduction of large amounts of non-dispatchable energy into the power grid, DOE should not consider potential congestion associated with what is yet to be determined need as meeting the threshold of being in the national interest. It is the Missouri Commission's hope that, as the need and commitment for wind power consumption develops over the coming years, efforts by states and stakeholders working through regional state committees/organizations will be able to determine a cost allocation to all consumers that all states can find to be just and reasonable.[1]

Section III provides DOE with an overview of Missouri utilities and how they are connected through the transmission system within Missouri. This section explains that there are three primary transmission providers within Missouri: 1) Midwest Independent System Operator (MISO); 2) Southwest Power Pool (SPP); and Associated Electric Cooperatives (AECI). MISO, a Federal Energy Regulatory Commission (FERC) recognized Regional Transmission Organization (RTO), provides most of the transmission service on the east-side of Missouri, SPP, also a FERC recognized RTO, provides most of the transmission service on the west-side of Missouri, and AECI's transmission system is the primary connection between MISO and SPP in Missouri. In this regard, there appears to be no significant congestion with respect to market activity from Missouri into MISO or into SPP. In addition, the similarity between MISO and SPP market prices indicates either a similarity in the fuel mix of generation resources in the two RTOs, or that there is no significant congestion between these two markets.

Section IV is a brief conclusion regarding transmission congestion in Missouri as it relates to the DOE 2009 Congestion Study. The Missouri Commission does not expect that DOE's 2009 study will result in the designation of NIETCs, within MISO, SPP, or AECI, that will impact Missouri ratepayers. If that expectation proves to be incorrect, the Missouri Commission respectfully requests that DOE inform of such at the earliest possible time.

An appendix to the main body of the comments was prepared by our Chief Economist, Dr. Michael Proctor. This appendix discusses the more technical issues that Dr. Proctor will be addressing at the June 18 meeting in Oklahoma City on DOE's Transmission Congestion Study.

[1] It is important to note that the Missouri Commission has been very involved both at MISO and SPP in issues regarding transmission expansion and cost allocation.

II. Background

Under Section 1221 of the 2005 Energy Policy Act, DOE may designate as a NIETC any geographic area experiencing electric energy transmission ***capacity constraints or congestion that adversely affects consumers.*** In this regard, Section 1221(a)(4) sets out the following key drivers for making a determination of what constitutes and adverse impact on consumers

- √ Impact of price of electricity on end markets
- √ Impact on economic growth / end markets from limited sources of energy
- √ Diversification of supply is warranted
- √ Energy independence is served
- √ National energy policy is enhanced
- √ Enhances national defense / homeland security

Further clarification of adverse impacts on consumers was set out in the National Electric Transmission Congestion Study issued in August 2006 by DOE in which DOE gave additional guidance to criteria by which it would evaluate whether or not congestion on the power grid would meet the threshold of needing to be classified as a NIETC. The following table summarizes these criteria.

Table 1

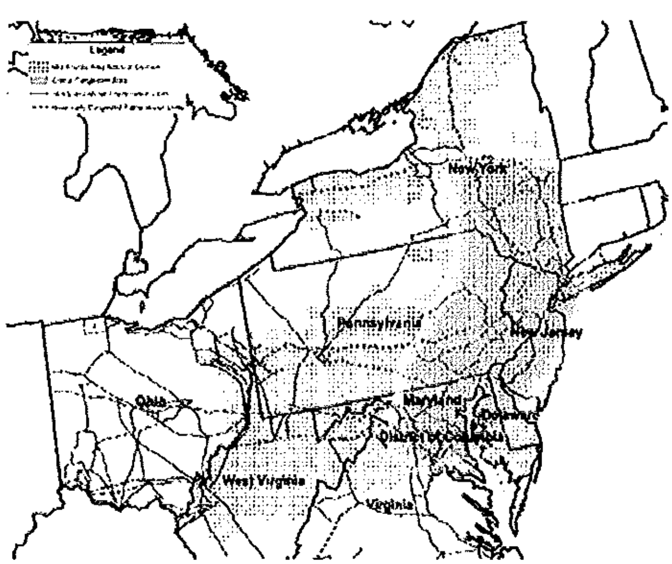
Criteria for Deciding NIETCs	
Reliability	Currently experiencing reiliability problems
	Future problems likely absent transmission upgrades
	Population of affected area
	Likely economic impact of grid failure
Supply Costs	Transmission upgrades lead to net economic benefit
	Source of economic benefits
Diversification	Reduce dependence on particular fuels
	Impact on security, price volatility and emergency suppies
National Policy	Further national energy policy
	Further national security

