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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Oklahoma Gas and Electric Company Redbud Energy LP	))))	Docket No. EC08-58-000

JOINT APPLICATION FOR AUTHORIZATION UNDER SECTION 203 OF THE FEDERAL POWER ACT FOR DISPOSITION OF JURISDICTIONAL FACILITIES

VOLUME 1 OF 2

March 20, 2008

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JOINT APPLICATION FOR AUTHORIZATION UNDER SECTION 203 OF THE FEDERAL POWER ACT OF DISPOSITION OF JURISDICTIONAL FACILITIES

Pursuant to Section 203 of the Federal Power Act[1] ("FPA") and Part 33 of the Federal Energy Regulatory Commission's ("FERC" or the "Commission") regulations,[2] Oklahoma Gas and Electric Company ("OG&E") and Redbud Energy LP ("Redbud Energy") (collectively, "Applicants") respectfully request Commission authorization for a transaction in which subsidiaries of Kelson Holdings, LLC ("Kelson Holdings") will sell to OG&E 100 percent of the partnership interests of Redbud Energy, which owns a 1,195 MW (summer rating) gas-fired, combined-cycle power generation facility located in Luther, Oklahoma, and related jurisdictional assets (the "Facility" or the "Redbud Facility"), and OG&E will immediately thereafter dissolve Redbud Energy and sell undivided interests in the Facility to Grand River Dam Authority ("GRDA") and Oklahoma Municipal Power Authority ("OMPA") (the "Transaction"). Upon completion of the Transaction, OG&E, GRDA, and OMPA will own undivided interests in the Facility of 51 percent, 13 percent, and 36 percent, respectively.

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1 16 U.S.C. § 824b (2006).

2 18 C.F.R. Part 33 (2007).

The Transaction satisfies fully the standards set forth in the Commission's Merger Policy Statement[3] and Order No. 642[4] and should be approved. The Transaction will have no adverse effect on competition in any relevant market, no adverse effect on wholesale power or transmission rates, and no adverse effect on federal or state regulation. Moreover, as required by the Energy Policy Act of 2005[5] ("EPAct of 2005") and Order No. 669,[6] Applicants affirm that the Transaction will not result in cross-subsidization of a non-utility associate company or a pledge or encumbrance of utility assets for the benefit of an associate company. Applicants respectfully request that the Commission grant the authorizations requested herein without condition, modification, or trial-type hearing.

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[3] *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, FERC Stats. & Regs. ¶ 31,044 (1996), *on reconsideration*, Order No. 592-A, 79 FERC ¶ 61,321 (1997) ("Merger Policy Statement").

[4] *Revised Filing Requirement Under Part 33 of the Commission's Regulations*, Order No. 642, 93 FERC ¶ 31,111 (2000) ("Order No. 642"), *reh'g denied*, Order No. 642-A, 94 FERC ¶ 61,289 (2001) ("Order No. 642-A").

[5] Pub. L. No. 109-58 § 1253, 119 Stat. 594 (2005).

[6] *Transactions Subject to FPA Section 203*, Order No. 669, FERC Stats. & Regs. ¶ 31,200 (2005) ("Order No. 669"), *on reh'g*, Order No. 669-A, FERC Stats. & Regs. ¶ 31,214 (2006) ("Order No. 669-A"), *on reh'g and clarification*, Order No. 669-B, FERC Stats. & Regs. ¶ 31,225 (2006), ("Order No. 669-B").

I. INTRODUCTION.

The acquisition of the Redbud Facility by OG&E, GRDA[7], and OMPA[8] meets an immediate need for capacity to serve each of the joint purchasers' existing load, and provides a long-term solution to the increasing capacity shortfalls facing each of them in the future. If the Transaction is not approved, OG&E, GRDA, and OMPA will still be required to obtain additional capacity in order to meet their respective load and reliability obligations. Each of the other options available to them, however, which include purchase power agreements or the siting and construction of new generation resources, are likely to come with higher costs and greater risks than the Transaction, and such additional costs would ultimately be borne by OG&E's GRDA's and OMPA's customers. Moreover, the Facility's location and configuration offers important benefits to the joint purchasers (and their customers) that would be difficult to replicate if the Transaction is not approved.

The need for new capacity is evident from a recent, albeit unsuccessful, proposal to construct a new coal-fired generation facility in Oklahoma. In 2006, OG&E and OMPA (together with another load-serving entity, Public Service Company of Oklahoma) proposed to construct and operate a 950 MW high-efficiency, coal-fired generating facility to be located in

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[7] GRDA is an agency of the state of Oklahoma, created by the Oklahoma Legislature in 1935 to be a "conservation and reclamation district for the waters of the Grand River." GRDA operates three hydroelectric facilities along the Grand River system and certain coal-fired generation facilities which total 1,480 MW. GRDA transmits and delivers this wholesale electricity across its 24-county service area in Northeast Oklahoma serving municipalities, electric cooperatives, and industrial end-users.

[8] OMPA is an agency of the State of Oklahoma, created pursuant to the Oklahoma Municipal Power Authority Act of 1981. OMPA is authorized by statute to jointly plan, finance, own and operate electric power supply facilities. It acts as a wholesale power supplier to 35 municipalities in Oklahoma and is a supplier of contract capacity and supplemental energy to four cities in Kansas. The coincident peak demand of all of OMPA's participants exceeds of 600 MW. OMPA meets its power-supply obligations, in part, with approximately 346 MW of OMPA generation, including undivided ownership interests in Oklaunion No. 1 (Coal, 80 MW); Dolet Hills No. 1 (Lignite, 25 MW); Pirkey No. 1 (Lignite, 16 MW); and McClain (Combined Cycle Natural Gas, 110 MW). OMPA meets the remainder of its power needs through purchases from utilities and through contractual entitlements to the output of approximately 75 MW of generating capacity operated by five OMPA members.

Red Rock, Oklahoma (the "Red Rock" facility) to meet the need for additional generating capacity for the project sponsors. While OG&E was unable to obtain necessary regulatory pre-approvals in Oklahoma and cancelled the project, the need for additional capacity remains. Indeed, while the Oklahoma Corporation Commission ("OCC") declined to grant pre-approval for recovery of the costs of the proposed Red Rock facility, it specifically recognized OG&E's need to obtain additional capacity.

In the Fall of 2007, Kelson Holdings, the indirect owner of the Redbud Facility, announced its intention to sell the Facility as part of a broader effort to market a portion of its generation portfolio. OG&E expressed an interest in acquiring the Redbud Facility on a stand-alone basis, and Kelson Holdings agreed to discuss the sale of the Facility separately from the rest of the generation assets. Subsequently, GRDA and OMPA joined with OG&E to consider the joint acquisition of the Facility by the three parties. On January 21, 2008, the parties executed definitive agreements pursuant to which OG&E, GRDA, and OMPA, respectively, would acquire 51 percent, 36 percent, and 13 percent interests in the Redbud Facility.

As detailed below and in the accompanying Prepared Direct Testimony and Exhibits of Mr. Jesse B. Langston ("Langston Testimony"), the Transaction offers significant benefits to OG&E, GRDA, OMPA and their customers. Specifically:

- The Transaction remedies OG&E's, GRDA's and OMPA's need for new capacity;
- The acquisition of the Redbud Facility will enhance reliability. The plant is a relatively new, highly reliable facility comprised of four units in a "4x1x1x1" configuration, a design that enhances both operational flexibility and reliability. The plant's location near major load centers also promotes reliability by limiting risks associated with potential line outages;
- The purchase of the Facility by OG&E, GRDA, and OPMA allows these parties to acquire a capacity needed to reliably serve its native load at reasonable cost. The cost of the Redbud Facility is less than the cost of new construction for a similar generation resource and the acquisition of an existing facility also shields the joint

purchasers from the risks associated with the often unpredictable costs, delays, and uncertainties associated with new generation resource construction projects;

- The acquisition of the Facility will lower operating costs by allowing dispatch of the Facility ahead of less efficient units and will protect OG&E, GRDA, and OMPA from risks of future increases in purchase power costs; and

- The acquisition of the Facility will complement new investment in wind resources.

If OG&E, GRDA, and OMPA had not responded to the opportunity presented by Kelson Holdings' decision to sell the Redbud Facility, it is not clear when – if ever – a similar resource would have become available. If this Application is not approved, the joint purchasers will be forced to rely on potentially volatile wholesale markets or other, more costly, options to remedy their current and projected capacity deficits.

The Transaction satisfies fully the Commission's public interest standards. The authorizations requested by Applicants are virtually identical to those granted by the Commission in the *Nevada Power*,[9] *Westar*,[10] *Duke*,[11] *Entergy Arkansas*,[12] and *Entergy Gulf States*[13] cases, in which the Commission approved the acquisition by a traditional utility of a generator located within the utility's service territory. As in those proceedings, the sale of the Facility to OG&E, GRDA, and OMPA will have no adverse competitive effects because it has only incidental effects on market concentration (as determined by the application of the Appendix A competitive screen analysis) and because Applicants have neither the incentive nor the ability to exercise any incremental market power that may result from the Transaction.

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[9] *Nevada Power Company*, 113 FERC ¶ 61,265 (2005).

[10] *Westar Energy Inc.*, 115 FERC ¶ 61,228 (2006), *reh'g*, 117 FERC ¶ 61,011 (2006), *reh'g*, 118 FERC ¶ 61,237 (2007).

[11] *Duke Power Company, LLC*, 117 FERC ¶ 62,094 (2006).

[12] *Quachita Power, LLC.*, 122 FERC ¶ 62,071 (2008).

[13] *Entergy Gulf States, Inc.*, 121 FERC ¶ 61,182 (2007).

Several factors combine to show that the Transaction poses no risk of competitive harm. As detailed below and in the accompanying affidavit prepared by Julie R. Solomon of CRA International, Inc. ("Solomon Affidavit"), any assertion that the Transaction will enhance any party's market power is without basis and any potential for the exercise of market power is fully mitigated by present market features:

- OG&E, GRDA, and OMPA are each capacity short and will use their respective shares of the Facility's capacity to meet their current and forecasted load and reliability obligations;
- All of the wholesale customers located within OG&E's balancing authority area (with one exception) are already being served via long-term, full-requirements contracts and, therefore, are not participants in wholesale markets. The one exception is OMPA, which intends to rely on its acquisition of a share of the Redbud Facility to meet its load without being forced to rely on contracts with third-party suppliers;
- OG&E does not have authority to sell at market-based rates within the OG&E balancing authority area. Within this market, OG&E is authorized to sell short-term energy (one week or less) only at cost-based rates and is not authorized to make any wholesale sales with a duration of more than one week and less than one year. Wholesale sales for a term of more than one year require prior Commission review and approval;
- The Redbud Facility represents only a small portion of the generating capacity located in the footprint of the SPP Energy Imbalance Services ("EIS") market, which is available to meet customers' real-time energy needs;
- OG&E is required to credit 80 percent to 100 percent of the profits of off-system sales and must, therefore, forego virtually all of the benefit of such sales; and
- Activities within the SPP market are subject to review by an independent market monitor.

These factors demonstrate conclusively that OG&E has neither the incentive nor the ability to exercise any market power that may be alleged to result from the Transaction. Further, as detailed below, the Transaction will have no adverse effects on rates or regulation and presents no cross-subsidization concerns. Accordingly, Applicants respectfully request that the Commission grant the requested authorizations promptly and without further condition, modification, or trial-type hearing.

II. DESCRIPTION OF THE APPLICANTS.

A. Oklahoma Gas and Electric Company.

OG&E, an Oklahoma corporation, is an electric utility operating company and a wholly-owned subsidiary of OGE Energy Corp. ("OGE Energy"). The company serves more than 762,000 retail customers in Oklahoma and western Arkansas, and sells electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. OG&E is a member of the Southwest Power Pool, Inc. ("SPP") and owns the transmission facilities within its service territory, which are functionally controlled by SPP. Requests for new transmission service on OG&E's transmission facilities are submitted to SPP in accordance with its Open Access Transmission Tariff ("OATT").

On March 21, 2006, the Commission conditionally granted OG&E cost-based rate authority based on a mitigation plan that (a) provides for cost-based pricing for short-term sales (one week or less) made within OG&E's balancing authority area, (b) prohibits OG&E from making sales of between one week and one year in duration for loads that sink in OG&E's balancing authority area, and (c) requires new agreements for long-term sales to be submitted to the Commission for prior review and approval.[14] OG&E has blanket market-based rate authority for sales in directly interconnected first-tier balancing authority areas.[15] On July 25, 2006, OG&E submitted revisions to its market-based rate tariff to be able to sell energy imbalance service into the SPP EIS market at market-based rates.[16]

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[14] *Oklahoma Gas and Electric Company*, 114 FERC ¶ 61,297 (2006).

[15] *Id.*

[16] *See Oklahoma Gas and Electric Company*, Docket Nos. ER98-511-008 and ER97-4345-020 (July 25, 2006). The Commission has not yet acted on this filing.

OG&E has two principal affiliates relevant to this Application. First, Enogex Inc. ("Enogex"), a wholly-owned subsidiary of OGE Energy, is engaged in the gathering, processing, transportation, storage, and marketing of natural gas and natural gas liquids. Enogex owns and operates approximately 8,200 miles of intrastate gathering and transportation pipelines located in Oklahoma. Enogex is subject to regulation by the Commission pursuant to Section 311 of the Natural Gas Policy Act.[17]

Second, OGE Energy Resources, Inc. ("OERI"), a wholly-owned subsidiary of OGE Energy, markets energy products, including natural gas and electric power, and provides energy-related services. OERI does not own or control any generating resources. Like OG&E, OERI is authorized to make wholesale power sales at market-based rates in first-tier markets and is subject to the same terms as OG&E with regard to wholesale sales within OG&E's balancing authority area.[18]

B. Redbud Energy LP.

Redbud Energy is a Delaware limited partnership created for the sole purpose of owning the Facility. It is an Exempt Wholesale Generator ("EWG") and has been authorized to make wholesale sales at market-based rates.[19] Redbud Energy owns only those limited transmission facilities necessary to interconnect the Facility to the OG&E transmission grid.

All of the partnership interests in Redbud Energy are owned by Redbud Energy I, LLC, Redbud Energy II, LLC, and Redbud Energy III, LLC, each a Delaware limited liability

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[17] 15 U.S.C. § 3371 (2000).

[18] *Oklahoma Gas and Electric Company*, 114 FERC ¶ 61,297 (2006).

[19] *See Redbud Energy LP*, 107 FERC ¶ 61,101 (2004) (granting EWG status); *Redbud Energy LP*, Docket Nos. ER01-1011-000, et al., (Mar. 29, 2001) (unpublished letter order) (authorizing market-based rates); *Redbud Energy LP*, 111 FERC ¶ 61,397 (2005) (accepting triennial market analysis filing); *Cottonwood Energy Co. LP*, Docket Nos. ER01-642-007, *et al.* (May 3, 2007) (unpublished letter order) (accepting triennial market analysis filing).

company and an indirect, wholly-owned subsidiary of Kelson Holdings.[20] Harbinger Capital Partners Master Fund I, Ltd. ("Harbinger Capital") owns a two-thirds interest in Kelson Holdings; the remaining one-third interest is owned by Harbinger Capital Partners Special Situations Fund, LP ("Special Situations Fund," and together with Harbinger Capital, "Harbinger").[21] Harbinger Capital and Special Situations Fund are separate investment funds that invest primarily in distressed/high yield debt securities, special situation equities, and private loans and notes, including equity and debt securities of entities owning generation assets. The Commission has granted Redbud Energy and the other public utility subsidiaries of Kelson Holdings blanket authorization under FPA Section 203 for the transfer of up to 45 percent of Kelson Holdings' voting securities pursuant to a private placement.[22] As of the date of this filing, no such transfer has occurred.

III. DESCRIPTION OF THE TRANSACTION.

A. The Redbud Facility.

The Redbud Facility is a 1,195 MW (summer rating) combined-cycle electric generating facility located in Luther, Oklahoma. The plant consists of four units, each consisting of a GE 7FA combustion turbine, a Foster Wheeler heat recovery steam generator, and an Alstom steam

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[20] In addition to its ownership interests in the Facility, Kelson Holdings also is the indirect owner and operator of (a) Cottonwood Energy Company, L.P., which owns and operates a 1,230 MW natural gas-fired, combined-cycle electric generating facility located in the town of Deweyville in Newton County, Texas, that is interconnected with the Entergy transmission system; (b) Dogwood Energy, LLC, which owns and operates a 620 MW natural gas-fired, combined-cycle electric generating facility located in Pleasant Hill, Missouri, that is interconnected with the Aquila, Inc./Missouri Public Service transmission system; and (c) Magnolia Energy LP, which owns and operates a 920 MW natural gas-fired, combined-cycle electric generating facility located in Ashland, Mississippi, that is interconnected with the Tennessee Valley Authority transmission system. The Transaction will have no effect on the ownership or operation of these generation facilities.

[21] Harbinger also invests in the securities of other companies that own generation facilities. The only investment where it is presumed to have control by virtue of holdings of 100 percent or that involves generation located in the markets relevant to this Transaction is Harbinger's approximately 21 percent interest in the common stock of Calpine Corporation ("Calpine").

[22] *Cottonwood Energy Company, LP*, 121 FERC ¶ 61,184 (2007).

turbine. The Facility is situated on a 320 acre site, of which 80 acres are used for the plant footprint. The Redbud Facility is interconnected with the OG&E transmission system pursuant to a November 27, 2000 Interconnection Agreement.[23] The jurisdictional facilities that are being transferred consist of transmission facilities used to interconnect the generation units to the OG&E transmission system, generation step-up transformers, Redbud Energy's market-based rate tariff, and associated books and records.[24]

B. Purchasers' Need for Additional Generation Capacity.

Each of the joint purchasers has a clear need for new capacity. OG&E currently does not own sufficient generation resources to meet its load and reliability obligations and relies on power purchase agreements ("PPA") to bridge this shortfall, which is expected to increase over time. OG&E's resource planning analysis projects a need for 424 MW of additional capacity in 2010, increasing to 731 MW by 2013, with annual increases of approximately 100 MW thereafter.[25] GRDA and OMPA also are capacity short and will be required to rely on purchase power agreements to meet progressively greater portions of their load and reliability obligations as their load increases over time. GRDA's projected capacity needs range from over 282 MW in 2010 to 349 MW in 2012, and OMPA's projected needs are approximately 150 MW in the same period.[26]

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[23] This agreement was accepted for filing by letter order issued in Docket No. ER01-646-000 on January 24, 2001. A revised interconnection agreement was accepted for filing by letter order issued in Docket No. ER01-2987-000 on October 26, 2001. The interconnection agreement will be assumed by OG&E as part of the Transaction.

[24] After consummation of the Transaction, OG&E will file with the Commission a notice of change of status under Section 205 of the FPA, and to cancel Redbud's market-based rate tariff and assume Redbud's existing interconnection agreement with OG&E.

[25] *See* Langston Testimony at 4.

[26] *See* Solomon Affidavit at 23-24.

As a result of this capacity deficit, the joint purchasers currently rely on PPAs – including agreements to purchase capacity from the Facility – to meet their load obligations. OG&E has contracted for a 300 MW purchase from the Redbud Facility, the result of a competitive bidding process, to meet its load and reserve obligations for the summer periods of both 2008 and 2009.[27] GRDA and OMPA also currently rely on purchases from the Facility, with GRDA purchasing 150 MW annually in 2008-2009 (summer period), and OMPA purchasing 80 MW, 95 MW, and 125 MW, respectively, in 2008-2010 (year round).[28] Absent the construction or acquisition of additional generation resources, the joint purchasers would be increasingly reliant on PPAs to meet load.

To address these circumstances, OG&E (together with OMPA and the Public Service Company of Oklahoma) proposed in 2006 to construct the Red Rock facility, a 950 MW coal-fired generating station to be located in Red Rock, Oklahoma.[29] Subject to regulatory approvals, construction of the Red Rock facility was to commence in 2007, with a projected in-service date of 2012. However, OG&E and its partners were unable to obtain necessary pre-approvals from the OCC and the project was terminated in 2007. In this proceeding, however, the OCC re-affirmed the need for new capacity, noting that there is "substantial evidence" that OG&E has a need for additional generating capacity.[30] Following this decision, OG&E re-focused its

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27 *See* Langston Testimony at 6.

28 *See* Solomon Affidavit at 23-24.

29 *See* Langston Testimony at 4.

30 *In The Matter Of The Application Of Oklahoma Gas And Electric Company For An Order Of The Commission Granting Pre-Approval To Construct Red Rock Generating Facility And Authorizing A Recovery Rider*, 2007 Okla. PUC LEXIS 249 (Oct. 11, 2007).

resource planning toward gas-fired generation, together with its continuing commitment to wind-powered generation and demand-side management.[31]

The availability of the Redbud Facility presents a unique opportunity for OG&E, OMPA, and GRDA. While these parties did not foresee that the Redbud Facility would be offered for sale, they recognized immediately that the acquisition of the Facility would meet their capacity needs. As Mr. Langston explains, Kelson Holdings' decision to sell the Redbud Facility presented a unique, one-time opportunity for OG&E and its partners to acquire such capacity and to lock-in value for their customers.[32]

C. Transaction Structure.

The Transaction provides for OG&E to acquire 100 percent of the partnership interests of Redbud Energy from Redbud Energy I, LLC, Redbud Energy II, LLC, and Redbud Energy III, LLC pursuant to the terms and conditions of the Purchase and Sale Agreement, dated January 21. 2008 ("PSA").[33] Immediately thereafter, OG&E will dissolve the limited partnership and sell undivided interests in the Facility's assets to OMPA and GRDA pursuant to the Asset Purchase Agreement, dated January 21, 2008 ("APA").[34] Following implementation of the Transaction, OG&E, OMPA, and GRDA will own the Facility as tenants-in-common in percentages of 51 percent, 13 percent, and 36 percent, respectively. These ownership percentages entitle OG&E,

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31 *See* Langston Testimony at 5.

32 *Id.* at 8-9.

33 A copy of the PSA is included with this Application as Exhibit I (A).

34 A copy of the APA is included with this Application as Exhibit I (B).

GRDA, and OMPA to proportionate shares of the Facility's capacity, giving them rights to approximately 610 MW, 155 MW, and 430 MW, respectively.[35]

Upon consummation of the Transaction, OG&E will operate the Facility on behalf of the joint owners. However, each owner will schedule the dispatch of and is entitled to sell all or any part of its share of the Facility's capacity. Each owner also is responsible for all fees, charges, and expenses (including any Imbalance Charges) associated with the scheduling, sale, transmission, or delivery of its share of the Facility's output to its network load or to any other point(s) of delivery, including the costs of any new facilities that may be required to be constructed to satisfy an owner's request for transmission service. Moreover, each owner is required to enter into individual fuel supply arrangements, although they may authorize an operations manager, or an agent, to purchase fuel for an individual owner's account.

D. The Transaction Creates Significant Customer Benefits.

The acquisition of the Redbud Facility will produce important benefits for OG&E, GRDA, OMPA, and their respective customers. These benefits are described herein and in Mr. Langston's testimony.

First, the Redbud Facility meets the joint purchasers' capacity needs. For OG&E, the Transaction cures an immediate capacity need that has been addressed in the short term by a 300 MW PPA with Redbud Energy.[36] As explained in Mr. Langston's testimony, absent the

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[35] The Commission has traditionally treated similar multi-part transactions as a single transaction for purposes of FPA Section 203 review, allowing applicants to demonstrate that the transaction, taken a as a whole, is consistent with the public interest. *See, e.g., DTE Energy Services, Inc.*, 120 FERC ¶ 62,040 at 64,203 (2007); *Rowan County Power, LLC*, 116 FERC ¶ 62,091 at 62,298 (2006); *Zeeland Power Company, LLC*, 120 FERC ¶ 62,209 (2007).

[36] On March 23, 2007, Redbud Energy entered into an Energy Management Agreement ("EMA") with Westar Energy Inc. ("Westar") for Westar to provide Redbud fuel procurement, energy sales, risk management, and settlement services. Pursuant to this EMA, Westar, acting as marketing agent for Redbud, entered into a PPA with OG&E under which OG&E purchased 300 MW from the Redbud Facility for the summer period of 2008 and 2009. The same arrangements were used with regard to the GRDA and OMPA contracts.

acquisition of the Facility, OG&E is expected to be short 424 MW of the capacity needed to meet its load and reserve obligations in 2010, and this capacity deficit will increase to 731 MW by 2013, with OG&E's load expected to increase by approximately 100 MW annually thereafter.[37] Similarly, without purchase of the Redbud Facility, GRDA and OMPA are expected to be capacity short by 282 MW and 157 MW, respectively, in 2010, and this deficit is projected to be 350 MW and 140 MW, respectively, by 2012.[38]

Second, the addition of the Redbud Facility will enhance the reliability of the owners' respective generation portfolios. The Facility is a relatively new plant with four units in a "1x1x1" configuration that allows the plant to operate any and all units as needed.[39] Further, the Facility has an excellent operating history and has not experienced any significant operational or maintenance issues.[40] The plant's location near OG&E's Oklahoma City load center also promotes system reliability by limiting the risks of transmission outages to load in that region.[41]

Third, the Transaction provides for the joint purchasers to acquire new capacity at reasonable cost. OG&E, GRDA, and OMPA agreed to acquire the Facility following a competitive sales process conducted by Goldman Sachs, Inc. on behalf of Kelson Holdings and a period of vigorous negotiations among the parties.[42] The Transaction enables the joint purchasers to acquire existing capacity at a price of $693/kW, which is approximately 24 percent less than the current estimate of $900/kW for construction of a similar generation resource.[43] In

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37 *See* Langston Testimony at 4.

38 *See* Solomon Affidavit at 23-24.

39 *See* Langston Testimony at 10.

40 *See id.*

41 *See id.*

42 *See id.* at 6.

43 *See id.* at 11.

addition, because the Facility is interconnected to the SPP-administered transmission grid, investments in transmission facilities required by the Facility have already been made.[44]

Fourth, the acquisition of the Facility will lower costs and will protect the joint purchasers (and their customers) from risks of future cost increases.[45] The Facility is a relatively new generation facility and significantly more efficient that many of OG&E's existing natural gas-fired peaking plants.[46] As a result, the Facility is expected to be dispatched ahead of less efficient units, thereby lowering operating costs.[47] Further, the acquisition of the Facility shields the joint purchasers from costs attributable to cost overruns as well as delays associated with new resource construction.[48] The Transaction also protects the joint purchasers (and their customers) from volatile wholesale markets and from cost increases under future PPAs.

Fifth, the addition of the Redbud Facility will complement new investment in wind energy. OG&E currently owns and operates 120 MW of wind resources and purchases an additional 50 MW of wind energy. OG&E also is planning to add an additional 600 MW of wind capacity over the next 4 years, thus increasing OG&E's total wind portfolio to 770 MW.[49] The Facility's ability to ramp up and down is particularly valuable in a portfolio that includes intermittent capacity, such as wind generation, because it allows the system operator to respond to the varying and often unpredictable changes in the output of such intermittent resources.[50]

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44 *See id.* at 13.

45 *See id.* at 13.

46 *See id.* at 12.

47 *See id* at 12-13.

48 *See id.* at 13.

49 *See id.* at 14.

50 *See id.*

IV. THE TRANSACTION IS CONSISTENT WITH THE PUBLIC INTEREST.

FPA Section 203(a), as amended by EPAct of 2005, provides that the Commission will approve a proposed transaction if it finds that the transaction will be "consistent with the public interest."[51] To consider whether a transaction is in the public interest, the Commission considers the following factors: (1) the effect on competition; (2) the effect on rates; and (3) the effect on regulation.[52] In addition, FPA Section 203(a)(4) directs the Commission to consider whether the transaction will result in inappropriate cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the benefit of an associate company.[53] This Application demonstrates that the proposed Transaction will have no adverse effect on competition, rates, or regulation, and will not result in cross-subsidization of a non-utility associate company or a pledge or encumbrance of utility assets for the benefit of an associate company. Accordingly, the proposed Transaction warrants the Commission's approval.

A. The Transaction Will Have No Adverse Effect on Competition

As set forth more fully below and in Ms. Solomon's affidavit, the Transaction will have no adverse effect on competition in any relevant market.[54]

1. Horizontal Competitive Market Analysis.

The Transaction will have no adverse effects on horizontal market power. An analysis of the SPP geographic market, as defined by the EIS market footprint, shows that there is no adverse effect on competition resulting from the Transaction, and an analysis of the relevant

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51 16 U.S.C. § 824b(a)(4) (2000 Supp. V).

52 *See* Merger Policy Statement at 30,116-121; *see also* 18 C.F.R. § 2.26(b).

53 *See* 18 C.F.R. § 33.2(j).

54 On March 7, 2008, the Federal Trade Commission ("FTC") granted early termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvement Act. Such notification indicates that neither the FTC nor the Department of Justice intend to investigate the transaction.

first-tier markets produces the same result. Further, while the Appendix A analysis does show screen failures when the narrow GRDA and OG&E balancing authority area markets are examined, the results of these base case analyses are not reflective of the actual conditions in the relevant markets, as shown by Applicants' sensitivity analyses that correct for certain unrepresentative and overly conservative base case assumptions. As detailed below, these sensitivity cases show only minor, incidental screen failures, which generally occur in shoulder periods. When these results are properly viewed together with other market features, such as the joint purchasers' capacity needs and OG&E's lack of market-based rate authority in its balancing authority area market, it is evident that the Transaction will have no adverse effect on competition. The same finding is equally evident with regard to the vertical competitive market analysis.

However, if the Commission were to conclude that the Transaction may result in an inappropriate increase in market power, OG&E is prepared to underwrite the construction of specific transmission upgrades that would mitigate fully any potential adverse competitive effects. These specific projects, which are identified and described in the accompanying Prepared Direct Testimony of Philip L. Crissup ("Crissup Testimony"), will increase the simultaneous import limits ("SILs") into the relevant geographic markets by an amount sufficient to reduce post-Transaction Herfindahl-Hirschman Index ("HHI") levels to levels equal to (or in some cases less than) the pre-Transaction HHI levels.[55] While OG&E does not believe that the Transaction presents competitive concerns that require mitigation, it is prepared to undertake such projects in order to facilitate and expedite approval of the proposed Transaction.

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[55] Crissup Testimony at 27; Solomon Affidavit at 35.

a. An analysis of the Transaction pursuant to Appendix A shows that there are no screen failures with regard to the SPP market and the first-tier markets and that there are only limited screen failures in the narrow OG&E and GRDA balancing authority area markets.

Appendix A of the Merger Policy Statement requires an analysis of the competitive effects of a proposed transaction that examines the effect of a proposed transaction on market concentration. An analysis of the Transaction in accordance with the Commission's regulations and Appendix A is contained in Ms. Solomon's affidavit, included as Exhibit J-1.

The Merger Policy Statement directs applicants to submit analyses of Economic Capacity ("EC") and Available Economic Capacity ("AEC"). While Ms. Solomon's analysis includes both EC and AEC measures, AEC is the more relevant measure of the competitive effect of the Transaction in the SPP as well as in the balancing authority markets studied by Ms. Solomon because all load-serving entities within the relevant geographic markets retain the obligation to plan for and procure resources required to reliably meet the load in their service territories. The Commission has acknowledged that AEC is the relevant measure when significant native load obligations remain and there is no expectation that the market will be restructured in the future to eliminate such obligations.[56]

Ms. Solomon examined the effect of the Transaction on four separate geographic markets or groups of geographic markets.

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[56] *See Duke Power Company, LLC*, 117 FERC ¶ 62,094 (2006); Nevada Power Company *et al.*, 113 FERC ¶ 61,265 (2005); *Westar Energy Inc.*, 115 FERC ¶ 61,228 (2006), *reh'g*, 117 FERC ¶ 61,011 (2006), *reh'g*, 118 FERC ¶ 61,237 (2007); *Aquila, Inc.*, 117 FERC ¶ 61,276 (2006), *National Grid plc*, 117 FERC ¶ 61,080 (2006); *Great Plains Energy Incorporated*, 121 FERC ¶ 61,069 (2007); *Entergy Gulf States, Inc.*, 121 FERC ¶ 61,182 (2007); *Entergy Arkansas, Inc.*, 122 FERC ¶ 62,071 (2008). While SPP has been a Commission-approved Regional Transmission Organization ("RTO") since October 1, 2004, and has established a real-time market with Commission approved market monitoring provisions (*Southwest Power Pool, Inc.*, 109 FERC ¶ 61,009 (2004) ("RTO Order"), *order on reh'g*, 110 FERC ¶ 61,137 (2005)), parties throughout the SPP footprint continue to have individual load and reliability obligations.

i. SPP Market.

Ms. Solomon initially examined the effect of the Transaction in the SPP market.[57] There is about 47,000 MW of generating capacity in the footprint of the SPP EIS market.[58] More than 8,000 MW of this capacity is gas-fired, combined-cycle generating capacity of similar vintage and operating characteristics as the Redbud Facility, and almost 20,000 MW of such generation has been added between 2000 and 2006 in the balancing authority areas adjacent to the OG&E balancing authority. Given the amount of third-party generation located in and around the SPP market, Ms. Solomon concludes that there is sufficient rival generation to serve any demand in the OG&E or GRDA balancing authority areas.[59]

The Transaction does not adversely impact competition in the SPP market. The Redbud Facility represents only 3 percent of the generating capacity located in the SPP footprint and the competitive analysis screen is easily passed for both EC and AEC measures in the SPP EIS

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[57] While destination markets typically are defined as individual balancing authority areas, the Commission's practice has been to aggregate customers that have the same supply alternatives into a single destination market. This approach has been accepted in a number of merger filings. *See* Order No. 642, ¶ 31,311 at 31,844-5 (citing *Atlantic City Electric Company and Delmarva Power & Light Company*, 80 FERC ¶ 61,126 (1997)); *Consolidated Edison Co., Inc. and Northeast Utilities* 91 FERC ¶ 61,225 (2000), *reh'g denied*. (To the extent there are internal transmission constraints within these markets, the Commission has considered smaller markets within these single control areas as potentially relevant). While the Commission has not previously explicitly relied upon SPP as a relevant geographic market in the context of merger analysis, it has relied on the existence of the SPP EIS market as sufficient to allow parties to sell into the EIS market at market-based rates. *Southwest Power Pool, Inc.*, 114 FERC ¶ 61,289 (2006).

[58] The real-time EIS market began in February 2007, and is based on a least cost bid-based security constrained economic dispatch and locational imbalance pricing system. This is equivalent to locational marginal pricing in markets administered by other RTOs. The SPP EIS market provides resources the opportunity either to make themselves available for dispatch by SPP's market systems or to self-dispatch to serve scheduled transactions or native load. SPP staff and stakeholders are in the process of developing and evaluating a comprehensive market services design for the region, which is expected to provide additional SPP markets for ancillary services, day-ahead unit commitment and day-ahead energy. In addition, SPP has a market monitor in place and its Market Monitoring Unit has conducted a variety of reviews of competitive conditions in the SPP region, including reviews of the EIS market.

[59] *See* Solomon Affidavit at 27.

market footprint.[60] The market is unconcentrated to moderately concentrated and the HHI changes are negative for AEC and only slightly positive of EC.[61]

ii. First-Tier Balancing Authority Area Markets.

Ms. Solomon's analysis also shows that the Transaction has no adverse competitive effect in the first-tier balancing authority area markets. Specifically, Ms. Solomon performed a competitive analysis screen for each of OG&E's and GRDA's first-tier balancing authority area markets.[62] The EC and AEC measures are passed in all first-tier balancing authority area markets.[63]

iii. OG&E Balancing Authority Area Market.

For the OG&E balancing authority area, Ms. Solomon conducted a base case analysis consistent with the Commission's Delivered Price Test ("DPT") methodology. This analysis, however, is affected by changes in market size attributable to the export of capacity to GRDA and by use of seasonal SILs that are well below the first contingency incremental transfer capability ("FCITC") for many of OG&E's individual first-tier balancing authority area markets. Reliance on these SIL values fails to provide a reasonable estimate of the amount of competing supply that may be imported into the OG&E market. Ms. Solomon therefore performed a sensitivity analysis utilizing a conservative FCITC-based value as a proxy for SIL. This sensitivity analysis shows only negligible effects on market concentration as a result of the Transaction.

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60 *See id.*

61 *See id.* at 31. The Redbud Facility is not economic in the off-peak periods, and, as a result, the HHI changes in those periods are zero.

62 *See id.* at 34.

63 *See id.*

Base Case. Ms. Solomon's base case analysis of the OG&E balancing authority area market takes into account the effect of import capability of the increased dispatch of the Redbud Facility and the delivery of GRDA's portion of the Redbud Facility to the GRDA balancing authority area.[64] Her analysis also attributes the existing contract amounts that OG&E, GRDA and OMPA are purchasing from the Redbud Facility in the respective pre-Transaction shares. This analysis shows that the market varies from unconcentrated (in the winter and shoulder peak periods) to highly concentrated (in the super peak and summer peak periods). The HHI changes from the Transaction range from very negative (when Kelson Holdings' pre-Transaction market share is significantly greater than OG&E's) to very positive (when both OG&E's and OMPA's market shares both increase).[65]

These results, however, are materially affected by the changes in market size between pre- and post-Transaction analysis, which makes the standard HHI metrics difficult to interpret and poor indicators of the actual impact of the Transaction on competition.[66] (HHIs typically are intended to be a static measure merely reflecting shifts in market share rather than changes in market size.) The HHI changes are in part a result of "moving" GRDA's portion of the Redbud Facility's capacity to the GRDA balancing authority area once it is designated as a network resource, such that the post-Transaction OG&E market size is reduced by 430 MW.[67]

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[64] Because OMPA does not operate a balancing authority area, and most of its load is located in the OG&E balancing authority area, this analysis is relevant to an evaluation of OMPA's purchase of the Redbud Facility as well.

[65] Solomon Affidavit at 32.

[66] *See id.* at 28.

[67] *Id.* at 29. The market size can also be affected to the extent the respective parties have an AEC deficit pre-Transaction (i.e., their loads are in excess of their economic supply). Under such conditions, some portion of the additional purchase of capacity from the Redbud Facility first offsets any "negative" AEC post-Transaction, thereby reducing market size for the AEC measure.

Sensitivity. The SILs used in the base case analysis were calculated in accordance with the Commission's directives that all first-tier balancing authority areas be consolidated into a single exporting entity.[68] However, as Mr. Crissup explains, strict adherence to the Commission's default SIL methodology in this specific instance produces SIL values that are quite low and that do not reflect OG&E's actual ability to import power into its balancing authority area from any single or subset of first-tier balancing authority areas. A review of the balancing authority area-to-balancing authority area limits into the OG&E balancing authority area indicates that some of the FCITC values from individual balancing authority areas into OG&E are much higher that the SIL for the OG&E balancing authority area, and that these FCITC values increase post-Transaction.[69] For example, while the default SIL methodology calculates SIL for the OG&E balancing authority area to be 137 MW in the summer season, the FCITC for that same period from SWPA is 800 MW and the FCITC from AEP West is 1,393 MW.[70] Mr. Crissup explains that these artificially low SIL values are due to extremely limited import capability from the Entergy balancing authority area and the incorrect assumption employed by the default SIL methodology that no further imports may occur once that limit is reached.[71]

The base case SIL analysis also fails to consider the likely dispatch and utilization of the capacity post-Transaction, and incorporates assumptions regarding imports that do not fully reflect the increase in transmission capability arising from the export of capacity from the OG&E

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68 Crissup Testimony at 11.

69 *Id.* at 13-14.

70 *Id.* at 11. Public Service Company of Oklahoma ("PSO") and Southwestern Electric Power Company ("SWEPCO") operate a single balancing authority area (referred to as CSWS or AEP West) that combines both their service territories.

71 *Id.* at 11-12.

balancing authority area to the GRDA balancing authority area. When GRDA reserves and schedules an additional portion of the Redbud Facility for delivery to the GRDA balancing authority area market, a counterflow is created that should increase the ability to import into the OG&E balancing authority area.[72] This effect is reflected in the balancing authority area-to-balancing authority area FCITC values, which indicate, for example, that the ability to import on the GRDA-to-OG&E path increases post-Transaction.[73] The Commission's traditional SIL methodology, however, ignores this counterflow effect.

In light of these facts, Ms. Solomon performed an additional alternative analysis for the OG&E balancing authority area that accounts for a higher import capability than is reflected in the base case. Specifically, she relied on the FCITC from AEP West to OG&E as a proxy for the ability for external supplies to be delivered into the OG&E balancing authority area. As Ms. Solomon explains, the use of the highest single FCITC value among the seven first-tier balancing authority areas is a reasonable, and conservative, proxy for the import capability from the combined first-tier markets.[74] The use of FCITC values also allows for recognition of the counter flow effects of capacity exports to the GRDA balancing authority area.

For AEC, this sensitivity analysis shows HHI changes that are negative in all periods except for the Shoulder Peak Period, in which the HHI change exceeds the Appendix A screen

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72 *Under SPP's tariff, if GRDA has a schedule (Network Integration Transmission Service or Firm) to deliver* its energy from the Redbud Facility in OG&E's balancing authority area to the GRDA balancing authority area, then rival suppliers could counter-schedule against it (on a firm or non-firm basis) and potential supply in the OG&E balancing authority area would be unchanged. (In fact, if the rival imports were provided by more than one supplier, the HHI, assuming counterflows are scheduled, would be lower than assuming GRDA's capacity remains in the market.)

73 Crissup Testimony at 14.

74 Solomon Affidavit at 31.

limits.[75] This one screen failure, however, should be discounted as an indicia of competitive harm because it is highly sensitive to modeling assumptions. As Ms. Solomon explains, if the sensitivity analysis is modified to utilize slightly lower market prices, this screen violation disappears.[76] Similarly, if the pre-existing PPAs (which cover only the June – September periods and have only limited applicability to the shoulder periods) are not taken into account for the shoulder period, the screen failure disappears.[77]

iv. GRDA balancing authority area market.

For the GRDA balancing area market, Ms. Solomon also conducted a base case analysis. In this instance, however, the results of the traditional DPT analysis were skewed by changes in market size between the pre- and post-Transaction analyses. This change is due to the transfer of GRDA's share of the Facility (443 MW) from the OG&E balancing authority area to the GRDA balancing authority area as a result of its acquisition of the capacity. Accordingly, Ms. Solomon performed a separate sensitivity analysis that treats 150 MW of the GRDA capacity, the amount currently needed to meet load and reliability obligations in the GRDA balancing authority area, as being exported to the GRDA balancing authority area market, while the additional GRDA capacity remains in the OG&E balancing authority area. This approach, which more accurately reflects the expected utilization of the GRDA capacity in the near term, produces HHI changes that are negative in three periods and that exceed the competitive analysis screen levels in only two periods.

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75 *Id.* at 32-33.

76 *Id.*

77 *Id.*

Base case. Ms. Solomon's analysis of the GRDA balancing authority area market utilized the traditional DPT methodology which, *inter alia*, treats GRDA's entire share of the Redbud Facility as exported to the GRDA balancing authority area market. Under this approach, the market is highly concentrated and the HHI changes are very high.[78]

Sensitivity. In order to take into account periods when GRDA might not need additional amounts of supply from the Redbud Facility, Ms. Solomon analyzed a scenario where GRDA's share of the Redbud Facility over and above its existing 150 MW capacity contract amount remains in the OG&E balancing authority area (rather than being exported to the GRDA balancing authority area).[79] As Ms. Solomon explains, this adjustment is reasonable because it assumes that GRDA would not import capacity into its balancing authority area market beyond that needed to serve its load and would not dispatch this capacity for delivery to GRDA if doing so would displace less expensive supply options.[80] It would make little sense to move capacity from the Redbud Facility to the GRDA balancing authority area only to then re-export it into the OG&E balancing authority area market.[81] Similarly, it is unreasonable to assume that GRDA would dispatch the Redbud Facility, a gas-fired combined cycle facility, ahead of its low-cost hydroelectric generation.

This sensitivity analysis results in HHI changes that exceed the competitive analysis screens thresholds in only two periods. Even these nominal screen failures may over-state the

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78 Solomon Affidavit at 34.

79 GRDA's existing fleet of generation consists nearly entirely of hydroelectric and coal-fired generation, such that gas-fired energy from the Redbud Facility is unlikely to economically displace these existing resources and, therefore, its share of the Redbud Facility located in the OG&E balancing authority area would constitute GRDA's excess resources.

80 *See* Solomon Affidavit at 30.

81 *See id.* at 32.

competitive impact of the Transaction in the GRDA market in that the increase in GRDA's AEC in the summer peak period, in which one of the two screen violations occurs, is 4 MW and even in the shoulder super peak is only 50 MW.[82] This modest increase in AEC is not likely to facilitate the exercise of market power.

b. Other factors demonstrate that the Transaction will have no adverse competitive effects.

Appendix A of the Merger Policy Statement provides that, if the competitive analysis screen shows HHI changes that exceed the safe harbor limits, the Commission may still conclude that a proposed transaction presents no adverse competitive effects based on an evaluation of other relevant factors.[83] Similarly, in the 2007 Supplemental Policy Statement, the Commission explained that Appendix A's indicative screens were intended to identify those transactions that required further competitive review, but that the Commission would examine and give weight to all relevant factors "that could affect competition in the relevant market."[84] In such cases, "the Commission typically considers a case-specific theory of competitive harm, which includes, but is not limited to, an analysis of the merged firm's ability and incentive to withhold output to drive up prices."[85] The Commission recently re-affirmed this approach.[86] Where, as is the case here, prospective purchasers have no incentive or ability to attempt to exercise horizontal market power, the Commission has relied on such factors to conclude that proposed transactions are

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82 *See id.* at 35.

83 FPA Section 203 Supplemental Policy Statement, FERC Stats. and Regs. ¶ 31,253 at P 65 (2007), ("Supplemental Policy Statement"), *clarified*, 122 FERC ¶ 61,157 (2008) ("Supplemental Policy Clarification").

84 Supplemental Policy Statement at P 65.

85 *Id.*

86 *FPA Section 203 Supplemental Policy Statement*, 122 FERC ¶ 61,157 at P 12 (2008); *see also Energy East Corp.*, 121 FERC ¶ 61,236 at PP 11-13 (2008)

consistent with the public interest.[87] The specific factors relevant here are discussed herein and in the Solomon Affidavit.

First, OG&E, OMPA and GRDA are obligated to obtain generation resources sufficient to meet their native and requirements loads and their reliability obligations. Notably, they are all currently capacity short and require additional resources to meet their present and future obligations. Each entity is currently a net buyer of energy and, more specific to this Application, OG&E, GRDA. and OMPA have contracts for portions of the Redbud Facility's output: 300 MW for OG&E. 150 MW for GRDA, and 80 MW for OMPA in 2008.[88] OG&E, for example, will require 424 MW of additional capacity in 2010 and is able to meet its load obligation in 2008 and 2009 only as a result of a 300 MW PPA with the Redbud Facility.[89] This need is expected to grow to 731 MW by 2013 and by approximately 100 MW annually thereafter. GRDA also is capacity short, and needs additional supply. The capacity GRDA will acquire is slightly in excess of its immediate needs, but, by 2015, any excess will be eliminated by expected load growth.[90] Similarly, OMPA, which also is capacity short, will have somewhat more capacity relative to its load and reserve requirements than it needs after purchasing its share of the Redbud Facility, but load growth is expected to eliminate this excess within a few years.[91]

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[87] *See Entergy Gulf States*, 121 FERC ¶ 61,182 at PP 61-62 (2007). In *Entergy*, the Commission recognized that, because the target facility's capacity was needed to meet the acquiring utility's existing capacity needs, the utility "will not have an incentive to attempt to exercise horizontal market power...by withholding the Facility from the market." *Id.* at P 62. The Commission reached similar conclusions in other cases. *See, e.g., Commonwealth Edison Co.*, 91 FERC ¶ 61,036 at n.42 (2000) (noting three reasons based on operational and market conditions faced by ComEd why screen violations did not imply that ComEd could profitably withhold capacity from the acquired facility); *see also Duke Energy Corp.*, et. al., 113 FERC ¶ 61,297 at P 83 (2005).

[88] *See* Solomon Affidavit at 3.

[89] *See id.* at 23.

[90] *See id.* at 23-24.

[91] *See id.* at 24.

Second, all of the wholesale customers located within OG&E's balancing authority area (with one exception) are already being served under long-term, full requirements contracts and, therefore, do not participate in wholesale markets.[92] The one exception is OMPA, which is the only wholesale customer in the OG&E balancing authority area that has a portion of its load not met by either its own generation or full-requirements service provided by OG&E. The Redbud Facility will allow OMPA to rely on its share of the plant's capacity to meet its load and hedge its exposure to market volatility by limiting OMPA's reliance on contracts with third-party suppliers.[93] Thus, any concern that the Transaction will be to the detriment of wholesale customers is purely theoretical.

Third, OG&E does not have authority to sell at market-based rates within the OG&E balancing authority area. Within its balancing authority area market, OG&E is authorized to sell short-term energy (one week or less) only at cost-based rates, and is not authorized to make any wholesale sales with a duration of more than one week or less than one year. Wholesale sales for terms of more than one year may take place only after the Commission's prior review and approval.

Fourth, OG&E's off-system sales are subject to profit-sharing mechanisms with ratepayers that prevent OG&E from retaining virtually any potential profits from such sales. Specifically, the OCC and the Arkansas Public Service Commission ("APSC") require that

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92 *See* Solomon Affidavit at 24. On April 2, 2007, Purcell, one of OG&E's wholesale customers, notified OG&E of its intent to terminate its requirements contract with OG&E in order to seek alternative suppliers. The contract's term renews annually on June 1 pursuant to an evergreen provision, and can be terminated by either party with written notice to the other party submitted not less than 12 months prior to the end of any current term. However, after providing OG&E with notice of its intent to terminate the contract in accordance with its terms, Purcell has indicated that it wants to continue its arrangements with OG&E until it contracts with alternative suppliers and secures the requisite transmission service from SPP to deliver power from such suppliers. As a result, it is unclear at this stage if or when Purcell will terminate the supply contract with OG&E.

93 *See* Langston Testimony at 13-14.

OG&E credit retail customers 80 percent and 100 percent, respectively, of profits from off-system sales. Further, OG&E's FERC Electric Tariff, 1st Revised Volume No. 1, requires OG&E to credit certain wholesale customers served under OG&E's WM-1, WC-1, and WM-2 rate schedules 90 percent of the profits from off-system sales of electricity to other utilities in certain time periods.

Fifth, the SPP EIS market is available to meet customers' real-time energy needs and mitigates any potential to exercise market power. The EIS market helps prevent any attempt to exercise market power over load in the region by providing a final market that suppliers can access that has broad participation and market monitoring and associated market mitigation rules.

Finally, the SPP market has Commission-approved market monitoring and mitigation measures in effect.[94] The SPP market monitor is responsible for monitoring market participant behavior to "remedy any actual or potential abuse of market power or market design inefficiencies as part of its monitoring process."[95] The market monitor may demand that any market participant violating the market monitoring and mitigation measures undertake any corrective action or, without prior discussion or demand, implement any Commission-approved, mitigation measure as appropriate.[96]

These factors, taken together, demonstrate that OG&E has no incentive to exercise any incremental market power that might be alleged to result from the Transaction. The simple facts are that OG&E (as well as GRDA and OMPA) intend to rely on the Facility to meet their load obligations and to provide mandated reserve margins. Accordingly, OG&E (as well as its co-

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[94] *See* Attachment AF of the SPP OATT.

[95] *See* Section 6.1, Attachment AG. of the SPP OATT.

[96] *Id.*

purchasers) cannot profit from a withholding strategy for the simple reason that, to the extent that OG&E withheld capacity from the market, it would be required to purchase from that same market to meet its load obligations such that any withholding strategy, if effective, would serve to raise OG&E's costs and nullify any potential "profit" from such withholding.

Further, even if one assumed that OG&E had any incentive to attempt to exercise any perceived increase in market power that may result from the Transaction, OG&E has no ability to profit from a withholding strategy or other similar conduct. OG&E is not authorized to make sales at market-based rates in its balancing authority area, and is authorized to offer cost-based service only for transactions of one week or less.[97] Moreover, OG&E may not make any wholesale sales (cost-based or market-based) for durations of more than one week and less than one year, and agreements for a term of more than one year require prior review and approval by the Commission. These limitations plainly foreclose the opportunity for OG&E to exercise market power. Finally, even if OG&E could somehow price its capacity above the appropriate market-clearing price, it would forfeit virtually all of the proceeds of such prices pursuant to existing crediting mechanisms that capture 80-100 percent of the "benefit" of off-system sales.

c. Should the Commission conclude that when all relevant facts are considered the Transaction will have adverse competitive effects, OG&E will implement specific transmission upgrades to remedy the competitive analysis screen failures and thereby mitigate fully the Transaction's competitive impacts.

In the event that the Commission determines that existing market features are inadequate to support a determination that the Transaction will have no adverse effect on competition, OG&E will commit to implement specific transmission upgrades that will increase SILs

[97] While OG&E may charge cost-based rates for sales of a duration of up to one week, any concern that cost-based rates would not fully mitigate the potential for the exercise of market power is allayed by customer access to the EIS market, which will discipline prices for short-term energy products.

sufficient to remedy the competitive analysis screen violations reflected in Ms. Solomon's base case analyses. As detailed above, the incidental screen violations identified in the Appendix A analyses of the transaction, coupled with the other relevant competitive facts, establish that there are no adverse competitive analysis impacts that warrant mitigation. If the Commission nonetheless concludes that mitigation is required to protect against the potential exercise of market power, OG&E will undertake certain mitigation projects to facilitate and expedite approval of the authorizations requested in this Application.

The specific mitigation projects are identified and described in detail in Mr. Crissup's testimony:

- Re-conductor a 161 kV transmission line that runs between Entergy's Russellville North and ANO substations;
- Upgrade terminal equipment in the Entergy Russellville South and Russellville East substations; and
- Upgrade terminal equipment located in the Ozark substation in the Van Buren, Arkansas area of the SWPA transmission system.[98]

These projects will remedy the competitive analysis screen violations and will increase post-Transaction SILs into both the OG&E and GRDA balancing authority areas to pre-Transaction levels. In fact, the increase in SILs resulting from these projects would actually exceed the level needed to simply restore the pre-Transaction status quo. As Mr. Crissup explains, the upgrades required to restore the SILs to at least pre-Transaction levels actually result in significantly more SIL capability into each market.[99] Some of the system upgrades improve the SIL in only some of the seasons. Further, certain transmission upgrades sometimes

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[98] Crissup Testimony at 18.

[99] *Id.* at 19.

resulted in SILs that exceeded the target level. As a result, in targeting a return to pre-Transaction levels in all seasons, the actual SILs resulting from the transmission upgrades exceed the pre-Transaction SILs.[100]

Ms. Solomon performed a DPT analysis for each of the OG&E and GRDA balancing authority area markets using the SIL values that reflect the mitigation projects. For the OG&E market, the HHI changes are negative in all periods, which indicates that all screen failures have been eliminated and that the Transaction is significantly deconcentrating.[101] For the GRDA market, there are no screen failures and the HHI changes are negative in six of the seven periods studied.[102]

2. Vertical Competitive Market Analysis.

The Transaction will have no adverse vertical competitive effects. The Transaction involves the sale of an existing generation resource to three load-serving entities. Redbud Energy owns only those transmission facilities needed to interconnect the Facility to the SPP-administered transmission grid and only those limited natural gas transportation facilities associated with its existing interconnection to the ONEOK Partners intrastate pipeline. Thus, the Transaction does not result in the acquisition by the purchasers of upstream assets, such as transmission lines or natural gas pipelines, and does not change the vertical competitive landscape.

There are no other grounds for asserting vertical competitive harm. OG&E and GRDA have transferred operational control of their respective transmission facilities to SPP, a

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100 *Id.*

101 Solomon Affidavit at 35.

102 *See id.*

Commission-approved RTO. The Commission has determined that operational control of an applicant's jurisdictional transmission system by an RTO protects against the potential for applicants to "abuse their ownership of transmission facilities to give themselves an advantage in energy markets."[103] OMPA is not a transmission owner.

In the rehearing order of the Supplemental Merger Policy, the Commission also identifies the potential for an applicant to utilize its ownership of natural gas pipelines to exercise market power by withholding transportation service in order to disadvantage competing generation facilities.[104] While OG&E's affiliate Enogex owns intrastate natural gas transportation, storage and gathering pipelines in Oklahoma, there are numerous interstate natural gas pipeline systems in Oklahoma in addition to the Enogex and ONEOK intrastate systems that provide competing natural gas transportation service to which new gas-fired generators could connect.[105] Concerns of dominant control over power plant sites for new capacity development in relevant markets are also not present. Oklahoma and the regions around the state have experienced a robust market for the development of new generation facilities, and the substantial new entry of additional generation demonstrates the absence of entry barriers.[106]

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[103] *See, e.g., Entergy Gulf States*, 121 FERC ¶ 61,182 at P 71 (2007).

[104] *See* Supplemental Policy Statement Clarification at P 12; *see also* Order No. 642 at 31,904; *Energy East Corporation*, 121 FERC ¶ 61,236 at P 23 (2007).

[105] As Ms. Solomon explains (Solomon Afifdiavit at 37), delivery capacity on Enogex is no more than about 13 percent of pipeline deliverability in Oklahoma. There is approximately 7.3 bcf/day of interstate pipeline deliverability into Oklahoma, plus an additional 3.4 bcf/day intrastate pipeline delivery capacity within Oklahoma. Enogex's average throughput is approximately 1.4 bcf/day. In the broader SPP market, Enogex's share of delivery capacity would be significantly less. Similarly, with respect to gas storage, Enogex's share of gas storage capacity in Oklahoma is about 12 percent, not a level that raises competitive concerns, and its share in a broader SPP market would be significantly less.

[106] Solomon Affidavit at 37.

B. The Transaction Will Have No Adverse Effect on Rates.

In evaluating a proposed transaction's effect on rates, the Commission traditionally examines whether a proposed transaction will have any adverse impact on wholesale transmission service rates or on the rates charged to long-term requirements customers.[107] The Transaction satisfies fully this element of the Commission's public interest standard.

First, the Transaction will have no adverse effect with regard to transmission service rates. Although Redbud Energy owns various transmission facilities that will be transferred to the joint purchasers, it does not provide transmission service and has no transmission customers. In order to ensure that the Transaction will have no adverse effect on rates for jurisdictional transmission services, OG&E proposes a "hold harmless" provision comparable to those previously approved by the Commission for transmission service providers utilizing formula rates.[108] Specifically, OG&E commits (a) that, for a five-year period commencing on the Transaction's closing date, it will not seek to include in its annual transmission revenue requirement any Transaction-related costs (*e.g.*, acquisition premium, transaction fees and related costs) that are not offset by savings related to the proposed Transaction; (b) that it will not seek to recover any acquisition premium through rates until it has obtained specific regulatory authority to do so; and (c) that, with respect to transmission rates, it will not include Transaction-related costs in those rates without: (i) specifically identifying them; (ii) demonstrating that the costs included in the rates are exceeded by the savings produced by the Transaction; and (iii) in the event of a dispute, it will bear the

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[107] Merger Policy Statement at 30,123.

[108] *See, e.g., ITC Holdings Corp.*, 116 FERC ¶ 61,271 at P 48 (2006), *revised*; *Consolidated Edison Inc.*, 94 FERC ¶ 61,079 at 61,366 (2001). On November 30, 2007, OG&E filed revised tariff sheets to implement a formula rate for transmission service. On January 31, 2008, the Commission accepted OG&E's proposed formula rate, subject to refund and the outcome of hearing and settlement judge procedures, to be effective July 1, 2008. *See Oklahoma Gas & Electric Co.*, 122 FERC ¶ 61,071 (2008).

burden of proof that the savings from the Transaction exceed the Transaction costs charged to the customer.[109]

In order to effectuate this commitment, Applicants respectfully request that the Commission authorize deferral of Transaction-related costs to the extent such costs are not otherwise deferred under generally applicable accounting principles. Costs deferred under the hold harmless commitment will be amortized over a five-year period commencing on the Transaction's closing date. The Commission previously has approved such accounting treatment for deferred costs.[110]

Second, the Transaction will have no adverse effect on OG&E's rates for wholesale requirements service. The Transaction will not result in OG&E changing the rates it charges any captive wholesale customer. At this time, OG&E provides wholesale requirements service to certain municipalities and governmental agencies within the OG&E balancing authority area. These agreements provide for service at stated rates (including fuel adjustment clauses) and do not enable OG&E to pass through Transaction-related costs. The Commission previously has held that such agreements adequately shield customers from potential adverse rate impacts.[111]

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[109] This hold harmless commitment is not a rate freeze, and would not preclude changes in transmission rates attributable to non-Transaction-related costs, including the addition of the net book cost of transmission facilities acquired pursuant to the Transaction into OG&E's transmission rate base. The Commission has accepted similar hold harmless commitments. *See, e.g., PNM Resources, Inc.*, 110 FERC ¶ 61,204 at P 39 (2002); *UniSource Energy Corp.*, 109 FERC ¶ 61,047 at PP 12-13 (2004); *Ameren Corp.*, 108 FERC ¶ 61,094 at PP 62-68 (2004).

[110] *See, e.g., Duke Energy Corp.*, 113 FERC ¶ 61,297 at PP 121-23 (2005).

[111] *See Calpine Corporation*, 121 FERC ¶ 62,223 at 64,787 (2007); *MidAmerican Energy Holdings Company*, 113 FERC ¶ 61,298 at PP 40 and 45 (2005) ("Applicants further state that their customers under fixed-rate wholesale power and transmission contracts will not be adversely affected by the Proposed Transaction. They note that these rates may be changed only under a Section 205 filing with the Commission. . . . The Commission finds that Applicants have shown that the Proposed Transaction will not adversely affect transmission rates or wholesale power rates."); *AEP Service Corporation*, 110 FERC ¶ 62,183 at 64,366 (2005); *Virginia Electric and Power Company*, 108 FERC ¶ 61,136 at P 19 (2004) ("We find that neither wholesale nor retail customers' current rates will increase as a result of the proposed transaction. Dominion Virginia Power sells power at fixed charge rates to its wholesale customers, which will not change, and fixed base rates to retail customers . . . which also will not change.")

Any revisions to existing agreements, or any new long-term wholesale requirements contracts, would require OG&E to file such agreements under Section 205 of the FPA, at which time the Commission and all interested parties will be able to review the proposed cost-based rates.

For wholesale sales outside of the OG&E balancing authority area market, OG&E is authorized to makes sales at market-based rates. These agreements will not be affected by the proposed Transaction.[112]

Third, the Transaction will have no adverse effects on Redbud Energy's long-term wholesale sales customers. Redbud Energy has no long-term power sales agreements that will extend beyond the anticipated closing date of the Transaction, other than certain agreements with OG&E, OMPA, and GRDA that will be assumed as a result of the Transaction. Redbud Energy's market-based rate tariff will be cancelled effective as of the closing date of the Transaction.

C. The Transaction Will Have No Adverse Effect on Regulation.

The Transaction will not diminish or impair state or federal regulation. The Commission's review of a jurisdictional transaction's effect on state or federal regulation is focused on ensuring that a transaction does not result in a regulatory gap.[113] These concerns are not present here. While the Commission requires Applicants to evaluate the effect of the Transaction on regulation, the Commission indicated in Order No. 642 that it would not ordinarily set an FPA Section 203 application for hearing with regard to the effect on regulation unless: (1) the proposed transaction involves public utility subsidiaries of a registered holding

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[112] *See FirstEnergy Generation Corp.*, 118 FERC ¶ 62,204 at 64,566 (2007); *Goldendale Energy Center, LLC*, 118 FERC ¶ 62,101 at 64,279 (2007); and *Rochester Gas and Electric Corporation*, 107 FERC ¶ 61,180 at P 17 (2004).

[113] *Revised Filing Requirements Under Part 33 of the Commission's Regulations*, Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,914-15 (2000).

company under the Public Utility Holding Company Act of 1935 ("PUHCA 1935"), *and* the relevant applicants do not commit to abide by the Commission's policies on pricing of non-power goods and services between affiliates, or (2) the affected state commissions lack authority over the proposed transaction and raise concerns about the effect on regulation.[114] The first prong of the test is no longer applicable due to the repeal of PUHCA 1935. Further, OG&E is subject to OCC regulations governing the sale of products and services between OG&E and its affiliates.[115] The second element of the Commission's analysis is inapplicable here because the PSA and the APA each provide for review of the Transaction by the OCC.[116]

OG&E's wholesale sales and transmission operations (and those of its affiliates) are subject to regulation by the Commission and its retail operations are subject to comprehensive state regulation in Oklahoma and Arkansas, and the Transaction will have no effect on state or federal regulation. While Redbud Energy is currently subject to Commission jurisdiction, it will divest all of its jurisdictional assets pursuant to the Transaction and its market-based rate tariff will be terminated. GRDA and OMPA will remain exempt from Commission regulation pursuant to FPA Section 201(f). Moreover, the Transaction is subject to review and pre-approval by the OCC, which will be fully authorized to evaluate the effect of the Transaction on state regulation. The petition for pre-approval of the Transaction will be filed with the OCC contemporaneously with this Application.

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[114] *Revised Filing Requirements under Part 33 of the Commission's Regulations*, Order No. 642, FERC Stats. & Regs ¶ 31,111 at 31,914-15 (2000).

[115] *See* Okla. Admin Code. § 165:35-31-20 ("any sale of products and services provided from the affiliate to the utility shall be priced at the 'lower of cost or fair market value.' Except as otherwise required by federal statute or regulations, or pursuant to [OCC] authorized competitive bidding, tariffs, special contracts or as otherwise ordered by the [OCC]; any sale of jurisdictional products and services provided from the utility to the affiliate shall be priced at the 'higher of cost or fair market value.").

[116] *See* Attachment 1, Exhibit I, Section 6.06(b) and 7.01(b) of the PSA and Section 5.06 of the APA; *see also* Okla. Stat. tit. 17, § 286(C)(2007); Okla. Admin. Code § 165:35-38-5.

D. The Transaction Will Not Result in Any Prohibited Cross-Subsidization or Pledge or Encumbrance of Utility Assets.

FPA Section 203, as amended by EPAct of 2005, states that the Commission "shall approve" a proposed transaction "if it finds that the proposed transaction...will not result in cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the benefit of an associate company, unless...the cross-subsidization, pledge, or encumbrance will be consistent with the public interest."[117] The Commission's regulations provide "safe harbors" for certain transactions and specify verification and informational requirements in order for applicants to demonstrate that a proposed transaction does not result in inappropriate cross-subsidies or pledges or encumbrances of utility assets for the benefit of an associate company.[118]

The Transaction satisfies the requirements for the Commission's safe harbor and therefore satisfies fully this element of the Commission's Section 203 standard. First, the transaction is between non-affiliates.[119] The Transaction provides for the sale and transfer of generation assets from Redbud Energy to OG&E, and the subsequent sale and transfer of 36-percent and 13-percent undivided interests in the Facility from OG&E to GRDA and OMPA, respectively. None of the parties to these transactions are affiliated. In the Supplemental Policy Statement, the Commission explained that transactions within the intended scope of this safe harbor "include[] a transfer of assets between a public utility and non-affiliates."[120] As a result,

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117 16 U.S.C. § 824b(a)(4).

118 *Transactions Subject to FPA Section 203*, Order No. 669, FERC Stats. & Regs. ¶ 31,200 at PP 146-171 (2006). Order No. 669-A, FERC Stats. & Regs. ¶ 31,214 at PP 134-148 (2006); *FPA Section 203 Supplemental Policy Statement*, FERC Stats. & Regs. ¶ 31,253 at PP 11-26 (2006).

119 Supplemental Policy Statement at P 19.

120 *Id.*

no further showing is required to demonstrate that the Transaction will not result in cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the benefit of an associate company.

In addition, the Supplemental Policy Statement established a safe harbor for transactions that are subject to review by a state commission.[121] The Transaction satisfies the requirements for this safe harbor because the PSA and the APA specifically provide for prior review of the Transaction by the OCC.[122] The petition for OCC pre-approval of the Transaction will be filed with the OCC contemporaneously with this Application, which will enable the OCC to review, *inter alia*, whether the Transaction violates state-imposed prohibitions on cross-subsidization.[123] Accordingly, no further showing is required to demonstrate that the Transaction will not result in cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the benefit of an associate company.

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[121] *Id.* at P 18.

[122] *See* Attachment 1, Exhibit I, Section 6.06(b) and 7.01(b) of the PSA and Section 5.06 of the APA; *see also* Okla. Stat. tit. 17, § 286(C); Okla. Admin. Code § 165:35-38-5.

[123] *See, e.g.*, Okla. Admin. Code, § 165:35-31-20(a) ("A utility shall not subsidize the business activities of any affiliate with revenues from a regulated service. A utility cannot recover more than its reasonable fair share of the fully allocated costs of any transaction or share services"); *see also* Arkansas Public Service Commission, *In the Matter of a Generic Proceeding to Establish Electric Affiliate Rules, Regulations for Functionally Separated Business Activities, and Standards of Conduct*, Rules 4.01-4.02 (Jun. 9, 2000). In addition, in approving OG&E's reorganization into a holding company structure in 1995, the OCC explained that the "corporate separation of the utility and non-utility entities will ensure that all costs of a particular business will be charged to that business and not become part of OG&E's costs. To further ensure elimination of any potential for cross-subsidizations of the various subsidiaries of the Holding Company, OG&E will adopt and implement formal policies and procedures on intercompany transactions." *Application of Oklahoma Gas and Electric Co. for an Order Approving the Formation of A Holding Company and the Execution of an Agreement and Plan of Share Acquisition*, Cause No. PUD 950000148 at 5 (Aug. 4, 1995). OCC's approval of OG&E's reorganization was conditioned on OG&E's agreement "not to pledge utility company assets or income for affiliate transactions without prior approval by the [OCC]." *Id.* at Memorandum of Understanding, at P 5. OG&E further agreed "to provide forty-five (45) days prior notice to [the OCC Staff] of transfers of any utility asset (including intangible) to the Holding Company or other affiliates with a new book value or market value in excess of $100,000." *Id.* at Memorandum of Understanding, at P 4. OG&E also must provide the OCC "an annual statement of any such transfers of less than $100,000 during the year ... within ninety (90) days of year-end," but "if at any time the aggregate of such transfers of assets individually valued at less than $100,000 during the year exceeds $3,000,000, [OG&E must provide within forty-five (45) days] a statement listing items transferred, valuation method, and individual amount." *Id.*

In the event that the Commission concludes that additional information is required to support a determination that the Transaction does not result in the cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the benefit of an associate company, Order No. 669 identified a four-factor test that applicants must satisfy in order to address any possible cross-subsidization, pledge, or encumbrance of utility assets associated with proposed transactions. Under this test, the Commission examines whether a proposed transaction results, at the time of the transaction or in the future, in:

(1) Any transfer of facilities between a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, and an associate company;

(2) The issuance of any securities by a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, for the benefit of an associate company;

(3) Any pledge or encumbrance of any assets of any traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, for the benefit of an associate company; or

(4) Any new affiliate contract between a non-utility associate company and a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, other than non-power goods and services agreements subject to review under Sections 205 and 206 of the FPA.

Based on facts and circumstances that are known to Applicants or are reasonably foreseeable, and as further discussed in Attachment 1, Exhibit M, hereto, Applicants attest that the proposed Transaction will not result in any cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the benefit of an associate company.

These attestations demonstrate that the Transaction does not raise any concerns with respect to cross-subsidization.[124]

1. Transfers of Facilities.

The Transaction does not contemplate or include the transfer of any facilities between OG&E, a traditional utility company, and an associate company, either at the time of the Transaction or in the future. As detailed herein, the parties to the Transactions are not affiliated.

2. Issuance of Securities.

No new securities will be issued by OG&E for the benefit of an associate company in connection with the Transaction and no such issuances associated with the Transaction are contemplated in the future.

3. New Pledge or Encumbrance.

OG&E will not enter into any new pledges or encumbrances of utility property in connection with the Transaction, and there are no plans to do so in the future.[125]

4. New Affiliate Contracts.

No new contracts between OG&E and its affiliates are contemplated by the Transaction, either at the time of the Transaction or in the future. As noted above, OG&E intends to rely on its 51-percent interest in the Redbud Facility to meet its current and anticipated native load obligations.

OG&E relies on competitive solicitations to procure fuel for its entire gas-fired generation fleet and intends to secure natural gas for the Facility in the same manner. It is,

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[124] *See, e.g., Entergy Gulf States*, 121 FERC ¶ 61,182 at P 87 (2007); *Duke Power Co.*, 117 FERC ¶ 62,094 at 64,270 (2006).

[125] OG&E does not have any existing pledges or encumbrances of utility property other than various incidental liens and encumbrances arising in the ordinary course of business. Further detail is contained in Exhibit M of Attachment 1.

therefore, possible that, in the future, an OG&E affiliate could be selected to supply natural gas for use at the Facility through this competitive bidding process. If an affiliate participates in the competitive solicitation process, it must do so in accordance with specific OCC requirements, which also impose specific pricing policies for any subsequent affiliate agreement.[126] This process protects against any risk of improper cross-subsidies with regard to such fuel supply agreements.

V. INFORMATION REQUIRED BY 18 C.F.R. § 33.2.

In accordance with Section 33.2 of the Commission's regulations,[127] Applicants provide the following information:

A. Names and principal business offices of Applicants.

For Redbud Energy LP:	For OG&E:
Redbud Energy LP c/o Kelson Energy, Inc. 6700 Alexander Bell Drive, Suite 360 Columbia, Maryland 21046	Oklahoma Gas and Electric Company 321 North Harvey Oklahoma City, Oklahoma 73101

B. Names and Addresses of the Persons Authorized to Receive Notices and Communications

Person authorized to receive notices and communications regarding this application are as follows:

For Redbud Energy LP:	For OG&E:
Patricia M. Alexander Deborah A. Carpentier Dickstein Shapiro LLP 1825 I Street, N.W. Washington, D.C. 20006 Tel: (202) 420-2200 Fax: (202) 420-2201	James C. Beh Sameh I. Mobarek JONES DAY 51 Louisiana Avenue, N.W. Washington, D.C. 20001 Tel: (202) 879-3939 Fax: (202) 626-1700

[126] *See* Okla. Admin. Code § 165:35-31-20(d); *see also id.* at § 165:35-34-3(c).

[127] 18 C.F.R. § 33.2.

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C. Description of Applicants, including:

1. Business Activities of Applicants.

A description of the business activities of Applicants is set forth in Part II above and in Exhibit A.

2. Energy Subsidiaries and Energy Affiliates and their Business Activities.

The subsidiaries and affiliates of Redbud Energy and OG&E relevant to the Transaction are fully described in Part II above and in Exhibit B.

3. Organizational Charts.

Because the Transaction will result in a purchase of assets rather than a merger or sale of a corporate entity, there is no change in the organization of OG&E as a result of the Transaction. Therefore, Applicants respectfully request waiver of the requirement for OG&E to present pre- and post-Transaction organizational charts.

4. Description of Business Agreements.

See Exhibit D.

5. Common Officers or Directors.

See Exhibit E.

6. Description of Customers.

See Exhibit F. As described in Section II.B. of this Application, Redbud Energy sells energy, capacity and ancillary services pursuant to a market-based rate tariff on file with the Commission and reports these transactions in the Electric Quarterly Reports required to be filed with the Commission. Also, as discussed in Section IV.B., Redbud Energy has no long-term power sales agreements that will extend beyond the anticipated closing of the Transaction, other than certain agreements with OG&E, OMPA and GRDA that will be assumed as a result of the Transaction. Redbud Energy, therefore, respectfully request a waiver of the requirements of 18 C.F.R. § 33.2(c)(6) to the extent necessary.

D. Description of Jurisdictional Facilities.

The jurisdictional facilities affected by the Transaction are described in Part II above and in Exhibit G.

E. Narrative Description of the Transaction.

The description of the Transaction is set forth in Parts II and III above, and in Exhibit H.

F. Contracts Related to the Proposed Transaction.

The PSA and APA are attached as Exhibits I. To the extent necessary, Applicants also request waiver of the requirements of Section 33.2(f)[128] as to other incidental contracts and written instruments that may be entered into by the parties, none of which is inconsistent with the PSA, the APA, or the description of the Transaction set forth in this Application.[129]

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[128] 18 C.F.R. § 33.2(f).

[129] *See EIF Berkshire Holdings, LLC*, 116 FERC ¶ 61,273 (2006).

E. Consistency of the Transaction with the Public Interest.

The facts relied upon to demonstrate that the Transaction is consistent with the public interest are set forth in Part IV above and in Exhibit J.

F. Maps.

See Exhibit K.

G. Regulatory Orders.

See Exhibit L. On March 7, 2008, the FTC granted early termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvement Act. Such notification indicates that neither the FTC nor the Department of Justice intend to investigate the transaction.

H. Cross-Subsidization.

The Transaction will not result in cross-subsidization of a non-utility associate company and does not include any pledge or encumbrance of the assets of a traditional public utility with captive ratepayers or that owns or provides transmission service over jurisdictional transmission facilities for the benefit of an associate company. Support for these conclusions is provided in Part IV.D. above and in Exhibit M.

VI. INFORMATION ON PROPOSED ACCOUNTING ENTRIES REQUIRED BY SECTION 33.5 OF THE COMMISSION'S REGULATIONS.

With respect to OG&E, enclosed as Attachment 4 are *pro forma* accounting entries showing the proposed accounting for the Transaction. Because Redbud Energy is not required to maintain its books of account in accordance with the Commission's Uniform System of Accounts, Section 33.5 of the Commission's regulations[130] is inapplicable to this Application

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[130] 18 C.F.R. § 33.5.

with respect to Redbud Energy, and Redbud Energy requests waiver of any requirement to file information with respect thereto.[131]

VII. VERIFICATION.

Pursuant to Section 33.7 of the Commission's regulations,[132] signed verifications by persons having authority with respect thereto and having knowledge of the matters set forth in this Application are included as Attachment 5.

VIII. REQUEST FOR PRIVILEGED TREATMENT.

Pursuant to Section 388.112 of the Commission's regulations,[133] Applicants respectfully request confidential treatment of the CD-ROM containing CRA International, Inc.'s ("CRA") Competitive Analysis Screening model ("CASm") and workpapers underlying the Solomon Affidavit. The workpapers contain certain confidential, non-public information, and the CASm is a model that was developed on a proprietary basis by CRA and is not generally available to the public. Thus, in accordance with Section 33.9 of the Commission's regulations,[134] Applicants have provided, as Attachment 6 to the Application, a proposed Protective Order, based on the Commission's Model Protective Order, under which copies of the CASm model and the workpapers can be provided. In accordance with the Commission's regulations in Section 33.8,[135] Applicants submit today three copies of the CD-ROM containing the CASm and the workpapers. These non-public copies are marked "CONFIDENTIAL WORKPAPERS UNDER

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131 The Commission has granted such waiver in similar circumstances. *See, e.g., Midwest Renewable Energy Corp., et al.*, 117 FERC ¶ 62,174 (2006); *Forked River Power, LLC*, 120 FERC ¶ 62,029 (2007); *Sunbury Generation LP*, 120 FERC ¶ 62,127 (2007).

132 18 C.F.R. § 33.7.

133 18 C.F.R. § 388.112.

134 18 C.F.R. § 33.9.

135 18 C.F.R. § 33.8.

18 C.F.R. § 388.112, PROPRIETARY MODEL OF JULIE R. SOLOMON, OKLAHOMA GAS AND ELECTRIC COMPANY, AND REDBUD ENERGY LP."

IX. CONCLUSION.

For the reasons set forth above, Applicants request that the Commission issue an order granting: (i) all authorizations necessary for the Transaction described herein; (ii) the waivers requested herein; and (iii) confidential and privileged treatment of the CASm model and the workpapers submitted as part of this filing.

Respectfully submitted,

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Attorneys for Oklahoma Gas and Electric Company

Dated: March 20, 2008

ATTACHMENT 1

INFORMATION REQUIRED BY 18 C.F.R. § 33.2

Exhibit A

Business Activities of Applicants

Applicants' business activities are described in Part II of the Application and in the Solomon Affidavit in Exhibit J of Attachment 1.

Exhibit B

Energy Subsidiaries and Affiliates

The energy subsidiaries and energy affiliates of the Applicants that are relevant to the Transaction are described in Part II of the Application and in the Solomon Affidavit in Exhibit J of Attachment 1.

Exhibit C

Organizational Charts

As contemplated in Order No. 642, Applicants respectfully request waiver of the requirement to present post- and pre-Transaction organizational charts because the Transaction will result in a purchase of assets owned by a special purpose entity and there is no change in the organization of OG&E as a result of the Transaction. For the same reason, the Transaction will not alter the remaining corporate structure of Kelson Holdings. Applicants also respectfully request waiver of the requirement that charts showing the pre- and post-Transaction organizational structure for OMPA and GRDA because OMPA and GRDA are not Applicants.

Exhibit D

Description of Business Agreements

All relevant joint ventures, strategic alliances, tolling arrangements or other business arrangements between the Applicants relevant to the Transaction are described in Parts II and III of the Application.

Exhibit E

Common Officers and Directors

There are no common officers or directors between Redbud Energy, OG&E, OMPA, and GRDA.

Description of Customers

OKLAHOMA GAS & ELECTRIC

Wholesale Customers

Customer Name	Customer Type	FERC Electric Tariff/Rate Schedule	Execution Date	Start Date	Termination Date	Existing Ratepayer Protections
Mississippi Delta Energy Agency	Firm Energy	Electric Tariff, Original Vol. 3	05-22-2007	6-01-2007	Initial term ends on 09-30-2012, and the agreement continues thereafter for additional one-year extensions until cancelled by either party with a 15 months notice.	The agreement is for a fixed rate that is unaffected by the acquisition.
Geary Utilities Authority	Full Requirements	Power Sales Tariff, Original Sheet No. 6	03-18-2005	03-18-2005	Initial term ends on 03-18-2006, and the agreement continues thereafter for additional one-year extensions until cancelled by either party with a 12 months notice.	The agreement is for a fixed rate or a formula rate that is unaffected by the acquisition.
Orlando Public Works Authority	Full Requirements	WM-1	01-13-94	01-21-94	Initial term of 5 years, and the agreement continues thereafter until cancelled by either party by 30 months notice. For customers whose billing demand has not exceeded 1000 kW in 12 months prior to notice, notice will not be less than 90 days.	The agreement is for a formula rate that is unaffected by the acquisition
City of Paris East Maple	Firm Energy	WM-1	10-24-79	10-1-79	An initial term of 5 years, and agreement continues thereafter until	The agreement is for a formula rate that is

Customer Name	Customer Type	FERC Electric Tariff/Rate Schedule	Execution Date	Start Date	Termination Date	Existing Ratepayer Protections
Street					cancelled by either party with 30 months notice.	unaffected by the acquisition.
The City of Paris, Arkansas	Firm Energy	Service Agreement No. 41, FERC Electric Tariff, Original Volume No. 3	12-20-2002	02-1-2003	Initial term of 5 years, and the agreement continues thereafter for additional one-year terms until cancelled by either party by 12 months notice.	The agreement is for a fixed rate or a formula rate that is unaffected by the acquisition.
Purcell Public Works Authority	Firm Energy	Power Sales Tariff, OG&E FERC Electric Tariff, Original Volume No. 3	04-30-2002	06-1-2002	Initial term of 5 years, and the agreement continues thereafter for additional one-year terms until canceled by either party by 12 months notice. Purcell has already given notice to terminate the agreement, such termination will be effective on May 31, 2009.[136]	The agreement is for a fixed rate or a formula rate that is unaffected by the acquisition.
United States Department of Energy (Vance AFB)	Firm Energy	OA97-591	06-1-98	05-31-97	05-31-2012	The agreement is for a fixed rate that is unaffected by the acquisition.
Arkansas Valley Electric Cooperative	Full Requirements	WC-1	09-23-96	12-1-96	No termination effective prior to 12-1-2001, unless notice to terminate by AVEC is given on or after date which	The agreement is for a fixed rate or a formula rate that is unaffected by the

[136] On April 2, 2007, Purcell, one of OG&E's wholesale customers, notified OG&E of its intent to terminate its requirements contract with OG&E in order to seek alternative suppliers. The contract's term renews annually on June 1 pursuant to an evergreen provision, and can be terminated by either party with written notice to the other party submitted not less than 12 months prior to the end of any current term. However, after providing OG&E with notice of its intent to terminate the contract in accordance with its terms, Purcell has indicated that it wants to continue its arrangements with OG&E until it contracts with alternative suppliers and secures the requisite transmission service from SPP to deliver power from such suppliers. As a result, it is unclear at this stage if or when Purcell will terminate the supply contract with OG&E.

Customer Name	Customer Type	FERC Electric Tariff/Rate Schedule	Execution Date	Start Date	Termination Date	Existing Ratepayer Protections
Corporation					OG&E has requested as the effective date for an increase in rates, then either party can terminate the agreement by 30 month notice.	acquisition.
Mississippi Delta Energy Agency	Firm Energy	Power Sales Tariff, OG&E FERC Electric Tariff, Original Volume No. 3	04-13-2004	05-1-2004	Initial term of 5 years, then the agreement continues thereafter for additional one-year terms until cancelled by either party with 12 months notice.	The agreement is for a fixed rate or a formula rate that is unaffected by the acquisition.
Oklahoma Municipal Power Authority	Firm Energy	Power Sales Tariff Service Agreement	07-09-2004	07-09-2004	N/A	The agreement is for a fixed rate that is unaffected by the acquisition.
Oklahoma Municipal Power Authority	Firm Energy	Power Sales Tariff Service Agreement	12-29-2003	1-1-2004	12-31-2013 unless terminated earlier by mutual agreement.	The agreement is for a fixed rate or a formula rate that is unaffected by the acquisition.
City of Watonga, Oklahoma	Full Requirements	WM-1	12-5-95	3-1-96	Initial term of 5 years, then the agreement continues thereafter for additional five-year terms until cancelled by either party with 24 month notice. Notice shall not be less than 90 days for any customer whose billing demand has not exceeded 1000 kW in any 12 month period prior to cancellation notice.	The agreement is for a fixed rate or a formula rate that is unaffected by the acquisition.

Exhibit G

Description of Jurisdictional Facilities

OG&E owns jurisdictional transmission facilities, generator-related interconnection facilities, wholesale power sales tariffs, rate schedules, service agreements, and related books and records. Applicants provided in Part II of the Application, in the Langston Testimony in Attachment 2, and in the Solomon Affidavit in Attachment 1, a description of the jurisdictional facilities relevant to the Commission's evaluation of the Transaction. Applicants request waiver of the need to describe any facilities not implicated or affected by the proposed Transaction.[137]

[137] The Commission has approved similar requests. *See Frederickson Power, L.P.*, 100 FERC ¶ 62,112 (2002); *Cogentrix Batesville, LLC*, 94 FERC ¶ 62,208 (2001).

Exhibit H

Narrative Description of the Transaction

A narrative description of the Transaction is set forth in Parts II and III of the Application and in the Langston Testimony in Attachment 2 and the Solomon Affidavit in Exhibit J-1 of Attachment 1.

Exhibit I

Contracts Related to the Transactions

The contracts related to the Transaction are the Purchase and Sale Agreement, dated January 21, 2008, by and between OG&E, Redbud Energy, Redbud Energy I, LLC, Redbud Energy II, LLC, and Redbud Energy III, LLC, and the Asset Purchase Agreement, dated January 21, 2008, by and between OG&E, OMPA, and GRDA. Copies of both contracts are provided in Volume 2 of this Application.

Exhibit J-1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Oklahoma Gas and Electric Company Redbud Energy LP	))))	Docket No. EC08-___-000

AFFIDAVIT OF JULIE R. SOLOMON

INTRODUCTION

My name is Julie R. Solomon. I am a Vice President at CRA International, Inc. ("CRA"). My business address is 1201 F Street, N.W., Suite 700, Washington, DC 20004-1204. A large portion of my consulting activities involves electric utility industry restructuring and the transition from regulation to competition. I have been involved extensively in consulting on market power issues concerning mergers, other asset transactions and market rate applications. I

have filed a number of affidavits before the Federal Energy Regulatory Commission ("FERC" or "Commission") in connection with electric utility mergers, the purchase and sale of jurisdictional assets, applications for market-based rates, and triennial updates. My resume is included as Exhibit J-2.

I have been asked by counsel for Oklahoma Gas and Electric Company ("OG&E") and Redbud Energy LP ("Redbud Energy") (collectively "Applicants") to evaluate the potential competitive impact on electricity markets of a proposed transaction under which OG&E will acquire Redbud Energy,[1] and subsequently convey a 36 percent undivided interest in the Redbud generating facility ("Redbud" or "Redbud Facility") to Grand River Dam Authority ("GRDA") and a 13 percent undivided interest to Oklahoma Municipal Power Authority ("OMPA") (collectively, the "Transaction"). Redbud is a 1,195 MW natural gas-fired combined cycle facility located in the OG&E balancing authority area.[2] Following the Transaction, Redbud will be owned 51 percent by OG&E (610 MW), 36 percent by GRDA (430 MW) and 13 percent (155 MW) by OMPA.

My affidavit addresses both potential horizontal and vertical market power effects of the Transaction. The potential horizontal market power effects are those arising from the combination of the Redbud Facility with generation owned or controlled by OG&E, GRDA and OMPA that theoretically could enable the buyers to increase prices in electricity markets. The potential vertical market power effects arise from barriers to entry that might undercut the presumption that long-run generation markets are competitive and, more generally, the potential to use control over fuel supplies, fuel transportation facilities, or electric transmission to exert vertical market power by increasing rivals' costs.

SUMMARY OF CONCLUSIONS

My analysis indicates that the Transaction does not raise competitive concerns for the following reasons:

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[1] Specifically, OG&E is acquiring 100 percent of the partnership interests in Redbud Energy that are held by Redbud Energy I, II and III, LLC, each of which is an indirect subsidiary of Kelson Holdings, LLC ("Kelson").

First, OG&E, GRDA and OMPA are buying their respective shares of Redbud in order to meet their load and reliability requirements, and without this purchase each would be capacity short. OG&E, GRDA and OMPA are obligated to secure generating resources necessary to meet their native and requirements loads and reliability obligations. Indeed, each of these entities currently has a contract for portions of the Redbud output: OG&E has contracted for 300 MW, GRDA for 150 MW, and OMPA for 80 MW in 2008.[3] Absent their existing contracts with Redbud Energy or replacement contracts, each entity requires additional generating resources. Any supply in excess of load and reserve requirements resulting from the purchase of the Redbud Facility, reflecting the "lumpiness" of generation additions, is short-lived. OG&E's expected load growth will eliminate any temporary excess supply by about 2012. GRDA and OMPA similarly will require additional resources beyond the Redbud purchase by about 2015 and 2010, respectively.