The 2006 congestion study by DOE found several congested areas within the Eastern Interconnection. These congested areas were classified into the following categories:

1. Critical Congestion Areas: "severe"
    i. Affected population is large
    ii. Congestion costs are high
    iii. Growing reliability problem
    iv. Severe national consequences of grid failure
2. Congestion Areas of Concern: "emerging"
    i. Congestion problem exist, but not yet severe
    ii. More information needed to determine
        a) Magnitude of the problem
        b) Relevance of transmission and other solutions
3. Conditional Congestion Areas: "future" location of generation
    i. Areas where new generations resources are likely to locate, but
    ii. New transmission needed to serve distant load centers

In the critical category were areas on the east coast running from New York south into the Baltimore – Washington DC. New England was determined to be a congestion area of concern. In the Midwest ISO, transmission in the Dakotas – Minnesota area would constrain the export of wind energy resources, and in the Southwest Power Pool, transmission in the Kansas – Oklahoma area would also constrain the export of wind energy resources. DOE determined that the New York to Washington DC congested areas should be designated as a NIETC:

Figure 1: Map of Designated NIETC for Eastern Interconnection



DOE is currently in the process of preparing for its congestion study for 2009. In this process, DOE is seeking information from the states regarding what the principle purposes and themes should be for this study.

III. Overview of Utility Service and Congestion in Missouri

A. Brief Overview of Population Centers and Utility Service Areas in Missouri

There are three major population centers in Missouri: 1) Saint Louis Metropolitan Area; 2) Kansas City Metropolitan Area; and 3) Springfield Metropolitan/Branson Area. In addition, the Central Missouri (Columbia – Jefferson City) area is experiencing rapid growth.

With respect to Investor-Owned Utilities, Union Electric Company (d/b/a AmerenUE) serves the majority of electric customers on the eastern half of Missouri; while the western half of Missouri is served by Kansas City Power and Light Company (KCPL), Aquila (d/b/a Aquila Networks -MPS and Aquila Networks – L&P) and The Empire District Electric Company (EMDE). The major municipal operated utilities are the City Utilities of Springfield, the City of Columbia, the City of Kirkwood (in the Saint Louis Metropolitan Area) and the City of Independence (in the Kansas City Metropolitan Area). In addition to these relatively large municipal companies, there are several small municipal utilities scattered throughout the state, as well as a system of generation, transmission and distribution cooperatives that serve the needs of rural electricity customers. The generation and transmission functions for the rural electric cooperatives are centralized through AECI. AECI's transmission system was built to provide generation to serve native load from geographically disperse locations (including federal power from the Southwestern Power Administration's (SWPA's) hydro projects and bordering utilities) and to move the power throughout the rural areas in Missouri. AECI is highly interconnected with all of the Missouri investor-owned utilities and many of the municipal utilities.

B. Transmission Providers and Transmission Service in Missouri

There are three major transmission providers in Missouri: 1) MISO; 2) SPP; and AECI. MISO provides transmission service on the eastern portion of Missouri, SPP provides transmission service on the western portion of Missouri, and AECI's transmission system provides the vast majority of interconnections between MISO and SPP in Missouri.