Second, essentially all wholesale customers located within the OG&E and GRDA balancing authority areas[4] are already served under long-term arrangements, so that any competitive concern about the impact of the Transaction on customers is purely theoretical.[5] With the exception of OMPA, all wholesale customers within the OG&E balancing authority area are requirements customers of OG&E.[6] These customers therefore are not participants in wholesale markets. GRDA and OMPA are state governmental agencies that transmit and deliver electricity to cities and towns that own their own electric systems and are served under long-term agreements with the state agencies.

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2 Unless otherwise indicated, generator ratings referred to here and elsewhere in my testimony reflect summer ratings. Redbud's winter rating is 1,270 MW.

3 OG&E's and OMPA's contracts cover the June through September period, while GRDA's contract is year round. I treat these contracts as part of generation owned or controlled by OG&E, GRDA and OMPA pre-Transaction.

4 OMPA does not operate a balancing authority area, and its load is located in both the OG&E balancing authority area, as well as in two balancing authority areas interconnected with OG&E, as discussed below.

5 The pricing provisions for each of the wholesale contracts is provided in Exhibit F of the Application. All of the contracts are priced either on a fixed or formula rate basis that is unaffected by the Transaction. These contracts also include a fuel adjustment clause.

6 Some of OG&E's wholesale customers also receive a entitlement of power from the Southwestern Power Administration ("SPA") federal hydroelectric resources.

Third, OG&E does not have authority to make wholesale sales at market-based rates within the OG&E balancing authority area. Post-Transaction, any bilateral wholesale sales made within the OG&E balancing authority area from OG&E's acquired share of Redbud will be subject to cost-based rates, as is the case with respect to any sales OG&E currently makes.[7] Since OG&E cannot sell at market-based rates, OG&E has no incentive to use any perceived increase in generation market power to raise market prices within its balancing authority area (and its cost-based rates are presumed to be just and reasonable), notwithstanding the fact that there are no applicable loads at risk, as already noted. For sales into the Energy Imbalance Service ("EIS") market of the Southwest Power Pool, Inc. ("SPP"), all market participants have been granted authority to sell at market-based rates.[8] OG&E also submitted revisions to its market-based rate tariff to be able to sell into the SPP EIS market at market-based rates.[9] In any event, all of OG&E's off-system sales, including those into the EIS market, are subject to sharing mechanisms with ratepayers such that OG&E is able to retain just a small portion of the profits on such sales.[10] These arrangements severely reduce any incentive for OG&E to exercise market power.

Fourth, the Redbud Facility represents only a small portion of the generating capacity located in the footprint of the SPP EIS market, and there is significant competing supply of similar combined-cycle plants in and around the SPP. There is about 47,000 MW of generating capacity in the footprint of the SPP EIS market,[11] and, hence, the Redbud Facility accounts for

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[7] The Commission conditionally granted OG&E cost-based rate authority based on a mitigation plan. *Oklahoma Gas and Electric Company*, 114 FERC ¶ 61,297 (2006).

[8] The EIS market began operation February 1, 2007. The Commission allows all market participants to sell at market-based based rates in the EIS market. (*See Southwest Power Pool, Inc.*, 114 FERC ¶ 61,289 (2006)) at P. 203.

[9] *See* filing of Oklahoma Gas and Electric Company in Docket Nos. ER98-511-008 and ER97-4345-020 (July 25, 2006 and Aug. 25, 2006). The Commission has not yet acted on this filing.

[10] Based on sharing mechanisms approved and administered by the respective regulatory commissions, OG&E is required to credit retail customers 80 percent in Oklahoma and 100 percent in Arkansas of profits from off-system sales. These sharing mechanisms reduce any incentive for OG&E to increase market prices because shareholders capture at most only 20 percent of any gains from their off-system sales.

The incentives of GRDA and OMPA, as state municipal government agencies, are to keep market prices low. There are no shareholders.

[11] The SPP has a number of different "footprints" based on the service being provided through the SPP. There is about 57,000 MW of generation in the SPP Regional Reliability Organization ("SPP RRO"), such that Redbud's

only about 3 percent of this SPP capacity. More than 8,000 MW of this SPP generating capacity consists of natural gas combined-cycle units having vintages and operating characteristics similar to Redbud, and there is almost 20,000 MW of such generation that has been added in the geographic area consisting of balancing authority areas first-tier to the OG&E balancing authority area between 2000 and 2006. The Transaction does not significantly diminish the competitive supply available in the broader market.

Fifth, despite some screen failures reflected in the numerical results of the Competitive Analysis Screen I performed, these other facts and evidence support a finding that the Transaction does not raise competitive concerns. The Competitive Analysis Screen is easily passed for both Economic Capacity ("EC") and Available Economic Capacity ("AEC") in the SPP EIS market footprint. AEC is the more relevant measure in the context of this Transaction.[12] The market is unconcentrated to moderately concentrated and any increases in the Herfindahl-Hirschman Index ("HHI") are small.[13] In the smaller balancing authority areas, the Competitive Analysis Screen also is passed in all balancing authority area markets interconnected to either OG&E or GRDA. The Delivered Price Test ("DPT") confirms that

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capacity is about 2 percent of the installed capacity. For my analysis, I have focused on the smaller SPP EIS footprint that includes only the members who are participating in the SPP's EIS market. (There is currently a proceeding before the Commission that would allow direct participation in SPP's EIS market by entities outside of the SPP EIS footprint which, if implemented, would broaden the geographic scope of participants in the market (*see* Docket Nos. ER06-451 *et al.*).)

12 Markets in Oklahoma, as well as in the SPP region more generally, have not been restructured, there is no retail access, and OG&E (as well as GRDA and OMPA) maintains significant native load obligations with no expectation that the market will be restructured in the future to eliminate such obligations. Thus, AEC is the relevant measure, as the Commission has recently recognized in several recent Orders. *See* note 22 *infra*. Nevertheless, I also have conducted the competitive analysis screen for the EC measure and the results are shown in applicable exhibits.

13 To determine whether a proposed merger requires further investigation because of a potential for a significant anti-competitive impact, the DOJ and FTC consider the level of the HHI after the merger (the post-merger HHI) and the change in the HHI that results from the combination of the market shares of the merging entities. Markets with a post-merger HHI of less than 1000 are considered "unconcentrated." The DOJ and FTC generally consider mergers in such markets to have no anti-competitive impact. Markets with post-merger HHIs of 1000 to 1800 are considered "moderately concentrated." In those markets, mergers that result in an HHI change of 100 points or less are considered unlikely to have anti-competitive effects. Finally, post-merger HHIs of more than 1800 are considered to indicate "highly concentrated" markets. The *Guidelines* suggest that in these markets, mergers that increase the HHI by 50 points or less are unlikely to have a significant anti-competitive impact, while mergers that increase the HHI by more than 100 points are considered likely to reduce market competitiveness. (*See* U.S. Department of Justice and Federal Trade Commission, *Horizontal Merger Guidelines* (April 2, 1992), *amended* 1997.)

OG&E, GRDA and OMPA each has little, if any, AEC available to compete in any relevant market under most system conditions. On the other hand, generation affiliated with Redbud Energy (including the Redbud Facility itself) has a significant share of AEC, particularly in the OG&E balancing authority area where Redbud is located. As a result, I find that during some time periods the effect of the Transaction is to transfer capacity from one supplier with a relatively high AEC market share (Redbud Energy and its affiliates) to three entities with relatively small AEC market shares (OG&E, GRDA, and OMPA), thereby deconcentrating the relevant markets.

Nevertheless, there are screen failures in the base case analysis of the OG&E and GRDA balancing authority areas where I use a simultaneous import limit ("SIL") calculated by OG&E transmission personnel. These results are driven, in part, by the fact that the market size is changing from pre- to post-Transaction. HHIs typically are intended to be a static measure, merely reflecting shifts in market share rather than changes in market size. In the instant case, however, the market size does change (for a few reasons, which I discuss below, including changes in transmission import capability) and, as a result, there are significant HHI changes (both positive and negative). I also conducted an alternative analysis based on different assumptions about import capability into the OG&E balancing authority area, again based on a transmission study conducted by OG&E personnel and explained in more detail below, and found that under this alternative, the HHI screen for AEC is passed in all but one time period in the OG&E balancing authority area (a nominal violation in the Shoulder season that is eliminated under slightly different treatment of the pre-Transaction contracts with Redbud Energy). Finally, given that GRDA's ownership share of the Redbud Facility post-Transaction exceeds its short-term needs to meet load and reliability obligations in the GRDA balancing authority area, I also analyzed the results assuming that GRDA's share of Redbud in excess of its short-term needs remains in the OG&E balancing authority area. In this case, there are no screen violations in the OG&E balancing authority area and only violations in only two time periods in the GRDA balancing authority area.

Sixth, OG&E will commit to transmission upgrades if the Commission requires it to do so as a condition of Transaction approval. Although the only evidence of competitive harm resulting from this Transaction is grounded in the HHI results, OG&E has agreed to undertake

certain transmission upgrades that will increase the SIL into the OG&E balancing authority area, should the Commission deem it necessary to do so. These upgrades would also increase the transfer capability into the GRDA balancing authority area. With these transmission upgrades, the Competitive Analysis Screen for AEC is passed in both the OG&E and GRDA balancing authority areas.

Finally, there are no vertical market power concerns raised by this Transaction. The only transmission assets transferred as a result of this Transaction are those necessary to connect Redbud to the electric grid. OG&E and GRDA are transmission owners, but their electric transmission systems are controlled by the SPP, and OMPA is not a transmission owner.[14] None of OG&E, GRDA or OMPA has control over essential fuels or delivery systems. Only OG&E is affiliated with a natural gas company, which operates an intrastate natural gas pipeline system in Oklahoma and delivers natural gas to a limited number of rival generators located in balancing authority areas interconnected to OG&E. Redbud does not receive gas transportation from OG&E's pipeline. There are numerous other pipelines in Oklahoma and the surrounding states to which new gas-fired generators could connect. Finally, concerns of dominant control over power plant sites for new capacity development in relevant markets also are not present. Oklahoma and the regions surrounding it have experienced a robust market for the development of generation, and the substantial new entry of additional generation demonstrates the absence of entry barriers.

DESCRIPTION OF TRANSACTING PARTIES

OG&E

OGE Energy Corp., OG&E's parent, is an energy and energy services provider of both electricity and natural gas in the south central United States. OG&E generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. OG&E is subject to state regulation by the Oklahoma Corporation Commission ("OCC") and the Arkansas Public Service Commission ("APSC"). OG&E serves more than 762,000 retail customers across 30,000 square miles in Oklahoma and western Arkansas, and a number of wholesale customers throughout the

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[14] OG&E customers primarily take service under the SPP Open Access Transmission Tariff, although there remain a few grandfathered wholesale requirements customers that take service under OG&E's OATT, as discussed below.

region. OG&E owns approximately 2,600 MW of coal-fired generation, 3,500 MW of natural gas-fired plants (the majority of which are older, high incremental cost facilities), and 120 MW of wind generation. OG&E also has approximately 500 MW of generation under long-term contract, in addition to the 300 MW contracted from Redbud Energy. See Exhibit J-3.

OG&E is directly interconnected with electric utility operating balancing authority areas in SPP, including American Electric Power (the "AEP West" balancing authority area), GRDA, SPA, Westar ("WR"), and Western Farmers Electric Cooperative ("WFEC"). OG&E is also directly interconnected to Entergy Corp. ("Entergy") and Associated Electric Cooperative, Inc. ("AECI"), which are located in the SERC Reliability Corporation ("SERC").

OG&E's affiliate, Enogex Inc. ("Enogex"), produces, gathers, processes, transports, markets and stores natural gas; and produces, transports, and markets natural gas liquids in Oklahoma, Arkansas and west Texas. Enogex has natural gas gathering, processing, transmission and storage operations in the major gas producing basins of Oklahoma. Enogex operates an intrastate pipeline system that provides gas to some of OG&E's gas fired generating facilities, to six gas-fired generators owned by AEP, and to three unaffiliated merchant generators all located in the interconnected AEP West balancing authority area.

OGE Energy Resources, Inc. ("OERI") markets natural gas and provides energy related services. OERI does not own or control any electric generation.

Redbud Energy and its Affiliates

Kelson indirectly owns Redbud Energy and three other generation companies: Dogwood Energy LLC, which owns and operates the 620 MW Dogwood facility located in the Missouri Public Service ("MPS") balancing authority area; Cottonwood Energy Company, LP, which owns and operates the 1,230 MW Cottonwood facility located in the Entergy balancing authority area; and Magnolia Energy Company LP, which owns and operates the 920 MW Magnolia facility

located in the Tennessee Valley Authority ("TVA") balancing authority area.[15] Westar Power Marketing, Inc. currently markets the output of the Redbud and Dogwood facilities.

Kelson is owned by Harbinger Capital Partners Master Fund I, Ltd. and Harbinger Capital Partners Special Situation Fund, LP (collectively "Harbinger"). Harbinger also owns approximately 21 percent of the common stock of Calpine Corporation ("Calpine") and has approval from the Commission to acquire up to a 40 percent share.[16] For purposes of my analysis, I have treated Calpine's generation as affiliated with Harbinger.[17] Subsidiaries of Calpine own generation throughout the United States. Of particular relevance to my analysis, subsidiaries of Calpine own and operate generating facilities located in the AEP West and Entergy balancing authority areas, namely the Oneta Energy Center (1,082 MW) and the Pryor Power Plant (112 MW) in the AEP West balancing authority area;[18] and the Pine Bluff Energy Center (184 MW) and the Carville Energy Center (449 MW) in the Entergy balancing authority area. A summary of the generation attributed to Kelson and Redbud Energy is provided in Exhibit J-3.

GRDA

GRDA provides wholesale electricity to 20 wholesale customers located in its balancing authority area in Northeast Oklahoma. Most are full-requirements customers, including some who own generation that they sell to GRDA; two are full-requirements customers for specific

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[15] A Redbud affiliate, Kelson Energy III LLC, was recently approved as the stalking horse bidder in the proposed sale of Southaven Power LLC ("Southaven") at a bankruptcy auction. Southaven owns an 810 MW combined-cycle natural gas-fired power plant located in DeSoto County, Mississippi, and interconnected to both Entergy and TVA. I have not attributed this generation to Kelson in my analysis.

[16] Harbinger also has acquired approximately 9 percent of the common stock of Mirant Corporation ("Mirant"). None of the generation owned by Mirant is located in or near any market relevant for this Transaction. Other Harbinger investments in the utility industry are in Foreign Utility Companies, in markets not relevant to my analysis, or are holdings of less than 5 percent.

[17] While Harbinger's ownership of Calpine shares exceeds the 10 percent level at which the Commission rebuttably presumes control, Calpine and Harbinger submitted to the Commission that Harbinger would not have control over the Calpine public utilities as Harbinger would not control decision-making over sales of electric energy from the Calpine public utilities. *See* Calpine Corporation and Its Public Utility Subsidiaries, Harbinger Capital Partners Master Fund I, Ltd., Harbinger Capital Partners Special Situations Fund, L.P., SPO Partners II, L.P., and San Francisco Partners II, L.P., Joint Application for Approval Under Section 203 of the Federal Power Act, Docket No. EC08-15-000 at pp. 25-26 (filed Nov. 16, 2007).

[18] The output of the Pryor Power Plant previously was sold under long-term contract to OG&E, however I understand that the contact was terminated December 31, 2007.

loads under contract; and one owns generation that supplements its requirements contract with GRDA. In addition, there are other wholesale customers located in the GRDA balancing authority area who are full-requirements customers of either KAMO Electric Cooperative or AEP.

GRDA operates a balancing authority that is interconnected to the OG&E balancing authority area as well as to WFEC, AEP West, SPA, and Empire Electric District ("EDE"), all located in the SPP, and to AECI, located in SERC.

GRDA owns approximately 1,300 MW of generation, mostly hydroelectric generation or coal-fired facilities. In addition, GRDA is currently purchasing 150 MW of the output of the Redbud Facility. A summary of GRDA's generation is provided in Exhibit J-3.

OMPA

OMPA provides wholesale electricity to 35 Oklahoma cities and towns that own their electric systems. All of OMPA's wholesale customers are full-requirements customers subject to long-term contracts, although some also receive an allocation of power from SPA. OMPA has no retail customers.

OMPA does not operate a separate balancing authority area, and its customer service territory includes customers located within the OG&E balancing authority area as well as in AEP West and WEFC. The majority of OMPA's load and resources are located in the OG&E balancing authority area. OMPA owns about 400 MW of generation, plus purchases approximately 250 MW, including 80 MW from the Redbud Facility. A summary of OMPA's generation is provided in Exhibit J-3.

FRAMEWORK FOR THE ANALYSIS

Market power is the ability of a firm profitably to maintain prices above competitive levels for a significant period of time. Market power analysis of a merger proposal examines whether the merger would cause a material increase in the merging firms' market power or a significant reduction in the competitiveness of relevant markets. The focus is on the effects of the merger, which means that the merger analysis examines those business areas in which the merging firms are competitors. This is referred to as horizontal market power assessment. In

most instances, a merger will not affect competition in markets in which the merging firms do not compete. For purposes of my analysis, I treat the proposed Transaction as a merger that will combine the respective shares of the Redbud Facility with generation assets attributed to OG&E, GRDA and OMPA. In the context of the proposed Transaction, therefore, the focus is properly on those markets in which OG&E, GRDA, OMPA and Redbud Energy are actual or potential competitors. The analysis is intended to measure the adverse impact, if any, of the elimination of a competitor as a result of the combination.

Potential vertical market power effects of the merger relate to the merging firms' ability and incentives to use their market position over a product or service to affect competition in a related business or market. For example, vertical effects could result if a merger created an opportunity and incentive to operate transmission in a manner that created market power for the generation activity of the merged company that did not exist previously. The Commission has identified market power as also arising from dominant control over potential generation sites or over fuel supplies and delivery systems. Such dominant control could undercut the presumption that long-run generation markets are competitive and could injure competition by raising rivals' costs.

Understanding the competitive impact of a merger requires defining the relevant market (or markets) in which the merging firms participate. Participants in a relevant market include all suppliers, and in some instances potential suppliers, who can compete to supply the products produced by the merging parties and whose ability to do so diminishes the ability of the merging parties to increase prices. Hence, determining the scope of a market is fundamentally an analysis of the potential for competitors to respond to an attempted price increase. Typically, markets are defined in two dimensions: geographic and product. Thus, the relevant market is composed of companies that can supply a given product (or its close substitute) to customers in a given geographic area.

Competitive Analysis Screen

In December 1996, the Commission issued Order No. 592,[19] the "Merger Policy Statement," which provides a detailed analytic framework for assessing the horizontal market power arising from electric utility mergers. This analytic framework is organized around a market concentration analysis. The Commission adopted the DOJ/FTC *Horizontal Merger Guidelines* for measuring market concentration levels by the HHI. On November 15, 2000, the Commission issued its Revised Filing Requirements Under Part 33 of the Commission's Regulations in Order No. 642, which affirmed the screening approach to mergers consistent with the Appendix A analysis set forth in the Merger Policy Statement, and codified the requirement to file a screen analysis, and the exceptions therefrom. The Commission recently issued additional guidance to confirm that applicants are expected to frame their arguments regarding the effect on competition in terms of a theory of merger- or acquisition-related harm to competition and, further, that while the DPT and its HHI metrics serve as a useful tool or screen to identify mergers or acquisitions that may harm competition, the Commission's analysis extends beyond the numerical screens.[20]

Appendix A of the Merger Policy Statement, the Competitive Analysis Screen, specifies a "delivered price" screening test (DPT) to measure EC, defined as energy that can be delivered into a destination market at a delivered cost less than 105 percent of the destination market price. The screening test also provides for an analysis of AEC, defined as energy that meets the delivered price test, but that is over and above that required to meet native load, long-term contractual obligations, such as requirements load, and other obligations that commit an entity's generation resources. The DPT is intended to be a conservative screen to determine whether further analysis of market power is necessary. If the Appendix A analysis shows that a company will not be able to exercise market power in the markets where its generation is located and its first-tier destination markets, it generally follows that the applicants will not have market power in more broadly defined and more geographically remote markets.

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[19] *Inquiry Concerning the Comm'n's Merger Policy Statement Under the Federal Power Act*, FERC Stats. & Regs. ¶ 31,044 (1996) ("Order No. 592"), *reh'g denied*, 79 FERC ¶ 61,321 (1997) ("Merger Policy Statement").

[20] *FPA Section 203 Supplemental Policy Statement*, 72 Fed. Reg. 42,277 (Aug. 2, 2007), FERC Stats. & Regs. ¶ 31,253 (2007), and *Order on Clarification and Reconsideration*, 122 FERC 61,157 (2008).

The screen is the first numerical step in determining whether there is a need for further investigation. If a proposed merger passes the Appendix A screen, the inquiry generally is terminated. If the screening test is not passed, leaving open the issue of whether the merger will create market power the Commission invites applicants to propose mitigation remedies targeted to reduce potential anti-competitive effects to safe harbor levels.

Relevant Product Markets

The Commission generally has been concerned with three relevant product markets: non-firm energy, short-term capacity (firm energy) and long-term capacity.[21] Both EC and AEC are used as measures of energy. The Commission's current policy does not specify required analyses of capacity markets as such. Order No. 642 directs Applicants to analyze relevant ancillary services markets (specifically, reserves and imbalance energy) "when the necessary data are available." There are currently no formal ancillary services markets in the SPP and balancing authority markets that I analyze.

As noted, under the EC and AEC Capacity measures, capacity that is attributed to a market participant is that capacity controlled by it that can reach the destination market, taking transmission constraints and costs into account, at a price no higher than 105 percent of the destination market price. The two measures differ merely as to the treatment of capacity used to meet native load requirements and other commitments. The Commission has determined that long-term capacity markets are presumed to be competitive, unless special factors exist that limit the ability of new generation to be sited or receive fuel.

AEC is the relevant measure in the SPP as well as in the balancing authority markets I examine, because all load-serving entities retain the obligation to plan for and procure resources required to serve their load reliably. The Commission has accepted this view that AEC is the

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[21] The market for long-term capacity generally does not need to be analyzed because the Commission has concluded as a generic matter that the potential for entry ensures that the long-term capacity market is competitive. See *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs., ¶ 31,036 (1996). The presumption that long-term capacity markets are competitive can be overcome if the applicants have dominant control over power plant sites or fuel supplies and delivery systems. This exception is addressed below.

relevant measure when significant native load obligations remain and there is no expectation that the markets of concern will be restructured in the future to eliminate such obligations.[22]

Relevant Geographic Markets

Traditionally, the Commission has defined the relevant geographic markets as centered on the applicants and on utilities directly interconnected with the applicants, referred to as first-tier utilities. Both Order No. 592 and the Revised Filing Requirements continue to define the relevant geographic market in terms of (a) balancing authority areas in which applicants control generation and (b) first-tier destination markets.[23]

Further, in a merger context, the Commission considers as potential additional destination markets other utilities that historically have been customers of the applicants. I reviewed historical data on OG&E and Redbud's purchases and sales in order to analyze whether there are any other relevant markets that need to be analyzed. In their Electric Quarterly Report ("EQR")[24] filings for 2006 and 2007, both Redbud Energy and OG&E report all of their sales at the OKGE Point of Delivery Balancing Authority ("POD-BA"). With respect to Redbud Energy's sales, it is not evident from the EQRs where the final sale was actually made, because, given the marketing agreement between Redbud Energy and Westar, Redbud Energy reports its customer for all sales either as Westar or the SPP EIS market. However, Westar subsequently

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22 *See Duke Power Company, LLC*, 117 FERC ¶ 62,094 (2006); *Nevada Power Company*, 113 FERC ¶ 61,265 (2005); *Westar Energy Inc.*, 115 FERC ¶61,228 (2006), *reh'g*, 117 FERC ¶ 61,011 (2006), *reh'g*, 118 FERC ¶ 61,237 (2007); *Aquila, Inc.*, 117 FERC ¶ 61,276 (2006), *National Grid plc*, 117 FERC ¶ 61,080 (2006); *Great Plains Energy Incorporated*, 121 FERC ¶ 61,069 (2007); *Entergy Gulf States, Inc.*, 121 FERC ¶ 61,182 (2007); *Entergy Arkansas, Inc.*, 122 FERC ¶ 62,071 (2008).

While SPP has been a Commission-approved RTO since October 1, 2004, and has established a real-time market with Commission approved market monitoring provisions (*Southwest Power Pool, Inc.*, 109 FERC ¶ 61,009 (2004) ("RTO Order"), *order on reh'g*, 110 FERC ¶ 61,137 (2005)), parties throughout the SPP footprint continue to have individual load and reliability obligations.

23 *Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement, Order No. 592*, ¶ 31,044 at 30,119 (1996); *Revised Filing Requirements under Part 33 of the Commission's Regulations, Order No. 642*, ¶ 31,111 at 31,910-11 (2000).

24 I reviewed EQR filings for 2006 and 2007 and the data are included in my workpapers. I also reviewed OG&E's purchases and sales as reported in its 2006 FERC Form 1 (pages 326 and 327 ("System Purchases from Others")). The data reported in these forms confirm that OG&E makes very few short-term energy sales, consistent with the DPT analysis that I have conducted. For example, in its FERC Form 1, OG&E reports only about 46,000 MWh of sales categorized as Other Service ("OS"), which in the Form 1 specifies short-term sales. In contrast, OG&E had about 950,000 MWh of OS purchases. Thus, OG&E was a net buyer in the market.

may market the power outside of the balancing authority area. I understand that, in 2006 and 2007, OG&E, GRDA and OMPA are the only customers located in the OGE and GRDA balancing authority areas that purchased power from the Redbud Facility, and these three customers accounted for less than 30 percent of Redbud's energy sales. The remainder of Redbud's output was purchased by other customers in SPP and surrounding regions, including in SERC and ERCOT.[25] On this basis, I concluded that I have analyzed all of the relevant markets.

While destination markets typically are defined as individual balancing authority areas, the Commission's practice has been to aggregate customers that have the same supply alternatives into a single destination market. This approach has been accepted in a number of merger filings.[26] While the Commission has not previously explicitly relied upon SPP as a relevant geographic market in the context of merger analysis, it has relied on the existence of the SPP EIS market as sufficient to allow parties to sell into the EIS market at market-based rates.[27] I have included an analysis of an SPP market based on the EIS footprint. The real-time EIS market began in February 2007, and is based on a least cost bid-based security constrained economic dispatch and locational imbalance pricing. This is equivalent to locational marginal pricing in markets administered by other RTOs. The SPP EIS market provides resources the opportunity either to make themselves available for dispatch by SPP's market systems or to self-dispatch to serve scheduled transactions or native load. SPP staff and stakeholders are in the process of developing and evaluating a comprehensive market services design for the region, which is expected to provide additional SPP markets for ancillary services, day-ahead unit commitment and day-ahead energy. In addition, SPP has a market monitor in place and its Market Monitoring Unit conducts periodic reviews of competitive conditions in the SPP, including reviews of the EIS market. The presence of the EIS market helps prevent any attempt

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[25] While I have not evaluated ERCOT, it is non-jurisdictional and, regardless, given that OG&E made no sales into the ERCOT market there is no need to evaluate the market.

[26] Revised Filing Requirements, ¶ 31,311 at 31,844-5, citing *Atlantic City Electric Company and Delmarva Power & Light Company*, 80 FERC ¶ 61,126 (1997), *reh'g denied*; *Consolidated Edison Co., Inc. and Northeast Utilities*, 91 FERC ¶ 61,225 (2000), *reh'g denied*. To the extent there are internal transmission constraints within these markets, the Commission has considered smaller markets within these single control areas as potentially relevant.

[27] *Southwest Power Pool, Inc.*, 114 FERC ¶ 61,289 (2006).

to exercise market power over load in the region by providing a final, centralized market that suppliers can access. This market has broad participation.

Description Of Methodology

The Appendix A competitive screening methodology considers both economics and physical transmission constraints in determining the potential supply available to a destination market. I have implemented the Appendix A analysis using a proprietary CRA model called the "Competitive Analysis Screening Model" ("CASm"). CASm is a linear programming model developed specifically to perform the calculations required in undertaking the DPT. The model includes each potential supplier as a distinct "node" or area that is connected via a transportation (or "pipes") representation of the transmission network. Each link in the network has its own non-simultaneous limit and cost. Potential suppliers are allowed to use all economically and physically feasible links or paths to reach the destination market. In instances where more generation meets the economic facet of the delivered price test than can actually be delivered on the transmission network, scarce transmission capacity is allocated based on the relative amount of economic generation that each party controls at a constrained interface. The model incorporates SILs consistent with the Commission's screens for evaluating generation dominance in connection with market-based rate applications.[28] This is described in more detail below. The source and methodology for the data required to conduct the DPT in CASm are described in Exhibit J-4. A technical description of CASm is provided in Exhibit J-5. CASm has been used in numerous previous analyses submitted to the Commission.

I conducted the Appendix A competitive screening test assuming the existing market structure and using publicly available data on generation and transmission capacity. The data inputs were adjusted to reflect 2008 conditions as a representative year (*e.g.*, to reflect updated

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[28] *AEP Power Mktg., Inc.*, 107 FERC ¶ 61,018 (2004), ("*AEP I*"), *order on reh'g*, 108 FERC ¶ 61,026 (2004).

fuel prices, load, and generation). I would not expect using an analysis using 2009 conditions to change my conclusions in any material way.[29]

Transmission Limits

Transmission capacity into and between the relevant balancing authority area markets is an important input into the DPT, because it is a key determinant of competitive supply and market size. At my request, OG&E transmission personnel provided SIL calculations for Summer, Winter, and Shoulder 2008 seasons for the OG&E and GRDA balancing authority areas and each of their first-tier balancing authority areas. These studies were conducted in a manner consistent with the Commission's requirements in market-based rate filings, except that instead of using historical data, the focus is on a forward-looking snapshot.[30] The transmission studies also included a calculation of the First Contingency Incremental Transfer Capability ("FCITC") into the OG&E and GRDA balancing authority areas. A description of the study and methodology is provided in the Testimony of Philip L. Crissup.

The SILs used in my analysis for the OG&E and GRDA balancing authority area are shown in Table 1 below, and a more complete list of SILs for other balancing authority areas as well as the balancing authority area-to-balancing authority area non-simultaneous FCITC limits used in the analysis is provided in workpapers. As shown, the SILs into both OG&E and GRDA are lower post-Transaction than pre-Transaction. This reflects the expected effect of designating Redbud as a network resource for OG&E, GRDA and OMPA, and securing SPP transmission for delivery to their respective loads.[31]

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[29] In 2009, OG&E, GRDA and OMPA also have contracted for portions of the Redbud Facility. OG&E's and GRDA's contracted amounts remain the same, but OMPA is increasing from 80 MW in 2008 to 95 MW in 2009 and 125 MW in 2010.

[30] SPP no longer posts balancing authority area–to-balancing authority area non-simultaneous limits. At my request, OG&E transmission personnel also estimated these limits for key paths in the analysis. For other balancing authority area to balancing authority area limits, I have used values from OASIS (outside of the RTO markets) and historical Total Transfer Capacity values for paths in the SPP. Given that I have applied SILs into each of the balancing authority area markets, the specific non-simultaneous limits are not critical in my analysis.

[31] OG&E's transmission personnel also analyzed whether the energy from Redbud is fully deliverable to the respective owners post-Transaction. The study found that the Redbud output could be fully delivered.

Table 1: SILs into OG&E and GRDA Balancing Authority Areas

	Pre-Transaction (Base case)			Post-Transaction		
Path/Nomogram	Summer	Shoulder	Winter	Summer	Shoulder	Winter
SIL into OKGE	137	594	930	106	564	889
SIL into GRDA	258	577	457	160	409	299

Market Prices, Time Periods and Load

The Competitive Analysis Screen is intended to consider the effect of a transaction over a range of system conditions. My analysis considers three seasons (Summer, Winter and Shoulder) to reflect the differences in unit availability, load and transmission capacity.[32] Hours were first separated into seasons to reflect differences in generating availability and then further differentiated by load levels during each season.[33] For each season, hours were segmented into peak- and off-peak periods.[34] In total, I divided the year into 10 different periods based on load conditions. The periods evaluated (and the designations used to refer to these periods in exhibits) are:

SUMMER (June-July-August)

Super Peak 1 (S_SP1):	Top load hour
Super Peak 2 (S_SP2):	Top 10% of peak load hours
Peak (S_P):	Remaining peak hours
Off-peak (S_OP):	All off-peak hours

WINTER (December-January-February)

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[32] The three seasons are defined in accordance with Appendix E in *AEP I*. The existing contracts between OG&E and OMPA with Redbud Energy cover the Summer and a portion of the Shoulder seasons. In the transmission modeling as well as in my base analysis I have included OG&E and OMPA's contracts in the pre-Transaction scenario for the Summer and Shoulder seasons.

[33] Appendix A requires applicants to evaluate the merger's impact on competition under different system conditions. For example, aggregating summer peak and shoulder peak conditions may mask important differences in unit availability and, therefore, a merger could potentially affect competition differently in these seasons. Thus, applicants are directed to evaluate enough sufficiently different conditions to show the merger's impact across a range of system conditions. On the other hand, the DOJ/FTC *Horizontal Merger Guidelines* discuss the ability to "sustain" a price increase, and a finding that a structural test (like the HHI statistic) violates the safe harbor for some small subset of hours during the year may not be indicative of any market power problems. *See* Order No. 592 at 30,128-37.

[34] Peak and off-peak hours were defined according to NERC's definition, except that I did not consider Saturdays to be peak days in order to better reflect load patterns. This assumption has no material impact on my analysis. See Appendix IF - Inadvertent Interchange Dispute Resolution Process, Error Adjustment procedures, and On- and Off-Peak Periods.

Super Peak (W_SP):	Top 10% of peak load hours
Peak (W_P):	Remaining peak hours
Off-peak (W_OP):	All off-peak hours

SHOULDER (March-April-May-September-October-November)

Super Peak (SH_SP):	Top 10% of peak load hours
Peak (SH_P):	Remaining peak hours
Off-peak (SH_OP):	All off-peak hours

In the particular circumstances of this Transaction, the only relevant system conditions are those in which natural gas combined-cycle units such as Redbud are economic and expected to operate. Based on market prices and the incremental costs of such facilities, none of the off-peak periods are relevant to my analysis.

In order to select market prices for the DPT analysis, I reviewed historical system lambdas for OG&E, bilateral prices, real-time (EIS) market prices and a forecast of expected market prices.[35] Each of these data sources has different attributes relevant to the determination of market prices for a forward-looking DPT analysis. Use of system lambda as the initial basis for market prices was suggested in Order No. 592, but even there, the Commission recognized that alternative price data might be used.[36] In Order No. 642, the Commission again suggested prices might need to be estimated.[37] Finally, in *AEP I*, the Commission described using "a combination of observed prices from the trade press or RTO/ISO data and system lambdas."[38]

My base case market prices were selected based primarily on a review of the EIS historical real-time prices and a forecast (by Ventyx, as noted earlier) of market prices in the SPP (both of which are reported on a hourly basis).[39] I aggregated the data into the 10 time periods

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[35] The forecast price data are from Ventyx (formerly Global Energy Decisions), Velocity Suite Online, a third-party vendor of such information.

[36] "Until market institutions mature enough to reveal single market clearing prices, applicants may use surrogate measures as long as they are properly supported." Order No. 592 at 30,131.

[37] "We are open to the use of estimated prices, provided that they are accurate representations of prevailing market conditions. The accuracy of such prices must be supported by available data." Order No. 642 at 31,891.

[38] *AEP I*, Appendix F, p.215.

[39] I also reviewed OG&E's system lambda data and pricing information from the Commission's February 2008 market oversight report for the SPP region (See http: www ferc.gov market-oversight mkt-electric spp.asp).

analyzed in the DPT and, for my base case prices, considered the average of these two data sources.[40] For the Summer Super Peak period, I used a $250/MWh price that captures all generation in the market. I also analyzed price sensitivities of 10 percent higher and lower in order to capture the full range of prices reported in each of the datasets.

I also reviewed the historical operation of generating facilities in the SPP in order to verify that my assumed market prices and the input prices that drive the incremental cost of units in the model were consistent with historical and expected operation. That is, I confirmed that the selected base case prices resulted in units operating in the different time periods as suggested by their capacity factors and information on the marginal fuel types in the SPP.[41] My base case prices reflect Redbud and other combined-cycle generation meeting the economic facet of the DPT in all peak time periods, but not in the three off-peak periods in which coal-fired generation is likely on the margin. This is consistent with the historical capacity factor of combined-cycle generation in the SPP, including Redbud.[42] I understand that it also is consistent with OG&E's expected operation of Redbud.

While generally using a broad range of market prices is sufficient to capture any competitive impacts of a proposed transaction, in this instance specifying prices correctly is particularly important. OG&E has some relatively high-cost generation, primarily at its older gas-fired units at Seminole (three units totaling about 1,500 MW that were built between 1971 and 1975) and Horseshoe Lake (800 MW of which was originally installed between 1958 and 1969). It is my understanding that Horseshoe Lake is generally operated to address voltage issues and that Seminole generally operates at a low capacity factor, but that one or more units at

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OG&E's 2006 system lambas show relatively little variation, with average prices of about $55/MWh for the year ($53/MWh in the Summer and Shoulder seasons and $63/MWh in the Winter). This is consistent with reported bilateral prices from the Commission's market report, which notes an average bilateral price of $56.3/MWh in 2006 (from Platts' SPP North Daily Spot Price Index) and also show very little daily variation.

40 The change in historical gas prices in 2007 and forecast gas prices for 2008 was used to adjust the EIS data to 2008. I also adjusted the prices forecast by Ventyx to be consistent with the gas prices used in my analysis.

41 The Commission's February 2008 market oversight report for the SPP region (*supra* note 39) indicates that the marginal fuel type in the region is coal and natural gas.

42 EPA's Continuous Emission Monitoring System ("CEMS") data provide hourly output data on fossil generators. I reviewed a summary of the data from the Velocity Online database that provides both the hourly data as well as capacity factors.

the Seminole facility are kept on-line to meet reserve obligations and to protect against unplanned outages at OG&E's coal-fired facilities. Seminole and Horseshoe Lake have similar incremental costs. Depending on the assumed market price in the DPT, the amount of capacity from these facilities that becomes economic (and excess AEC) ranges from zero to about 1,500 MW. Even though the factors surrounding when and why Seminole and Horseshoe Lake operate suggest they, perhaps, should not be economic for purposes of my analysis, my base case analysis, in effect, takes a middle position, and uses prices that result in a portion of these units (about 700 MW) being economic. The impact of lower and higher market prices is reflected in my price sensitivity analyses.

Hourly loads were based on FERC Form 714 filings for 2006, escalated to 2008 based on the forecasts included in these filings. I understand that the entire load reported in OG&E's FERC Form 714 is served by OG&E. Where I did not have reliable information on the loads of smaller load-serving entities that are potential suppliers in my model, I generally have assumed that they have zero AEC. This is a conservative assumption because it reduces the actual amount of rival generation included in the analysis. Also, I conservatively have not incorporated any deduction for operating reserve obligations, which, like native and requirements load sales, makes some amount of each supplier's capacity unavailable for sale at wholesale because the capacity is being used to provide the required obligation. OG&E's operating reserves, determined by the SPP Reserve Sharing Group, have historically been around 180-200 MW per hour. Thus, while both operating and planning reserves are important determinants in the need for capacity to meet load and reliability requirements, my Competitive Analysis Screen does not reflect these requirements.

IMPACT OF THE TRANSACTION ON COMPETITION

Horizontal Market Power

The Transaction is Driven by the Need to Meet Statutory Load and Reliability Obligations

OG&E, GRDA and OMPA are currently "short" capacity relative to their load and reliability obligations. Each is obligated to secure resources necessary to meet their native and requirements loads and reliability obligations. Absent their existing contracts with Redbud, each company requires additional generating resources. When OG&E, GRDA and OMPA buy the

Redbud Facility, each will have some excess capacity as compared to their reserve requirement, although this surplus is short-lived. Utility investments tend to be lumpy, and hence, this short-term excess is to be expected. OG&E's expected load growth will eliminate any temporary excess supply by about 2012, and GRDA and OMPA similarly will once again require additional resources by about 2015 and 2010, respectively.

As shown in Table 2 below, OG&E is currently capacity short without the 300 MW contracted from Redbud in 2008. Without the purchase of Redbud, OG&E will remain capacity short through 2012, *i.e.*, in the absence of the Transaction it would need to purchase capacity (or enter into additional contracts) to meet a 12 percent SPP capacity margin requirement.[43] OG&E's short-term peak load growth is forecast to be in excess of 100 MW per year, but settles at about 80 MW per year post-2009. With the Redbud Transaction, OG&E will be slightly long on capacity relative to its load and reserve requirements, but this excess is worked off by about 2012, as shown below. Table 2 reflects the 300 MW OG&E contract with Redbud in 2008 and 2009 (July-September). If OG&E did not buy a share of Redbud, it presumably would have had to replace the 300 MW with another purchase going-forward. Thus, the incremental generation owned or contracted for via this Transaction is 310 MW (610 MW of Redbud minus 300 MW purchase).[44]

Table 2: OG&E Load and Resource Balance, 2008-2012

	2008	2009	2010	2011	2012
Peak Load (MW)	5,986	6,107	6,192	6,279	6,349
Capacity Requirement (12% Capacity Margin)	6,802	6,940	7,036	7,135	7,215
Capacity plus Net Purchases	6,612	6,612	6,612	6,612	6,612
Excess (Shortfall)	(190)	(328)	(424)	(523)	(603)
Redbud Contract Purchase	300	300	0	0	0
Redbud Purchase	0	310	610	610	610
Net Excess (Shortfall)	110	282	186	87	7
Net Projected Capacity Margin	13.40%	15.44%	14.26%	13.06%	12.09%

GRDA also is capacity short, as shown in Table 3 below. Its current needs are just being met with the 150 MW purchase from Redbud, which means that the acquisition of its share of

[43] Capacity margin is calculated as (Capacity minus Peak Load)/Capacity*100.

[44] For the months not covered by the existing contract, the incremental generation is 610 MW.

Redbud will result in GRDA having some excess capacity relative to its load and reserve requirements until this excess is worked off by about 2015. Table 3 reflects the 150 MW GRDA contract with Redbud in 2008 and 2009 (July-September). If GRDA did not buy a share of Redbud, it presumably would have had to replace the 150 MW with another purchase going-forward. Thus, the incremental generation owned or contracted for via this Transaction is 280 MW (430 MW minus 150 MW purchase).

Table 3: GRDA Load and Resource Balance, 2008-2012

	2008	2009	2010	2011	2012
Peak Load (MW)	1,243	1,268	1,384	1,413	1,443
Capacity Requirement (12% Capacity Margin)	1,413	1,441	1,573	1,606	1,640
Capacity plus Net Purchases	1,235	1,291	1,291	1,291	1,291
Excess (Shortfall)	(178)	(150)	(282)	(315)	(349)
Redbud Contract Purchase	150	150	0	0	0
Redbud Purchase	0	280	430	430	430
Net Excess (Shortfall)	(28)	280	148	115	81
Net Projected Capacity Margin	10.25%	26.32%	19.58%	17.90%	16.15%

Finally, as shown in Table 4 below, OMPA also is capacity short. With the Redbud Transaction, OMPA will have a very short period before it needs to contract for or buy capacity to meet its load and reserve requirements. Table 4 reflects the 80 MW OMPA contract with Redbud in 2008, increasing to 95 MW in 2009 and 125 MW in 2010. If OMPA did not buy a share of Redbud, it presumably would have had to replace this power with another purchase going-forward. Thus, the incremental generation owned or contracted for via this Transaction is 75 MW for 2008, 60 MW for 2009, and 30 MW for 2010.

Table 4: OMPA Load and Resource Balance, 2008-2012

	2008	2009	2010	2011	2012
Peak Load (MW)	663	674	684	693	703
Capacity Requirement (12% Capacity Margin)	753	766	777	788	799
Capacity plus Net Purchases	656	656	620	620	661
Excess (Shortfall)	(97)	(110)	(157)	(168)	(138)
Redbud Contract Purchase	80	95	125	0	0
Redbud Purchase	0	60	30	155	155
Net Excess (Shortfall)	(17)	45	(2)	(13)	17
Net Projected Capacity Margin	9.92%	16.89%	11.74%	10.58%	13.85%

There is Limited Load in the Relevant Balancing Authority Areas not Already Subject to Long-Term Requirements Contracts

There are no wholesale customers located within the OG&E (with the exception of OMPA) or GRDA balancing authority areas who are not already served under long-term arrangements at fixed or formula rates,[45] so that any competitive concerns about a lack of supply alternatives for customers in the balancing authority areas post-Transaction are purely theoretical.

With the exception of OMPA, all wholesale customers within the OG&E balancing authority area are requirements customers of OG&E with long-term contracts, although a few also receive an allocation of power from SPA.[46] Thus, other than OMPA, these customers are not participants in wholesale markets. OMPA has generation and load outside of the OG&E control area, but between its owned generation and its contracted supply,[47] most of its energy requirements are already met.

GRDA and OMPA are state governmental agencies that transmit and deliver electricity to cities and towns that own their own electric systems and are served under long-term agreements with the state agencies.

GRDA has 20 wholesale customers located in its balancing authority area. Most are full requirements customers, including some whose owned generation is sold to GRDA. A few are full-requirements customers for a portion of their loads subject to contract, and one has its own generation that supplements its requirements contract. In addition, there are other wholesale customers located in the GRDA balancing authority area who are full requirements customers of either KAMO Electric Cooperative or AEP.

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45 As noted earlier, these fixed or formula rates are unaffected by the Transaction.

46 A current wholesale customer of OG&E (with approximately 20 MW of peak load), has indicated its intention to terminate its agreement with OG&E, subject to securing an alternative long-term supplier. Whether or when the contract will be terminated is unknown at this time.

47 OMPA's total peak load in 2006 was 660 MW, of which 446 MW was located in the OG&E balancing authority area. In addition to a 25 MW purchase from OG&E, OMPA owns approximately 275 MW of generation in the OG&E balancing authority area and is currently purchasing 80 MW from Redbud. OMPA also manages an allocation of hydropower from SPA for some of the cities it serves.

OG&E Does Not Have Market-Based Rate Authority For Sales In Its Balancing Authority Area

OG&E does not have authority to make wholesale sales within its balancing authority area at market-based rates. This eliminates OG&E's incentive to use any perceived increase in generation market power to raise market prices within its balancing authority area, notwithstanding the fact that there are no unserved wholesale customers in the area, other than OMPA, as noted above.[48]

In compliance with Commission Orders regarding their applications to retain market-based rate authority, OG&E has submitted cost-based rate tariffs for sales (based on default cost-based mitigation in Order No. 697)[49] within the OG&E balancing authority area.[50] OG&E has committed to sell at incremental costs plus 10 percent for sales less than one week within the OG&E balancing authority area and file with the Commission any sales longer than one year. OG&E has agreed not to enter into agreements to sell for durations between one week and less than one year within the OG&E balancing authority area and proposed to file and provide cost justification for any new contract of this duration. EIS market participants are authorized to make market-based rate sales into the EIS market.[51] For sales outside of the OG&E balancing authority area, OG&E also is able to sell at market-based rates in accordance with prior Commission orders.[52] As such, post-Transaction the restrictions applicable to OG&E will apply to wholesale sales, if any, made from OG&E's acquired share of Redbud.

Further limiting, if not eliminating, any incentive for OG&E to increase prices in its balancing authority area (assuming, as is not the case, that there were wholesale customers seeking supply within the balancing authority area) are the sharing mechanisms approved and administered by the respective regulatory commissions. The OCC and APSC require that OG&E

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48 Even if market prices were below OG&E's Commission-approved cost-based rates, OG&E is not expected to sell below cost, and its cost-based rates are presumably just and reasonable.

49 *Market-Based Rates For Wholesale Sales Of Electric Energy, Capacity And Ancillary Services By Public Utilities*, Order No. 697, FERC Stats. and Regs. ¶ 31,252 (2007) (codified at 18 C.F.R. Part 35) ("*Order No. 697*"), and Order Clarifying Final Rule, 121 FERC ¶ 61,260 (2007) ("*Clarification Order*").

50 *See* Docket No. ER97-4345 *et al.*, April 20, 2006 and August 25, 2006.

51 *Southwest Power Pool, Inc.*, 114 FERC ¶ 61,289 (2006).

52 *Oklahoma Gas and Electric Company*, 114 FERC ¶ 61,297 (2006).

credit retail customers 80 percent and 100 percent, respectively, of profits from off-system sales, and OG&E's FERC tariff requires it to credit certain wholesale customers 90 percent of the profits from off-system sales in some time periods. These sharing mechanisms reduce any incentive for OG&E to increase market prices because shareholders capture at most only 20 percent of any gains from their off-system sales.

The incentives of GRDA and OMPA, as state municipal government agencies, are to keep market prices low. There are no shareholders.

Redbud Represents a Small Share of Generation in the SPP and there is a Significant Amount of Economically-Similar Generation in the Region

The SPP EIS footprint has about 47,000 MW of generating capacity. Redbud's capacity represents about 3 percent of this total generation.

There also is more than 8,000 MW of gas-fired combined cycle capacity that is of similar vintage and operating characteristics as Redbud in the SPP, and almost 20,000 MW that has been added in areas first-tier to the OG&E balancing authority area between 2000 and 2006. This is evidence that there is a significant amount of combined-cycle generation not controlled by OG&E, GRDA or OMPA such that competing generation is still available within the relevant markets after the purchase of Redbud. This means that the sale of Redbud should not undermine the ability for customers (here, mostly theoretical customers) to obtain alternative supply. This alternative supply could come either from rival generators inside the relevant markets or from imports using available transmission capacity. Based on preliminary transmission analysis, even in the summer peak season, post-Transaction OG&E can import more than 100 MW and GRDA more than 150 MW of energy on a simultaneous basis (see Table 1). In other seasons, the import capability is substantially higher. Also, the individual transfer limits (FCITCs) from some first-tier balancing authority areas are substantially higher than the SIL, indicating sufficient alternative sources of supply should be available, as discussed below.

Given the amount of third-party generation located in and around the relevant balancing authority areas, and in the EIS market, it is evident that there is sufficient rival generation to serve any demand in the OG&E or GRDA balancing authority areas (notwithstanding the fact, as noted, there is no such load).

Results of the DPT

The DPT analyses I conducted reflect the existing contracts that OG&E, GRDA and OMPA have for the output of Redbud pre-Transaction.[53] Specifically, in the pre-Transaction scenario, these existing contracts are incorporated by assigning 300 MW to OG&E and 80 MW to OMPA in the Summer and Shoulder seasons and 150 MW to GRDA, in the GRDA balancing authority area, during all seasons.[54] In the absence of this Transaction, such contracts would either be extended or replaced by contracts with some other party, as the need to meet load and reliability obligations would require OG&E, GRDA and OMPA to contract for additional supply. My understanding is that each of these parties has a transmission agreement with SPP for delivery of the currently contracted power to their loads. When OG&E, GRDA and OMPA acquire additional ownership shares in Redbud, they will need additional transmission to deliver the power to their respective loads. As a result, transmission capability into the OG&E and GRDA balancing authority area changes as Redbud is dispatched to supply the respective shares to its new owners.

I discuss the results of the DPT below, but I note that the results are materially affected by changes in market size between the pre- and post-Transaction analyses. The change in market size makes the standard HHI metrics difficult to interpret and not necessarily good indicators of the actual impact of the Transaction on competition. HHIs typically are intended to be a static measure merely reflecting shifts in market share rather than changes in market size. Here, three factors affect the size of the balancing authority area markets and complicate application of the Commission's DPT metrics. First, a portion of Redbud, over and above the 150 MW that GRDA is currently buying is assumed to be transferred from the OG&E balancing authority area to the GRDA balancing authority area. All other things equal, this reduces the amount of generation

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[53] While this treatment reduces the absolute increase in capacity acquired as a result of the transaction, it also reduces the deconcentrating effect of the Transaction arising from the fact that Redbud generally has more AEC than do the buyers.

[54] OG&E and OMPA have contracted for the same seasonal periods (June-September). OMPA's contract is through 2010, and its purchase increases from 80 MW in 2008 to 95 MW in 2009 and 125 MW in 2010. Since the OG&E and OMPA contracts are for June-September, they are relevant to my pre-Transaction analysis of the Summer season. These contracts also are in effect in part of the Shoulder season (one month only), and I included them as such in order to be consistent with the transmission analysis conducted by OG&E. However, I also include a sensitivity analysis that does not include these pre-Transaction contracts in the Shoulder.

within the OG&E balancing authority area (thus, reducing market size) and increases the amount of generation "within" the GRDA balancing authority area (thus, increasing market size). Second, during time periods when OG&E, GRDA or OMPA have an AEC deficit pre-Transaction (*i.e.*, their loads are in excess of their economic supply), some portion of the additional generation supplied by Redbud first offsets any "negative" AEC, thereby reducing the market size. Third, transmission reservations will be required from SPP in order to deliver ownership shares of Redbud to respective loads post-Transaction (*i.e.*, designation as a network resource), which could have an effect on transmission availability. While the formal analyses required to grant the new reservations will be conducted and approved by SPP, studies conducted by OG&E transmission personnel indicate that dispatching Redbud to the new owners reduces the SILs into the OG&E and GRDA balancing authority areas.

While the transmission data reflect the change in SIL resulting from the change in ownership and dispatch of the Redbud Facility (see Table 1), they do not reflect the counterflow effect that occurs when GRDA reserves and schedules an additional portion of the Redbud Facility for delivery to the GRDA balancing authority area. This should increase the ability to import into the OG&E balancing authority area.[55] While this counterflow effect is completely hidden by the use of the SILs, it is clear from the balancing area-to-balancing area FCITC transmission limits, as shown in Table 5 below.[56] Pre-Transaction import levels from GRDA to OG&E are 331 MW (summer). When an additional 280 MW of Redbud is dispatched for delivery to GRDA post-Transaction, the import level from GRDA to OG&E increases to 600 MW (summer) as a result of the counterflow. It is also notable, as compared to the SILs reported in Table 1, that the balancing authority area-to-balancing authority area limits into OG&E are much higher from most individual sources. Indeed, OG&E is able to import more power from any single source (other than Entergy) than the SIL.

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[55] Under SPP's tariff, it is my understanding that if GRDA has a schedule (NITS or Firm) to deliver its energy from Redbud in OG&E's balancing authority area to the GRDA balancing authority area, then rival suppliers could counter-schedule against it (on a firm or non-firm basis) and potential supply in the OG&E balancing authority area would be unchanged. (In fact, to the extent that the rival imports were provided by more than one supplier, the HHI assuming counterflows are scheduled would be lower than assuming GRDA's capacity remains in the market.)

[56] Abbreviations in the table that differ from my use are PSO=AEP West, SWPA=SPA, ENTR Entergy, WERE=WR.

Table 5: FCITC Limits into OG&E Balancing Authority Area

	Pre-Transaction (Base case)			Post-Transaction		
Path/Nomogram	Summer	Shoulder	Winter	Summer	Shoulder	Winter
GRDA to OGE	331	127	355	600	276	580
PSO to OGE	1393	1269	1800	1441	1315	1868
ENTR to OGE	97	442	648	74	416	620
SWPA to OGE	800	299	532	785	283	818
WERE to OGE	326	165	280	312	158	281
WFEC to OGE	409	570	468	409	571	468
AECI to OGE	440	762	1150	404	715	1087

In light of these facts, I conducted an alternative additional DPT analysis for the OG&E balancing authority area (which I term the "FCITC Case"), to account for the much higher import capability than reflected in the SILs.[57] I used the import capability from AEP West (PSO in Table 5) to OG&E as a proxy for the ability to import from a single source. Any economic supply located within AEP West, or within two wheels of AEP West can be imported into the OG&E balancing authority area if it is economic and deliverable.

Finally, I also analyzed the results assuming that GRDA does not immediately need its full incremental share of Redbud to meet existing load requirements (which I term the "GRDA Case"). Based on GRDA's current load and resource estimates, it will not require all of its share until about 2015. GRDA's existing fleet of generation consists nearly entirely of hydroelectric and coal-fired generation, and the energy from the Redbud Facility is unlikely to economically displace these existing resources. Under these circumstances, GRDA's share of Redbud located in the OG&E balancing authority area would constitute GRDA's excess resources. For this purpose, I assume that GRDA's share of Redbud over and above its existing 150 MW contract amount remains in the OG&E balancing authority area (rather than being exported to the GRDA balancing authority area). The theory is that if GRDA has no need for additional energy from

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[57] My understanding is that SILs are calculated pursuant to the Commission's approach (described in Appendix E of *AEP I*), which groups all the first-tier markets as a single exporting entity. The effect is that the SIL may reflect a limit reached for the group (*i.e.*, from all directions) that may be lower than the amount that can be imported over a single (or even multiple), alternative path(s). For example, if a constraint is reached in importing from the Entergy balancing authority area, the SIL determination stops, even though it is possible that substantially more power could be imported from another source, such as AEP West. The result is a SIL that may substantially understate import capability into a market from any particular direction. I understand that this was an issue in a market-based rate proceeding on behalf of Arizona Public Service (*see Affidavit of Ronald R. Calvert*, Docket Nos. ER00-2268-000, *et al.*, February 20, 2007), where the Commission ultimately accepted the SIL developed based on an alternative scaling methodology in order to avoid this problem. *Pinnacle West Capital Corporation et al.*, 120 FERC ¶ 61,153 (2007).

Redbud in any given period, its share of Redbud that is in excess of 150 MW will not be dispatched to serve its load. As such, rather than "moving" it from the OG&E to the GRDA balancing authority area, GRDA's share of Redbud in excess of 150 MW remains as supply potentially available in the OG&E balancing authority area.

The following are the results of the DPT.[58]

SPP EIS Market. In the SPP EIS market,[59] the market is unconcentrated and the HHI changes are negative, reflecting the fact that the Transaction results in transferring AEC from a relatively large market participant (Redbud and its affiliates) to three smaller entities, as shown in Table 6 below and in Exhibit J-6.[60] The Transaction also passes the EC measure, with small HHI changes, as shown in Exhibit J-6.[61]

Table 6: Available Economic Capacity, SPP EIS Market

		Pre-Transaction										Post-Transaction								
		GRDA		Kelson		OKGE		OMPA				GRDA		OKGE		OMPA				
Period	Price	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	HHI Chg
S_SP1	$250	50	0.5%	2,010	21.3%	158	1.7%	0	0.0%	9,429	987	299	3.2%	422	4.5%	50	0.5%	9,416	794	-193
S_SP2	$120	57	0.6%	2,022	21.1%	306	3.2%	0	0.0%	9,566	992	306	3.2%	570	6.0%	54	0.6%	9,557	811	-181
S_P	$75	241	2.4%	1,974	19.9%	0	0.0%	80	0.8%	9,946	994	489	5.1%	0	0.0%	144	1.5%	9,683	863	-131
W_SP	$85	230	2.3%	2,263	22.1%	501	4.9%	0	0.0%	10,258	999	459	4.5%	1,037	10.1%	128	1.2%	10,250	786	-214
W_P	$60	425	4.6%	1,815	19.5%	0	0.0%	68	0.7%	9,319	963	570	6.4%	0	0.0%	175	2.0%	8,902	827	-136
SH_SP	$80	367	3.3%	1,758	15.8%	960	8.6%	149	1.3%	11,161	794	566	5.1%	1,156	10.3%	195	1.8%	11,161	736	-59
SH_P	$55	165	2.0%	1,255	15.6%	0	0.0%	97	1.2%	8,046	868	287	3.6%	0	0.0%	115	1.5%	7,961	814	-53

[58] Note that the tables and exhibits reflecting the DPT results refer to "Kelson" rather than "Redbud" in the pre-Transaction scenario. This is because the energy reflected in the DPT includes supply from the Redbud Facility as well as from the other generating facilities attributed to Kelson for the purpose of my analysis. Also, note that although Kelson's post-Transaction share is not reported in the tables and exhibits, its post-Transaction share is included in the calculation of the market HHI. My workpapers ("Supplier Reports") detail the MW, share and HHI contribution of each market participant, including Kelson.

[59] The SPP EIS market consists of the entities participating in the SPP's EIS market and a conservative estimate of imports, as described in Exhibit J-4.

[60] The post-Transaction MWs reflected in this and subsequent tables reflect the incremental purchases of Redbud over and above the amounts OG&E, GRDA and OMPA have already contracted for (which are reflected in their pre-Transaction shares), a total of 610 MW, derated to reflect forced and planned outages. Pre-Transaction, Kelson is also shown attributed with affiliated generation either located in the relevant destination market or allocated a pro rata share of imports. In addition, I have modeled two incremental cost segments for Redbud's output in order to reflect the fact that a portion of it is available via duct-firing (this same treatment was applied where applicable for other suppliers in the analysis). Therefore, not all of Redbud's capacity meets the economic facet of the DPT during the non-Super peak periods.

[61] The Exhibits reflect results for all ten time periods, although the tables in the text reflect only those periods when Redbud is economic (super peak and peak periods). The Exhibits also reflect the EC results.

OG&E Balancing Authority Area. For the OG&E balancing authority area market, shown in Table 7 below and Exhibit J-7, the HHI ranges from unconcentrated (in the winter and shoulder peak periods) to highly concentrated (in the super peak and summer peak periods). The HHI changes range from very negative (when the Kelson pre-Transaction market share is significantly greater than OG&E's) to very positive (when both OG&E's and OMPA's market shares increase post-Transaction).

Table 7: Available Economic Capacity, OG&E Balancing Authority Area, Base Case

		Pre-Transaction										Post-Transaction							
		GRDA		Kelson		OKGE		OMPA				GRDA		OKGE		OMPA			
Period	Price	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	HHI Chg
S_SP1	$250	1	0.1%	606	64.9%	158	16.9%	0	0.0%	933	4,560	2	0.3%	422	65.8%	50	7.8%	641	4,519	-41
S_SP2	$120	1	0.1%	606	56.0%	306	28.3%	0	0.0%	1,081	3,986	2	0.3%	570	71.8%	54	6.9%	793	5,287	1,303
S_P	$75	2	0.3%	604	76.3%	0	0.0%	80	10.1%	792	5,948	3	1.2%	0	0.0%	144	57.5%	250	3,527	-2,421
W_SP	$85	8	0.4%	1,098	47.1%	501	21.5%	0	0.0%	2,332	2,749	14	0.7%	1,037	50.5%	128	6.2%	2,054	2,753	4
W_P	$60	8	0.5%	798	47.8%	0	0.0%	68	4.1%	1,667	2,425	11	1.1%	0	0.0%	175	16.4%	1,064	673	-1,751
SH_SP	$80	4	0.2%	567	26.5%	960	44.8%	149	7.0%	2,142	2,793	6	0.3%	1,155	60.3%	196	10.2%	1,913	3,823	1,030
SH_P	$65	0	0.0%	276	30.1%	0	0.0%	97	10.6%	917	1,228	0	0.1%	0	0.0%	115	17.0%	679	685	-543

In this case, the FCITC case better reflects potential supply that can be imported into the OG&E balancing authority area. Under some circumstances, the SILs based on an aggregation of all import sources may result (as it does here) in a limit that is far lower than the amount that can be imported over single or multiple alternative paths. While the FCITC case uses data for the AEP West-OG&E path, which happens to be the highest of the individual paths (see Table 5), it still is conservative in that it is possible that the simultaneous import capability could be higher than on the single path, as long as there is no common limiting element affecting those paths. Thus, using the highest FCITC on a single path is a reasonable, but conservative, proxy of how much can be delivered into the market.

In the FCITC case, as shown in Table 8 below and in Exhibit J-8, the HHI changes are negative in all but one time-period (Shoulder super peak). At slightly lower market prices, the screen failure in the shoulder super peak would disappear. Also, the shoulder period is distinguishable because of the treatment of the pre-existing OG&E and OMPA contracts with Redbud. These contracts cover the June-September period, and hence only a small portion of the shoulder period, yet I included them in the analysis of the shoulder period. If I did not include the existing OG&E and OMPA contracts in the Shoulder season, the single screen failure

disappears, as shown at the bottom of Exhibit J-8.[62] Since any screen failure is for a single time period and hence, is non-systematic, and also is eliminated with this minor assumption change, it should not be concerning.

Table 8: Available Economic Capacity, OG&E Balancing Authority Area, FCITC Case

		Pre-Transaction										Post-Transaction								
		GRDA		Kelson		OKGE		OMPA				GRDA		OKGE		OMPA				
Period	Price	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	HHI Chg
S_SP1	$250	5	0.2%	901	41.2%	158	7.2%	0	0.0%	2,188	2,053	27	1.4%	422	21.3%	50	2.5%	1,976	1,145	-907
S_SP2	$120	6	0.3%	892	38.2%	306	13.1%	0	0.0%	2,336	1,888	32	1.5%	570	26.8%	54	2.6%	2,129	1,252	-635
S_P	$75	27	1.3%	876	42.8%	0	0.0%	80	3.9%	2,047	2,178	52	3.3%	0	0.0%	144	9.1%	1,585	1,128	-1,050
W_SP	$85	18	0.6%	1,292	40.4%	501	15.7%	0	0.0%	3,202	2,009	36	1.2%	1,037	34.2%	128	4.2%	3,033	1,521	-488
W_P	$80	17	0.7%	940	37.1%	0	0.0%	68	2.7%	2,532	1,589	26	1.3%	0	0.0%	175	8.6%	2,043	554	-1,036
SH_SP	$80	9	0.3%	733	26.0%	960	34.1%	149	5.3%	2,818	1,963	13	0.5%	1,155	43.3%	195	7.3%	2,665	2,176	213
SH_P	$56	0	0.0%	332	20.8%	0	0.0%	97	6.1%	1,592	808	0	0.0%	0	0.0%	115	8.1%	1,430	587	-221

The GRDA case also represents a credible scenario in terms of evaluating potential supply in the OG&E balancing authority since, as discussed above, GRDA may not need supply in excess of 150 MW in the short-term. It would make little sense to move this Redbud supply to the GRDA and then have it compete to be re-exported into the OG&E balancing authority area. The results of the GRDA case (again, with imports based on the FCITCs) are shown in Table 9 below and in Exhibit J-9. There are no screen violations.

Table 9: Available Economic Capacity, OG&E Balancing Authority Area, GRDA Case

		Pre-Transaction										Post-Transaction								
		GRDA		Kelson		OKGE		OMPA				GRDA		OKGE		OMPA				
Period	Price	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	HHI Chg
S_SP1	$250	5	0.2%	901	41.2%	158	7.2%	0	0.0%	2,188	2,053	253	11.9%	422	19.8%	50	2.3%	2,134	1,066	-986
S_SP2	$120	6	0.3%	892	38.2%	306	13.1%	0	0.0%	2,336	1,888	256	11.2%	570	24.9%	54	2.4%	2,286	1,163	-725
S_P	$75	27	1.3%	876	42.8%	0	0.0%	80	3.9%	2,047	2,178	278	16.0%	0	0.0%	144	8.2%	1,743	1,095	-1,083
W_SP	$85	18	0.6%	1,292	40.4%	501	15.7%	0	0.0%	3,202	2,009	248	7.8%	1,037	32.4%	128	4.0%	3,197	1,412	-597
W_P	$80	17	0.7%	940	37.1%	0	0.0%	68	2.7%	2,532	1,589	161	7.6%	0	0.0%	175	8.2%	2,124	542	-1,046
SH_SP	$80	9	0.3%	733	26.0%	960	34.1%	149	5.3%	2,818	1,963	208	7.4%	1,155	41.0%	195	6.9%	2,814	1,991	28
SH_P	$56	0	0.0%	332	20.8%	0	0.0%	97	6.1%	1,592	808	122	8.2%	0	0.0%	115	7.7%	1,503	563	-245

GRDA Balancing Authority Area. For the GRDA balancing authority area market, shown in Table 10 below and in Exhibit J-7, the market is highly concentrated and the HHI

[62] This case is relevant, and perhaps more representative, because OG&E's and OMPA's existing contracts with Redbud cover only one month (September) out of the six Shoulder months. I included the contracts in the Shoulder base case in order to conform with the assumptions made in the transmission modeling. The HHI change for the Shoulder super peak period is actually negative when the OG&E and OMPA contracts are not included in the pre-Transaction Shoulder season.

changes are very high in the Base Case.[63] The HHI changes are largely driven by GRDA's share increasing significantly post-Transaction with the addition of its share of Redbud.

Table 10: Available Economic Capacity, GRDA Balancing Authority Area, Base Case

		Pre-Transaction										Post-Transaction								
		GRDA		Kelson		OKGE		OMPA				GRDA		OKGE		OMPA				
			Mkt		Mkt		Mkt		Mkt				Mkt		Mkt		Mkt			HHI
Period	Price	MW	Share	MW	Share	MW	Share	MW	Share	Mkt Size	HHI	MW	Share	MW	Share	MW	Share	Mkt Size	HHI	Chg.
S_SP1	$250	50	16.4%	68	22.1%	2	0.8%	0	0.0%	308	1,272	299	65.1%	4	0.9%	0	0.1%	459	4,384	3,113
S_SP2	$120	57	18.2%	70	22.3%	4	1.4%	0	0.0%	315	1,308	306	65.6%	5	1.2%	1	0.1%	466	4,458	3,150
S_P	$75	241	48.3%	75	15.1%	0	0.0%	1	0.1%	498	2,777	489	75.3%	0	0.0%	1	0.2%	649	5,765	2,988
W_SP	$85	230	33.5%	199	29.0%	0	0.0%	0	0.0%	687	2,048	459	60.5%	12	1.6%	15	2.0%	758	3,788	1,740
W_P	$60	425	48.2%	145	16.4%	0	0.0%	3	0.4%	882	2,665	570	65.6%	0	0.0%	18	2.0%	869	4,365	1,700
SH_SP	$80	367	38.9%	214	22.6%	0	0.0%	33	3.5%	944	2,114	566	58.0%	0	0.0%	41	4.2%	975	3,529	1,416
SH_P	$55	165	22.2%	22	2.9%	0	0.0%	3	0.4%	742	909	287	41.2%	0	0.0%	2	0.3%	696	1,934	1,025

In the GRDA case, when the GRDA share of Redbud over its existing contract amount remains in the OG&E market, the results are significantly better, with only two nominal screen violations, in the summer peak and shoulder super peak periods, as shown in Table 11below and in Exhibit J-9. All of the analyses of the GRDA balancing authority area use SILs. Note that the increase in GRDA's AEC in the summer peak period, is only 4 MW, and the increase in the shoulder super peak period is only 50 MW. Again, this is a credible sensitivity that assumes the additional Redbud supply will not be moved into the GRDA balancing authority area when it is not needed to serve GRDA load.

Table 11: Available Economic Capacity, GRDA Balancing Authority Area, GRDA Case

		Pre-Transaction										Post-Transaction								
		GRDA		Kelson		OKGE		OMPA				GRDA		OKGE		OMPA				
			Mkt		Mkt		Mkt		Mkt				Mkt		Mkt		Mkt			HHI
Period	Price	MW	Share	MW	Share	MW	Share	MW	Share	Mkt Size	HHI	MW	Share	MW	Share	MW	Share	Mkt Size	HHI	Chg.
S_SP1	$250	50	16.4%	68	22.1%	2	0.8%	0	0.0%	308	1,272	54	19.5%	5	2.0%	1	0.2%	275	1,194	-77
S_SP2	$120	57	18.2%	70	22.3%	4	1.4%	0	0.0%	315	1,308	61	21.5%	7	2.5%	1	0.2%	282	1,288	-21
S_P	$75	241	48.3%	75	15.1%	0	0.0%	1	0.1%	498	2,777	245	52.6%	0	0.0%	1	0.3%	465	3,113	336
W_SP	$85	230	33.5%	199	29.0%	0	0.0%	0	0.0%	687	2,048	271	37.3%	17	2.4%	22	3.1%	726	1,711	-337
W_P	$60	425	48.2%	145	16.4%	0	0.0%	3	0.4%	882	2,665	454	49.3%	0	0.0%	26	2.8%	921	2,587	-78
SH_SP	$80	367	38.9%	214	22.6%	0	0.0%	33	3.5%	944	2,114	418	44.3%	0	0.0%	50	5.3%	944	2,250	137
SH_P	$55	165	22.2%	22	2.9%	0	0.0%	3	0.4%	742	909	165	22.2%	0	0.0%	3	0.4%	742	909	0

First-Tier Balancing Authority Areas. The AEC measure (as well as the EC measure) is passed in all first-tier markets and the results are shown in Exhibit J-10.

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[63] As shown in this table, OG&E receives a zero allocation of imports during some time periods where it had positive AEC in the OG&E market analysis. While OG&E continues to have available AEC, the additional transmission

Mitigation. As discussed above, OG&E has agreed to undertake certain transmission upgrades that will increase the SIL into the OG&E balancing authority area (and, as a consequence, also increase the SIL into the GRDA balancing authority area), should the Commission deem it necessary to do so. Based on analyses conducted by OG&E (see Testimony of Mr. Crissup), the increases in SILs resulting from these proposed transmission upgrades are shown in Table 12 below. The increase in SILs relative of both pre-and post-Transaction SILs is significant.

Table 12: SILs into OG&E and GRDA Balancing Authority Areas with Proposed Mitigation

	Pre-Transaction (Base case)			Post-Transaction			Post-Mitigation		
Path/Nomogram	Summer	Shoulder	Winter	Summer	Shoulder	Winter	Summer	Shoulder	Winter
SIL into OKGE	137	594	930	106	564	889	711	1127	1255
SIL into GRDA	258	577	457	160	409	299	1108	1078	922

The DPT results for the OG&E balancing authority area incorporating these transmission upgrades are shown below in Table 13 below and in Exhibit J-11, and indicate that the screen failures are completely eliminated, and the Transaction is significantly deconcentrating. The simultaneous import capability into the OG&E balancing authority area is significantly increased relative to pre-Transaction levels.

Table 13: Available Economic Capacity, OG&E Balancing Authority Area, with Transmission Upgrades

		Pre-Transaction										Post-Mitigation								
		GRDA		Kelson		OKGE		OMPA				GRDA		OKGE		OMPA				
		MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	HHI Chg
Period	Price																			
S_SP1	$250	1	0.1%	605	64.9%	158	16.9%	0	0.0%	933	4,560	14	1.1%	422	33.9%	50	4.0%	1,245	1,558	-3,002
S_SP2	$120	1	0.1%	606	56.0%	306	28.3%	0	0.0%	1,081	3,985	14	1.0%	570	40.8%	54	3.9%	1,398	1,982	-2,003
S_P	$75	2	0.3%	604	76.3%	0	0.0%	80	10.1%	792	5,948	20	2.3%	0	0.0%	144	16.8%	854	1,112	-4,836
W_SP	$85	8	0.4%	1,098	47.1%	501	21.5%	0	0.0%	2,332	2,749	20	0.8%	1,037	42.9%	128	5.3%	2,420	2,102	-647
W_P	$80	8	0.5%	798	47.8%	0	0.0%	68	4.1%	1,667	2,425	16	1.1%	0	0.0%	175	12.2%	1,430	595	-1,830
SH_SP	$80	4	0.2%	567	26.5%	960	44.8%	149	7.0%	2,142	2,793	11	0.5%	1,155	46.6%	195	7.9%	2,476	2,421	-371
SH_P	$56	0	0.0%	276	30.1%	0	0.0%	97	10.6%	917	1,228	1	0.1%	0	0.0%	115	9.3%	1,242	561	-668

These transmission upgrades similarly eliminate screen failures in the GRDA balancing authority area, as shown below in Table 14 below and in Exhibit J-11.

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cost makes this supply uneconomic for delivery to GRDA. However, the sensitivity analyses included in my workpapers reflect the impact of OG&E's AEC at higher market prices.

Exhibit J-1

Table 14: Available Economic Capacity, GRDA Balancing Authority Area, with Transmission Upgrades

		Pre-Transaction										Post-Mitigation								
		GRDA		Kelson		OKGE		OMPA				GRDA		OKGE		OMPA				
			Mkt		Mkt		Mkt		Mkt				Mkt		Mkt		Mkt			HHI
Period	Price	MW	Share	MW	Share	MW	Share	MW	Share	Mkt Size	HHI	MW	Share	MW	Share	MW	Share	Mkt Size	HHI	Chg.
S_SP1	$250	50	16.4%	68	22.1%	2	0.8%	0	0.0%	308	1,272	299	21.2%	29	2.1%	3	0.2%	1,407	1,215	-57
S_SP2	$120	57	18.2%	70	22.3%	4	1.4%	0	0.0%	315	1,308	306	21.6%	38	2.7%	4	0.3%	1,414	1,273	-36
S_P	$75	241	48.3%	75	15.1%	0	0.0%	1	0.1%	498	2,777	489	30.6%	0	0.0%	8	0.5%	1,597	1,674	-1,103
W_SP	$86	230	33.5%	199	29.0%	0	0.0%	0	0.0%	687	2,048	459	33.2%	38	2.7%	47	3.4%	1,381	1,466	582
W_P	$60	425	48.2%	145	16.4%	0	0.0%	3	0.4%	882	2,665	570	36.2%	0	0.0%	54	3.6%	1,492	1,677	988
SH_SP	$80	367	38.9%	214	22.6%	0	0.0%	33	3.5%	944	2,114	566	34.4%	0	0.0%	108	6.6%	1,644	1,582	-532
SH_P	$55	165	22.2%	22	2.9%	0	0.0%	3	0.4%	742	909	287	21.0%	0	0.0%	5	0.4%	1,364	871	-38

Vertical Market Power

The Transaction does not raise any competitive concerns with regard to vertical market power. First, there are no transmission market power concerns because the Transaction does not convey any relevant transmission; that is, Redbud's assets related to transmission are restricted to those necessary to interconnect to the grid. The Transaction thus does not provide OG&E or GRDA with additional control over electric transmission assets.

While OG&E and GRDA own transmission, their electric transmission systems are controlled by the SPP. OMPA is not a transmission owner. OG&E customers primarily take service under the SPP Open Access Transmission Tariff, although there remain a few grandfathered wholesale requirements customers that take service under OG&E's OATT.[64]

The Commission also considers whether applicants have the ability to erect barriers to entry by other suppliers in terms of such things as 1) control of sites for new capacity development other than those that may exist at the sites being acquired; 2) control of fuel inputs to generation; and 3) control of any equipment suppliers or facilities used to transport fuels or other inputs to generation.

OG&E's affiliate, Enogex, operates an intrastate natural gas pipeline system in Oklahoma and delivers natural gas to most of the OG&E-owned gas fired generating facilities (within the OG&E balancing authority area); and to six gas-fired generators owned by AEP (approximately 4,000 MW), and three unaffiliated merchant generators (Oneta (1,082 MW), Green Country (795 MW) and Pryor (112 MW)), all located in the adjacent AEP West balancing authority area. The

[64] These include Purcell, Paris, Vance Air Force Base and City of Geary.

Redbud Facility receives deliveries from the ONEOK pipeline. Given that the Redbud Facility is not a Enogex customer, and other relevant factors that support a determination of the lack of competitive vertical effect, I have not conducted a vertical Competitive Analysis Screen.[65]

There are numerous other pipelines in Oklahoma and the surrounding states to which new gas-fired generators could connect. Delivery capacity on Enogex is no more than about 13 percent of pipeline deliverability in Oklahoma. There is approximately 7.3 bcf/day of interstate pipeline deliverability into Oklahoma,[66] plus an additional 3.4 bcf/day intrastate pipeline delivery capacity within Oklahoma.[67] Enogex's average throughput is approximately 1.4 bcf/day.[68] In the broader SPP market, Enogex's share of delivery capacity would be significantly less. Enogex's share of gas storage capacity in Oklahoma is about 12 percent (23 bcf relative to 188 bcf),[69] not a level to raise competitive concerns, and its share in the broader SPP market would be significantly less.

Concerns of dominant control over power plant sites for new capacity development in relevant markets are also not relevant to the proposed Transaction. Oklahoma and the regions around the state have experienced a robust market for the development of generation, and the substantial new entry of additional generation demonstrates the absence of entry barriers.

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[65] A vertical Competitive Analysis need not be filed if the applicant can affirmatively demonstrate that "(i) the merging entities currently do not provide inputs to electricity products (i.e., upstream relevant products) and electricity products (i.e., downstream relevant products) in the same geographic markets or that the extent of the business transactions in the same geographic market is *de minimis*; or that (ii) the extent of the upstream relevant products currently provided by the merging entities is used to produce a *de minimis* amount of the relevant downstream products in the relevant destination markets." 18 C.F.R. § 33.4(a)(2)(2006).

[66] Energy Information Administration, *State-to-State Natural Gas Pipeline Capacity Levels*, http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/usage.html; http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/StatetoState.xls

[67] Energy Information Administration, *U.S. Intrastate Natural Gas Pipeline Systems - April 2007*, http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/intrastate.html; http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/PIPEintra.xls; and OGE Enogex Partners L.P., Initial Public Offering, http://ccbn.10kwizard.com/cgi/image?repo=tenk&ipage=5017559&doc=2&fdl=1&cik=1403302&odef=8&rid=12&quest=1&dn=2.

[68] *Id.*, OGE Enogex Partners L.P., Initial Public Offering. There are no data reported for Enogex's total deliverability, and therefore I used its average throughput.

CONCLUSION

The market power analyses discussed herein demonstrate that the Transaction as proposed will not have anti-competitive effects in any of the relevant markets. No other relevant concerns exist with respect to competition issues.

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[69] *Id.*, and Energy Information Administration, *Regional Underground Natural Gas Storage, Beginning of 2007*, Http: www.eia.doe.gov pub oil gas natural gas analysis publications ngpipeline UGTable.html?title=&product &submit2=A-Z List of publications.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Oklahoma Gas and Electric Company	)	**Docket No. EC08-___-000**
Redbud Energy LP	)	
	)	

AFFIDAVIT

District of Columbia	§
	§
	§

JULIE R. SOLOMON being duly sworn, deposes and states: that she prepared the Affidavit and Exhibits of Julie R. Solomon and that the statements contained therein and the Exhibits attached hereto are true and correct to the best of her knowledge and belief.

Julie R. Solomon

SUBSCRIBED AND SWORN TO BEFORE ME, this the 6th day of March 2008.

Notary Public, District of Columbia

Printed Name: Karyn W. Miller

My Commission Expires: 1/1/2013

Karyn W. Miller
Notary Public, District of Columbia
My Commission Expires 1/1/2013

Exhibit J-2

JULIE R. SOLOMON

Vice President

B.A. Economics
Connecticut College

M.B.A. Finance
The Wharton School
University of Pennsylvania

EXPERIENCE

Julie Solomon has more than 20 years of consulting experience, specializing in the areas of regulatory and utility economics, financial analysis and business valuation. She has participated in analysis of proposed regulatory reforms, supply options and utility industry restructuring in the gas and electric industries. She also has advised utility clients in corporate strategy and corporate restructuring, and consulted to legal counsel on a variety of litigation and regulatory matters, including antitrust litigation and contract disputes. Much of her current practice focuses on regulatory and market power issues concerning mergers and acquisitions and compliance filings.

- Advised clients in the electric and gas utility industry on competition issues, including the impact of mergers on competition. Directed a large number of analytic studies relating to obtaining merger approval from regulatory authorities.

- Advised clients in the electric utility industry on restructuring strategies, including potential mergers and acquisitions, functional unbundling and cost savings.

- Consulted in the electric and gas utility industries in a variety of regulatory and competition matters, including rate proceedings, prudence reviews, proposed regulatory reforms, analysis of supply options, privatization and restructuring.

- Advised utility and non-utility clients on many aspects of the competitive independent power industry, including strategic and financial consulting assignments.

- Consulted legal counsel on a variety of litigation matters, including the development of expert testimony on liability issues and the calculation of damages in a variety of industries.

- Provided strategic and economic analyses for clients in trade regulatory proceedings such as dumping and subsidies.

- Provided financial and business valuation analyses in a number of transactions, including fair market value for taxation purposes and valuation of family-owned businesses.

ELECTRIC AND GAS UTILITIES

Mergers and Acquisitions (Market Power and Competition Issues)

- Advised clients and conducted analytic studies in connection with a large number of major electric and electric-gas mergers and asset transactions of regulated companies. Provided testimony to FERC for a number of these types of transactions.

- Advised clients and provided confidential pre-screening analyses for potential mergers and acquisitions.

- Conducted numerous analytic studies in connection with FERC market-based rate applications and compliance filings for electricity sellers. Provided testimony to FERC for a number of these types of transactions.

- Conducted numerous analytic studies in connection with FERC market-based rate applications and compliance filings for gas storage facilities. Provided testimony to FERC for a number of these types of transactions.

Utility Restructuring and Stranded Cost

- Conducted analytic studies and provided litigation support in connection with state stranded cost proceedings in Ohio (Cincinnati Gas & Electric and Dayton Power & Light); West Virginia (Monongahela Power and Potomac Edison); Maryland (Potomac Edison) and Pennsylvania (West Penn Power).

- Provided analytic support evaluating the benefits of Public Service of Colorado's proposed DC transmission line between Colorado and Kansas in support of a regulatory proceeding.

- Assisted in studies relating to privatization of the electricity industry in the United Kingdom, including development of a computer model to simulate electricity dispatch and project future prices, capacity needs and utility revenues under various scenarios. During temporary assignment to London office.

- Participated in antitrust litigation involving a utility and a cogenerator, including preparation of an expert report on liability and damage issues, preparation of expert witnesses for deposition, and assistance in preparation for depositions of opposing expert and in-house witnesses.

- Assisted in the valuation of the interests of several firms in various cogeneration projects for the purpose of combining these interests into a new entity or selling interests to third parties.

- Analyzed the financial feasibility and viability of a large number of cogeneration projects, assisted in the preparation of presentations and filings and presented testimony to the relevant public utility commission. Ms. Solomon also assisted in the development of a PC-based financial model to analyze various cogeneration projects.

- Participated in a study to analyze the financial effects of a variety of restructuring options for a utility, including transfer and/or sale of assets and subsequent sale-leasebacks, and debt restructuring alternatives. In addition, she developed a PC-based financial model with applications to utility restructuring plans.

- Provided litigation support in major utility rate proceedings, including assisting in the preparation of responses to interrogatories and data requests, preparation of company and outside expert witnesses for deposition and hearings, and assistance in the deposition and cross-examination of intervenor witnesses.

- Participated in proceedings involving regulation of an oil pipeline, which included evaluating the business risks faced by the company.

BUSINESS VALUATION

- Participated in a valuation study involving the fair market value of a privately held company for purposes of an IRS proceeding.

- Participated in a valuation study in a divorce proceeding, where the assets being valued included a privately held business.

- Participated in two strategic engagements that developed business plans and identified potential acquisition candidates for the client.

- Provided advice to a client concerning the benefits and potential risks of developing a partnership with a competitor.

PROFESSIONAL HISTORY

1986-2000	Putnam, Hayes and Bartlett, Inc. and PHB Hagler Bailly, Inc., Washington, DC, Senior Vice President
1979-1986	Economic Consulting Services, Inc., Washington, DC
1976-1979	U.S. Department of Labor, Washington, DC

LIST OF TESTIMONY

Affidavit on behalf of Calpine Corp. and LS Power Development, LLC et al., FERC Docket No. EC08-15-000, January 22, 2008

Affidavit on behalf of AES Western Wind MV Acquisition, Docket No. EC08-37, January 15, 2008.

Affidavit on behalf of Dominion Energy Marketing, Inc. et al., application for market-based rate authority, FERC Docket No. ER01-468, January 14, 2008.

Affidavit on behalf of Baltimore Gas and Electric Company et al., updated market-based rate filing, FERC Docket No. ER99-2948-____, January 14, 2008.

Affidavit on behalf of Allegheny Energy Supply Company, LLC et al., updated market-based rate filing, FERC Docket No. ER00-814-000, January 14, 2008.

Affidavit on behalf of Exelon Generation Company, LLC et al., updated market-based rate filing, FERC Docket No. ER00-3251, January 14, 2008.

Affidavit on behalf of Pepco Holdings, Inc., et al., updated market-based rate filing, FERC Docket No. ER08-___-000, January 14, 2008.

Affidavit on behalf of Green Mountain Power Corporation, updated market-based rate filing, FERC Docket No. ER01-0989, January 14, 2008.

Affidavit on behalf of Duquesne Light Company et al., updated market-based rate filing, FERC Docket No. ER98-4159 et al., January 11, 2008.

Affidavit on behalf of Central Hudson Gas and Electric Corporation, updated market-based rate filing, FERC Docket No. Docket No. ER97-2872 et al., January 11, 2008.

Affidavit on behalf of Bicent (California) Malburg LLC, application for market-based rate authority, FERC Docket No. ER08-314-000, December 7, 2007.

Affidavit on behalf of Northern Indiana Public Service Co. and Broadway Gen Funding, LLC, application and related exhibits requesting authorization for a transaction to transfer a generating facility, FERC Docket No. EC08-21-000, December 6, 2007.

Affidavit on behalf of Langdon Wind, LLC, application for market-based rate authority, FERC Docket No. ER08-250-000, November 21, 2007.

Affidavit on behalf of Calpine Corp. and Harbinger Capital Partners Master Fund I, Ltd. et al., joint application for approval of the proposed distribution of common stock of a reorganized Calpine to Acquirors, FERC Docket No. EC08-15-000, November 16, 2007.

Affidavit on behalf of Waterbury Generation, LLC, application for market-based rate authority, FERC Docket No. ER08-200-000, November 9, 2007.

Affidavit on behalf of FPL Energy Oliver Wind II, LLC, application for market-based rate authority, FERC Docket No. ER08-197-000, November 8, 2007.

Affidavit on behalf of Central Power & Lime, Inc., application for market-based rate authority, FERC Docket No. ER08-148-000, November 1, 2007

Affidavit on behalf of Gilberton Power Company, application for market-based rate authority, FERC Docket No. ER08-83-000, October 23, 2007.

Affidavit on behalf of Black Bayou Storage, LLC, application for market-based rate authority for a natural gas storage facility, FERC Docket No. CP07-451, September 25, 2007

Affidavit on behalf of NedPower Mount Storm LLC, application for market-based rate authority, FERC Docket No. ER07-1306-000, August 23, 2007.

Affidavit on behalf of Sempra Energy Trading Corp. in connection with market-based rate authority, FERC Docket No. ER03-1413-005, July 25, 2007.

Affidavit on behalf of KGen Acquisition I LLC et al., application for disposition of jurisdictional facilities, FERC Docket No. EC07-116-000, July 13, 2007

Supplemental Affidavit on behalf of Williams Power Company, Inc., application for market-based rate authority, FERC Docket No. EC07-106-000, June 28, 2007.