MISO is the transmission provider for AmerenUE, the City of Kirkwood, the City of Columbia and the smaller municipals in AmerenUE's control area. AmerenUE, the City of

Columbia and some of the smaller municipal utilities participate in the MISO energy markets.[2] SPP is the transmission provider for KCPL, the City of Springfield, EMDE, Aquila and some of the smaller municipal utilities located in the control areas of these larger utilities as well as providing contract services for the SWPA. KCPL, the City of Springfield, EMDE and some of the smaller municipal utilities participate in the SPP energy imbalance market.[3] Both MISO and SPP energy markets are based on nodal prices that reflect congestion through price differences at the various locations for generation and loads. For both electricity markets, the locational prices reflect the marginal cost of meeting an additional megawatt of demand at each location, where the locational marginal price is based on the lowest incremental cost from market offers not dispatched to meet market demand, but deliverable through the transmission system to the specific location.

The third transmission provider in Missouri is AECI, a non-FERC or Missouri Commission jurisdictional utility, who serves all but one of the distribution cooperatives and the small municipal utilities located in its balancing authority area/control area. Neither AECI nor SWPA participates in an RTO facilitated energy market, and therefore wholesale energy prices and congestion within their control areas are not transparent. However, where AECI and SWPA are interconnected with MISO and SPP, there are interface nodes where market prices are calculated. Thus, to some extent, congestion into and out of AECI or SWPA can be determined.

With the deregulation of wholesale power, the smaller municipals have become dependent on a mix of long-term and shorter-term purchased power agreements as sources of generation to meet their loads. These power contracts can, and do involve generation sources located outside the control areas of their previous utility providers. Much of the small municipal load is served through a joint arrangement called the Missouri Municipal Energy Pool. When these municipals are long on energy from their contractual sources, they will sell their excess purchased power into both the MISO and SPP energy markets, depending on the source of the contracted power. Long-term firm service is very limited in both areas. So, for example, while the Missouri Municipal Energy Pool might want to serve its load in either SPP or AECI from contracted resources in MISO, it has only been able to arrange a limited amount of firm transmission

[2] The City of Kirkwood is a full requirements wholesale power customer of AmerenUE, and is therefore does not directly participate in the MISO energy markets.
[3] At the present time, Aquila is not a participant in either the MISO or SPP energy markets.

service, and otherwise has to make such transfers using non-firm transmission service on an as available basis.

C. Some General Observations on Congestion in Missouri

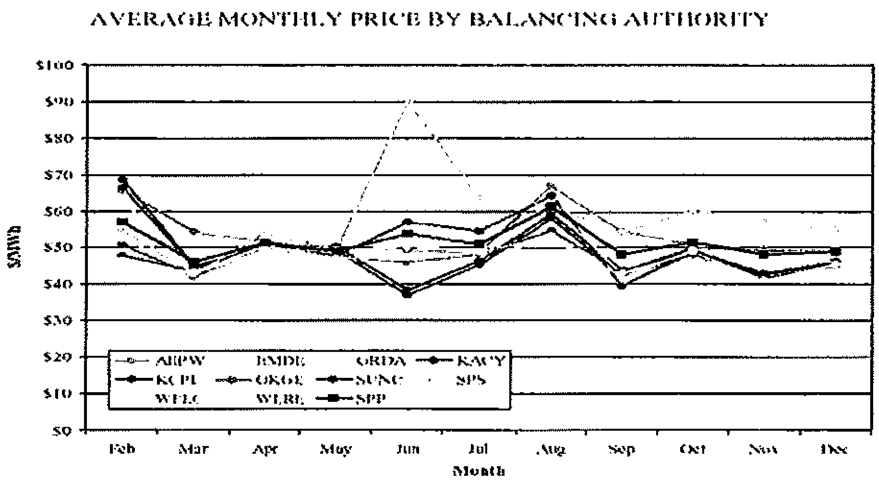
In the MISO markets, AmerenUE is predominately a seller of electricity. This is because AmerenUE has lower-cost power (base-load coal) available to sell during non-system peak hours. As a general matter, AmerenUE's base-load coal plants operate at very high capacity factors, which is a strong indication that congestion is not a significant deterrent to sales. A major reason for this lack of congestion is the investment that AmerenUE has put into its transmission system in the recent past.[4] While the purpose of this investment was to increase the import/export capability into/out of the AmerenUE control area, it also resulted in reducing congestion on the AmerenUE transmission system.