Affidavit on behalf of Williams Power Co, Inc and Bear Energy LP, joint application for authorization of the disposition of jurisdictional facilities, FERC Docket No. EC07-106-000, June 14, 2007.

Affidavit on behalf of Bluegrass Generation Company, LLC et al., notice of non-material change in status, FERC Docket No. ERC2-506-008 et al., May 31, 2007.

Affidavit on behalf of BG Dighton Power LLC et al., notice of non-material change in status, FERC Docket Nos. ER06-1367-003 et al., May 30, 2007.

Affidavit on behalf of FPL Energy Point Beach, LLC, application for market-based rate authority, FERC Docket No. ER07-904-000, May 16, 2007.

Affidavit on behalf of Copiah Storage, LLC, application for market-based rate authority for a natural gas storage facility, FERC Docket No, CP02-24, March 29, 2007

Affidavit on behalf of NRG Power Marketing, Inc. and thirty-one affiliates most of which own generating facilities, triennial market power update and notice of change in status, FERC Docket Nos. ER97-4281-016 et al., March 26, 2007.

Affidavit on behalf of Egan Hub Storage, application for market-based rate authority for a natural gas storage facility, FERC Docket No. CP07-88, February 20, 2007.

Affidavit on behalf of Wisconsin Electric Power Co and FPL Energy Point Beach, LLC, joint application for authorization to dispose of jurisdictional facilities, FERC Docket No. EC07-57-000, February 1, 2007.

Affidavit on behalf of Lake Road Generating Company, LP et al., joint application for authorization of the disposition of jurisdictional facilities pursuant to Section 203 of the Federal Power Act, FERC Docket No. EC07-50-000, January 22, 2007.

Affidavit on behalf of Exelon Generation Company, LLC et al., notice of non-material change in status, FERC Docket Nos. ER00-3251-013 et al., December 15, 2006.

Revised Affidavit on behalf of Calpine Energy Services, LP, triennial market analysis, FERC Docket No. ER00-3562-004, December 13, 2006

Affidavit on behalf of Dynegy Entities and LSP Entities, notice of non-material change in status, FERC Docket Nos. ER02-506-007 et al., November 2, 2006.

Affidavit on behalf of Wisconsin Energy Corp.'s, Wisconsin Electric Power Co. et al. for authorization to dispose of jurisdictional facilities, FERC Docket No. ER07-14-000, November 2, 2006.

Affidavit on behalf of Calpine Energy Services, LP, updated triennial market power analysis, FERC Docket No. ER00-3562-004, October 30, 2006

Affidavit on behalf of Dynegy, application for authorization of transactions pursuant to Section 203 of the Federal Power Act, FERC Docket No. EC07-9-000, October 26, 2006.

Affidavit on behalf of Coral Power, LLC et al., triennial updated market analysis, FERC Docket Nos. ER96-25-028 et al., October 23, 2006.

Affidavit on behalf of Westar Energy, Inc. and Kansas Gas and Electric, request for rehearing, FERC Docket Nos. ER03-9-007 et al., October 6, 2006.

Affidavit on behalf of The Empire District Electric, request for rehearing, FERC Docket Nos. ER99-1757-011 et al., September 14, 2006.

Joint Affidavit (with William H. Hieronymus) on behalf of Powerex Corp., errata to its 7/31/06 triennial market power update, FERC Docket No. ER01-48-007, September 11, 2006

Affidavit on behalf of FPLE Companies, joint triennial market power update, FERC Docket Nos. ER02-2559-007 et al., August 28, 2006.

Affidavit on behalf of FPL Energy Oliver Wind, LLC application for market-based rates, FERC Docket No. ER06-1392-000, August 23, 2006.

Affidavit on behalf of The Constellation MBR Entities, errata to their joint triennial market power update submitted on 8/14/06, FERC Docket Nos. ER99-2948-009 et al., August 16, 2006.

Affidavit on behalf of Constellation MBR Entities, joint triennial market power update, FERC Docket Nos. ER99-2948-009 et al., August 14, 2006.

Affidavit on behalf of Sempra Energy Trading Corp., updated market analysis, FERC Docket No. ER03-1413-005, August 1, 2006

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Affidavit on behalf of Reliant Energy Power Supply, LLC, application for market-based rates, FERC Docket No. ER06-1272-000, July 20-21, 2006.

Affidavit on behalf of Lincoln Generating Facility LLC fka Allegheny Energy Supply, updated generation market power study, FERC Docket No. ER05-524-001, June 19, 2006.

Affidavit on behalf of Alcoa Power Generating, Inc & Alcoa Power Marketing, Inc., amendment to triennial, updated market analysis under ER02-2074 et al., FERC Docket Nos. ER02-2074-002 et al., May 17, 2006

Affidavit on behalf of Alcoa Power Generating, Inc and Alcoa Power Marketing Inc., updated market analysis of the triennial review of market-based rate authority, FERC Docket Nos. ER02-2074-002 et al., April 13, 2006

Affidavit on behalf of Morgan Energy Center, LLC et al., Calpine Gilroy Cogen, LP, Los Medanos Energy Center, LLC, and KIAC Partners et al., market-based rate filings, FERC Docket Nos. ER06-741-000 et al., March 16, 2006.

Affidavit on behalf of Midland Cogeneration Venture Limited Partnership, market-based rate application, FERC Docket No. ER06-733-000, March 15, 2006.

Affidavit on behalf of Duke Power Co, LLC et al., notice of change in status filing, FERC Docket Nos. ER96-110-020 et al., March 1, 2006.

Affidavit on behalf of Westar Energy Inc & ONEOK Energy Services Co. LP, answer to protests filed by Oklahoma Municipal Power Authority et al., FERC Docket No. ER06-48-000, February 21, 2006.

Affidavit on behalf of Edgecombe Genco, LLC and Spruance Genco, LLC, market-based rate application, FERC Docket No. ER06-635-000 and ER06-634-000, February 13, 2006.

Affidavit on behalf of NRG Energy, Inc. et al., joint application for authorization under Section 203 of the Federal Power Act to transfer jurisdictional facilities, FERC Docket No. EC06-66-000, January 20, 2006.

Affidavit on behalf of Westar Energy, Inc. et al. joint application for authorization under Section 203 of the Federal Power Act for the disposition of jurisdictional facilities, FERC Docket No. EC06-48-000, December 21, 2005

Affidavit on behalf of Calpine Energy Center, LLC, joint updated market power analysis, FERC Docket Nos. ER02-2227-003 et al., August 30, 2005

Affidavit on behalf of Allegheny Power, Allegheny Energy Supply Co., LLC, Allegheny Energy Supply Gleason Generating Facility, Inc et al., combined triennial market power report, FERC Docket Nos. ER98-1466-003 et al., August 11, 2005.

Affidavit on behalf of Hermiston Power Partnership et al., joint updated market power analysis, filed on 5/3/05, FERC Docket Nos. ER02-1257-003 et al., August 5, 2005.

Affidavit on behalf of MidAmerican Energy Co., in connection with market-based rate update, FERC Docket No. ER96-719-006, August 1, 2005.

Affidavit on behalf of Occidental Power Services Inc., updated market power analysis, FERC Docket No. ER02-1947-006, August 1, 2005.

Affidavit on behalf of FPL Energy Duane Arnold LLC, joint application for approval of disposition of jurisdictional facilities, FERC Docket Nos. EC05-114-000 et al., July 29, 2005.

Affidavit on behalf of FPL Energy Duane Arnold, LLC, authorization to sell at market-based rates, FERC Docket No. ER05-1281-000, July 29, 2005.

Affidavit on behalf of MidAmerican Energy Holdings Co. et al., application for approval of disposition of jurisdictional facilities under Section 203 of the Federal Power Act, FERC Docket No. EC05-110-000, July 22, 2005.

Affidavit on behalf of Calpine Entities, joint updated market power analysis, FERC Docket Nos. EC02-136?-003 et al., July 18, 2005.

Affidavit on behalf of Bayonne Plant Holding LLC, as successor in interest of Cogen Technologies NJ Venture et al., as successor in interest to Camden Cogen et al., triennial updated market analysis, FERC Docket Nos. EC02-1486-003 et al., July 15, 2005.

Affidavit on behalf of Cabazon Wind Partners, LLC & Whitewater Hill Wind Partners, consolidated triennial updated market analysis, FERC Docket Nos. ER02-1695-003 et al., June 24, 2005.

Affidavit on behalf of TransAlta Energy Marketing (U.S.) Inc. et al., in connection with market-based rate authority, FERC Docket Nos. ER05-1014-000 et al., May 24, 2005.

Affidavit on behalf of Mnergy Neenah, LLC, updated triennial market power analysis, FERC Docket No. ER99-3125-001, May 16, 2005.

Affidavit on behalf of Hermiston Power Partnership et al., joint updated market power analysis, FERC Docket Nos. ER02-1257-002 et al., May 3, 2005.

Affidavit on behalf of CES Marketing VI, LLC et al., market-based rate application, FERC Docket Nos. ER05-816-000 et al., April 13, 2005.

Affidavit on behalf of Onondaga Cogeneration Limited Partnership, triennial updated market analysis, FERC Docket No. ER00-895-006, March 24, 2005.

Affidavit on behalf of The Williams Entities' (Williams Power Co., Inc. et al.), joint triennial market power update, FERC Docket Nos. ER03-1331-004 et al., March 24, 2005.

Affidavit on behalf of J. Aron & Co. and Power Receivable Finance LLC, errata to triennial updated market analysis submitted on 12/30/04, FERC Docket Nos. ER02-237-003 et al., February 25, 2005.

Affidavit on behalf of Delta Energy Center LLC, updated power analysis, FERC Docket No. ER02-600-003, February 14, 2005.

Affidavit on behalf of Wisconsin Electric Power Company, market-based rate filing, FERC Docket No. ER05-540-000, February 4, 2005.

Affidavit on behalf of J. Aron & Co. and Power Receivable Finance, LLC, consolidated triennial updated market analysis, December 30, 2004.

Affidavit on behalf MidAmerican Energy Co., supplement to 10/29/04 market-power update filing, FERC Docket No. ER96-719-004, November 23, 2004.

Affidavit in connection with Comments of Cinergy Services, Inc. re Reporting Requirement for Changes in Status for Public Utilities with Market-Based Rate Authority under RM04-14, FERC Docket No. RM04-14-000, November 15, 2004.

Affidavit on behalf of Metcalf Energy Center, LLC and Pastoria Energy Center, LLC, market-based rate application, FERC Docket No. ER05-68-000 and ER05-67-000, October 25, 2004.

Affidavit on behalf Calpine Bethpage 3, LLC and TBG Cogen Partners, market-based rate filing, FERC Docket No. ER05-48-000 and ER04-1100-000, August 4, 2004.

Affidavit on behalf of The Empire District Electric Co., updated market power analysis, FERC Docket No. ER99-1757-005, September 27, 2004.

Affidavit on behalf of Wisconsin Electric Power Co, revised generation market power portion of its pending three-year market power update, FERC Docket No. ER98-855-004, September 27, 2004

Affidavit on behalf of *Duke Power, a Division of Duke Energy Corp., market power analysis*, FERC Docket No. ER96-110-010, August 11, 2004.

Affidavit on behalf of Virginia Electric & Power Co et al., application for the proposed transfer of substantially all of the assets of Multitrade to Dominion Power, FERC Docket No. EC04-139-000, July 30, 2004

Affidavit on behalf of Goldendale Energy Center, market-based rate application, FERC Docket No. ER04-1038-000, July 23, 2004

Affidavit on behalf of Calumet Energy Team, LLC, updated triennial market power analysis, FERC Docket No. ER01-389-001, July 20, 2004.

Affidavit on behalf of Calpine Parlin, LLC, market-based rate filing, FERC Docket No. ER04-832-000, May 11, 2004.

Affidavit on behalf of Calpine Newark, LLC, market-based rate filing, FERC Docket No. ER04-831-000, May 11, 2004

Affidavit on behalf of Virginia Electric & Power Co, application for market-based rates, FERC Docket No. ER04-834-000, May 11, 2004.

Affidavit on behalf of Virginia Electric and Power Co., UAE Mecklenburg Cogeneration, LP et al., authorization for the proposed transfer of 100% of the ownership interests of Cogenco etc., FERC Docket No. EC04-104-000, May 6, 2004.

Affidavit on behalf of Occidental Power Marketing, LP, triennial market power analysis, FERC Docket No. ER99-3665-004, April 14-15, 2004.

Affidavit on behalf of The Williams Entities, joint triennial market power update, FERC Docket Nos. ER03-1331-003 et al., March 12, 2004.

Affidavit on behalf of Wisconsin Electric Power Co., updated triennial market-power analysis, FERC Docket No. ER98-855-003, January 29, 2004.

Affidavit on behalf of GEN~SYS Energy, triennial update market power analysis, FERC Docket No. ER97-4335-006, October 17, 2003.

Affidavit on behalf of Calpine Energy Services LP, updated market power analysis, FERC Docket No. ER00-3562-001, September 22, 2003.

Affidavit on behalf of Rocky Mountain Energy Center LLC, application for market-based rates, FERC Docket No. ER03-1288-000, September 3, 2003.

Affidavit on behalf of Fox Energy Co, LLC, application for market-based rates, FERC Docket No. ER03-983-000, June 24, 2003.

Affidavit on behalf of Chehalis Power Generating Limited Partnership, application for market-based rates etc., FERC Docket No. ER03-717-000, April 7, 2003.

Affidavit on behalf of Calpine Northbrook Energy Marketing LLC, triennial updated market power analysis, FERC Docket No. ER03-717-000, October 23, 2002.

Affidavit on behalf of Choctaw Generation Limited Partnership, updated triennial market power analysis, FERC Docket No. ER98-3774-001, October 17, 2002.

Affidavit on behalf of Riverside Energy Center, LLC, market-based rate filing, FERC Docket No. ER03-49-000, October 16, 2002.

Affidavit on behalf of Blue Spruce Energy Center, LLC, market-based rate filing, FERC Docket No. ER03-25-000, October 8, 2002.

Prepared Responsive Testimony on behalf of Calpine Energy Services, LP et al. re San Diego Gas & Electric Co. v. Sellers of Energy & Ancillary Services etc. under EL00-95 et al., FERC Docket Nos. EL00-95-045 et al., September 27, 2002.

Affidavit on behalf of Duke Power Co., a division of Duke Energy Corp., market-based rate filing, FERC Docket No. ER96-110-007, December 17, 2001.

OG&E's Generation Assets

NERC Region	Balancing Authority Area	Plant Name	Unit #	Unit Type	Summer Rating (MW)	Ownership Share	Summer Net Interest (MW)	Purchases (Sales)	Summer Net Capacity (MW)
SPP	OG&E	Enid	1	GTNG	14	100.0%	0		0
SPP	OG&E	Enid	2	GTNG	14	100.0%	0		0
SPP	OG&E	Enid	3	GTNG	14	100.0%	0		0
SPP	OG&E	Enid	4	GTNG	14	100.0%	0		0
SPP	OG&E	Horseshoe Lake	10	STNG	46	100.0%	46		46
SPP	OG&E	Horseshoe Lake	6	STNG	169	100.0%	169		169
SPP	OG&E	Horseshoe Lake	8	STNG	387	100.0%	387		387
SPP	OG&E	Horseshoe Lake	9	STNG	46	100.0%	46		46
SPP	OG&E	Horseshoe Lake	GT7	CCNG	17	100.0%	17		17
SPP	OG&E	Horseshoe Lake	ST7	CCNG	217	100.0%	217		217
SPP	OG&E	Muskogee	3	STNG	166	100.0%	166		166
SPP	OG&E	Muskogee	4	STCOAL	511	100.0%	511		511
SPP	OG&E	Muskogee	5	STCOAL	522	100.0%	522		522
SPP	OG&E	Muskogee	6	STCOAL	515	100.0%	515		515
SPP	OG&E	Mustang	1	STNG	53	100.0%	53		53
SPP	OG&E	Mustang	2	STNG	53	100.0%	53		53
SPP	OG&E	Mustang	3	STNG	118	100.0%	118		118
SPP	OG&E	Mustang	4	STNG	250	100.0%	250		250
SPP	OG&E	Mustang	5A	GTNG	31	100.0%	31		31
SPP	OG&E	Mustang	5B	GTNG	33	100.0%	33		33
SPP	OG&E	Seminole	1	STNG	506	100.0%	506		506
SPP	OG&E	Seminole	2	STNG	501	100.0%	501		501
SPP	OG&E	Seminole	3	STNG	519	100.0%	519		519
SPP	OG&E	Seminole	GT1	GTNG	16	100.0%	16		16
SPP	OG&E	Woodward	GT1	GTNG	12	100.0%	12		12
SPP	OG&E	Sooner	1	STCOAL	531	100.0%	531		531
SPP	OG&E	Sooner	2	STCOAL	535	100.0%	535		535
SPP	OG&E	McClain Energy Facility	CT1	CCNG	146	77.0%	112		112
SPP	OG&E	McClain Energy Facility	CT2	CCNG	148	77.0%	114		114
SPP	OG&E	McClain Energy Facility	ST1	CCNG	167	77.0%	129		129
SPP	OG&E	Centennial Wind Farm	WT1	WTWND	120	100.0%	120		120
						Total	**6,226**	**0**	**6,226**

OG&E's Generation Assets

NERC Region	Balancing Authority Area	Plant Name	Unit #	Unit Type	Summer Rating (MW)	Ownership Share	Summer Net Interest (MW)	Purchases (Sales)	Summer Net Capacity (MW)
OG&E Purchases									
SPP	OG&E	Oklahoma Wind Energy Center	GE15	WTWND	51			51	51
SPP	CSWS	PowerSmith Cogeneration Project	GT01	CCNG	111			111	111
SPP	OG&E	Redbud Power Plant	CC	CCNG	1,195			300	300
SPP	OG&E	AES Shady Point	GEN1	STCOAL	320			320	320
SPP	SWEPA	Purchase From SWEPA	NA	NA				31	31
						Total		**813**	**813**
Total OG&E Capacity							**6,226**	**813**	**7,039**

Source for unit ratings in Exhibit J-3: Unit ratings are from Annual Electric Generator Report, Energy Information Administration, EIA Form-860
http://www.eia.doe.gov/cneaf/electricity/page/capacity/capacity.html

GRDA's Generation Assets

NERC Region	Balancing Authority Area	Plant Name	Unit #	Unit Type	Summer Rating (MW)	Ownership or Control Share	Summer Net Interest (MW)	Purchases (Sales)	Summer Net Capacity (MW)
SPP	GRDA	GRDA	1	STCOAL	490	100.0%	490		490
SPP	GRDA	GRDA	2	STCOAL	520	62.0%	322		322
SPP	GRDA	Markham	1	HYWAT	28	100.0%	28		28
SPP	GRDA	Markham	2	HYWAT	28	100.0%	28		28
SPP	GRDA	Markham	3	HYWAT	29	100.0%	29		29
SPP	GRDA	Markham	4	HYWAT	29	100.0%	29		29
SPP	GRDA	Pensacola	1	HYWAT	20	100.0%	20		20
SPP	GRDA	Pensacola	2	HYWAT	20	100.0%	20		20
SPP	GRDA	Pensacola	3	HYWAT	20	100.0%	20		20
SPP	GRDA	Pensacola	4	HYWAT	20	100.0%	20		20
SPP	GRDA	Pensacola	5	HYWAT	20	100.0%	20		20
SPP	GRDA	Pensacola	6	HYWAT	20	100.0%	20		20
SPP	GRDA	Pensacola	A	HYWAT	1	100.0%	1		1
SPP	GRDA	Salina	1	PSWAT	43	100.0%	43		43
SPP	GRDA	Salina	2	PSWAT	43	100.0%	43		43
SPP	GRDA	Salina	3	PSWAT	43	100.0%	43		43
SPP	GRDA	Salina	4	PSWAT	43	100.0%	43		43
SPP	GRDA	Salina	5	PSWAT	44	100.0%	44		44
SPP	GRDA	Salina	6	PSWAT	44	100.0%	44		44
SPP	GRDA	Boomer Lake Station	1	STNG	11	100.0%	11		11
SPP	GRDA	Boomer Lake Station	2	STNG	13	100.0%	13		13
SPP	GRDA	Boomer Lake Station	3	ICFO2	2	100.0%	2		2
SPP	GRDA	Boomer Lake Station	4	ICFO2	2	100.0%	2		2
SPP	GRDA	Boomer Lake Station	5	ICFO2	2	100.0%	2		2
SPP	GRDA	Stillwater Water Treatment F	6	ICFO2	2	100.0%	2		2
SPP	GRDA	Cushing	1	ICFO2	2	100.0%	2		2
SPP	GRDA	Cushing	10	ICFO2	4	100.0%	4		4
SPP	GRDA	Cushing	11	ICFO2	6	100.0%	6		6
SPP	GRDA	Cushing	2	ICFO2	1	100.0%	1		1
SPP	GRDA	Cushing	3	ICFO2	0	100.0%	0		0
SPP	GRDA	Cushing	4	ICFO2	0	100.0%	0		0
SPP	GRDA	Cushing	5	ICFO2	0	100.0%	0		0
SPP	GRDA	Cushing	6	ICFO2	1	100.0%	1		1

GRDA's Generation Assets

NERC Region	Balancing Authority Area	Plant Name	Unit #	Unit Type	Summer Rating (MW)	Ownership or Control Share	Summer Net Interest (MW)	Purchases (Sales)	Summer Net Capacity (MW)
SPP	GRDA	Cushing	7	ICFO2	2	100.0%	2		2
SPP	GRDA	Cushing	8	ICFO2	2	100.0%	2		2
SPP	GRDA	Cushing	9	ICFO2	2	77.0%	2		2
							1,358	**0**	**1,358**
GRDA Purchases									
SPP	OG&E	Redbud Power Plant	CC	CCNG	1,195	0.0%		150	150
Total GRDA Capacity							**1,358**	**150**	**1,508**

OMPA's Generation Assets

NERC Region	Balancing Authority	Plant Name	Unit #	Unit Type	Summer Rating (MW)	Ownership or Control Share	Summer Net Interest (MW)	Purchases (Sales)	Summer Net Capacity (MW)
SPP	OG&E	Kaw Hydro	1	HYWAT	30	100.0%	30		30
SPP	OG&E	Ponca City	1	CCNG	19	100.0%	19		19
SPP	OG&E	Ponca City	3	GTNG	8	100.0%	8		8
SPP	OG&E	Ponca City	3	CCNG	36	100.0%	36		36
SPP	OG&E	Ponca City	4	GTNG	44	100.0%	44		44
SPP	OG&E	Laverne	1	ICFO2	2	100.0%	2		2
SPP	OG&E	Laverne	2	ICFO2	2	100.0%	2		2
SPP	AEP West	Pirkey	1	STNG	675	2.3%	16		16
SPP	AEP West	Oklaunion	1	STCOAL	690	11.8%	81		81
SPP	OG&E	McClain Energy Facility	CT1	CCNG	146	23.0%	34		34
SPP	OG&E	McClain Energy Facility	CT2	CCNG	148	23.0%	34		34
SPP	OG&E	McClain Energy Facility	ST1	CCNG	167	23.0%	38		38
SPP	OG&E	Dolet Hills	1	STCOAL	650	3.9%	25		25
SPP	AEP West	Pawhuska	1	ICFO2	1	100.0%	1		1
SPP	AEP West	Pawhuska	2	ICFO2	1	100.0%	1		1
SPP	AEP West	Pawhuska	3	ICFO2	3	100.0%	3		3
SPP	AEP West	Pawhuska	5	ICFO2	2	100.0%	2		2
SPP	AEP West	Ponca	2	STNG	36	100.0%	36		36
SPP	AEP West	Ponca Diesel	1	ICFO2	5	100.0%	0		0
SPP	AEP West	Ponca Diesel	10	ICFO2	2	100.0%	2		2
SPP	AEP West	Ponca Diesel	11	ICFO2	2	100.0%	0		0
SPP	AEP West	Ponca Diesel	4	ICNG	2	100.0%	2		2
SPP	AEP West	Ponca Diesel	6	ICNG	1	100.0%	1		1
SPP	AEP West	Ponca Diesel	7	ICNG	2	100.0%	2		2
SPP	AEP West	Ponca Diesel	8	ICNG	3	100.0%	3		3
SPP	AEP West	Ponca Diesel	9	ICNG	5	100.0%	5		5
						Total	**427**	**0**	**427**
OMPA Purchases									
SPP	OG&E	Oklahoma Wind Energy Center	GSOO	WTWND	51	0.0%		51	51
SPP	GRDA	Purchase From GRDA	NA	NA				50	50
SPP	OG&E	Redbud Power Plant	CC	CCNG	1,195	0.0%		80	80
SPP	SWEPA	Purchase From SWEPA	NA	NA				78	78
						Total		**259**	**259**
Total OMPA Capacity							**427**	**259**	**686**

Redbud and Affiliates' Generation Assets in and Around SPP

Owner	NERC Region	Balancing Authority Area	Plant Name	Unit Type	Summer Rating (MW)	Ownership or Control Share	Summer Net Interest (MW)	Purchases (Sales)	Summer Net Capacity (MW)
Kelson	SPP	OG&E	Redbud Power Plant	CCNG	927	100.0%	927	(531)	396
Kelson	SPP	OG&E	Redbud Power Plant	GTNG	268	100.0%	268		268
Kelson	SPP	MPS	Aries Power Project	CCNG	558	100.0%	558		558
Kelson	SPP	MPS	Aries Power Project	GTNG	62	100.0%	62		62
Kelson	SERC	Entergy	Cottonwood Energy Project	CCNG	957	100.0%	957		957
Kelson	SERC	Entergy	Cottonwood Energy Project	GTNG	276	100.0%	276		276
Kelson	SERC	TVA	Magnolia Power Plant	CCNG	729	100.0%	729		729
Kelson	SERC	TVA	Magnolia Power Plant	GTNG	78	100.0%	78		78
	Total Kelson Capacity				**3,856**		**3,856**	**(531)**	**3,325**
	SPP								
Calpine	SPP	CSWS	Oneta Energy Center		1,082	100.0%	1,082		1,082
Calpine	SPP	CSWS	Pryor Power Plant		112	100.0%	112		112
	Total Calpine SPP Capacity						**1,194**	**0**	**1,194**
	SERC								
Calpine	SERC	DUK	Broad River Energy Center	GTNG	841	100.0%	841	(841)	0
Calpine	SERC	EES	Carville Energy Center	CCNG	500	100.0%	500		500
Calpine	SERC	EES	Pine Bluff Energy Center	CCNG	198	100.0%	198	(55)	143
Calpine	SERC	SCEG	Columbia Energy Center	CCNG	288	100.0%	288		288
Calpine	SERC	SCEG	Columbia Energy Center	GTNG	177	100.0%	177		177
Calpine	SERC	SOCO	Hog Bayou Energy Center	CCNG	230	100.0%	230		230
Calpine	SERC	SOCO	Santa Rosa Energy Center		236	100.0%	236		236
Calpine	SERC	TVA	Decatur Energy Center		624	100.0%	624	(624)	0
Calpine	SERC	TVA	Morgan Energy Center		749	100.0%	749		749
	Total Calpine SERC Capacity						**3,843**	**(1,520)**	**2,323**

MODELING AND DATA INPUTS

CASm is a linear programming model developed specifically to perform the calculations required in undertaking the delivered price test. The model includes each potential supplier as a distinct "node" or area that is connected via a transportation (or "pipes") representation of the transmission network. Each link in the network has its own non-simultaneous limit and cost. Potential suppliers are allowed to use all economically and physically feasible links or paths to reach the destination market. In instances where more generation meets the economic facet of the delivered price test than can actually be delivered on the transmission network, scarce transmission capacity is allocated based on the relative amount of economic generation that each party controls at a constrained interface.

I conducted the competitive analysis screen using the existing market structure and publicly available data on generation and transmission capacity. The data inputs were adjusted to reflect 2008 conditions (*e.g.*, to reflect updated fuel prices, load, and generation), when the Transaction is expected to be completed. A complete set of the input data used in my analysis is contained in my workpapers. I provide a summary of the key inputs in Exhibit J-1 and below.

Regions Modeled

I included as potential suppliers all entities within three wheels of the specified destination market.[1] The model includes all significant generation and load sources, including traditional utilities, non-utility and merchant generators, municipal utilities and cooperatives. Each entity is generally modeled as an individual "node."[2] For most of the regions included in the model,

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[1] This list was selected in recognition of the Commission's guidance regarding the number of wheels a potential supplier can realistically travel and still be considered a player in the destination market. For example, in *FirstEnergy*, the Commission limited the number of wheels "a supplier could reasonably travel to reach the destination market," recognizing that "[m]ore distant suppliers would face considerable losses and transmission costs." The Commission limited the potential suppliers to those within four wheels. *Ohio Edison Co.*, 80 FERC ¶ 61,039, *reh'g denied*, 81 FERC ¶ 61,109 (1997), *reh'g denied*, 85 FERC ¶ 61,203 (1998).

Also, the request for comments on the use of computer models in merger analysis suggests that "three wheels has been deemed adequate." Inquiry Concerning the Commission's Policy on the Use of Computer Models in Merger Analysis, Notice of Request for Written Comments and Intent to Convene a Technical Conference, Docket No. PL 98-6-000, April 16, 1998, at 24. Including a broader geographic region implies adding additional potential suppliers not controlled by applicants; thus, defining the set of potential suppliers in this manner is conservative.

[2] The term "nodes" is used in CASm to denote a region or bubble where load, generation, or transmission assets are aggregated.

including the relevant regional transmission organizations ("RTOs"), balancing authorities were used to aggregate generation and transmission assets.[3]

Generating Resources

The main sources for data on generating plant capability are the most recent EIA-860 and EIA-411 reports (2007), supplemented by earlier editions as necessary, as well as data from Ventyx (formerly Global Energy Decisions), Velocity Suite Online, a third-party vendor of such information. These data sources provide information on capacity (nameplate and seasonal (summer and winter) net dependable capacity ("NDC") ratings), planned retirements and additions, unit status, primary and secondary fuel, and ownership, including jointly-owned units. NDC ratings were used for the analyses, with the Summer ratings used for the Shoulder time periods.[4] Planned retirements and capacity additions were reflected in the analysis, as described below. For jointly-owned plants, shares were assigned to each of the respective owners. The capacity representing shares of jointly-owned units was "moved" in most regions of the model from its actual physical location to the geographic location of the owner because I assume that there is firm transmission to the owner's balancing authority area. This should be consistent with the treatment of base flows in the relevant SIL studies and the non-simultaneous limits.

Each supplier's generating resources were adjusted to reflect long-term (one year or more) capacity purchases and sales where they could be identified from publicly available data.[5] The capacity representing firm purchases and sales, analogous to the treatment of jointly-owned units, was "moved" in the model from its actual physical location to the geographic location of the buyer. Generation ownership was adjusted to reflect the transfer of control by assuming that the sale resulted in a decrease in capacity for the seller and a corresponding increase in capacity for the buyer.[6] Consistent with guidance provided in Appendix A, it was assumed that system power sales

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[3] The PJM RTO was conservatively excluded in the analysis, even though it is technically within 3 wheels.

[4] The three seasons are Summer (June, July and August), Winter (December, January and February) and Shoulder (March through May and September through November).

[5] Sources for such information include FERC Form 1 and EIA Forms 411 and 412, utility resource plans and NERC's Electricity Supply and Demand database (as complied by Ventyx). Requirements contracts are treated as the equivalent of native load and potential supplier's Economic Capacity was not adjusted to reflect them.

[6] Consistent with this assumption, NUGs were assumed to be under the control of the purchasing utility. The Revised Filing Requirements direct applicants to consider whether operational control of a unit is transferred to the buyer. Such information generally is not readily available for non-applicants. Therefore, I treated long-term sales as being under the control of the purchaser.

were comprised of the lowest-cost supply for the seller unless a more representative price could be identified.[7] Public data on purchases and sales, however, are not entirely complete or consistent across sources. In any event, adjustments to generating capacity for long-term sales and purchases are primarily relevant for OG&E, GRDA, OMPA and, to a lesser degree, other suppliers in the SPP.

Because the delivered price test is intended to evaluate energy products, seasonal capacity was de-rated to approximate the actual availability of the units in each period. That is, it was assumed that generation capacity would be unavailable during some hours of the year for either (planned) maintenance or forced (unplanned) outages. Data reported in the NERC "Generating Availability Data System" ("GADS") was used to calculate the "average equivalent availability factor" to estimate total outages, and the "average equivalent forced outage rate" to estimate forced outages for fossil and nuclear plants.[8] Based on a review of historical planned outages in OG&E and the SPP more generally (as reported in FERC Form 714s), scheduled maintenance was assumed to occur mostly in the Shoulder season (70 percent), with the remainder scheduled during the Winter season. Forced outages were assumed to occur uniformly throughout the year. Forced and planned outages are applied consistently to all units in my analysis, such that the impact of alternative outage rates will typically have a largely symmetric impact on the amount of potential generation included in the analysis.

Supply curves were developed for each potential supplier in the model, based on estimates of each unit's incremental costs. The incremental cost is calculated by multiplying the fuel cost for the unit by the unit's efficiency (heat rate) and adding any additional variable costs that may apply.

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[7] "[T]he lowest running cost units are used to serve native load and other firm contractual obligations" (Order No. 592 at 30,132). The lowest-cost supply that was available year-round (i.e., excluding hydro) was used. To the extent that long-term sales could be identified specifically as unit sales, the capacity of the specific generating unit was adjusted to reflect the sale, and the variable element of the purchase price attributed to the sale was the variable cost of the unit. The dispatch price for system purchases was based on the energy price reported for long-term purchases in FERC Form 1 where such purchases could be identified and a variable cost price determined. In instances where the purchases could not be matched with FERC Form 1 data, the dispatch price was estimated.

[8] For combined-cycle units, the most recent GADS dataset does not report a value and the 1999-2003 version of GADs was used. In addition to thermal unit availability, hydro unit availability and generation are specified for each time period. For each of the time periods analyzed, hydro capacity factors have been assigned to each unit based on historical operation. Capacity factors for hydro units were based on five years of Form 759 monthly generation data, reported maximum capacities and, where necessary, assumptions regarding minimum capacity (assumed to be 15 percent of maximum if no data is available).

such as costs for variable operations and maintenance ("O&M") and costs for environmental controls.[9]

Data used to derive incremental cost estimates for each unit were taken from the following sources:

- Heat Rates – EIA Form 860 and data reported in Ventyx's database. (Note that the most recently available data from the Form 860 date back to 1995.)[10] Full-load heat rate were used in estimating incremental costs.

- Fuel Costs - Futures prices and Regional Projections. Regional dispatch costs for natural gas and oil units were derived from futures market data and spot price history (retrieved in February 2008). For gas-fired units, I relied on 2008 NYMEX Henry Hub natural gas futures contract prices and applied regional basis differentials. I used these data to estimate regional delivered commodity prices for all gas-fired units modeled. Basis differentials were estimated from a review of regional market center and Henry Hub prices from EIA. The NYMEX Henry Hub price, plus each region's basis differential equals my estimated regional price. For oil-fired units, I relied on the NYMEX futures contract for light sweet crude oil. I estimated delivered residual and distillate oil prices based on a multi year analysis of delivered refined products versus spot crude oil prices. I used plant specific forecasts of coal prices (from FERC Form 423 supplemented by Ventyx) as the basis for my coal unit dispatch cost and escalated to 2008 using information in EIA's Annual Energy Outlook (table 15). In instances where no forecast was available for a given unit, I used regional average price estimate as my default.

- Variable O&M – $1/MWh for gas and oil steam units, $3/MWh for scrubbed coal-fired units and $2/MWh for other coal-fired units (generic estimates based on trade and industry sources). Additional Variable O&M adders for other unit types are shown in my workpapers. As noted, these variable O&M costs are generic estimates by plant type and do not necessarily match actual individual unit O&M costs. Notably, variable O&M accounts for a minor portion of the dispatch costs used in the analysis, and, importantly, the specific O&M assumption tends not to alter the merit order of the generic types of generation.

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[9] For non-utility generation ("NUGs"), the incremental costs were estimated on the basis of the energy price reported in relevant regulatory filings, if available. Otherwise, NUGs were assumed to be must-run and the variable costs set to zero. New merchant and utility capacity included in the analysis was priced assuming an average full-load heat rate of 10,000 Btu/kWh for combustion turbines and 7,000 Btu/kWh for combined cycle plants unless information from Ventyx was available. These values were derived from an evaluation of existing technology. Variable O&M costs for new units were assumed to be the same as for existing units.

[10] For combined-cycle units, Ventyx provides information on the combined-cycle and peaking (e.g., duct firing) modes of operation and I have incorporated this information where available. I assumed a generic heat rate for the duct firing capacity of 8,600 btu/kWh.

- Environmental Costs – All units covered by Phase II of the Clean Air Act Amendments of 1990 (CAAA) are assessed a variable dispatch adder to cover costs associated with SO2 emissions. This unit-specific cost is calculated using the SO2 content of fuel burned at the unit as reported in FERC Form 423 (adjusting for emissions reduction equipment at the facility) and an SO2 allowance cost of $556/ton for 2008.[11] In addition to SO2, the unit dispatch costs also reflect the impact of existing NOx trading programs in the Northeast (OTR). Unit-specific data on NOx rates (lbs/mmBtu) were taken from the EPA's "2000 Acid Rain Program Emission Scorecard."[12] The NOx allowance price for the OTR was assumed to be $650/ton.[13]

Price Data

As noted in Exhibit J-1, market prices were selected based primarily on a review of the EIS historical real-time prices (an hourly series of data) and a forecast of market prices in the SPP from Ventyx (reported on an hourly basis).[14] For the EIS prices and Ventyx's hourly data series, I aggregated the data into the 10 time periods analyzed in the DPT. For my base case prices, I relied primarily on the average of the EIS data and Ventyx's forecast in each of the 10 time periods.[15]

I also reviewed the historical operation of generating facilities in the SPP in order to verify that my assumed market prices and the input prices that drive the incremental cost of units in the model were consistent with historical and expected operation. Included in workpapers is an analysis of the operation of these units, using information collected by the Environmental Protection Agency ("EPA").[16] While examining capacity factors and historical operating

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[11] Consistent with my methodology for estimating coal prices, I used plant specific forecasts of SO2 emissions from Platts as the basis for my coal unit dispatch cost. When there was no forecast for a given unit, I defaulted to regional average SO_2 estimate. SO_2 costs are from Evolution Markets LLC's Monthly Market Update - SO2 Markets (September 3rd 2007).

[12] In cases where unit-specific data were not available, such as for new capacity, the following boiler level assumptions were applied, based on the unit's fuel type: Coal – 0.4; Oil – 0.2; Natural Gas – 0.1.

[13] NOx rates were derived from EPA's 2000 Acid Rain Program Emission Scorecard and NOx allowance price is from Evolution Markets LLC's Monthly Market Update - NOx Markets (September 3rd 2007).

[14] I also reviewed OG&E's system lambda data and pricing information from FERC's February 2008 market oversight report for the SPP region (See http://www.ferc.gov/market-oversight/mkt-electric/spp.asp)

[15] I verified that the underlying gas prices used in my analysis and those underlying Ventyx's forecast were consistent, as shown in workpapers. I also confirmed that the resulting seasonal average prices were consistent with the actual capacity factors for combined-cycle generation like Redbud.

[16] EPA's Continuous Emission Monitoring System ("CEMS") data provides hourly output data on fossil generators. I retrieved the data from Ventyx.

information is not necessarily a direct indicator of expected operation,[17] the data supports the market prices that I have selected. Specifically, the data show that combined-cycle units historically have operated at relatively high capacity factors in the Summer season, although not during the off-peak hours. During the Winter season, they do not appear to have operated outside of the peak hours. Combined-cycle operation during the Shoulder months is mixed, operating similar to the Summer pattern during months near the Summer (May and September) and operating similar to the Winter season during the Shoulder months around the Winter (November, March).

Transmission

The Commission's Appendix A analysis specifies that the transmission system be modeled on the basis of inter-control area transmission capability using transmission prices based on transmission providers' maximum non-firm OATT rates, except where lower rates can be clearly documented. This dictates a transportation representation of the transmission network, and the structure of CASm was designed to conform to Appendix A. This representation remains appropriate for some regions in the United States (*i.e.*, those where transmission service is still generally provided under each transmission owner's OATT), such as in SERC. Basing tariffs on OATT rates is increasingly modified by RTO transmission pricing arrangements, however, and the Commission has instructed applicants to account for them.[18] As discussed below, I incorporated the RTO arrangements in my modeling of transmission rates and limits and have also explicitly incorporated SILs into my modeling assumptions.

Balancing authority area-to-balancing authority area transmission capability was taken primarily from OG&E's transmission study (for the direct interconnections between OG&E and GRDA and their first-tier balancing authority areas) and from postings on the Open Access Same-Time Information System ("OASIS"). For non-SPP markets, OASIS reports Total Transmission Capability ("TTC"), firm Available Transmission Capability ("ATC") and non-firm ATC. Data

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[17] There are a number of reasons why it is problematic to use historical operations directly to predict expected operations, in addition to the obvious forecasting issues. For example, units may operate for non-economic reasons, such as for local reliability conditions, in response to specific outages or in support of cogeneration processes. Units also may have experienced extended outages or faced other system conditions that would not be expected to occur in the future. Nevertheless, a review of historical operation can inform the selection of market prices.

[18] *See Revised Filing Requirements Under Part 33 of the Commission's Regulations*, Order No. 642, FERC Stats. & Regs. Regs. Preambles July 1996-Dec. 2000] ¶ 31,111 at 31,890 (2000), *on reh'g*, Order No. 642-A, 94 FERC ¶ 61,289 (2001). ("Revised Filing Requirements" or "Order No. 642").

generally are provided monthly for a twelve-month period starting with the next month. Monthly non-firm ATC postings were used in most instances where data from OASIS is available. For regions where transmission is no longer posted on a balancing authority area-to-balancing authority area basis, I have generally used values from older filings or used information from other sources, although I would note that the assumption on transmission capacity in the regions outside of the destination markets' first-tier regions has an insignificant impact on the results of my analysis.

For my analysis of the SPP EIS market, I used transmission limits into SPP from a recent SPP report (*Southwest Power Pool Intra-Regional Appraisal and Study Observation, 2006 Summer Peak Transmission Assessment*, May 2006). I used the largest of the FCITCs into SPP as an SIL from Eastern Interconnection regions, based on the assumption that the SIL would be no less than the maximum of any one of the FCITCs.[19] In my modeling, I also reflected the FCITCs from each of the other NERC regions in the Eastern Interconnection, with the SIL limiting imports overall.[20] In addition to the SIL for Eastern Interconnection imports, I also included potential imports from WECC (610 MW from the DC ties between WECC and SPP) and from the Electricity Reliability Council of Texas ("ERCOT") (820 MW from the DC ties between ERCOT and SPP). Since the DC ties are not synchronous with the SPP transmission system, they have no affect on the SIL. There is more than sufficient capacity (both Economic and Available Economic) in WECC and ERCOT to fill this transmission capacity. Rather than develop a detailed model of WECC and ERCOT, I assumed that these additional imports would be divided among a sufficient number of parties that these imports would not materially impact the market HHIs.

Consistent with Order No. 592, the ceiling rates in Schedule 8 (Non-Firm Point-to-Point Transmission Service) of each utility's Order No. 888 filings were used for utilities that are not part of RTO arrangements.[21] In many instances, utilities report both on-peak and off-peak ceiling rates

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[19] *This is consistent with the manner in which I used FCITCs in the FCITC case described in Exhibit J-1.*

[20] The FCITC values between regions were based on *NERC's Summer Assessment*, 2004, Figure 3 (Normal Base Electricity Transfers and FCITCs). Note that the 2004 report is the most recent that includes the FCITCs between NERC subregions. Given the overall SIL applied into the SPP EIS market, the individual FCITCs are not critical to this analysis.

[21] In instances where transmission data were not reported in dollars per MWh, the $/MW rates were converted to $ MWh rates using the "Appalachian" method. *Appalachian Power Co.*, 39 FERC ¶ 61,296 at 61,965 (1987). If instances when data was not available, I assumed default transmission rates of $2 MWh and $1 MWh for peak and off-peak periods, respectively.

in its Order No. 888 filing. If so, the applicable transmission rate for the on- and off-peak periods were used. If not, the filed ceiling rate was applied for all periods. Ancillary service charges from Schedules 1 (Scheduling, System Control and Dispatch Service) and 2 (Reactive Supply and Voltage Control from Generation Sources Service) of Order No. 888 filings were added where applicable to determine the final rates.

Losses, which are assumed to be 2.8 percent, are assessed for each wheel incurred along the path to deliver power to the destination market but are not added for the final wheel into the destination market.

Allocation of Limited Transmission

Appendix A notes that there are various methods for allocating transmission, and that applicants should support the method used.[22] For purposes of this analysis, limited transmission capacity was allocated using a prorata "squeeze-down" method, so-named because it seeks to prorate capacity at each node and is the closest approximation to what the Commission applied in *FirstEnergy*[23] that is computationally feasible. Under this method, shares of available transmission are allocated at each interface, diluting the importance of distant capacity as it gets closer to the destination market. When there is economic supply (*i.e.*, having a delivered cost less than 105 percent of the destination market price) competing to get through a constrained transmission interface into a control area, the transmission capability is allocated to the suppliers in proportion to the amount of economic supply each supplier has outside the interface.