In the SPP markets, KCPL is predominately a seller of electricity and EMDE is predominately a purchaser of electricity. KCPL has a greater percentage of its generation in base-load facilities than EMDE, while EMDE has a greater percentage of its generation in natural-gas fired and intermittent/wind generation facilities than KCPL. Aquila participates in bilateral markets as both a buyer and a seller, as its fuel mix is between that of KCPL and EMDE. Congestion in the SPP market relative to Missouri appears to be occurring at a small number of locations. In the 2007 State of the Market Report for SPP, the external market advisor and monitor for SPP reported that, "We found that 75% of the congestion occurred on just 10 flowgates (out of a total number of over 200 flowgates)."[5] From a Missouri perspective, the nodal prices for EMDE and KCPL are at or below the SPP system average as shown in figure 2 taken from the State of the Market Report.

[4] Over the 2005 to 2007 time period, AmerenUE placed over $121 million in transmission upgrades in service that included eight major projects, most notably a new 345 kV line from Callaway to Franks costing $35 million and a new 345 kV line from Rush Island to St. Francois costing $16 million. These transmission upgrades addressed congestion issues within the AmerenUE control area.

[5] 2007 State of the Market Report; prepared by Boston Pacific Company, Inc.; released April 24, 2008. This report can be downloaded from the SPP website at spp.org.

Figure 2[6]



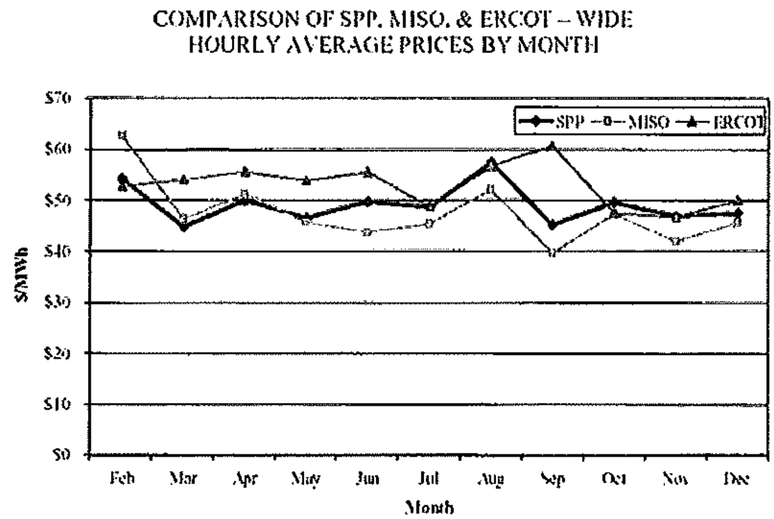
With respect to the SPP and MISO energy markets, it is important to note the lack of direct interconnections between MISO and SPP. There are only three tie lines with a total rating of 720 MVA connecting these two RTOs. On the other hand, there are 112 tie lines with a total rating of 19,224 MVA connecting SPP to AECI, and 63 tie lines with a total rating of 15,409 MVA connecting MISO to AECI. Thus, either east to west (from MISO to SPP) or west to east (from SPP to MISO) flows may significantly impact the AECI transmission system. If that transmission system is built primarily to move power from AECI generation to AECI's customer loads, this could imply significant congestion between the two RTOs.

Unfortunately, information comparable to nodal price data from MISO and SPP is not available for the AECI transmission system. As suggested earlier, another possible data source is for DOE to examine the nodal prices where MISO and SPP interface with AECI.

A similar type of price analysis can be performed at a higher level of aggregation by comparing average prices in SPP to those in MISO. The following graph from the SPP Market Monitor's report for 2007 shows such a comparison.

[6] Ibid, Figure III.4, p. 54.

Figure 3[7]



The similarity in SPP and MISO average monthly prices indicates that the two markets are tracking each other, at least on a monthly basis. The lower summer prices in MISO are an indication of the difference in fuel mix between the two RTOs, with the SPP region having a higher percent of natural gas. Absent any congestion between the two markets, the prices would be identical, but with a maximum difference in the range of $3/MWh, there does not appear to be a significant congestion issue between the two markets

IV. Conclusions

The Missouri Commission hopes that DOE finds these comments helpful, and offers additional assistance that might be needed regarding DOE's upcoming efforts in its 2009 Transmission Congestion Study. The Missouri Commission would be very surprised to find DOE designating a NIETC in its 2009 Transmission Congestion Study that would impact Missouri citizens. However, if our expectations are wrong and DOE finds critical or concern areas of congestion affecting Missouri, the Missouri Commission requests that DOE would make the Missouri Commission aware of this situation at the earliest possible date so that we might bring together the transmission expertise that exists within our staff and utilities to better understand the problem and provide DOE with timely information before it makes a final decision..

[7] Ibid, Figure III.1, p. 49.

Appendix A
Metrics for Congestion

A. Defining Congestion

In its agenda for the June 18 meeting in Oklahoma City, DOE announced that it was seeking information on several topics, including concepts of congestions and metrics to use for measuring such congestion. At the outset, the DOE may want to consider the following definitions of congestion.

a. Transmission constraints are operating limits on electricity flows that are set to maintain the reliable operation of the integrated power grid. These operating limits apply to both
   i. Individual transmission facilities; and
   ii. Groupings of transmission facilities that are highly loaded.
b. Congestion occurs when a transmission constraint restricts the desired dispatch of generation to meet load, resulting in flows across that transmission constraint at its specified operating limit.

These definitions are not significantly different from those included in the DOE published 2006 congestion study. However, an important difference is giving the definition of transmission constraints first, and then using that term in the definition of congestion.

B. Measuring Congestion

Given this definition of congestion, the next question to address is how to measure congestion on the transmission system. The following are some suggestions regarding improving the metrics used by DOE in its 2006 Transmission Congestion Study.

The five measures of congestion used by DOE in its 2006 congestion include:

1. Binding Hours - % time/year transmission constraint is loaded to its limit;
2. U90 - % time/year loading above 90%;
3. All-Hours Shadow Price (SP)[8] – simple average;
4. Binding-Hours SP – simple average; and
5. Congestion Rent – Sum over all hours (SP_h*MWh); where h = hours.

[8] A Shadow Price is the cost savings that would occur if the capacity of the congested transmission constraint is increased by one megawatt. This cost savings occurs as the more expensive generation downstream of the congestion is decreased by one megawatt and the less expensive generation upstream of the congestion is increased by one megawatt.

Possible refinements of these five measures that DOE may wish to consider are:

1. Binding Hours - Include both frequency and duration (% time/year and average duration) over the year;
2. U90 – include both frequency and duration;
3. All-Hours SP – graphical ranking of hours from highest to lowest;
4. Binding-Hours SP – covered by 3 above; and
5. Congestion Rent – graphical ranking of hours from highest to lowest.

The North American Electricity Reliability Council (NERC) standards for operation of the transmission system require transmission providers to specify as "flowgates" certain paths (from a source point to a destination point) on the transmission system that are subject to frequent congestion. There are several routes that electricity travels from the source to the destination of the flowgate, and NERC reliability standards require operators to restrict power flows on the flowgate to the maximum megawatts that can move from the source to the destination when the route carrying the largest megawatts of flow is out of service.[9] One approach to measuring congestion would focus on metrics of relative amounts (megawatts) and values (dollars) of congestion on the set of flowgates that have been previously specified by transmission operators. Taking this approach, the DOE could determine a relative ranking of flowgates. For example, rankings could be developed for flowgates from those with the most frequent congestion to those with the least frequent congestion, or from those having the highest congestion costs to those having the lowest congestion costs. This is precisely the approach taken by SPP in one of its most recent market reports.[10] What is interesting about this report is that the ranking of flowgates by frequency (shown in table 2 as number of five-minute intervals that the flowgate is constrained) is different from the ranking that comes from looking at the cumulative dollar values of marginal costs associated with the congestion.[11]