Shares on each transmission path are based on the shares of deliverable energy at the source node for the particular path being analyzed. The calculations start at the outside of a network, defined with the destination market as its center, and end at the destination market itself. A series of decision rules are required to accomplish this proration. The purpose of these decision

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[22] *See Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, FERC Stats. & Regs.[Regs. Preambles 1996-2000] ¶ 31,044 at 30,133(1996) ("Merger Policy Statement" or "Order No. 592") ("In many cases, multiple suppliers could be subject to the same transmission path limitation to reach the same destination market and the sum of their economic generation capacity could exceed the transmission capability available to them. In these cases, the ATC must be allocated among the potential suppliers for analytic purposes. There are various methods for accomplishing this allocation. Applicants should support the method used."), *reconsideration denied*, Order No. 592-A, 79 FERC ¶ 61,321 (1997).

[23] *Ohio Edison Co.* at 61,106-07: "When there was more economic capacity (or available economic capacity) outside of a transmission interface than the unreserved capability would allow to be delivered into the destination market, the transmission capability was allocated to the suppliers in proportion to the amount of economic capacity each supplier had outside the interface."

rules is limited to assigning a unique power flow direction to each link for any given destination market analysis. Once the links are given a direction, the complex network can be solved. CASm implements a series of rules to determine the direction of the path. The first rule (and the one expected to be applied most frequently) is based on the direction of the flow under an economic allocation of transmission capacity. Other options take into consideration the predominant flow on the line based on desired volume (the amount of economic capacity seeking to reach the destination market, the number of participants seeking to use a path in a particular direction, and the path direction that points toward the destination market).

The model proceeds to assign suppliers at each node a share equal to their maximum supply capability. At each node, "new" suppliers (those located at the node outside of the next interface) are given a share equal to their supply capability, and the shares of more distant suppliers (those who have had to pass through interfaces more remote from the destination market in order to reach the node) are scaled down to match the line capacity into the node. Ultimately, the shares at the destination market represent the prorated shares of Economic Capacity or Available Economic Capacity that is economically and physically feasible. Additional technical details of how CASm operates, including how transmission is allocated, is provided in Exhibit J-5.

Exhibit J-5

COMPETITIVE ANALYSIS SCREENING MODEL (CASm)

CRA International's Competitive Analysis Screening model ("CASm") is designed to perform the calculations required in order to conduct a market power analysis under Appendix A of the FERC Merger Policy Statement ("Order No. 592" or "Appendix A").[1] The delivered price test specified in Appendix A requires an analysis of market concentration for a large number of markets under a number of different conditions. CASm facilitates this process by performing the required calculations.

The primary requirement of Appendix A is to assess potential suppliers to a market using a "delivered price test." This test involves comparing variable generation costs plus delivery costs (transmission rates, transmission losses and ancillary services) to a "market price." If the delivered cost of generation is less than 105 percent of the market price, the generation is considered economic. Economic generation is further limited to the amount that can be delivered into the market, given transmission capability and constraints.

CASm is a linear programming ("LP") model that implements the prescribed delivered price test by determining -- for each destination market, for each relevant time period, and for each relevant supply measure -- potential supply to the destination market both pre- and post-merger (or transaction). In effect, CASm determines the relevant geographic market by applying the delivered price test, based on the economics of production and delivery (transmission rates, transmission losses and ancillary services), and also based on the physical transmission capacity available to the competing suppliers on an open access basis. This requires a delivery route for the energy on the established transmission paths, each of which has a capability, transmission rate and transmission losses associated with it. CASm finds the supply that can be delivered to the destination market consistent with cost minimization and the delivered price test.

As a formal matter, CASm minimizes the production and transmission costs of supplying demand in the destination market. Any shortfall in demand is filled by a hypothetical generator located in the destination market that can produce an unlimited amount of energy at 105 percent of the market price. On this basis, any supplier who can profitably supply energy to the destination market will do so, to the maximum extent that their cost structure and the transmission system allow. This formulation ensures that no supplied generation is uneconomic; the hypothetical generator will undercut all such suppliers.

CASm determines pre- and post-merger market shares and calculates concentration (as measured by the Herfindahl-Hirschman Index, or HHI) and the change in HHIs.

To undertake these analyses, CASm solves a series of scenarios involving a network of interconnected suppliers. By limiting suppliers based on the economics of generation and delivery,

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[1] CASm was developed under the direction of CRA employees while employed by Putnam, Hayes & Bartlett and PHB-Hagler Bailly, and has been used in analyzing numerous mergers and power plant acquisitions as well as market-based rate authority proceedings before the Commission.

- **Economic Capacity** is the amount of capacity that can reach a market at a cost (including transmission rates, transmission losses and ancillary services) no more than 105 percent of the destination market price.

- **Available Economic Capacity** is the amount of Economic Capacity that is available after serving native load and other net firm commitments with the lowest cost units.

For every analysis, the following process is undertaken:

First, a LP problem is solved. The LP construction is slightly different, depending on the underlying assumptions of each of the supply measures. CASm includes two options for allocating scarce transmission capacity. CASm has a "proration" option, which is called "squeeze-down." This is discussed in detail below. (Another option is an economic allocation of limited transfer capability. Under this option, where available supply exceeds the ability of the network to deliver that capacity to the destination market, the least-cost supply is allocated the available transmission capacity.[2])

The final step involves calculating what can be delivered to the destination market, after accounting for line losses. CASm allocates total system losses amongst suppliers on the basis on how much they injected, and how far away (how many wheels) they are from the destination market.

Economic Capacity

For the Economic Capacity analysis, CASm solves an LP with the following form:

minimize cost for supplies at the destination market

subject to:

supply cost at destination < system lambda + 5%, for all suppliers

supply < quantity[3], for each node and tranche

supply + flows in - flows out + "demand", for each node

line flows are adjusted for losses, for all interconnections

line flows < available limit, for all interconnections (constrained network only)

sum over lines (flow * simultaneous factor) <- simultaneous limit, for all limits

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[2] CASm can be modified to apply different proration methods when appropriate for some analyses.

[3] Available quantity may be modified. See discussion in the Output Capacity section.

sum over nodes (net injection * flowgate factor) <- flowgate limit, for all limits

The objective is slightly different when transmission capacity is to be prorated. The objective then becomes:

minimize cost for supplies at the destination market; and

minimize divergence from calculated pro rata "share," for each supplier

And, where ownership imputation is being used, the following constraints are added:

sum over economic[4] tranches < imputed share of economic tranches, for all owners at each imputed node

Available Economic Capacity

For the Available Economic Capacity analysis, CASm solves an LP with the following form:

minimize cost for supplies at the destination market

subject to:

supply cost at destination < system lambda + 5%, for all suppliers

supply < quantity (less native load), for each node and tranche

supply - flows in flows out + "demand", for each node

line flows are adjusted for losses, for all interconnections

line flows < available limit, for all interconnections (constrained network only)

sum over lines (flow * simultaneous factor) <- simultaneous limit, for all limits

sum over nodes (net injection * flowgate factor) <- flowgate limit, for all limits

This is different from the economic capacity analysis only to the extent that potential suppliers are required to meet their load obligations prior to participating in the market.

When transmission capacity is to be prorated the objective becomes:

minimize cost for supplies at the destination market; and

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[4] Economic tranches are those that can deliver to the destination within a specified mark up of the market price (typically 105%).

minimize divergence from calculated pro rata "share," for each supplier

And, where ownership imputation is being used, the following constraints are added:

sum over economic tranches ≤ imputed share of economic tranches, for all owners at each imputed node

OUTPUTS

The primary output from CASm is a report that summarizes the results of different analyses. For each destination market, load period and FERC analysis type, CASm reports the following for both pre- and post-merger:

- Supplied MW
- Market Share
- HHIs

This report also shows the change in HHIs post-merger compared to pre-merger.

CASm also produces a transmission report that shows the detail of each node, and the injections and flows between them. Finally, a summary of the results for each market is also produced.

"SQUEEZE-DOWN" PRORATION

In the "squeeze-down" proration algorithm, prorated shares on each line are based on the weighted shares of deliverable energy at the source node for that line. As discussed more fully below, weighted shares at the destination market node are calculated by a recursive algorithm that starts at the "outside" of the network then calculates shares on each line until it reaches the "middle." Specifically, where available supply exceeds the ability of the network to deliver that capacity to the destination market, suppliers are allocated shares at each node, and hence each outgoing line, based on the results of an algorithm that considers both supply and transfer capability at each node. Starting at the "outside" of the network, CASm calculates a share at each node that is based on a proportion of the incoming transfer capability (and the share of that capability allocated to each supplier), and the maximum economic supply available at that node. When the algorithm reaches the destination market, a total share of the incoming transfer capability has been determined.

This algorithm requires that all possible paths are simultaneously feasible, which, in turn, requires that each line be assigned a unique "direction." The steps of the proration algorithm include:

1. A C++ program enumerates all possible paths to the destination, the cost of transmission on each path and the maximum possible flow on the path. A "wheel limit," or maximum number of point-to-point links, may be imposed on paths.

2. The minimum "entry cost" for each supplier is calculated. This cost is the injection cost of the cheapest generator that has capacity for possible delivery to the destination.

3. Paths for which the entry cost plus the transmission cost are higher than 105% of the destination market price are rejected as being uneconomic.

4. To the extent remaining paths are not simultaneously feasible (because, for example, suppliers can seek to use the paths in both directions), a series of decision rules for determining the direction of the line are undertaken (in the following order):

    - Instructions can be manually input as to the chosen direction of a line.
    - Merger-case decisions should be consistent with base-case decisions.
    - The direction of the line as determined in an economic allocation of available transmission is applied.
    - The direction heading toward a destination market, if it is clear, is chosen.
    - The direction that retains the maximum potential volume-weighted flow on the line (calculated from the paths that depend on this line) is chosen.
    - The direction on which the maximum number of economic paths depend is chosen.

If these other options fail to reach a feasible solution, manual input will be required.

5. If there are simultaneous limits, they are checked for feasibility. All lines that have a worsening effect on a simultaneous constraint, given their defined flow direction, are checked against the simultaneous limit. If they would exceed the simultaneous limit if fully utilized, then their maximum capacity is prorated downwards in proportion to their respective limit participation factors. In this way, no set of targets will be produced that could not be delivered in a way that is feasible with the simultaneous limits.

6. Proration begins at nodes furthest from the destination market (where only exports, and no imports are being attempted). Suppliers at these nodes are assigned a "share" equal to their maximum economic supply capability.

7. Proration continues at the next set of nodes that should consist only of nodes with inflows from "resolved" nodes from step 5. Suppliers at these nodes are assigned a "share" equal to their maximum economic supply capability. Suppliers from the "resolved" nodes have their shares scaled down to match the transmission capacity into the node.

8. To the extent an iteration of the algorithm does not resolve any additional nodes and the destination market has not yet been reached (i.e., a loop is detected), flow is disallowed from any unresolved node to the furthest and smallest node affected by a loop.

9. The proration has been completed when the destination market node has been resolved. At that point, the "shares" at the destination market represent the prorated shares of deliverable energy.

10. If ownership at a node is to be "imputed," or credited to another node, further proration targets are calculated. First, only those tranches that can deliver to the destination within 105% of the market price are considered. A factor representing the share each owner has of these economic tranches is calculated. For each owner, a constraint is calculated that limits the sum of injections attributed to that owner to be not more than that owner's "share" of the target calculated above. In this way, the proportion of ownership of economic capacity at a node is fairly reflected in the final solution outcome.

11. Injections for each supplier are "capped" at the calculated shares, and these injections are then checked for economic feasibility. While suppliers need not deliver their energy to the destination in exactly the way that their share was calculated, the solution is still both economically and physically feasible. The final solution represents the least-cost method of delivering these supplies.

CASM IMPLEMENTATION

CASm has been implemented using GAMS (Generalized Algebraic Modeling System). GAMS is a programming language which supports both data manipulation and calls to many mainstream mathematical modeling systems. The linear programming problems generated by CASm are solved by BDMLP or CPLEX. The path enumeration program has been written in Microsoft Visual C++ version 5.

SPP EIS Market

		Pre-Transaction										Post-Transaction								
		GRDA		Kelson		OKGE		OMPA				GRDA		OKGE		OMPA				
Period	Price	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	HHI Chg.
Available Economic Capacity																				
S_SP1	$250	50	0.5%	2,010	21.3%	158	1.7%	0	0.0%	9,429	987	299	3.2%	422	4.5%	50	0.5%	9,416	794	-193
S_SP2	$120	57	0.6%	2,022	21.1%	306	3.2%	0	0.0%	9,566	992	306	3.2%	570	6.0%	54	0.6%	9,557	811	-181
S_P	$75	241	2.4%	1,974	19.9%	0	0.0%	80	0.8%	9,946	994	489	5.1%	0	0.0%	144	1.5%	9,683	863	-131
S_OP	$45	0	0.0%	0	0.0%	0	0.0%	0	0.0%	4,194	343	0	0.0%	0	0.0%	0	0.0%	4,194	343	0
W_SP	$85	230	2.3%	2,263	22.1%	501	4.9%	0	0.0%	10,258	999	459	4.5%	1,037	10.1%	128	1.2%	10,250	785	-214
W_P	$60	425	4.6%	1,815	19.5%	0	0.0%	68	0.7%	9,319	963	570	6.4%	0	0.0%	175	2.0%	8,902	827	-136
W_OP	$40	134	2.8%	0	0.0%	0	0.0%	0	0.0%	4,816	402	134	2.8%	0	0.0%	0	0.0%	4,816	402	0
SH_SP	$80	367	3.3%	1,758	15.8%	960	8.6%	149	1.3%	11,161	794	566	5.1%	1,155	10.3%	195	1.8%	11,161	735	-59
SH_P	$55	165	2.0%	1,255	15.6%	0	0.0%	97	1.2%	8,046	868	287	3.6%	0	0.0%	115	1.5%	7,961	814	-53
SH_OP	$35	92	2.1%	0	0.0%	0	0.0%	0	0.0%	4,337	386	92	2.1%	0	0.0%	0	0.0%	4,337	386	0
Economic Capacity																				
S_SP1	$250	1,293	2.8%	1,779	3.9%	6,344	13.8%	649	1.4%	46,141	995	1,542	3.3%	6,608	14.3%	713	1.6%	46,142	1,007	12
S_SP2	$120	1,271	2.8%	1,781	3.9%	6,344	14.0%	638	1.4%	45,194	1,014	1,519	3.4%	6,608	14.6%	702	1.6%	45,195	1,026	12
S_P	$75	1,171	3.4%	1,742	5.1%	3,485	10.2%	576	1.7%	34,307	1,015	1,419	4.1%	3,749	10.9%	640	1.9%	34,308	1,023	8
S_OP	$45	774	3.6%	0	0.0%	2,737	12.8%	298	1.4%	21,344	1,034	774	3.6%	2,737	12.8%	298	1.4%	21,344	1,034	0
W_SP	$85	1,148	3.1%	2,034	5.5%	5,070	13.8%	481	1.3%	36,726	971	1,377	3.8%	5,605	15.3%	617	1.7%	36,726	997	27
W_P	$60	1,073	4.1%	1,754	6.7%	2,731	10.4%	414	1.6%	26,153	782	1,218	4.7%	3,148	12.0%	521	2.0%	26,153	797	14
W_OP	$40	693	3.6%	0	0.0%	2,422	12.5%	279	1.4%	19,317	984	693	3.6%	2,422	12.5%	279	1.4%	19,317	984	0
SH_SP	$80	1,128	3.3%	1,470	4.3%	4,748	14.0%	555	1.6%	33,986	994	1,327	3.9%	4,942	14.5%	601	1.8%	33,986	1,005	11
SH_P	$55	819	3.3%	1,211	4.9%	2,971	11.9%	446	1.8%	24,919	803	941	3.8%	3,056	12.3%	464	1.9%	24,919	807	4
SH_OP	$35	669	3.5%	0	0.0%	2,371	12.5%	277	1.5%	18,943	976	669	3.5%	2,371	12.5%	277	1.5%	18,943	976	0

Imports from DC-Ties modeled as being supplied by 14 equal size entities.

EIS Market includes the following balancing authority areas.
OG&E, AEP West, EDE, GRDA, KACY, KCPL, SECI, SPRM, SWPS, WFEC and WR.
(see http://www.spp.org/publications/SPP_Footprints.pdf)

OG&E and GRDA Balancing Authority Areas
Base Case

		Pre-Transaction										Post-Transaction								
		GRDA		Kelson		OKGE		OMPA				GRDA		OKGE		OMPA				
Period	Price	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	HHI Chg.
Available Economic Capacity, OG&E																				
S_SP1	$250	1	0.1%	605	64.9%	158	16.9%	0	0.0%	933	4,560	2	0.3%	422	65.8%	50	7.8%	641	4,519	-41
S_SP2	$120	1	0.1%	606	56.0%	306	28.3%	0	0.0%	1,081	3,985	2	0.3%	570	71.8%	54	6.9%	793	5,287	1,303
S_P	$75	2	0.3%	604	76.3%	0	0.0%	80	10.1%	792	5,948	3	1.2%	0	0.0%	144	57.5%	250	3,527	-2,421
S_OP	$45	0	0.0%	0	0.0%	0	0.0%	0	0.0%	137	869	0	0.0%	0	0.0%	0	0.0%	137	869	0
W_SP	$85	8	0.4%	1,098	47.1%	501	21.5%	0	0.0%	2,332	2,749	14	0.7%	1,037	50.5%	128	6.2%	2,054	2,753	4
W_P	$60	8	0.5%	798	47.8%	0	0.0%	68	4.1%	1,667	2,425	11	1.1%	0	0.0%	175	16.4%	1,064	673	-1,751
W_OP	$40	6	0.7%	0	0.0%	0	0.0%	0	0.0%	930	594	6	0.7%	0	0.0%	0	0.0%	930	594	0
SH_SP	$80	4	0.2%	567	26.5%	960	44.8%	149	7.0%	2,142	2,793	6	0.3%	1,155	60.3%	195	10.2%	1,913	3,823	1,030
SH_P	$55	0	0.0%	276	30.1%	0	0.0%	97	10.6%	917	1,228	0	0.1%	0	0.0%	115	17.0%	679	685	-543
SH_OP	$35	1	0.2%	0	0.0%	0	0.0%	0	0.0%	594	618	1	0.2%	0	0.0%	0	0.0%	594	618	0
Available Economic Capacity, GRDA																				
S_SP1	$250	50	16.4%	68	22.1%	2	0.8%	0	0.0%	308	1,272	299	65.1%	4	0.9%	0	0.1%	459	4,384	3,113
S_SP2	$120	57	18.2%	70	22.3%	4	1.4%	0	0.0%	315	1,308	306	65.6%	5	1.2%	1	0.1%	466	4,458	3,150
S_P	$75	241	48.3%	75	15.1%	0	0.0%	1	0.1%	498	2,777	489	75.3%	0	0.0%	1	0.2%	649	5,765	2,988
S_OP	$45	0	0.0%	0	0.0%	0	0.0%	0	0.0%	258	765	0	0.0%	0	0.0%	0	0.0%	258	765	0
W_SP	$85	230	33.5%	199	29.0%	0	0.0%	0	0.0%	687	2,048	459	60.5%	12	1.6%	15	2.0%	758	3,788	1,740
W_P	$60	425	48.2%	145	16.4%	0	0.0%	3	0.4%	882	2,665	570	65.6%	0	0.0%	18	2.0%	869	4,365	1,700
W_OP	$40	134	22.7%	0	0.0%	0	0.0%	0	0.0%	591	842	134	22.7%	0	0.0%	0	0.0%	591	842	0
SH_SP	$80	367	38.9%	214	22.6%	0	0.0%	33	3.5%	944	2,114	566	58.0%	0	0.0%	41	4.2%	975	3,529	1,416
SH_P	$55	165	22.2%	22	2.9%	0	0.0%	3	0.4%	742	909	287	41.2%	0	0.0%	2	0.3%	696	1,934	1,025
SH_OP	$35	92	13.8%	0	0.0%	0	0.0%	0	0.0%	670	638	92	13.8%	0	0.0%	0	0.0%	670	638	0

OG&E and GRDA Balancing Authority Areas
Base Case

		Pre-Transaction										Post-Transaction								
		GRDA		Kelson		OKGE		OMPA				GRDA		OKGE		OMPA				
Period	Price	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	HHI Chg.
Economic Capacity, OG&E																				
S_SP1	$250	6	0 1%	580	7.4%	6,344	80.9%	649	8.3%	7,842	6,669	5	0.1%	6,608	87 4%	713	9.4%	7,564	7,722	1,053
S_SP2	$120	6	0.1%	580	7.4%	6,344	81.0%	638	8.2%	7,830	6,686	5	0.1%	6,608	87.5%	702	9.3%	7,552	7,743	1,057
S_P	$75	6	0.1%	583	12.1%	3,485	72.0%	576	11 9%	4,839	5,477	5	0 1%	3,749	82.2%	640	14.0%	4,560	6,956	1,480
S_OP	$45	5	0.2%	0	0.0%	2,737	84 5%	298	9 2%	3,238	7,237	5	0.2%	2,737	84.5%	298	9.2%	3,238	7,237	0
W_SP	$85	25	0.3%	955	12.8%	5,070	68.1%	481	6 5%	7,447	4,855	26	0.4%	5,605	78.1%	617	8 6%	7,178	6,187	1,332
W_P	$60	20	0 4%	716	14.9%	2,731	56.8%	414	8.6%	4,804	3,554	21	0 5%	3,148	68.2%	521	11.3%	4,618	4,801	1,247
W_OP	$40	21	0 6%	0	0.0%	2,422	65.6%	279	7.5%	3,691	4,423	21	0 6%	2,422	65 6%	279	7.5%	3,691	4,423	0
SH_SP	$80	7	0.1%	475	7.4%	4,748	74.2%	555	8.7%	6,397	5,648	7	0 1%	4,942	80.1%	601	9 8%	6,168	6,524	876
SH_P	$55	7	0.2%	247	5.8%	2,971	69.2%	446	10.4%	4,295	4,944	7	0.2%	3,056	73.8%	464	11 2%	4,142	5,587	643
SH_OP	$35	6	0.2%	0	0.0%	2,371	71 8%	277	8.4%	3,300	5,265	6	0.2%	2,371	71 8%	277	8 4%	3,300	5,265	0
Economic Capacity, GRDA																				
S_SP1	$250	1,293	83.4%	11	0.7%	29	1.9%	3	0.2%	1,551	6,983	1,542	90.6%	19	1.1%	2	0.1%	1,702	8,213	1,231
S_SP2	$120	1,271	83.2%	11	0.7%	29	1 9%	3	0.2%	1,528	6,942	1,519	90 5%	19	1 2%	2	0 1%	1,679	8,190	1,248
S_P	$75	1,171	82.0%	17	1.2%	23	1 6%	3	0.2%	1,428	6,745	1,419	89.8%	16	1 0%	3	0 2%	1,579	8,080	1,336
S_OP	$45	774	75.0%	0	0.0%	20	1.9%	2	0.2%	1,031	5,689	774	75.0%	20	1 9%	2	0 2%	1,031	5,689	0
W_SP	$85	1,148	71.5%	38	2.4%	102	6.3%	11	0.7%	1,605	5,200	1,377	82 1%	77	4.6%	10	0.6%	1,676	6,783	1,583
W_P	$60	1,073	70.2%	38	2.5%	104	6.8%	14	0.9%	1,530	5,006	1,218	80.3%	79	5.2%	12	0.8%	1,517	6,486	1,480
W_OP	$40	693	60.3%	0	0.0%	27	2.4%	3	0 3%	1,150	3,779	693	60.3%	27	2.4%	3	0.3%	1,150	3,779	0
SH_SP	$80	1,128	66.1%	39	2.3%	120	7 0%	22	1.3%	1,705	4,482	1,327	76.4%	95	5 4%	17	1.0%	1,736	5,897	1,415
SH_P	$55	819	58.6%	10	0.7%	150	10.8%	21	1.5%	1,396	3,631	941	69 7%	106	7.9%	15	1 1%	1,350	4,959	1,328
SH_OP	$35	669	53.7%	0	0.0%	42	3.4%	5	0.4%	1,246	3,072	669	53.7%	42	3 4%	5	0 4%	1,246	3,072	0

OG&E Balancing Authority Area
FCITC Case

		Pre-Transaction										Post-Transaction								
		GRDA		Kelson		OKGE		OMPA				GRDA		OKGE		OMPA				
Period	Price	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	HHI Chg.
Available Economic Capacity, OG&E																				
S_SP1	$250	5	0.2%	901	41.2%	158	7.2%	0	0.0%	2,188	2,053	27	1.4%	422	21.3%	50	2.5%	1,976	1,145	-907
S_SP2	$120	6	0.3%	892	38.2%	306	13.1%	0	0.0%	2,336	1,888	32	1.5%	570	26.8%	54	2.6%	2,129	1,252	-635
S_P	$75	27	1.3%	876	42.8%	0	0.0%	80	3.9%	2,047	2,178	52	3.3%	0	0.0%	144	9.1%	1,585	1,128	-1,050
S_OP	$45	0	0.0%	0	0.0%	0	0.0%	0	0.0%	1,393	957	0	0.0%	0	0.0%	0	0.0%	1,393	957	0
W_SP	$85	18	0.6%	1,292	40.4%	501	15.7%	0	0.0%	3,202	2,009	36	1.2%	1,037	34.2%	128	4.2%	3,033	1,521	-488
W_P	$60	17	0.7%	940	37.1%	0	0.0%	68	2.7%	2,532	1,589	26	1.3%	0	0.0%	175	8.6%	2,043	554	-1,035
W_OP	$40	11	0.6%	0	0.0%	0	0.0%	0	0.0%	1,800	655	11	0.6%	0	0.0%	0	0.0%	1,800	655	0
SH_SP	$80	9	0.3%	733	26.0%	960	34.1%	149	5.3%	2,818	1,963	13	0.5%	1,155	43.3%	195	7.3%	2,665	2,176	213
SH_P	$55	0	0.0%	332	20.8%	0	0.0%	97	6.1%	1,592	808	0	0.0%	0	0.0%	115	8.1%	1,430	587	-221
SH_OP	$35	3	0.2%	0	0.0%	0	0.0%	0	0.0%	1,269	615	3	0.2%	0	0.0%	0	0.0%	1,269	615	0
Economic Capacity, OG&E																				
S_SP1	$250	63	0.7%	635	7.0%	6,344	69.7%	649	7.1%	9,098	4,992	71	0.8%	6,608	74.3%	713	8.0%	8,899	5,611	619
S_SP2	$120	63	0.7%	634	7.0%	6,344	69.8%	638	7.0%	9,086	5,001	71	0.8%	6,608	74.3%	702	7.9%	8,888	5,621	621
S_P	$75	60	1.0%	660	10.8%	3,485	57.2%	576	9.5%	6,094	3,522	69	1.2%	3,749	63.6%	640	10.9%	5,896	4,216	694
S_OP	$45	48	1.1%	0	0.0%	2,737	60.9%	298	6.6%	4,494	3,877	48	1.1%	2,737	60.9%	298	6.6%	4,494	3,877	0
W_SP	$85	56	0.7%	1,009	12.1%	5,070	61.0%	481	5.8%	8,317	3,936	64	0.8%	5,605	68.7%	617	7.6%	8,157	4,826	890
W_P	$60	46	0.8%	763	13.5%	2,731	48.1%	414	7.3%	5,674	2,621	53	1.0%	3,148	56.2%	521	9.3%	5,597	3,331	710
W_OP	$40	41	0.9%	0	0.0%	2,422	53.1%	279	6.1%	4,561	3,015	41	0.9%	2,422	53.1%	279	6.1%	4,561	3,015	0
SH_SP	$80	18	0.3%	516	7.3%	4,748	67.1%	555	7.9%	7,073	4,651	20	0.3%	4,942	71.4%	601	8.7%	6,920	5,210	560
SH_P	$55	12	0.3%	271	5.5%	2,971	59.8%	446	9.0%	4,970	3,742	13	0.3%	3,056	62.5%	464	9.5%	4,894	4,056	314
SH_OP	$35	12	0.3%	0	0.0%	2,371	59.6%	277	7.0%	3,976	3,698	12	0.3%	2,371	59.6%	277	7.0%	3,976	3,698	0
Excluding Existing Contracts for OG&E and OMPA in the Shoulder Periods																				
Available Economic Capacity, OG&E																				
SH_SP	$80	9	0.3%	1,106	39.3%	660	23.5%	69	2.5%	2,816	2,188	13	0.5%	1,155	43.4%	195	7.3%	2,663	2,164	-23
SH_P	$55	0	0.0%	710	37.9%	0	0.0%	17	0.9%	1,872	1,660	0	0.0%	0	0.0%	115	8.2%	1,410	559	-1,100
SH_OP	$35	3	0.2%	0	0.0%	0	0.0%	0	0.0%	1,253	606	3	0.2%	0	0.0%	0	0.0%	1,253	606	0
Economic Capacity, OG&E																				
SH_SP	$80	21	0.3%	896	12.7%	4,448	62.9%	475	6.7%	7,071	4,190	24	0.3%	4,942	71.4%	601	8.7%	6,918	5,211	1,021
SH_P	$55	12	0.2%	655	13.2%	2,671	53.8%	366	7.4%	4,968	3,174	13	0.3%	3,056	62.5%	464	9.5%	4,892	4,056	882
SH_OP	$35	12	0.3%	0	0.0%	2,371	59.7%	277	7.0%	3,973	3,699	12	0.3%	2,371	59.7%	277	7.0%	3,973	3,699	0

OG&E and GRDA Balancing Authority Areas
GRDA Share of Redbud Over Requirements Remains in OG&E Balancing Authority Area

		Pre-Transaction										Post-Transaction								
		GRDA		Kelson		OKGE		OMPA				GRDA		OKGE		OMPA				
Period	Price	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	HHI Chg.
Available Economic Capacity, OG&E																				
S_SP1	$250	5	0.2%	901	41.2%	158	7.2%	0	0.0%	2,188	2,053	253	11.9%	422	19.8%	50	2.3%	2,134	1,066	-986
S_SP2	$120	6	0.3%	892	38.2%	306	13.1%	0	0.0%	2,336	1,888	255	11.2%	570	24.9%	54	2.4%	2,286	1,163	-725
S_P	$75	27	1.3%	876	42.8%	0	0.0%	80	3.9%	2,047	2,178	278	16.0%	0	0.0%	144	8.2%	1,743	1,095	-1,083
S_OP	$45	0	0.0%	0	0.0%	0	0.0%	0	0.0%	1,393	957	0	0.0%	0	0.0%	0	0.0%	1,393	957	0
W_SP	$85	18	0.6%	1,292	40.4%	501	15.7%	0	0.0%	3,202	2,009	248	7.8%	1,037	32.4%	128	4.0%	3,197	1,412	-597
W_P	$60	17	0.7%	940	37.1%	0	0.0%	68	2.7%	2,532	1,589	161	7.6%	0	0.0%	175	8.2%	2,124	542	-1,046
W_OP	$40	11	0.6%	0	0.0%	0	0.0%	0	0.0%	1,800	655	11	0.6%	0	0.0%	0	0.0%	1,800	655	0
SH_SP	$80	9	0.3%	733	26.0%	960	34.1%	149	5.3%	2,818	1,963	208	7.4%	1,155	41.0%	195	6.9%	2,814	1,991	28
SH_P	$55	0	0.0%	332	20.8%	0	0.0%	97	6.1%	1,592	808	122	8.2%	0	0.0%	115	7.7%	1,503	563	-245
SH_OP	$35	3	0.2%	0	0.0%	0	0.0%	0	0.0%	1,269	615	3	0.2%	0	0.0%	0	0.0%	1,269	615	0
Economic Capacity, OG&E																				
S_SP1	$250	63	0.7%	635	7.0%	6,344	69.7%	649	7.1%	9,098	4,992	310	3.4%	6,608	73.0%	713	7.9%	9,057	5,425	433
S_SP2	$120	63	0.7%	634	7.0%	6,344	69.8%	638	7.0%	9,086	5,001	309	3.4%	6,608	73.1%	702	7.8%	9,045	5,435	434
S_P	$75	60	1.0%	660	10.8%	3,485	57.2%	576	9.5%	6,094	3,522	307	5.1%	3,749	61.9%	640	10.6%	6,054	4,018	496
S_OP	$45	48	1.1%	0	0.0%	2,737	60.9%	298	6.6%	4,494	3,877	48	1.1%	2,737	60.9%	298	6.6%	4,494	3,877	0
W_SP	$85	56	0.7%	1,009	12.1%	5,070	61.0%	481	5.8%	8,317	3,936	284	3.4%	5,605	67.4%	617	7.4%	8,321	4,646	710
W_P	$60	46	0.8%	763	13.5%	2,731	48.1%	414	7.3%	5,674	2,621	191	3.4%	3,148	55.5%	521	9.2%	5,678	3,243	622
W_OP	$40	41	0.9%	0	0.0%	2,422	53.1%	279	6.1%	4,561	3,015	41	0.9%	2,422	53.1%	279	6.1%	4,561	3,015	0
SH_SP	$80	18	0.3%	516	7.3%	4,748	67.1%	555	7.9%	7,073	4,651	216	3.1%	4,942	69.9%	601	8.5%	7,069	5,000	349
SH_P	$55	12	0.3%	271	5.5%	2,971	59.8%	446	9.0%	4,970	3,742	134	2.7%	3,056	61.5%	464	9.3%	4,966	3,941	199
SH_OP	$35	12	0.3%	0	0.0%	2,371	59.6%	277	7.0%	3,976	3,698	12	0.3%	2,371	59.6%	277	7.0%	3,976	3,698	0

OG&E and GRDA Balancing Authority Areas
GRDA Share of Redbud Over Requirements Remains in OG&E Balancing Authority Area

		Pre-Transaction										Post-Transaction								
		GRDA		Kelson		OKGE		OMPA				GRDA		OKGE		OMPA				
Period	Price	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	HHI Chg.
Available Economic Capacity, GRDA																				
S_SP1	$250	50	16.4%	68	22.1%	2	0.8%	0	0.0%	308	1,272	54	19.5%	5	2.0%	1	0.2%	275	1,194	-77
S_SP2	$120	57	18.2%	70	22.3%	4	1.4%	0	0.0%	315	1,308	61	21.5%	7	2.5%	1	0.2%	282	1,288	-21
S_P	$75	241	48.3%	75	15.1%	0	0.0%	1	0.1%	498	2,777	245	52.6%	0	0.0%	1	0.3%	465	3,113	336
S_OP	$45	0	0.0%	0	0.0%	0	0.0%	0	0.0%	258	765	0	0.0%	0	0.0%	0	0.0%	258	765	0
W_SP	$85	230	33.5%	199	29.0%	0	0.0%	0	0.0%	687	2,048	271	37.3%	17	2.4%	22	3.1%	726	1,711	-337
W_P	$60	425	48.2%	145	16.4%	0	0.0%	3	0.4%	882	2,665	454	49.3%	0	0.0%	26	2.8%	921	2,587	-78
W_OP	$40	134	22.7%	0	0.0%	0	0.0%	0	0.0%	591	842	134	22.7%	0	0.0%	0	0.0%	591	842	0
SH_SP	$80	367	38.9%	214	22.6%	0	0.0%	33	3.5%	944	2,114	418	44.3%	0	0.0%	50	5.3%	944	2,250	137
SH_P	$55	165	22.2%	22	2.9%	0	0.0%	3	0.4%	742	909	165	22.2%	0	0.0%	3	0.4%	742	909	0
SH_OP	$35	92	13.8%	0	0.0%	0	0.0%	0	0.0%	670	638	92	13.8%	0	0.0%	0	0.0%	670	638	0
Economic Capacity, GRDA																				
S_SP1	$250	1,293	83.4%	11	0.7%	29	1.9%	3	0.2%	1,551	6,983	1,294	85.3%	26	1.7%	3	0.2%	1,518	7,294	311
S_SP2	$120	1,271	83.2%	11	0.7%	29	1.9%	3	0.2%	1,528	6,942	1,272	85.1%	26	1.8%	3	0.2%	1,495	7,257	314
S_P	$75	1,171	82.0%	17	1.2%	23	1.6%	3	0.2%	1,428	6,745	1,172	84.0%	21	1.5%	3	0.2%	1,395	7,078	334
S_OP	$45	774	75.0%	0	0.0%	20	1.9%	2	0.2%	1,031	5,689	774	75.0%	20	1.9%	2	0.2%	1,031	5,689	0
W_SP	$85	1,148	71.5%	38	2.4%	102	6.3%	11	0.7%	1,605	5,200	1,154	70.2%	124	7.5%	16	1.0%	1,644	5,027	-173
W_P	$60	1,073	70.2%	38	2.5%	104	6.8%	14	0.9%	1,530	5,006	1,079	68.8%	130	8.3%	20	1.3%	1,569	4,833	-173
W_OP	$40	693	60.3%	0	0.0%	27	2.4%	3	0.3%	1,150	3,779	693	60.3%	27	2.4%	3	0.3%	1,150	3,779	0
SH_SP	$80	1,128	66.1%	39	2.3%	120	7.0%	22	1.3%	1,705	4,482	1,136	66.6%	127	7.4%	23	1.4%	1,705	4,544	62
SH_P	$55	819	58.6%	10	0.7%	150	10.8%	21	1.5%	1,396	3,631	819	58.6%	150	10.8%	21	1.5%	1,396	3,631	0
SH_OP	$35	669	53.7%	0	0.0%	42	3.4%	5	0.4%	1,246	3,072	669	53.7%	42	3.4%	5	0.4%	1,246	3,072	0

Transmission values for OG&E based on FCITC.

First-Tier Balancing Authority Areas

			Pre-Transaction										Post-Transaction								
			GRDA		Kelson		OKGE		OMPA				GRDA		OKGE		OMPA				
Market	Period	Price	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	HHI Chg.
Available Economic Capacity																					
AECI	S_SP1	$250	39	0.9%	702	16.0%	68	1.6%	0	0.0%	4,387	696	159	3.6%	198	4.5%	23	0.5%	4,387	573	-123
AECI	S_SP2	$120	44	1.1%	837	21.0%	198	5.0%	0	0.0%	3,992	735	161	4.0%	418	10.5%	40	1.0%	3,992	530	-206
AECI	S_P	$75	99	2.0%	857	17.0%	0	0.0%	17	0.3%	5,043	1,220	164	3.2%	0	0.0%	66	1.3%	5,043	1,095	-125
AECI	S_OP	$45	0	0.0%	0	0.0%	0	0.0%	0	0.0%	4,098	810	0	0.0%	0	0.0%	0	0.0%	4,098	810	0
AECI	W_SP	$85	91	1.5%	1,682	27.5%	0	0.0%	0	0.0%	6,119	1,334	163	2.7%	153	2.5%	64	1.1%	6,119	850	-484
AECI	W_P	$60	54	0.8%	1,086	16.4%	0	0.0%	21	0.3%	6,627	1,199	94	1.4%	0	0.0%	68	1.0%	6,546	1,081	-118
AECI	W_OP	$40	80	1.5%	0	0.0%	0	0.0%	0	0.0%	5,516	624	80	1.5%	0	0.0%	0	0.0%	5,516	624	0
AECI	SH_SP	$80	39	1.2%	688	21.6%	0	0.0%	68	2.1%	3,181	1,251	56	1.8%	0	0.0%	130	4.1%	3,181	1,074	-177
AECI	SH_P	$55	3	0.1%	51	1.6%	0	0.0%	4	0.1%	3,141	947	3	0.1%	0	0.0%	4	0.1%	3,141	947	0
AECI	SH_OP	$35	33	1.2%	0	0.0%	0	0.0%	0	0.0%	2,713	645	33	1.2%	0	0.0%	0	0.0%	2,713	645	0
AEP West	S_SP1	$250	2	0.0%	1,279	27.1%	21	0.5%	0	0.0%	4,712	2,642	9	0.2%	67	1.4%	8	0.2%	4,712	2,563	-80
AEP West	S_SP2	$120	2	0.0%	1,282	25.3%	37	0.7%	0	0.0%	5,063	2,375	9	0.2%	84	1.7%	8	0.2%	5,063	2,313	-62
AEP West	S_P	$75	7	0.1%	1,246	22.2%	0	0.0%	5	0.1%	5,607	2,210	17	0.3%	0	0.0%	19	0.4%	5,607	2,166	-44
AEP West	S_OP	$45	0	0.0%	0	0.0%	0	0.0%	0	0.0%	589	633	0	0.0%	0	0.0%	0	0.0%	589	633	0
AEP West	W_SP	$85	7	0.1%	1,180	22.2%	0	0.0%	0	0.0%	5,310	2,153	12	0.2%	15	0.3%	8	0.2%	5,310	2,117	-36
AEP West	W_P	$60	9	0.2%	1,045	23.5%	0	0.0%	2	0.0%	4,439	2,570	14	0.3%	0	0.0%	14	0.3%	4,439	2,520	-50
AEP West	W_OP	$40	4	0.7%	0	0.0%	0	0.0%	0	0.0%	651	539	4	0.7%	0	0.0%	0	0.0%	651	539	0
AEP West	SH_SP	$80	15	0.3%	1,208	20.6%	0	0.0%	25	0.4%	5,865	1,946	24	0.4%	0	0.0%	41	0.7%	5,865	1,905	-40
AEP West	SH_P	$55	1	0.0%	906	20.4%	0	0.0%	2	0.0%	4,447	2,107	1	0.0%	0	0.0%	2	0.0%	4,447	2,107	0
AEP West	SH_OP	$35	7	0.7%	0	0.0%	0	0.0%	0	0.0%	1,025	579	7	0.7%	0	0.0%	0	0.0%	1,025	579	0
EDE	S_SP1	$250	1	0.3%	46	17.9%	5	2.2%	0	0.0%	254	2,019	3	1.4%	17	6.6%	2	0.8%	254	1,853	-166
EDE	S_SP2	$120	1	0.4%	47	23.7%	8	4.0%	0	0.0%	200	1,280	3	1.7%	19	9.8%	2	1.1%	200	1,008	-272
EDE	S_P	$75	3	1.9%	50	32.6%	0	0.0%	1	0.9%	153	1,400	6	4.1%	0	0.0%	5	3.1%	153	854	-545
EDE	S_OP	$45	0	0.0%	0	0.0%	0	0.0%	0	0.0%	153	840	0	0.0%	0	0.0%	0	0.0%	153	840	0
EDE	W_SP	$85	5	1.5%	124	33.8%	0	0.0%	0	0.0%	366	1,343	12	3.2%	0	0.0%	12	3.2%	366	669	-675
EDE	W_P	$60	6	1.7%	55	15.0%	0	0.0%	1	0.3%	366	581	10	2.6%	0	0.0%	9	2.3%	366	464	-118
EDE	W_OP	$40	4	1.2%	0	0.0%	0	0.0%	0	0.0%	366	613	4	1.2%	0	0.0%	0	0.0%	366	613	0
EDE	SH_SP	$80	11	2.3%	141	28.9%	0	0.0%	16	3.2%	487	1,083	17	3.4%	0	0.0%	25	5.1%	487	737	-346
EDE	SH_P	$55	1	0.1%	19	3.8%	0	0.0%	0	0.0%	487	628	1	0.1%	0	0.0%	0	0.0%	487	628	0
EDE	SH_OP	$35	7	1.4%	0	0.0%	0	0.0%	0	0.0%	487	597	7	1.4%	0	0.0%	0	0.0%	487	597	0

First-Tier Balancing Authority Areas

			Pre-Transaction										Post-Transaction								
			GRDA		Kelson		OKGE		OMPA				GRDA		OKGE		OMPA				
Market	Period	Price	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	HHI Chg.
Available Economic Capacity																					
Entergy	S_SP1	$250	26	0.1%	2,680	13.6%	41	0.2%	0	0.0%	19,694	963	149	0.8%	110	0.6%	13	0.1%	19,694	941	-22
Entergy	S_SP2	$120	30	0.2%	2,716	14.1%	59	0.3%	0	0.0%	19,318	919	154	0.8%	127	0.7%	14	0.1%	19,318	896	-23
Entergy	S_P	$75	120	0.9%	2,834	20.4%	0	0.0%	8	0.1%	13,874	857	202	1.5%	0	0.0%	30	0.2%	13,874	826	-32
Entergy	S_OP	$45	0	0.0%	0	0.0%	0	0.0%	0	0.0%	4,974	668	0	0.0%	0	0.0%	0	0.0%	4,974	668	0
Entergy	W_SP	$85	114	0.8%	2,884	19.7%	0	0.0%	0	0.0%	14,639	780	196	1.3%	0	0.0%	28	0.2%	14,639	744	-36
Entergy	W_P	$60	123	0.9%	2,051	15.1%	0	0.0%	5	0.0%	13,561	635	216	1.6%	0	0.0%	31	0.2%	13,546	610	-25
Entergy	W_OP	$40	59	1.1%	0	0.0%	0	0.0%	0	0.0%	5,653	553	59	1.1%	0	0.0%	0	0.0%	5,653	553	0
Entergy	SH_SP	$80	150	1.1%	2,555	19.2%	0	0.0%	19	0.1%	13,314	761	183	1.4%	0	0.0%	29	0.2%	13,314	747	-14
Entergy	SH_P	$55	8	0.1%	932	8.0%	0	0.0%	0	0.0%	11,701	557	8	0.1%	0	0.0%	0	0.0%	11,701	557	0
Entergy	SH_OP	$35	75	1.4%	0	0.0%	0	0.0%	0	0.0%	5,380	623	75	1.4%	0	0.0%	0	0.0%	5,380	623	0
SPA	S_SP1	$250	0	0.2%	40	30.7%	3	2.3%	0	0.0%	129	1,312	1	1.1%	9	6.9%	1	0.8%	129	956	-356
SPA	S_SP2	$120	0	0.2%	42	32.8%	5	4.2%	0	0.0%	129	1,427	1	1.1%	12	9.2%	1	0.9%	129	1,067	-360
SPA	S_P	$75	1	0.9%	46	35.6%	0	0.0%	1	0.5%	129	1,692	2	1.6%	0	0.0%	2	1.8%	129	1,336	-356
SPA	S_OP	$45	0	0.0%	0	0.0%	0	0.0%	0	0.0%	129	631	0	0.0%	0	0.0%	0	0.0%	129	631	0
SPA	W_SP	$85	4	0.5%	311	32.0%	0	0.0%	0	0.0%	971	1,334	8	0.9%	27	2.8%	20	2.1%	971	877	-458
SPA	W_P	$60	11	1.2%	162	17.9%	0	0.0%	3	0.3%	908	595	19	2.1%	0	0.0%	25	2.7%	908	408	-187
SPA	W_OP	$40	12	1.3%	0	0.0%	0	0.0%	0	0.0%	863	454	12	1.3%	0	0.0%	0	0.0%	863	454	0
SPA	SH_SP	$80	6	0.6%	270	27.0%	0	0.0%	8	0.8%	999	1,016	8	0.8%	0	0.0%	12	1.2%	999	932	-84
SPA	SH_P	$55	1	0.2%	41	4.4%	0	0.0%	1	0.1%	930	543	1	0.2%	0	0.0%	1	0.1%	930	543	0
SPA	SH_OP	$35	3	0.3%	0	0.0%	0	0.0%	0	0.0%	930	585	3	0.3%	0	0.0%	0	0.0%	930	585	0
WFEC	S_SP1	$250	3	1.2%	76	26.3%	4	1.3%	0	0.0%	288	1,283	17	6.0%	10	3.5%	1	0.4%	288	1,056	-228
WFEC	S_SP2	$120	4	1.4%	82	28.6%	7	2.4%	0	0.0%	288	1,359	17	6.1%	13	4.6%	1	0.4%	288	1,113	-246
WFEC	S_P	$75	14	5.0%	76	26.5%	0	0.0%	1	0.3%	288	1,387	25	8.7%	0	0.0%	3	0.9%	288	1,217	-170
WFEC	S_OP	$45	0	0.0%	0	0.0%	0	0.0%	0	0.0%	288	741	0	0.0%	0	0.0%	0	0.0%	288	741	0
WFEC	W_SP	$85	18	2.3%	238	30.4%	0	0.0%	0	0.0%	782	1,277	33	4.2%	25	3.2%	11	1.5%	782	858	-419
WFEC	W_P	$60	16	2.0%	155	19.8%	0	0.0%	2	0.3%	782	693	25	3.2%	0	0.0%	13	1.6%	782	498	-195
WFEC	W_OP	$40	11	1.4%	0	0.0%	0	0.0%	0	0.0%	782	545	11	1.4%	0	0.0%	0	0.0%	782	545	0
WFEC	SH_SP	$80	19	2.9%	181	28.2%	0	0.0%	14	2.2%	643	1,164	27	4.2%	0	0.0%	20	3.2%	643	930	-233
WFEC	SH_P	$55	1	0.1%	39	6.0%	0	0.0%	2	0.2%	643	567	1	0.1%	0	0.0%	2	0.2%	643	567	0
WFEC	SH_OP	$35	5	0.8%	0	0.0%	0	0.0%	0	0.0%	643	696	5	0.8%	0	0.0%	0	0.0%	643	696	0

First-Tier Balancing Authority Areas

			Pre-Transaction										Post-Transaction								
			GRDA		Kelson		OKGE		OMPA				GRDA		OKGE		OMPA				
Market	Period	Price	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	HHI Chg.
Available Economic Capacity																					
WR	S_SP1	$250	15	0 9%	285	16.6%	13	0.8%	0	0 0%	1,716	745	83	4.9%	35	2 1%	4	0.2%	1,716	660	-84
WR	S_SP2	$120	17	1.2%	278	19.2%	24	1.7%	0	0.0%	1,445	722	85	5.9%	45	3 1%	4	0 3%	1,445	614	-108
WR	S_P	$75	66	4.6%	280	19 4%	0	0 0%	3	0.2%	1,445	783	120	8.3%	0	0.0%	9	0 7%	1,445	700	-83
WR	S_OP	$45	0	0.0%	0	0.0%	0	0.0%	0	0.0%	1,445	719	0	0.0%	0	0 0%	0	0.0%	1,445	719	0
WR	W SP	$85	15	3.2%	97	20.6%	0	0.0%	0	0.0%	472	686	27	5 8%	7	1.5%	6	1 3%	472	484	-203
WR	W_P	$60	18	3.8%	52	11.0%	0	0.0%	1	0.2%	472	491	33	6.9%	0	0.0%	5	1.1%	472	448	-43
WR	W OP	$40	12	1.8%	0	0.0%	0	0.0%	0	0.0%	668	1,121	12	1.8%	0	0.0%	0	0.0%	668	1,121	0
WR	SH_SP	$80	119	5 6%	367	17.2%	0	0.0%	29	1.3%	2,133	600	168	7.9%	0	0.0%	46	2.2%	2,133	520	-80
WR	SH_P	$55	10	0.5%	69	3.5%	0	0.0%	4	0.2%	1,989	528	10	0.5%	0	0 0%	4	0 2%	1,989	528	0
WR	SH_OP	$35	51	2.6%	0	0.0%	0	0 0%	0	0.0%	1,989	646	51	2.6%	0	0 0%	0	0 0%	1,989	646	0

First-Tier Balancing Authority Areas

			Pre-Transaction										Post-Transaction								
			GRDA		Kelson		OKGE		OMPA				GRDA		OKGE		OMPA				
Market	Period	Price	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	HHI Chg.
Economic Capacity																					
AECI	S_SP1	$250	200	2.3%	133	1.6%	331	3.9%	34	0.4%	8,589	3,135	212	2.5%	351	4 1%	38	0.4%	8,589	3,137	1
AECI	S_SP2	$120	199	2.4%	136	1.6%	332	4 0%	33	0.4%	8,382	3,056	211	2.5%	353	4.2%	37	0.5%	8,382	3,057	1
AECI	S_P	$75	203	2.5%	196	2.4%	263	3.2%	40	0 5%	8,171	2,921	218	2.7%	292	3 6%	46	0.6%	8,171	2,921	1
AECI	S_OP	$45	184	2.8%	0	0.0%	288	4.3%	31	0 5%	6,699	1,989	184	2.8%	288	4 3%	31	0.5%	6,699	1,989	0
AECI	W_SP	$85	166	1.8%	389	4.3%	609	6.8%	67	0.7%	9,026	2,197	181	2.0%	703	7.8%	88	1 0%	9,026	2,203	6
AECI	W_P	$60	119	1.3%	272	3.1%	554	6.2%	75	0.8%	8,885	2,118	131	1.5%	626	7.1%	95	1 1%	8,885	2,125	7
AECI	W_OP	$40	110	1 5%	0	0 0%	286	3.8%	33	0.4%	7,557	1,411	110	1.5%	286	3.8%	33	0.4%	7,557	1,411	0
AECI	SH_SP	$80	84	1.3%	166	2.6%	212	3 3%	38	0.6%	6,459	3,765	92	1.4%	233	3.6%	43	0.7%	6,459	3,765	0
AECI	SH_P	$55	69	1.3%	20	0.4%	279	5.0%	38	0.7%	5,562	3,078	69	1 3%	279	5.0%	38	0.7%	5,562	3,078	0
AECI	SH_OP	$35	56	1.1%	0	0.0%	105	2.1%	12	0 2%	5,087	2,652	56	1 1%	105	2.1%	12	0.2%	5,087	2,652	0
AEP West	S_SP1	$250	19	0.1%	1,125	7.7%	91	0.6%	9	0 1%	14,615	4,586	20	0 1%	98	0 7%	11	0 1%	14,615	4,586	-1
AEP West	S_SP2	$120	18	0.1%	1,126	7.7%	92	0.6%	9	0.1%	14,565	4,574	20	0 1%	98	0 7%	10	0.1%	14,565	4,574	-1
AEP West	S_P	$75	18	0.1%	1,075	8.3%	77	0.6%	12	0.1%	12,986	4,169	19	0 2%	86	0 7%	14	0.1%	12,986	4,167	-2
AEP West	S_OP	$45	14	0 3%	0	0.0%	69	1 4%	7	0.2%	4,769	6,872	14	0.3%	69	1.4%	7	0 2%	4,769	6,872	0
AEP West	W_SP	$85	16	0.1%	1,061	8.4%	79	0 6%	9	0.1%	12,640	4,097	17	0.1%	91	0.7%	11	0.1%	12,640	4,095	-2
AEP West	W_P	$60	13	0.1%	998	11.0%	69	0.8%	9	0.1%	9,058	2,795	14	0.2%	80	0.9%	12	0.1%	9,058	2,792	-3
AEP West	W_OP	$40	10	0.2%	0	0.0%	61	1.4%	7	0.2%	4,354	6,429	10	0.2%	61	1.4%	7	0 2%	4,354	6,429	0
AEP West	SH_SP	$80	25	0.2%	988	8.1%	118	1.0%	21	0.2%	12,159	3,910	27	0.2%	129	1.1%	24	0.2%	12,159	3,908	-2
AEP West	SH_P	$55	17	0.2%	898	10.1%	132	1.5%	18	0 2%	8,865	2,665	17	0.2%	132	1.5%	18	0.2%	8,865	2,665	0
AEP West	SH_OP	$35	13	0.3%	0	0.0%	108	2.3%	13	0.3%	4,646	5,414	13	0.3%	108	2.3%	13	0.3%	4,646	5,414	0
EDE	S_SP1	$250	9	0.7%	5	0 4%	11	0.9%	1	0 1%	1,318	7,829	10	0 7%	12	0 9%	1	0.1%	1,318	7,829	0
EDE	S_SP2	$120	9	0.7%	6	0.5%	15	1.2%	2	0.1%	1,318	7,829	10	0 7%	16	1 2%	2	0.1%	1,318	7,829	0
EDE	S_P	$75	9	1.7%	9	1.7%	11	2 1%	2	0.3%	516	5,021	9	1.8%	12	2 3%	2	0.4%	516	5,021	0
EDE	S_OP	$45	7	1.3%	0	0.0%	18	3.5%	2	0.4%	516	5,030	7	1.3%	18	3 5%	2	0.4%	516	5,030	0
EDE	W_SP	$85	18	2.0%	24	2.6%	22	2 4%	4	0.4%	908	3,659	20	2.2%	27	2.9%	5	0 5%	908	3,659	0
EDE	W_P	$60	15	2.2%	15	2.2%	29	4.2%	4	0 6%	688	2,349	17	2.5%	33	4.8%	5	0 7%	688	2,352	2
EDE	W_OP	$40	14	2.0%	0	0.0%	47	6.8%	5	0.8%	688	2,386	14	2.0%	47	6.8%	5	0 8%	688	2,386	0
EDE	SH_SP	$80	21	2.3%	28	3.0%	31	3.3%	6	0 6%	935	2,466	23	2.5%	33	3.6%	6	0 7%	935	2,466	0
EDE	SH_P	$55	16	2.0%	8	1.0%	46	5.7%	5	0.7%	801	1,783	16	2 0%	46	5.7%	5	0.7%	801	1,783	0
EDE	SH_OP	$35	13	1.7%	0	0.0%	45	5.6%	5	0 7%	801	1,788	13	1 7%	45	5.6%	5	0.7%	801	1,788	0

First-Tier Balancing Authority Areas

			Pre-Transaction										Post-Transaction								
			GRDA		Kelson		OKGE		OMPA				GRDA		OKGE		OMPA				
Market	Period	Price	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	HHI Chg.
Economic Capacity																					
Entergy	S_SP1	$250	69	0.2%	2,052	4.4%	340	0 7%	35	0 1%	46,373	2,967	71	0.2%	363	0.8%	39	0 1%	46,373	2,966	0
Entergy	S_SP2	$120	70	0.2%	2,054	4.5%	339	0.7%	34	0.1%	46,090	2,945	72	0 2%	362	0.8%	39	0 1%	46,090	2,945	0
Entergy	S_P	$75	86	0 3%	2,146	7.5%	271	1.0%	41	0.1%	28,615	1,615	89	0.3%	302	1 1%	48	0.2%	28,615	1,613	-2
Entergy	S_OP	$45	103	0.7%	0	0.0%	186	1.2%	20	0.1%	15,653	2,494	103	0 7%	186	1.2%	20	0 1%	15,653	2,494	0
Entergy	W SP	$85	71	0.2%	2,107	6.0%	286	0.8%	38	0.1%	35,208	2,325	75	0.2%	338	1.0%	51	0 1%	35,208	2,323	-2
Entergy	W_P	$60	83	0.3%	1,592	6.2%	260	1 0%	35	0.1%	25,711	1,540	88	0.3%	305	1.2%	46	0 2%	25,711	1,538	-2
Entergy	W_OP	$40	105	0.7%	0	0.0%	236	1 6%	27	0.2%	15,047	2,221	105	0.7%	236	1.6%	27	0 2%	15,047	2,221	0
Entergy	SH_SP	$80	60	0 2%	1,913	6 8%	145	0.5%	26	0.1%	28,131	1,749	63	0.2%	159	0 6%	29	0.1%	28,131	1,748	-1
Entergy	SH_P	$55	86	0.4%	626	2.8%	326	1.5%	38	0.2%	22,183	1,444	86	0 4%	326	1.5%	38	0.2%	22,183	1,444	0
Entergy	SH_OP	$35	103	0.7%	0	0.0%	122	0.8%	14	0 1%	14,579	2,229	103	0.7%	122	0.8%	14	0 1%	14,579	2,229	0
SPA	S_SP1	$250	4	0.3%	6	0.6%	19	1.8%	2	0.2%	1,092	5,027	4	0.4%	21	1.9%	2	0.2%	1,092	5,027	0
SPA	S_SP2	$120	4	0.3%	6	0.6%	20	1 8%	2	0.2%	1,089	5,048	4	0.4%	21	1 9%	2	0 2%	1,089	5,048	0
SPA	S_P	$75	3	0.4%	10	1.1%	16	1.8%	2	0.3%	911	4,416	4	0 4%	18	2 0%	3	0.3%	911	4,416	0
SPA	S_OP	$45	3	0.4%	0	0.0%	12	1.5%	1	0.2%	795	3,944	3	0.4%	12	1 5%	1	0.2%	795	3,944	0
SPA	W_SP	$85	15	0.9%	71	4.1%	101	5.8%	11	0.6%	1,750	1,904	17	1.0%	117	6 7%	15	0 8%	1,750	1,907	3
SPA	W_P	$60	17	1.1%	50	3.2%	100	6.5%	14	0.9%	1,543	1,385	18	1.2%	118	7.7%	18	1.2%	1,543	1,395	10
SPA	W_OP	$40	13	0.9%	0	0.0%	47	3 3%	5	0.4%	1,438	1,192	13	0.9%	47	3.3%	5	0.4%	1,438	1,192	0
SPA	SH_SP	$80	13	0.8%	70	4.1%	66	3.9%	12	0.7%	1,706	1,518	15	0.9%	72	4.3%	13	0 8%	1,706	1,517	-1
SPA	SH_P	$55	9	0 6%	17	1.3%	131	9.4%	18	1.3%	1,389	895	9	0 6%	131	9.4%	18	1.3%	1,389	895	0
SPA	SH_OP	$35	13	0.9%	0	0.0%	58	4.1%	7	0.5%	1,394	915	13	0.9%	58	4.1%	7	0 5%	1,394	915	0
WFEC	S_SP1	$250	45	3.1%	16	1.1%	46	3.2%	5	0.3%	1,451	6,490	49	3.4%	49	3 4%	5	0.4%	1,451	6,492	2
WFEC	S_SP2	$120	45	3.2%	16	1 1%	46	3.3%	5	0.3%	1,412	6,404	49	3.5%	49	3.5%	5	0.4%	1,412	6,406	2
WFEC	S_P	$75	43	3 6%	23	1.9%	36	3 0%	5	0.5%	1,205	5,859	47	3.9%	39	3 3%	6	0.5%	1,205	5,861	2
WFEC	S_OP	$45	34	4.7%	0	0.0%	36	5.0%	4	0.5%	730	3,901	34	4.7%	36	5.0%	4	0 5%	730	3,901	0
WFEC	W_SP	$85	63	3.5%	70	4.0%	179	10.1%	20	1.1%	1,772	3,361	70	3.9%	204	11.5%	26	1.5%	1,772	3,383	22
WFEC	W_P	$60	51	4.4%	69	5.9%	140	11.9%	19	1.6%	1,177	1,528	57	4.8%	164	13.9%	25	2.1%	1,177	1,558	31
WFEC	W_OP	$40	45	3.8%	0	0 0%	144	12.2%	17	1 4%	1,177	1,611	45	3 8%	144	12.2%	17	1 4%	1,177	1,611	0
WFEC	SH_SP	$80	45	2 9%	49	3.1%	138	8.9%	25	1.6%	1,560	3,656	50	3 2%	150	9 7%	28	1.8%	1,560	3,667	11
WFEC	SH_P	$55	31	3.0%	21	2.0%	142	13.8%	19	1.9%	1,029	1,852	31	3.0%	142	13 8%	19	1.9%	1,029	1,852	0
WFEC	SH_OP	$35	31	3.0%	0	0.0%	136	13.2%	16	1.5%	1,029	1,876	31	3.0%	136	13 2%	16	1.5%	1,029	1,876	0

First-Tier Balancing Authority Areas

			Pre-Transaction										Post-Transaction								
			GRDA		Kelson		OKGE		OMPA				GRDA		OKGE		OMPA				
Market	Period	Price	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	HHI Chg.
Economic Capacity																					
WR	S_SP1	$250	28	0.3%	64	0.8%	105	1.3%	11	0.1%	8,295	4,943	29	0.4%	112	1.4%	12	0.2%	8,295	4,943	0
WR	S_SP2	$120	28	0.4%	65	0.8%	106	1.3%	11	0.1%	7,994	5,220	29	0.4%	113	1.4%	12	0.2%	7,994	5,220	0
WR	S_P	$75	37	0.6%	86	1.5%	88	1.5%	13	0.2%	5,763	5,278	39	0.7%	98	1.7%	15	0.3%	5,763	5,278	0
WR	S_OP	$45	41	0.8%	0	0.0%	70	1.4%	8	0.2%	4,930	4,829	41	0.8%	70	1.4%	8	0.2%	4,930	4,829	0
WR	W_SP	$85	9	0.2%	26	0.6%	37	0.8%	4	0.1%	4,837	7,035	10	0.2%	43	0.9%	5	0.1%	4,837	7,035	0
WR	W_P	$60	11	0.3%	20	0.6%	35	1.0%	5	0.1%	3,525	7,139	11	0.3%	41	1.2%	6	0.2%	3,525	7,139	0
WR	W_OP	$40	10	0.3%	0	0.0%	15	0.4%	2	0.1%	3,525	7,140	10	0.3%	15	0.4%	2	0.1%	3,525	7,140	0
WR	SH_SP	$80	38	0.6%	103	1.7%	132	2.2%	24	0.4%	6,114	4,048	41	0.7%	145	2.4%	27	0.4%	6,114	4,048	0
WR	SH_P	$55	41	0.8%	25	0.5%	166	3.4%	23	0.5%	4,957	3,487	41	0.8%	166	3.4%	23	0.5%	4,957	3,487	0
WR	SH_OP	$35	46	0.9%	0	0.0%	74	1.5%	9	0.2%	4,957	3,491	46	0.9%	74	1.5%	9	0.2%	4,957	3,491	0

SIL into each market based on OG&E's transmission analysis for pre-Transaction scenario.

Exhibit J-11

OG&E and GRDA Balancing Authority Markets
Base Case, with Transmission Upgrades (Mitigation)

		Pre-Transaction										Post-Mitigation								
		GRDA		Kelson		OKGE		OMPA				GRDA		OKGE		OMPA				
Period	Price	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	HHI Chg.
Available Economic Capacity, OG&E																				
S_SP1	$250	1	0.1%	605	64.9%	158	16.9%	0	0.0%	933	4,560	14	1.1%	422	33.9%	50	4.0%	1,245	1,558	-3,002
S_SP2	$120	1	0.1%	606	56.0%	306	28.3%	0	0.0%	1,081	3,985	14	1.0%	570	40.8%	54	3.9%	1,398	1,982	-2,003
S_P	$75	2	0.3%	604	76.3%	0	0.0%	80	10.1%	792	5,948	20	2.3%	0	0.0%	144	16.8%	854	1,112	-4,836
S_OP	$45	0	0.0%	0	0.0%	0	0.0%	0	0.0%	137	869	0	0.0%	0	0.0%	0	0.0%	137	869	0
W_SP	$85	8	0.4%	1,098	47.1%	501	21.5%	0	0.0%	2,332	2,749	20	0.8%	1,037	42.9%	128	5.3%	2,420	2,102	-647
W_P	$60	8	0.5%	798	47.8%	0	0.0%	68	4.1%	1,667	2,425	16	1.1%	0	0.0%	175	12.2%	1,430	595	-1,830
W_OP	$40	6	0.7%	0	0.0%	0	0.0%	0	0.0%	930	594	6	0.7%	0	0.0%	0	0.0%	930	594	0
SH_SP	$80	4	0.2%	567	26.5%	960	44.8%	149	7.0%	2,142	2,793	11	0.5%	1,155	46.6%	195	7.9%	2,476	2,421	-371
SH_P	$55	0	0.0%	276	30.1%	0	0.0%	97	10.6%	917	1,228	1	0.1%	0	0.0%	115	9.3%	1,242	561	-668
SH_OP	$35	1	0.2%	0	0.0%	0	0.0%	0	0.0%	594	618	1	0.2%	0	0.0%	0	0.0%	594	618	0
Available Economic Capacity, GRDA																				
S_SP1	$250	50	16.4%	68	22.1%	2	0.8%	0	0.0%	308	1,272	299	21.2%	29	2.1%	3	0.2%	1,407	1,215	-57
S_SP2	$120	57	18.2%	70	22.3%	4	1.4%	0	0.0%	315	1,308	306	21.6%	38	2.7%	4	0.3%	1,414	1,273	-36
S_P	$75	241	48.3%	75	15.1%	0	0.0%	1	0.1%	498	2,777	489	30.6%	0	0.0%	8	0.5%	1,597	1,674	-1,103
S_OP	$45	0	0.0%	0	0.0%	0	0.0%	0	0.0%	258	765	0	0.0%	0	0.0%	0	0.0%	258	765	0
W_SP	$85	230	33.5%	199	29.0%	0	0.0%	0	0.0%	687	2,048	459	33.2%	38	2.7%	47	3.4%	1,381	1,466	-582
W_P	$60	425	48.2%	145	16.4%	0	0.0%	3	0.4%	882	2,665	570	38.2%	0	0.0%	54	3.6%	1,492	1,677	-988
W_OP	$40	134	22.7%	0	0.0%	0	0.0%	0	0.0%	591	842	134	22.7%	0	0.0%	0	0.0%	591	842	0
SH_SP	$80	367	38.9%	214	22.6%	0	0.0%	33	3.5%	944	2,114	566	34.4%	0	0.0%	108	6.6%	1,644	1,582	-532
SH_P	$55	165	22.2%	22	2.9%	0	0.0%	3	0.4%	742	909	287	21.0%	0	0.0%	5	0.4%	1,364	871	-38
SH_OP	$35	92	13.8%	0	0.0%	0	0.0%	0	0.0%	670	638	92	13.8%	0	0.0%	0	0.0%	670	638	0

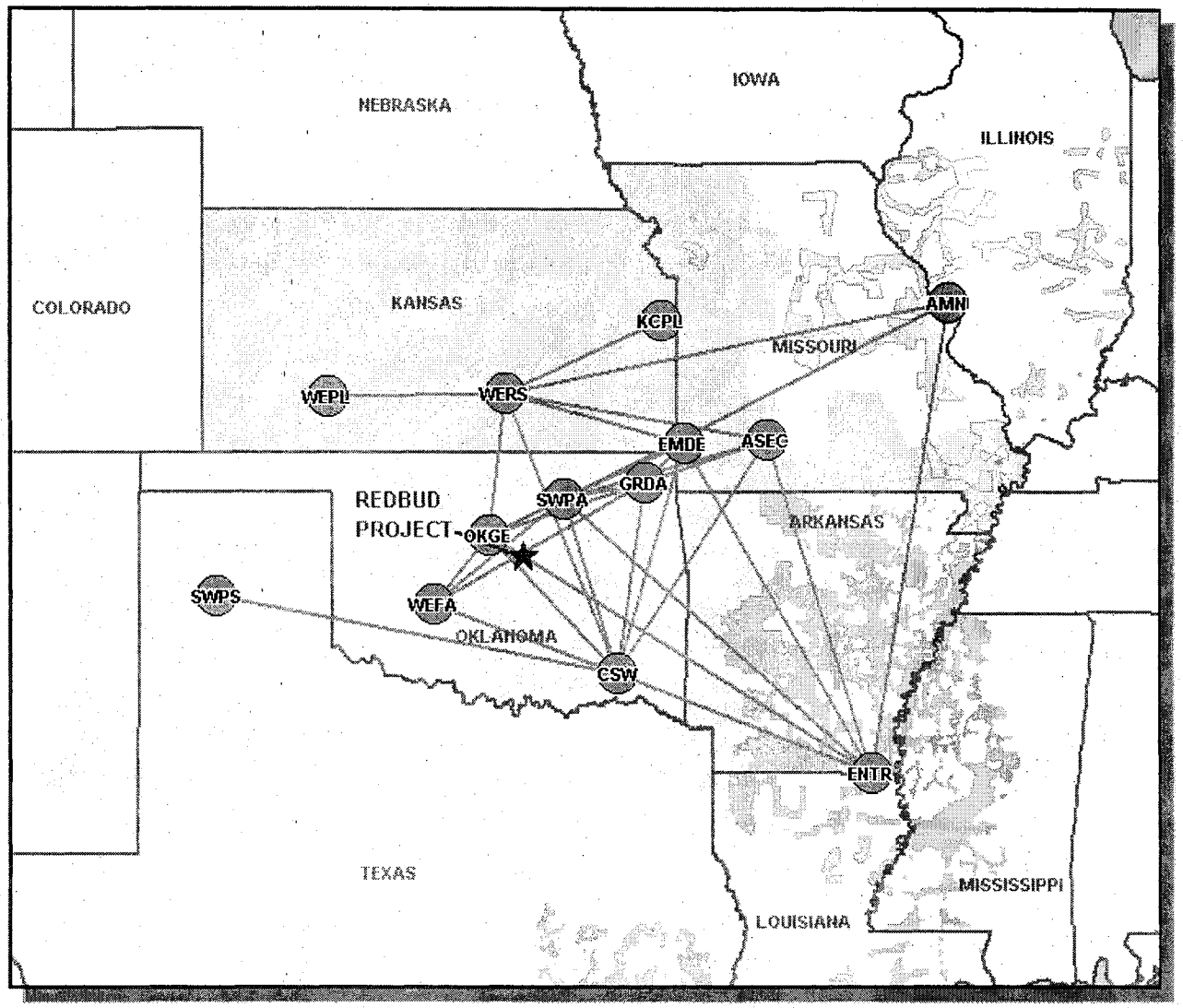
OG&E and GRDA Balancing Authority Markets
Base Case, with Transmission Upgrades (Mitigation)

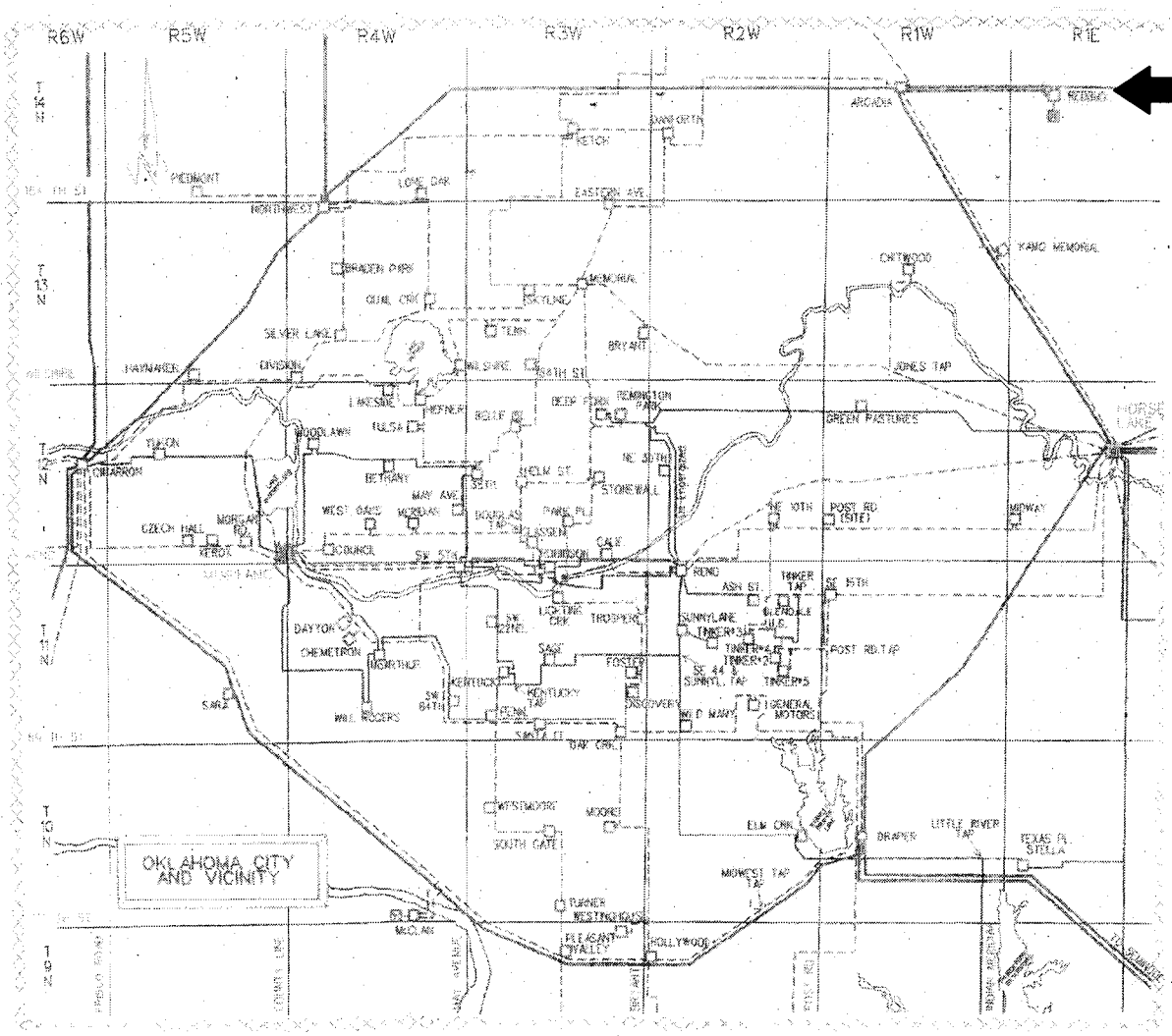
		Pre-Transaction										Post-Mitigation								
		GRDA		Kelson		OKGE		OMPA				GRDA		OKGE		OMPA				
Period	Price	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	MW	Mkt Share	MW	Mkt Share	MW	Mkt Share	Mkt Size	HHI	HHI Chg.
Economic Capacity, OG&E																				
S_SP1	$250	6	0.1%	580	7.4%	6,344	80.9%	649	8.3%	7,842	6,669	35	0.4%	6,608	80.9%	713	8.7%	8,168	6,630	-39
S_SP2	$120	6	0.1%	580	7.4%	6,344	81.0%	638	8.2%	7,830	6,686	35	0.4%	6,608	81.0%	702	8.6%	8,157	6,646	-40
S_P	$75	6	0.1%	583	12.1%	3,485	72.0%	576	11.9%	4,839	5,477	34	0.7%	3,749	72.6%	640	12.4%	5,165	5,440	-37
S_OP	$45	5	0.2%	0	0.0%	2,737	84.5%	298	9.2%	3,238	7,237	5	0.2%	2,737	84.5%	298	9.2%	3,238	7,237	0
W_SP	$85	25	0.3%	955	12.8%	5,070	68.1%	481	6.5%	7,447	4,855	37	0.5%	5,605	74.3%	617	8.2%	7,543	5,613	759
W_P	$60	20	0.4%	716	14.9%	2,731	56.8%	414	8.6%	4,804	3,554	30	0.6%	3,148	63.2%	521	10.5%	4,984	4,144	591
W_OP	$40	21	0.6%	0	0.0%	2,422	65.6%	279	7.5%	3,691	4,423	21	0.6%	2,422	65.6%	279	7.5%	3,691	4,423	0
SH_SP	$80	7	0.1%	475	7.4%	4,748	74.2%	555	8.7%	6,397	5,648	15	0.2%	4,942	73.4%	601	8.9%	6,731	5,497	-151
SH_P	$55	7	0.2%	247	5.8%	2,971	69.2%	446	10.4%	4,295	4,944	14	0.3%	3,056	65.0%	464	9.9%	4,705	4,366	-578
SH_OP	$35	6	0.2%	0	0.0%	2,371	71.8%	277	8.4%	3,300	5,265	6	0.2%	2,371	71.8%	277	8.4%	3,300	5,265	0
Economic Capacity, GRDA																				
S_SP1	$250	1,293	83.4%	11	0.7%	29	1.9%	3	0.2%	1,551	6,983	1,542	58.2%	133	5.0%	14	0.5%	2,650	3,565	-3,418
S_SP2	$120	1,271	83.2%	11	0.7%	29	1.9%	3	0.2%	1,528	6,942	1,519	57.8%	134	5.1%	14	0.5%	2,627	3,527	-3,416
S_P	$75	1,171	82.0%	17	1.2%	23	1.6%	3	0.2%	1,428	6,745	1,419	56.1%	109	4.3%	17	0.7%	2,527	3,309	-3,436
S_OP	$45	774	75.0%	0	0.0%	20	1.9%	2	0.2%	1,031	5,689	774	75.0%	20	1.9%	2	0.2%	1,031	5,689	0
W_SP	$85	1,148	71.5%	38	2.4%	102	6.3%	11	0.7%	1,605	5,200	1,377	59.9%	238	10.4%	30	1.3%	2,299	3,769	-1,432
W_P	$60	1,073	70.2%	38	2.5%	104	6.8%	14	0.9%	1,530	5,006	1,218	56.9%	244	11.4%	37	1.7%	2,141	3,441	-1,565
W_OP	$40	693	60.3%	0	0.0%	27	2.4%	3	0.3%	1,150	3,779	693	60.3%	27	2.4%	3	0.3%	1,150	3,779	0
SH_SP	$80	1,128	66.1%	39	2.3%	120	7.0%	22	1.3%	1,705	4,482	1,327	55.2%	249	10.4%	46	1.9%	2,405	3,247	-1,235
SH_P	$55	819	58.6%	10	0.7%	150	10.8%	21	1.5%	1,396	3,631	941	46.6%	280	13.9%	38	1.9%	2,018	2,492	-1,139
SH_OP	$35	669	53.7%	0	0.0%	42	3.4%	5	0.4%	1,246	3,072	669	53.7%	42	3.4%	5	0.4%	1,246	3,072	0

Exhibit K

Maps

A maps of the relevant properties owned by the Applicants is attached below.





LEGEND

- OG&E 69KV TRANSMISSION LINES
- OG&E 138KV OR 161KV TRANSMISSION LINES
- OG&E 345KV OR 500KV TRANSMISSION LINES
- (2) FOREIGN OWNED TRANSMISSION LINES
- INTERCONNECTION
- OGE GENERATING STATION
- SWITCHING AND SUBSTATION (SHOWN IN CONCEALED AREAS ONLY)
- IPP GENERATING STATION
- WIND GENERATING STATION

Exhibit L

Other Regulatory Approvals

In addition to Commission approval of this Application, approvals or clearances from the following federal agencies are required for the Transaction:

1. Pre-approval by the OCC pursuant to Okla. Stat. tit. 17, § 286(C); Okla. Admin. Code § 165:35-38-5(a);

2. Approval from the Federal Communications Commission to transfer certain licenses associated with the Facility to OG&E; and

3. Clearance from the Department of Justice and the FTC under the Hart-Scott Rodino Antitrust Improvement Act. On March 7, 2008, the FTC granted early termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvement Act. Such notification indicates that neither the FTC nor the Department of Justice intend to investigate the transaction.

Exhibit M

Explanation Concerning Cross-Subsidy Concerns

The proposed Transaction raises no issues concerning cross-subsidization. Based on the discussions in Section III.D of the Application, information contained in Exhibit I, and on facts and circumstances known to Applicants or that are reasonably foreseeable as of the date of this Application, the proposed Transaction will not result in, at the time of the proposed Transaction or in the future, cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the benefit of an associate company.

(i) Disclosure of Existing Pledges or Encumbrances

OG&E does not currently have outstanding any debt or other security that is secured, in whole or in part, by a lien or other encumbrance of utility property. The only pledges or encumbrances that relate to OG&E's utility property are various incidental encumbrances incurred in the ordinary course of business, including, for example, mechanics' liens, liens for taxes, assessments or other governmental charges that are not delinquent, and various easements, building, zoning or similar restrictions. Also, as noted in Section III.D.2 of the Application, OG&E will not pledge or encumber any of its utility property as part of the Transaction. For these reasons, OG&E respectfully requests waiver of any requirement to specifically identify any existing pledges or encumbrances on grounds that they are not relevant or material to the Commission's evaluation of the proposed Transaction pursuant to FPA Section 203.

Further, Applicants respectfully request waiver of the requirement to provide this information for Redbud Energy. OG&E will acquire Redbud Energy and subsequently dissolve

it to complete the Transaction and, therefore, Redbud Energy's pledges and encumbrances, to the extent that any currently exist, will be terminated upon consummation of the Transaction.

(ii) Relevant Detailed Showings Concerning The Proposed Transaction

As discussed in detail in Section III.D of the Application, based on facts and circumstances known to the Applicants, or that are reasonably foreseeable, the Transaction will not result in, at the time of such Transaction or in the future:

(1) Any transfer of facilities between a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, and an associate company;

(2) The issuance of any securities by a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, for the benefit of an associate company;

(3) Any pledge or encumbrance of any assets of any traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, for the benefit of an associate company; or

(4) Any new affiliate contract between a non-utility associate company and a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, other than non-power goods and services agreements subject to review under sections 205 and 206 of the FPA.

ATTACHMENT 2

TESTIMONY OF JESSE B. LANGSTON

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Oklahoma Gas and Electric Company Redbud Energy, LP	))))	Docket No. EC08- ___ -000

PREPARED DIRECT TESTIMONY AND EXHIBITS
OF JESSE B. LANGSTON

I. INTRODUCTION.

Q. PLEASE STATE YOUR NAME, YOUR EMPLOYER, AND YOUR BUSINESS ADDRESS.

A. My name is Jesse B. Langston. I am employed by Oklahoma Gas and Electric Company ("OG&E" or the "Company") and my business address is 321 N. Harvey, P. O. Box 321, Oklahoma City, Oklahoma 73101.

Q. WHAT POSITION DO YOU HOLD WITH OG&E?

A. I hold the position of Vice President of Utility Commercial Operations. I have served in this capacity for over two years. Prior to assuming my current duties, I served as Director of Corporate Planning for OGE Energy Corporation for approximately four years where my primary duties were to lead the Company's corporate and business strategy development. My current responsibilities include the Company's resource planning efforts. The resource planning team assesses OG&E's power supply requirements and

evaluates the resources needed to meet these requirements at the lowest reasonable cost, with due consideration of risk factors.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I have been employed by OG&E since 1985. I have over 20 years of experience in the electric utility industry in various areas including corporate planning, business planning, engineering, transmission, distribution, metering, end-use forecasting, load forecasting, telecommunications, corporate marketing, demand-side management and generation planning. Over the past few years, I have led a number of significant initiatives within the Company including the acquisition of the McClain plant, a state-of-the-art 400 MW natural gas combined cycle plant, and the development of Centennial, a 120 MW wind farm.

I hold an MBA from Oklahoma City University (May 2002) and a Bachelor of Science degree in Electrical Engineering from Oklahoma State University (1985).

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION ("COMMISSION")?

A. No. This is the first time I have testified before the Commission.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony will address three topics. First, I will describe OG&E and the Company's need for new capacity to meet its growing load obligations. Second, I will address the process that lead up to the agreement for OG&E, the Grand River Dam Authority ("GRDA"), and the Oklahoma Municipal Power Authority ("OMPA") to acquire the

Redbud plant. Third, I will describe the significant customer benefits that flow from the proposed transaction.

II. BACKGROUND.

Q. PLEASE DESCRIBE OKLAHOMA GAS AND ELECTRIC COMPANY.

A. OG&E, an Oklahoma corporation, is an electric utility operating company and a wholly-owned subsidiary of OGE Energy Corp. OG&E serves more than 762,000 retail customers in Oklahoma and western Arkansas, and sells electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. OG&E is a member of the Southwest Power Pool, Inc. ("SPP").OG&E owns the transmission facilities within its service territory but the SPP has functional control of those facilities. Requests for new transmission service on OG&E's transmission facilities are made through and processed by SPP in accordance with SPP's Open Access Transmission Tariff.

Q. WHAT IS OG&E'S CURRENT LOAD?

A. OG&E's forecasted peak load for 2008 is 6,106 MW.

Q. WHAT RESOURCES DOES OG&E USE TO SERVE THIS LOAD?

A. OG&E meets its peak load (and provides for the required reserve margin) using a mix of generation resources owned or controlled by OG&E and by capacity and energy purchased under power supply agreements.

Q. PLEASE DESCRIBE OG&E'S MOST RECENT LOAD FORECAST.

A. OG&E updates its load forecast each September to support the annual budgeting process and ongoing resource planning efforts. The September 2007 load forecast, prepared by

Quantec, LLC and based on econometric statistical analyses for each class of service (e.g., residential, commercial, etc.), is presented in Exhibit OGE-2. As shown in Exhibit OGE-2, OG&E expects its retail energy demands to grow at an average annual rate of 2.0% over the 2007-2017 period. Peak demands are expected to grow at a slightly lower rate of 1.7 % over this same period. The forecasted growth in peak demands is consistent with OG&E's recently experienced growth of approximately 100 MW per year.

In addition to its retail load requirements, OG&E has wholesale contracts with nine entities for approximately 300 MW of load. OG&E anticipates continuing to serve wholesale customers and therefore has included these loads in its forecast for purposes of determining future capacity needs.

Q. DOES OG&E REQUIRE ADDITIONAL CAPACITY TO SERVE ITS EXPECTED LOAD OBLIGATIONS?

A. Yes. Exhibit OGE-3 presents OG&E's peak demand forecast, the supply and demand resources available to meet such peak demands, and the "gap" that must be met through new resources. The gap is defined as the capacity required to satisfy SPP's minimum 12% capacity margin requirement. In practice, OG&E will experience years where it exceeds the 12% requirement to ensure that OG&E remains above the requirement at all times. Doing so will require OG&E to build or acquire resources of significant size, and to respond to market opportunities.

As shown in Exhibit OGE-3, OG&E is able to meet its requirements in 2008 and 2009 as a result of the 300 MW PPA with Redbud Energy, LP. However, after expiration

of the Redbud PPA in 2009, OG&E's capacity needs are expected to be 424 MW in 2010, and to increase to 524 MW in 2011, to 604 MW in 2012 and to 731 MW in 2013.

Q. HOW DOES OG&E INTEND TO OBTAIN THE CAPACITY NEEDED TO SERVE THIS INCREASING LOAD?

A. In 2006, OG&E (together with OMPA and the Public Service Company of Oklahoma) proposed to construct the "Red Rock" facility, a 950 MW coal-fired generating station to be located near Red Rock, Oklahoma. OG&E had planned to commence construction of the Red Rock facility in 2007, and to have the plant in service in 2012. However, OG&E and its partners were unable to obtain necessary state regulatory pre-approvals and, in 2007, the Company terminated the project. As a result of this decision, OG&E re-focused its resource planning toward gas-fired generation, together with its continuing commitment to wind and demand side management.

III. THE PROPOSED TRANSACTION.

Q. PLEASE DESCRIBE THE TRANSACTION THAT IS THE SUBJECT OF THIS PROCEEDING.

A. On January 21, 2008, the Company, together with two partners, GRDA and OMPA, executed definitive agreements pursuant to which they will acquire the Redbud Facility from subsidiaries of Kelson Holdings LLC ("Kelson"). The Redbud Facility is a 1,230 MW, combined-cycle generating facility located near Luther, Oklahoma. Upon closing the transaction, OG&E will hold a 51% interest in the facility and GRDA and OMPA will own 36% and 13%, respectively.

Q. WHAT WAS YOUR ROLE IN THIS TRANSACTION?

A. I was responsible for the overall Redbud transaction and my involvement included participation in the bid, due diligence and negotiation phases of the process. The Resource Planning Department reports to me and I provided direction to that group during the process.

Q. PLEASE DESCRIBE THE REDBUD GENERATING FACILITY.

A. Redbud is a 1,230 MW (nominal rating) gas-fired combined-cycle plant located near Luther, Oklahoma. The plant uses four GE 7FA combustion turbines with a heat recovery system comprised of four additional steam turbines. These eight turbines are supplemented with four duct burners that boost the output of the plant to meet peak demand conditions. This configuration allows Redbud to serve base-load, mid-merit and peaking needs based on the dispatch needs of our portfolio.