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[9] This is called an N-1 contingency condition. The concept is that the power grid would be able to continue to support the flows even under the contingency that the power line carrying the greatest flow is forced out of service by some unknown event.

[10] Supplemental Report Summarizing EIS Market Flowgate Congestion April 2008, published May 18, 2008, Figure A.4, p.7. This market report is available on the SPP website.

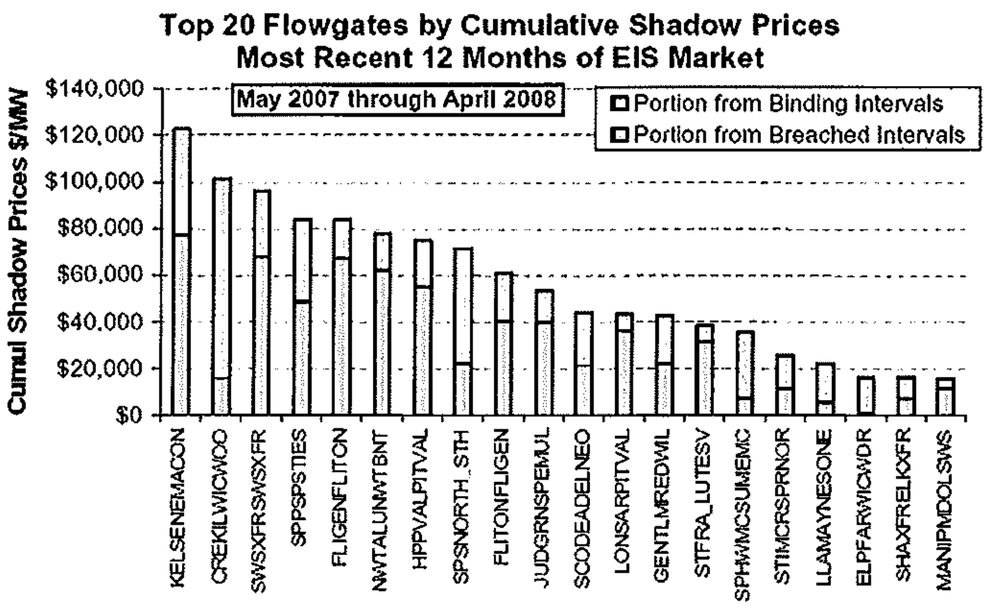
[11] Adding the Shadow Prices over a period of time (in this case, the twelve-months ending April 30, 2007) provides an indication of the cumulative incremental cost to the market from the constraint.

Table 2:

May 2007 through April 2008											
						Sorted Decreasing	Intervals with a Breach			All Congested Intervals	
	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11
Row Index	CONSTRAINT (FLOWGATE)	FG ID	FG RC	BINDING CONSTRAINT-INTERVALS	BREACHED CONSTRAINT-INTERVALS	TOTAL CONGESTED CONSTRAINT-INTERVALS	MAX MW BREACH	MEDIAN MW BREACH	MEDIAN BREACH AS % OF LIMIT	AVERAGE 5-MINUTE SHADOW PRICE ($/MW)	CUMUL HOURLY SHADOW PRICE ($/MW)
	ALL CONSTRAINTS			71,496	6,790	78,286	387	6	2.3	$253	1,652,316
1	SPPSPSTIES	5247	SPP	28,385	376	28,761	326	38	27.5	$35	$83,842
2	SPSNORTH_STH	5196	SPP	14,982	232	15,214	317	25	3.7	$56	$71,338
3	TEMP03_14375	14375	SPP	4,461	75	4,536	30	4	1.3	$274	$103,719
4	CREKILWICWOO	5077	SPP	3,719	117	3,836	53	6	3.1	$316	$100,965
5	HPPVALPITVAL	5203	SPP	1,989	378	2,367	80	7	2.3	$378	$74,650
6	SWSXFRSWSXFR	5330	SPP	1,600	523	2,123	80	4	0.7	$542	$95,937
7	SPHWMCSUMEMC	5204	SPP	1,997	48	2,045	25	4	1.8	$207	$35,268
8	SCODEADELNEO	5078	SPP	1,141	159	1,300	37	5	2.3	$406	$43,977
9	GENTLMREDWIL	6007	MAPP	1,156	142	1,298	145	8	2.0	$395	$42,758
10	KELSENEMACON	5328	SPP	710	486	1,196	15	1	1.1	$1,230	$122,613

The following graph, included in that same report, ranks constraints by their cumulative incremental cost to the market over the twelve months ending April 30, 2008.

Figure 4[12]



[12] Ibid; Figure A5, p.9.

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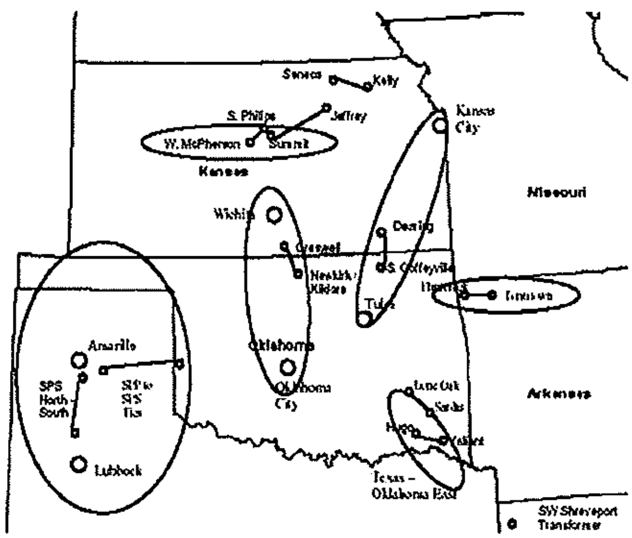
While these traditional measures that focus on transmission flowgates, or in some cases even transmission elements, are appropriate from the perspective of the details on transmission facilities that may be good candidates for economic upgrades, DOE's focus on congestion should be at a higher level. More specifically, the focus should be on areas rather than specific transmission elements or flowgates of the transmission grid that are constrained. An example of this type of analysis is provided in the SPP Market Monitor's report for 2007 where a few constrained areas were identified based on the Market Monitor's analysis of constrained flowgates and transmission elements over the operation of the SPP Energy Imbalance Market from its start up in February 2007 through December 2007. This analysis led the Independent Market Monitor to identify the following six constrained areas within the SPP market.

Figure 5[13]



From south to north, the six constrained areas identified are:

1. Texas Panhandle
2. Northeast Texas / Southeast Oklahoma
3. Oklahoma to Wichita
4. Tulsa to Kansas City
5. Northwest Arkansas
6. Central Kansas[14]

[13] Ibid, Figure III.7, p. 71.

[14] It should be noted that the congestion in this area is due to a "temporary flowgate" created to address a reliability concern resulting from the outage of a substation breaker. Congestion was relieved when the outage was resolved.

It is important to note that SPP planning is in the process of or has addressed each of the transmission system constraints involved for these congested areas. Such evaluations initially address whether or not reliability upgrades are needed over the next ten years, and additionally address whether or not any upgrades related to these congested areas should be included for economic reasons.[15]

[15] Upgrades justified for economic reasons will be included in what is called a Balanced Portfolio. At this time, the SPP Regional State Committee (RSC) has approved the concepts of a Balance Portfolio and the tariff language is under development for submission to the Federal Energy Regulatory Commission (FERC) later this summer.