Redbud is interconnected to OG&E's transmission system and relies on transmission services arranged by SPP. Redbud is also interconnected to ONEOK Partners, LP's interstate gas transmission system. Energy management services are currently provided by Westar Energy, Inc. and plant operations are performed by North American Energy Services Company. The plant has a Long-Term Parts and Service Agreement ("LTSA") with General Electric International, Inc.

Q. DOES OG&E HAVE ANY EXPERIENCE WITH THE REDBUD PLANT?

A. Yes. As noted above, Redbud is located within our operating control area and is interconnected with the OG&E transmission system. OG&E has purchased energy and capacity from Redbud since 2005, most recently under a PPA for 300 MW to meet

OG&E's 2008 and 2009 load requirements. This PPA was the result of an RFP conducted by OG&E in May of 2007.

Q. WHEN DID OG&E LEARN OF THE OPPORTUNITY TO ACQUIRE REDBUD?

A. In October 2007, OG&E was contacted by UBS Investment Bank ("UBS") who informed OG&E of an ongoing auction process to sell a package of Kelson assets that included Redbud. The process was being conducted by Goldman Sachs. OG&E subsequently executed a confidentiality agreement with Kelson and was provided with the offering memorandum and limited access to the transaction data room. Kelson's offering memorandum described a plan to sell four natural gas combined cycle plants as a package. However, OG&E expressed an interest in the Redbud facility on a stand-alone basis and Kelson agreed to consider a bid for Redbud separately from the rest of the portfolio.

Q. WHAT FACTORS CONTRIBUTED TO OG&E'S PRELIMINARY INTEREST IN AN ACQUISITION OF REDBUD?

A. Redbud's location within OG&E's control area, the age of the plant, and OG&E's reliance on Redbud for energy through the years were reasons enough to spark our interest in the sales process. OG&E's analysis indicated that we had a need for capacity in a time frame that could be met by an acquisition of Redbud. OG&E had been counting on its proposed Red Rock plant to meet this need, but following the Oklahoma Corporation Commission order denying pre-approval to construct Red Rock, OG&E began a new resource planning cycle to determine how it would meet its growing resource requirements.

OG&E has concluded that natural gas-fired capacity, whether obtained through a PPA, construction of a generating plant, or the acquisition of an existing facility, is the only viable mid-term resource option after taking into account our progressive commitment to wind energy. Redbud can serve a range of needs throughout the year including baseload, peaking and mid-merit requirements. Redbud will complement our prospective investments in wind energy by providing assurance that capacity needs will be met. The Redbud plant represents "iron-in-the-ground" capacity that is not subject to development and construction cost risks and with interconnections to natural gas and electric transmission facilities that can be costly for new plants depending on their location.

Finally, an acquisition of the Redbud plant limits OG&E's exposure to potentially volatile purchase power cost by locking in the capacity for the remaining life of the facility and avoids the need to either purchase or acquire capacity in an SPP market that the Company expects to become increasingly capacity short over time. It should be noted that capacity needs vary within the SPP and that the market in OG&E's geographical areas is much tighter.

Q. **WHY DID OG&E BEGIN DISCUSSIONS WITH POTENTIAL PARTNERS?**

A. OG&E understood that it could not purchase 100% of the plant. We also knew that other load serving entities in Oklahoma were likely in a similar situation. OG&E contacted OMPA who is currently our partner in the McClain plant. We have had an outstanding business relationship OMPA and believed that they would have an interest in partnering again on this opportunity. OG&E then contacted GRDA who we saw as a logical partner

on this project. This is our first opportunity to enter into a business arrangement with GRDA..

Q. WHAT TYPES OF CUSTOMERS ARE SERVED BY GRDA AND OMPA?

A The GRDA serves 21 cities, 1 distribution cooperative, 2 public power joint action agencies representing approximately 105 municipalities and approximately 80 industrial customers located primarily in the Mid America Industrial Park. OMPA serves 35 cities or about 230,000 electric consumers throughout the State of Oklahoma. Both GRDA and OMPA believe Redbud is critical to long-term reliability at a reasonable cost to their Oklahoma customers.

Q. DID OG&E SEE KELSON'S DECISION TO SELL THE REDBUD FACILITY AS A UNIQUE OPPORTUNITY?

A. Yes. It is not clear when, if ever, OG&E would have another chance to acquire the Redbud plant. The Kelson sales process represents a potential one-time opportunity for OG&E to lock in value for its customers. I believe it would have been irresponsible for OG&E not to participate in this process given the capacity shortage in our service territory.

IV. CUSTOMER BENEFITS RESULTING FROM THE PROPOSED TRANSACTION.

Q. WHAT WILL YOU ADDRESS IN THIS SECTION OF YOUR TESTIMONY?

A. I will present a discussion of the many benefits to OG&E's customers of completing the acquisition of the Redbud plant. While my testimony will focus on OG&E and its

customers. I expect that many – if not all – of these benefits would also flow to customers served by GRDA and OMPA.

1. The Redbud Acquisition Satisfies an Immediate Need for Additional Capacity

Q. HOW DOES THE PROPOSED TRANSACTION AFFECT OG&E'S CAPACITY REQUIREMENTS?

A. As I previously explained, OG&E has a need for capacity beginning in 2010 after the expiration of the current Redbud PPA. Our estimate of the need to meet SPP's minimum capacity requirement is 424 MW and grows by approximately 100 MW per year, assuming that OG&E does not retire any of its aging plants. The Red Rock plant would have met this need beginning in either 2011 or 2012. The Redbud acquisition will satisfy OG&E's needs beginning in 2009 and extending through approximately 2012, at which time OG&E will need to obtain additional capacity. The acquisition of Redbud will carry OG&E and its customers through a challenging period.

2. The Acquisition of the Redbud plant will enhance reliability.

Q. HOW DOES THE ACQUISITION OF THE REDBUD PLANT IMPROVE THE RELIABILITY OF THE OG&E SYSTEM?

A. The addition of a relatively new plant to an aging portfolio improves the reliability of supply. Due to its "4x1x1x1" configuration, OG&E will be able to operate the plant as four units and continue to provide power when a one or more of the turbine are shut down. The fact that Redbud is located within OG&E's service area and proximate to our largest load center also contributes to an increase in the reliability of supply as it provides

some protection against transmission outages in other parts of SPP and in neighboring regions.

Q. ARE THERE OTHER FACTORS THAT CAUSE THE REDBUD PLANT TO PROMOTE RELIABILITY?

A. Yes. The Redbud plant has an excellent operating history. During its less than four-year operating life, Redbud has been primarily serving the mid-merit and peak load requirements of its contract customers, including OG&E. More importantly, our due diligence revealed that Redbud has not experienced any significant operating or maintenance issues that were not promptly and correctly addressed and that periodic maintenance has been performed in accordance with Prudent Operator Practices as recommended by Redbud's equipment suppliers and manufacturers. Therefore, we are acquiring a plant that we have every reason to expect will perform well and serve our customers reliably throughout its remaining life.

3. The Proposed Transaction Enables OG&E to Acquire Capacity at a Reasonable Cost.

Q. WHY DOES OG&E BELIEVE THAT IT HAS ACQUIRED THE REDBUD PLANT AT A REASONABLE COST?

A. The price that the joint owners have agreed to pay for Redbud is the result of a competitive sales process conducted by Goldman Sachs, Inc., Kelson's investment bankers, and subsequent negotiations between the parties. The terms and conditions of the transaction are the product of vigorous arms-length negotiation that took place over several months.

The Redbud transaction price represents the lowest reasonable cost to customers. The Redbud transaction price of $852 million ($693/kw) is approximately 24% less than the cost of new construction for a similar generation resources, currently estimated to exceed $900/kw. This price also compares favorably to the expected costs of purchase power over the next several years.

Further, because the facility is located within our service area and is fully deliverable into the OGE and GRDA balancing authority areas, the transaction avoids costs that OG&E would incur were it to construct a new generating unit. For example, Redbud is already interconnected to natural gas and electric transmission facilities and, as a result, OG&E and the other joint purchasers will not have to develop new interconnection or transmission facilities. The costs of interconnection facilities and potential network upgrades can be substantial. Moreover, the transmission review and approval process, siting, and development can take as long or longer than constructing the plant.

4. The Proposed Transaction will lower OG&E's costs and will serve as a hedge against future cost increases.

Q. HOW WILL THE REDBUD ACQUISITION AFFECT THE OPERATION OF OG&E'S GENERATION PORTFOLIO?

A. OG&E dispatches its portfolio on a least-cost basis. The addition of Redbud, a plant that is significantly more efficient than many of OG&E's existing natural-gas fired peaking plants, will lower operating costs and thereby provide savings to OG&E's customers.

Q. HOW DOES OG&E'S CONTROL OVER REDBUD PROVIDE VALUE TO OG&E'S CUSTOMERS?

A. Ownership and control over Redbud's operations has another advantage over continuing as a contract purchaser under a PPA. As an owner and operator, OG&E will be able to dispatch the plant to maximize overall portfolio benefits. As a contract purchaser, OG&E has attempted to negotiate operating terms that achieve this outcome, but actual control over the asset and the ability to modify operations as conditions change is preferred. As the operating plant owner, OG&E will be able to dispatch this plant, along with its other plants and contracts, to improve the overall efficiency of the portfolio.

Q. DOES "IRON-IN-THE-GROUND" HAVE COST ADVANTAGES OVER NEW BUILD GENERATION?

A. Yes, at least based on the present environment. New power plant construction costs have risen dramatically over the past several years. A September 2007 study prepared by The Brattle Group cited several factors that are contributing to escalating power plant construction costs, including dramatically increased materials costs, a shortage of shop capacity necessary to fabricate major equipment, and a tightening market for Engineering, Procurement and Construction (EPC) services. Further, on February 14, 2008, a newly published Power Capital Costs Index ("PCCI") developed by IHS Inc. and CERA indicates that the cost of new power plant construction in North America increased 27 percent in 2006 (over 2005) and an additional 19 percent in the first six months of 2007, reaching a level 130 percent higher than in 2000.

As a result, the landscape for building new power plants has shifted in a way that gives a preference to the acquisition of an operating asset. By acquiring Redbud, our customers will be shielded from risks associated with often unpredictable cost escalations, scheduling delays, and other uncertainties of new generation construction projects. As an existing plant, OG&E will not have to develop new transmission facilities. The transmission review and approval process, siting, and development can take as long or longer than constructing the plant. Acquisition of an existing asset also avoids the need for siting, permitting and other land-use development issues.

Q. DOES THE REDBUD ACQUISITION PROVIDE PROTECTION AGAINST TIGHTENING MARKET CONDITIONS?

A. Yes. The acquisition of Redbud also serves as a hedge against the potential that prices will be higher than we have projected in our analysis. There are many factors, in addition to tightening regional market conditions, which are driving capacity costs higher including construction costs and the installation of equipment to meet stricter emissions requirements. Should these factors contribute to capacity prices rising at a more accelerated pace, then OG&E will have locked in a better price for Redbud, deferred the need for the next portfolio addition (including potentially a higher priced asset or PPA acquisition), and avoided paying higher PPA prices over the interim period.

5. The Acquisition of the Redbud Plant Complements Further Investments in Wind Energy.

Q. HOW DOES THE REDBUD PLANT FIT INTO OG&E'S EXISTING GENERATION PORTFOLIO?

A. The Redbud facility is a strong addition to OG&E's existing generation portfolio. Redbud's "4 x (1 x 1 x 1)" configuration provides load following capacity and enhances the Company's operational flexibility. This is particularly valuable not only in terms of the Company's existing portfolio, but also with regard to a potential future portfolio with as much as 810 MW of wind. Natural gas plants that are able to ramp capacity contributions up and down are particularly valuable as a complement to wind energy which is subject to varying and difficult to predict operating conditions.

Q. **ARE THERE ANY OTHER BENEFITS THAT YOU WOULD LIKE TO MENTION?**

A. Yes. These similar benefits accrue to the customers of GRDA and OMPA, many of whom are located in Oklahoma.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Oklahoma Gas and Electric Company Redbud Energy LP	)))	Docket No. EC08-____ -000

AFFIDAVIT

County of Oklahoma)
)
State of Oklahoma)

I, Jesse B. Langston, being first duly sworn, deposes and say that I am the witness identified in the foregoing Prepared Direct Testimony, that I have read the testimony and am familiar with its contents, and that the facts set forth therein are true and correct to the best of my knowledge, information, and belief.

Jesse B. Langston

SUBSCRIBED AND SWORN to before me on this ___ day of March, 2008.

Nancy L Sampley
Notary Public

My commission expires: 05-22-08

NANCY L SAMPLEY NOTARY PUBLIC #05006402 EXP. 05-22-08 IN AND FOR CANADIAN COUNTY STATE OF OKLAHOMA

OG&E LOAD FORECAST

	Peak (MW)	Energy (GWh)
2008	6,106	29,249
2009	6,234	29,845
2010	6,328	30,425
2011	6,426	30,985
2012	6,507	31,547
2013	6,619	32,084
2014	6,725	32,701
2015	6,845	33,379
2016	6,955	34,104
2017	7,111	34,872
Growth Rate:	1.7%	2.0%

OG&E Capacity Needs

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
A. Resources (MW)										
Total Owned Capacity (MW)	6,141	6,141	6,141	6,141	6,141	6,127	6,127	6,127	6,120	6,120
Purchase Contracts (MW)	771	771	471	471	471	471	471	471	471	471
Total Capability	6,912	6,912	6,612	6,612	6,612	6,598	6,598	6,598	6,591	6,591
B. Demand (MW)										
Demand Forecast (MW) (Incl Wholesale)	6,112	6,243	6,340	6,441	6,525	6,640	6,749	6,873	6,985	7,144
(includes impact of Existing DSM Programs)	(6)	(9)	(12)	(15)	(18)	(21)	(24)	(27)	(30)	(33)
Net Demand Forecast (MW)	6,106	6,234	6,328	6,426	6,507	6,619	6,725	6,845	6,955	7,111
Curtailment and Interruptible Capacity	(113)	(116)	(117)	(119)	(121)	(123)	(125)	(127)	(129)	(132)
New DSM Program Impacts	(7)	(11)	(19)	(28)	(37)	(47)	(56)	(66)	(75)	(84)
Net On System Demand	5,986	6,107	6,192	6,279	6,349	6,449	6,544	6,652	6,750	6,895
C. Needed Capacity and Associated Capacity Margin With Wholesale										
Capacity Margin (MW)	926	834	844	857	867	880	893	908	921	941
Capacity Needed to Satisfy SPP 12 % Margin	**0**	**29**	**424**	**524**	**604**	**731**	**839**	**962**	**1,080**	**1,245**

Attachment 3

ATTACHMENT 3

TESTIMONY OF PHILIP L. CRISSUP

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Oklahoma Gas and Electric Company Redbud Energy LP	)	Docket No. EC08-_____ -000

PREPARED DIRECT TESTIMONY
OF PHILIP L. CRISSUP

I. INTRODUCTION.

Q. PLEASE STATE YOUR NAME, YOUR EMPLOYER, AND YOUR BUSINESS ADDRESS.

A. My name is Philip L. Crissup. I am employed by Oklahoma Gas and Electric Company ("OG&E") and my business address is 321 N. Harvey, P. O. Box 321, Oklahoma City, Oklahoma 73101.

Q. WHAT IS YOUR POSITION AT OG&E?

A. I hold the position of Director of Regional Transmission Affairs.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE?

A. I received a Bachelor of Science Degree in Electrical Engineering from the University of Oklahoma in 1983. Upon graduation, I began my career at OG&E at the Northern Region Engineering office in Enid, Oklahoma, as a Distribution Engineer in 1983. I was promoted to Design Engineer in the Transmission Design section of Corporate Engineering in 1987, and then to Senior Engineer in the same department in 1994. I moved to the Engineering Planning section in 1997, and became Manager of the

Transmission Planning group in 2002. In 2007, I became Director of Regional Transmission Affairs. I am a Licensed Professional Engineer in the state of Oklahoma.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION?

A. No. I have testified several times before the Oklahoma Corporation Commission, but this is the first time I have submitted testimony before the Federal Energy Regulatory Commission ("FERC").

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY AND HOW IS IT ORGANIZED?

A. The purpose of my testimony is to explain and support certain transmission analyses that OG&E performed in relation to the proposed acquisition of the Redbud generating facility by OG&E, Grand River Dam Authority ("GRDA"), and Oklahoma Municipal Gas Authority ("OMPA"). I refer to the sale and transfer of the Redbud facility as the "Transaction."

First, my testimony addresses the deliverability of the output of the Redbud generating facility to the three purchasers after closing of the Transaction, and concludes that the facility's capacity will be fully deliverable at that time.

Second, in order to assist in the preparation of the analysis evaluating the proposed Transaction's effects on competition, OG&E conducted a simultaneous import limits ("SIL") analysis to determine SILs into both the GRDA and OG&E balancing authority areas, as well as first-tier balancing authority areas. My testimony describes how the SIL analysis was performed and sets out the study results. This portion of my testimony also details the posted First Contingency Incremental Transfer Capability

("FCITC") values for imports from each of OG&E and GRDA's first-tier balancing authority areas.

Third, I performed a sensitivity analysis for the OG&E and GRDA balancing authority areas in which only the portion of GRDA's capacity needed to meet its current load obligations (150 MW) is delivered to the GRDA balancing authority area as of the closing of the Transaction.

Finally, my testimony identifies and describes certain transmission projects that OG&E could agree to fund in the event that the FERC determines that such projects are required to mitigate the competitive effects of the sale of the Redbud generation facility to OG&E, GRDA, and OMPA.

II. BACKGROUND.

Q. PLEASE DESCRIBE OKLAHOMA GAS AND ELECTRIC COMPANY.

A. OG&E is an Oklahoma corporation and is a utility operating company subsidiary of OGE Energy Corp. OG&E is a member of the Southwest Power Pool, Inc. ("SPP") and owns transmission facilities that are under the operational control of SPP. Requests for new transmission service on OG&E's transmission facilities are made through and acted upon by SPP in accordance with the terms and conditions of its open access transmission tariff ("OATT"). OG&E serves more than 760,000 retail customers in Oklahoma and western Arkansas and sells electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives, and other market participants.

Q. PLEASE DESCRIBE OG&E'S EXISTING TRANSMISSION SYSTEM AND ITS FIRST-TIER INTERCONNECTIONS.

A. The OG&E transmission system was designed, constructed, and funded primarily to deliver generation from OG&E generation facilities to OG&E loads, and consists of a total of over 4,600 miles of transmission lines in Oklahoma and western Arkansas. The OG&E system is comprised of the following voltages and corresponding line-miles: 69kV – 1,535 miles, 138kV – 1,913 miles, 161kV – 192 miles, 345kV – 941 miles and 500kV – 47 miles. OG&E transferred operational control of its transmission system to SPP on February 10, 2004, the same day that FERC recognized SPP as a Regional Transmission Organization ("RTO"). OG&E provides transmission service to a limited number of customers pursuant to agreements entered into under the OG&E OATT before SPP began offering transmission service under the SPP OATT. New requests for transmission service are provided in accordance with the SPP OATT.

The OG&E balancing authority area is interconnected with seven neighboring first-tier balancing authority areas: Public Service Company of Oklahoma ("PSO"),[1] Western Farmers Electric Cooperative ("WFEC"), Entergy Corp. ("Entergy"), Westar Energy ("Westar"), GRDA, Southwestern Power Administration ("SWPA"), and Associated Electric Cooperative, Inc. ("AECI").

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[1] While OG&E is directly interconnected to PSO, PSO and Southwestern Electric Power Company together operate a single balancing authority area (referred to as CSWS or AEP West).

Q. PLEASE DESCRIBE GRDA'S EXISTING TRANSMISSION SYSTEM AND ITS FIRST-TIER INTERCONNECTIONS.

A. GRDA owns and maintains approximately 1,200 miles of transmission lines and substations to deliver power and energy to its customers. GRDA is a member of the SPP, and has transferred functional control of its transmission system to SPP. The GRDA balancing authority area is interconnected with six neighboring first-tier balancing authority areas: AECI, PSO, OG&E, SWPA, WFEC, and Empire District Electric Company. GRDA transferred operational control of its transmission system to SPP on February 10, 2004.

Q. PLEASE DESCRIBE THE OMPA TRANSMISSION SYSTEM.

A. OMPA does not have a separate balancing authority area and does not own transmission facilities other than those related to the interconnection of its generation facilities to the grid. The municipalities that OMPA serves are located within OG&E's balancing authority area or other balancing authority areas within the SPP.

III. DELIVERABILITY ANALYSIS.

Q. PLEASE DESCRIBE YOUR DELIVERABILITY ANALYSIS.

A. I performed an analysis to determine the deliverability of the Redbud generating facility output to GRDA, OMPA and OG&E, in proportion to their respective ownership shares of the facility. Table 1 below summarizes the amount of MW that would be transferred to the three parties pursuant to the Transaction:

Table 1: Ownership Percentages and MW Output By Prospective Owner

	Ownership	Winter, MW	Summer, MW
OG&E	51%	648	610
GRDA	36%	457	430
OMPA	13%	165	155
Total	100%	1270	1195

The base case for this deliverability analysis was the pre-Transaction status quo, which included existing contracts that OG&E, OMPA and GRDA have with the current owner of the Redbud facility for the purchase of capacity and associated energy, *i.e.*, 300 MW, 80 MW and 150 MW, respectively.

In conducting this deliverability analysis, we used versions of the 2008 series SPP 2008 Summer, Shoulder, and Winter Models. These models are developed by the SPP Model Development Working Group and submitted to the FERC.[2] These models were then modified to reflect the preexisting contracts with OG&E, GRDA, and OMPA identified above. The output from the Redbud generating facility was then transferred into the OG&E and GRDA balancing authority areas and generation in the OG&E and GRDA balancing authority areas was backed down to allow for the modeled increase in Redbud generation.

The analysis was performed for OG&E's and GRDA's balancing authority areas and their first-tier balancing authority areas. Using the modified models and a PSSE AC Contingency analysis function,[3] a transfer between the first-tier neighbors of OG&E and

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2 At the time my analysis was conducted, the 'first pass' of SPP models (as opposed to the final versions of the models) were the most up to date models available.

3 Siemens' PSSE power-flow model is a widely-used industry power systems analysis tool that provides power flow, short circuit and other analysis functions.

GRDA was applied and the resulting scenarios were analyzed. Facilities rated in excess of 100kV were monitored, and facilities with loadings in excess of 100% in the base-case were excluded from the analyses.

Q. WHAT ARE THE RESULTS OF THE DELIVERABILITY ANALYSIS?

A. This analysis demonstrates that the Redbud facility is fully deliverable to all three prospective buyers for their respective shares for the seasons analyzed.

Q. IS THIS DELIVERABILITY ANALYSIS SUBJECT TO FURTHER REVIEW?

A. Yes. OG&E has conducted the analysis using SPP models, but the SPP must conduct its own analysis in accordance with its aggregate study process to determine whether the facility is fully deliverable. I believe that OG&E has effectively replicated the SPP study process given the information available at this time, but SPP will provide the final analysis.

Q. PLEASE DESCRIBE THE SPP AGGREGATE STUDY PROCESS.

A. SPP accumulates all transmission service requests made over a four-month open season, and then studies these requests in aggregate. The three prospective buyers, OG&E, OMPA, and GRDA, have submitted transmission service requests in the amount of their pro-rata shares of the output of the Redbud facility to serve their respective loads. (They already have secured transmission service from the SPP to deliver their pre-Transaction contracted amounts.) These transmission service requests were each separately entered into the SPP Aggregate Study open-season window that closed January 31, 2008. SPP will analyze each transmission service request for impact on the SPP system, and assign cost responsibility for any required system upgrades.

IV. SIMULTANEOUS IMPORT LIMIT ANALYSIS.

Q. WHAT OTHER TRANSMISSION ANALYSIS DID OG&E PERFORM RELATED TO THE TRANSACTION?

A. OG&E also performed an analysis of the SILs into the OG&E and GRDA balancing authority areas using a MUST transfer analysis function.[4] This information was relied upon by Julie Solomon with CRA International, Inc. in the market analysis she performed in support of the application for approval of the Transaction.

Q. HOW DID YOU CONDUCT YOUR SIL ANALYSIS?

A. To determine pre-Transaction SIL into the OG&E and GRDA balancing authority areas, I studied the FCITC values for each of the first-tier balancing authority areas located adjacent to OG&E and GRDA to calculate an estimate of the Available Simultaneous Transfer Capacity in the same pre-Transaction scenario used in the deliverability analysis. Hence, the pre-Transaction base case included existing contracts that OG&E, OMPA and GRDA have with the current owner of the Redbud facility, *i.e.*, 300 MW, 80 MW and 150 MW, respectively.

The FCITC analysis for a targeted balancing authority area involved backing down resources in the targeted balancing authority area and then scaling up generation in a balancing authority area adjacent to targeted balancing authority area to determine the FCITC. The FCITC resulting from this analysis is essentially the amount of power capable of being transferred between the targeted balancing authority area and the first-tier balancing authority area before a constraint binds. This value is a conservative

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[4] Siemens' Managing Utility System Transmission ("MUST") is commonly used to evaluate transfer impacts on transmission areas' monitored elements or flowgates.

measure of transfer capability because it examines only the incremental transfer capability between balancing authority areas over and above base transfers.

The pre-Transaction analysis also was performed for OG&E's seven first-tier balancing authority areas to determine the FCITC into those first-tier balancing authority areas and then the FCITC from those first-tier balancing authority areas into the OG&E balancing authority area. The seasons used in the analysis were 2008 Summer, 2008 Shoulder, and 2008 Winter. Table 2 contains the results of pre-Transaction FCITC from first-tier balancing authority areas to the OG&E balancing authority area:

Table 2: Pre-Transaction FCITC from First-Tier Balancing Authority Areas to OG&E

FCITC	Summer	Shoulder	Winter
GRDA to OG&E	331	127	355
PSO to OG&E	1393	1269	1800
ENTR to OG&E	97	442	648
SWPA to OG&E	800	299	532
Westar to OG&E	326	165	280
WFEC to OG&E	409	570	468
AECI to OG&E	440	762	1150

To determine pre-Transaction FCITC into the GRDA balancing authority area, I used the same pre-Transaction scenario discussed above, for the same seasons. The pre-Transaction FCITC analysis was performed for GRDA's five first-tier balancing authority areas to determine the FCITC into those first-tier balancing authority areas and then the FCITC from those first-tier balancing authority areas into the GRDA balancing

authority area. Table 3 contains the results of pre-Transaction FCITC from first-tier balancing authority areas to the GRDA balancing authority area:

Table 3: Pre-Transaction FCITC from First-Tier Balancing Authority Areas to GRDA

FCITC	Summer	Shoulder	Winter
AECI to GRDA	258	577	457
EDE to GRDA	258	577	239
PSO to GRDA	258	577	457
WFEC to GRDA	258	570	457
SWPA to GRDA	258	285	322
OG&E to GRDA	258	577	422

Q. WHAT DO THESE FCITC RESULTS INDICATE ABOUT TRANSMISSION CAPABILITY?

A. The seasonal FCITC results discussed above essentially identify the capability of the transmission system to move power from one balancing authority area to another, with the source being the exporting balancing authority areas and the sinks being either OG&E or GRDA. They do not represent an SIL, but do represent the capability to import from one or another balancing authority area into OG&E or GRDA at any given time.

Q. WHAT DID YOU CALCULATE FOR PRE-TRANSACTION SILS?

A. Using FCITC values, OG&E then performed an analysis that, consistent with the Commission's instructions, aggregates all the first tier balancing authority areas and treats them as a single exporting entity for purposes of identifying a single SIL value into each of the OG&E and GRDA balancing authority areas (as well as into first-tier

balancing authority areas).[5] Table 4 below contains the pre-Transaction SILs resulting from treating the first-tier balancing authority areas as a single exporting entity:

Table 4: Pre-Transaction SILs Into OG&E and GRDA

	Summer	Shoulder	Winter
SIL into OG&E	137	594	930
SIL into GRDA	258	577	457

Q. DO THESE VALUES ACCURATELY REFLECT THE AMOUNT OF SUPPLY THAT MAY BE IMPORTED INTO THE OG&E BALANCING AUTHORITY MARKET AND THAT WOULD BE AVAILABLE TO POTENTIAL WHOLESALE PURCHASERS IN THIS MARKET?

A. In this instance, strict adherence to the Commission's standard SIL methodology produces SIL values that are quite low, and do not reflect the ability of external suppliers to deliver power to the OG&E balancing authority area market. Although the individual balancing authority area-to-balancing authority area FCTTC's into OG&E are relatively high (see Table 2 above), when one groups all the first-tier balancing authority areas together and considers them as a single exporting entity, the SIL values into the OG&E balancing authority areas hit their limits in the FCTTC analysis more quickly and the results are very low SIL values.

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[5] In Appendix E to *AEP Power Marketing, Inc.*, 107 FERC ¶ at 61,086 (2004), the Commission described its preferred methodology for calculating SILs. This methodology specifies that the individual first-tier markets should be treated as a single aggregated area and that "the import capability of the study area is the simultaneous transfer limit from the aggregated first-tier market area into the study area."

The comparison between the FCITC values and the SIL values highlights this effect. For example, the FCITC value from the PSO balancing authority area to the OG&E balancing authority area shown in Table 2 above for the summer period is 1,393 MW. However, when the first-tier balancing authority areas are consolidated into a single exporting entity, the SIL value into the OG&E balancing authority area during the same period is only 137 MW.[6] Essentially, when all the first-tier balancing authority areas are treated as a single exporting entity, the most limiting constraint (*i.e.*, in this case the Entergy FCITC) restricts the overall SIL into the OG&E balancing authority area. The SIL determination stops, even though it is possible that substantially more power could be imported into the OG&E balancing authority area from one or more other sources, such as from the PSO balancing authority area. The result is a SIL that substantially understates import capability into a market from any particular direction.

Q. HOW DID YOU PERFORM YOUR POST-TRANSACTION ANALYSIS?

A. Using the same models developed for the pre-Transaction analysis, I adjusted the analysis so that the output from the Redbud generating facility was transferred to the three prospective purchasers and into the OG&E and GRDA balancing authority areas. Based on the results of the AC Contingency analysis performed and described previously, OG&E assumed that the Redbud facility was fully deliverable to all three prospective buyers of the facility.

Q. WHAT WERE THE RESULTS OF YOUR POST-TRANSACTION SIL ANALYSIS?

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[6] A similar result applies to the FCITC from AECI to OG&E, that is, FCITC is higher than the SIL.

A. Table 5 below contains a comparison of the pre- and post-Transaction FCITC from first-tier balancing authority areas to the OG&E balancing authority area:

Table 5 - Comparison of the Pre- and Post-Transaction FCITC from First-Tier Balancing Authority Areas to OG&E

	PRE-TRANSACTION			POST-TRANSACTION		
	Summer	Shoulder	Winter	Summer	Shoulder	Winter
GRDA to OG&E	331	127	355	600	276	580
PSO to OG&E	1393	1269	1800	1441	1315	1868
ENTR to OG&E	97	442	648	74	416	620
SWPA to OG&E	800	299	532	785	283	818
Westar to OG&E	326	165	280	312	158	281
WFEC to OG&E	409	570	468	409	571	468
AECI to OG&E	440	762	1150	404	715	1087

Note that the pre- to post-Transaction FCITC data from GRDA to OG&E evidences a counterflow effect resulting from dispatching an additional 280 MW of Redbud from the OG&E balancing authority area to the GRDA balancing authority area. For example, in the summer, the FCITC from GRDA to OG&E increases from 331 MW pre-Transaction to 600 MW post-Transaction.[7] This counterflow effect is not evident in the SILs. Table 6 contains a comparison of the pre- and post-Transaction FCITC from first-tier balancing authority areas to the GRDA balancing authority area:

[7] SPP informed me that if GRDA has a schedule (NITS or Firm) to deliver energy from Redbud to the GRDA control area, it is possible to counter-schedule against that schedule (on a firm or non-firm basis).

Table 6 - Post-Transaction FCITC from First-Tier Balancing Authority Areas to GRDA

	PRE-TRANSACTION			POST-TRANSACTION		
	Summer	Shoulder	Winter	Summer	Shoulder	Winter
AECI to GRDA	258	577	457	160	409	299
EDE to GRDA	258	577	239	160	409	245
PSO to GRDA	258	577	457	160	409	299
WFEC to GRDA	258	570	457	160	409	299
SWPA to GRDA	258	285	322	160	271	299
OG&E to GRDA	258	577	422	160	409	299

Table 7 below contains the results of the post-Transaction SIL analysis when one combines all the first tier balancing authority areas and treats them as a single exporting entity:

Table 7: Post-Transaction SILs into OG&E and GRDA

	Summer	Shoulder	Winter
SIL into OG&E	106	564	889
SIL into GRDA	160	409	299

Q. WHAT CONCLUSIONS CAN YOU DRAW FROM COMPARING THE PRE-TRANSACTION AND POST-TRANSACTION ANALYSES?

A. Whereas Tables 5 and 6 evidence some increased FCITC in the balancing authority area by balancing authority area post-Transaction FCITC analysis, the standard Commission approach to calculating a single SIL value into each of the OG&E and GRDA balancing authority areas shows SIL reductions after the purchase of the Redbud generating facility

during 2008 summer, shoulder and winter seasons. Table 8 below contains both the pre-Transaction and post-Transaction SIL results:

Table 8: Comparison of Pre-Transaction and Post-Transaction SIL

	PRE-TRANSACTION			POST-TRANSACTION		
	Summer	Shoulder	Winter	Summer	Shoulder	Winter
SIL to OG&E	137	594	930	106	564	889
SIL to GRDA	258	577	457	160	409	299

Q. WHAT ACCOUNTS FOR THESE SIL CHANGES?

A. The change in the SILs is the combined effect of (1) the additional dispatch of Redbud, which tends to reduce import capability into OG&E; and (2) the transmission to GRDA of its portion of Redbud.

Q. WOULD YOU EXPECT THAT FOLLOWING THE COMPLETION OF THE TRANSACTION THAT ADDITIONAL SUPPLIES BEYOND THE SILs WOULD BE DELIVERABLE INTO THE OG&E AND GRDA BALANCING AUTHORITY AREAS?

A. Yes. As I noted before, the SILs calculated in my analysis reflect the aggregation of all of the first-tier balancing area markets into a single market. Such analysis produces a relatively low SIL value because of the impact of limiting facilities in the Entergy balancing authority area.

Q. WHAT ADDITIONAL AMOUNT OF IMPORT CAPABILITY DO YOU BELIEVE IS PRACTICALLY AVIALBLE BEYOND THE RESULTS OF THE SIL ANALYSIS?

A. It is difficult to say, and I have not modeled it as such. However, at least two sources, PSO and AECI, are individually capable of transmitting substantially more power to the OG&E balancing authority area than the SIL reflects. I understand that Ms. Solomon's analysis considers this effect by using both the SILs and the balancing authority area-to-balancing authority area FCITC for PSO as a basis for performing a sensitivity analyses. This is a reasonable approach and the use of this sensitivity recognizes that that this FCITC would be available as predicted by this transfer analysis.

V. GRDA SENSITIVITY ANALYSIS.

Q. HAVE YOU PERFORMED ANY OTHER TRANSMISSION ANALYSES?

A. Yes. At the request of Ms. Solomon, I performed a study of the post-Transaction SILs into the OG&E and GRDA balancing authority areas when GRDA's share of the Redbud's output over and above the 150 MW existing contract is not dispatched, and therefore available to the wholesale market in the OG&E balancing authority area (rather than being exported to the GRDA balancing authority area). This sensitivity analysis is based on the reasonable assumption that GRDA will import into its balancing authority area only the amount of power needed to meet its load and reliability obligations, currently 150 MW, and that additional imports will take place over time in response to contingencies and load growth.

Q. WHAT ARE THE RESULTS OF THIS SENSITIVITY ANALYSIS?

A. Under such assumptions, the post-Transaction SILs are increased and, in most cases, exceed pre-Transaction levels. Table 9 contains the results of this analysis:

Table 9: Post-Transaction SILs Without Full Transfer of GRDA's Portion to GRDA

	PRE-TRANSACTION			POST-TRANSACTION		
SEASON	Summer	Shoulder	Winter	Summer	Shoulder	Winter
SIL to OG&E	137	594	930	149	604	920
SIL to GRDA	258	577	457	225	577	496

VI. POTENTIAL MITIGATION PROJECTS.

Q. PLEASE EXPLAIN THE ANALYSIS YOU HAVE PERFORMED REGARDING POTENTIAL MITIGATION PROJECTS.

A. It is my understanding that OG&E, under certain circumstances, is willing to construct new transmission facilities that will bring about additional post-Transaction import capability for the OG&E and GRDA balancing authority markets.

Q. WHAT ARE THE SPECIFIC MITIGATION PROJECTS?

A. OG&E has identified three potential upgrades that would increase SILs into both the OG&E and GRDA balancing authority areas relative to pre-Transaction levels.

First, OG&E would re-conductor a 161 kV transmission line that runs between Entergy's Russellville North and ANO substations. This upgrade will increase the transfer capability of the existing line, and therefore, the SIL into the OG&E and GRDA balancing authority areas.

Second, OG&E would upgrade terminal equipment in the Entergy Russellville South and Russellville East substations. These upgrades would increase the transfer capability into the OG&E balancing authority area and thereby increase the SIL into the OG&E and GRDA markets in the same manner as the re-conductor project.

Third, OG&E would upgrade the limiting terminal equipment located in the Ozark substation in the Van Buren, Arkansas area of the SWPA transmission system. Upgrading such terminal equipment (*e.g.*, by installing or upgrading a switch, breaker, transformer or wave trap) will increase the capability of a 161 kV transmission line between the Ozark substation located in Ozark, Arkansas and the Van Buren substation located in Van Buren, Arkansas, and further increase SIL into OG&E and GRDA.

Q. HAS OG&E IDENTIFIED THE APPROXIMATE COSTS OF SUCH UPGRADES?

A. Yes. OG&E approximates that the costs of the projects identified above would be approximately $17,000,000. The re-conductor would cost approximately $10,000,000, the Russellville upgrades would cost approximately $6,400,000, and the terminal equipment upgrades on the SWPA transmission system would cost approximately $500,000.

Q. YOU STATED THAT THE SPECIFIC MITIGATION PROJECTS ARE LOCATED ON THE SWPA AND ENTERGY TRANSMISSION SYSTEMS. WHAT IS THE PROCESS FOR HAVING THESE PROJECTS CONSTRUCTED?

A. OG&E would contact the respective owners of the limiting equipment and propose the upgrade of the facilities. If Entergy and SWPA agreed to undertake the upgrades, OG&E would reimburse such owners the cost of the upgrades. It is anticipated that the upgrades could require 27 months to complete.

Q. WHAT ARE THE ESTIMATED SILs INTO THE OG&E AND GRDA BALANCING AUTHORITY AREAS AFTER THE UPGRADES?

A. The resulting SILs are shown in Table 9. As shown, the upgrades required to raise the SILs back to at least pre-Transaction levels actually result in significantly more SIL capability into each market. As a result, in targeting a return to pre-transaction levels in all seasons, the actual SILs resulting from the transmission upgrades were in excess of the pre-Transaction SILs.

Table 9 – Comparison of Pre-Transaction and Post-Transaction with Transmission Upgrades SILs

	PRE-TRANSACTION			POST-TRANSACTION		
	Summer	Shoulder	Winter	Summer	Shoulder	Winter
SIL to OG&E	137	594	930	711	1127	1255
SIL to GRDA	258	577	457	1108	1078	922

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Oklahoma Gas and Electric Company Redbud Energy LP	)	Docket No. EC08-_____-000

AFFIDAVIT

County of OKLAHOMA)
)
State of Oklahoma)

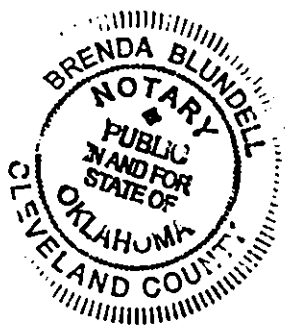
I, Philip L. Crissup, being first duly sworn, deposes and say that I am the witness identified in the foregoing Prepared Direct Testimony, that I have read the testimony and am familiar with its contents, and that the facts set forth therein are true and correct to the best of my knowledge, information, and belief.

Philip L. Crissup

SUBSCRIBED AND SWORN to before me on this ___ day of March, 2008.

Brenda Blundell
Notary Public

My commission expires: April 21, 2010



Attachment 4

ATTACHMENT 4

PROPOSED ACCOUNTING ENTRIES

Attachment 4
Proposed Accounting Entries

OG&E provides below the *pro forma* accounting entries for the proposed Transaction. The amount used is based on the PSA and reflects OG&E's best present assessment of the manner in which the Transaction will ultimately be recorded for accounting purposes. To the extent necessary, OG&E respectfully requests waiver of the obligation under 18 C.F.R. § 35.5 to provide accounting entries showing the effect of the Transaction on OG&E's income statements or other relevant financial statements. OG&E will submit proposed final accounting treatment within 6 months of the consummation of the Transaction.

Journal Entries to Record Purchase	Debit	Credit
Journal entry #1		
Account 102 — Electric Plant Purchased or Sold	$435,000,000	
Account 131 -- Cash		$435,000,000
To record cash payment for Redbud facility in accordance with CFR 18, Part 101, Electric Plant Instruction 5A and FERC order (Docket No. EC08-XXX) issued		
Journal entry #2		
Account 101 — Utility Plant	$338,000,000	
Account 101 — Land	1,000,000	
Account 102 — Electric Plant Purchased or Sold	53,000,000	
Account 102 — Electric Plant Purchased or Sold		$339,000,000
Account 108 — Accumulated Depreciation		53,000,000
To record the original cost of Redbud facility and accumulated depreciation in accordance with CFR 18, Part 101, Electric Plant Instruction 5 B(1) and (2) and FERC order (Docket No. EC08-XXX) issued		

Journal Entries to Clear Account 102	Debit	Credit
Journal entry #3		
Account 114 — Electric Plant Acquisition Adjustment	$149,000,000	
Account 102 — Electric Plant Purchased or Sold		$149,000,000
To record the plant acquisition adjustment for Redbud facility in accordance with CFR 18, Part 101, Electric Plant Instruction 5 B(4) and FERC order (Docket No. EC08-XXX) issued		

Attachment 5

ATTACHMENT 5

VERIFICATIONS

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Oklahoma Gas and Electric Company Redbud Energy LP	)	Docket No. EC08-_____-000

VERIFICATION

County of Oklahoma)
)
State of Oklahoma)

Jesse B. Langston, being duly sworn, deposes and says: That he is Vice President of Utility Commercial Operations at Oklahoma Gas and Electric Company; that he has read said Application; and that to the best of his knowledge, information, and belief, all of the statements contained therein pertaining to Oklahoma Gas and Electric Company are true and correct.

Jesse B. Langston

SUBSCRIBED AND SWORN to before me on this ___ day of March, 2008.

Nancy L. Sampley
Notary Public

My commission expires: 05-22-08

NANCY L SAMPLEY NOTARY PUBLIC # 00004402 EXP 5/22/08 IN AND FOR STATE OF OKLAHOMA CANADIAN COUNTY

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Oklahoma Gas and Electric Company Redbud Energy LP	)	Docket No. EC08-_____-000

VERIFICATION

~~County~~ of District of Columbia)
)
~~State of~~ _____)

Robert J. Janssen, being duly sworn, deposes and says: That he is President of Redbud Energy, LP ("Redbud"), that he has read said Application; and that to the best of his knowledge, information, and belief, all of the statements contained therein pertaining to Redbud are true and correct.

Robert J Janssen

SUBSCRIBED AND SWORN to before me on this 19th day of March, 2008.

Graciela V Baten
Notary Public

My commission expires: _____

GRACIELA V. BATEN
Notary Public District of Columbia
My Commission Expires October 15, 2008

Attachment 6

ATTACHMENT 6

PROTECTIVE ORDER

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Oklahoma Gas and Electric Company Redbud Energy LP	)	Docket No. EC08- _____-000

PROTECTIVE ORDER

(Issued)

1. This Protective Order shall govern the use of all Protected Materials produced by, or on behalf of, any Participant. Notwithstanding any order terminating this proceeding, this Protective Order shall remain in effect until specifically modified or terminated by the Presiding Administrative Law Judge ("Presiding Judge") or the Federal Energy Regulatory Commission ("Commission").

2. This Protective Order applies to the following two categories of materials: (A) A Participant may designate as protected those materials which customarily are treated by that Participant as sensitive or proprietary, which are not available to the public, and which, if disclosed freely, would subject that Participant or its customers to risk of competitive disadvantage or other business injury; and (B) A Participant shall designate as protected those materials which contain critical energy infrastructure information, as defined in 18 C.F.R. § 388.113(c)(1) ("Critical Energy Infrastructure Information").

3. Definitions - For purposes of this Order:

(a) The term "Participant" shall mean a Participant as defined in 18 C.F.R. § 385.102(b).

(b) (i) The term "Protected Materials" means (A) materials (including depositions) provided by a Participant in response to discovery requests and designated by such Participant as protected; (B) any information contained in or obtained from such designated materials; (C) any other materials which are made subject to this Protective Order by the Presiding Judge, by the Commission, by any court or other body having appropriate authority, or by agreement of the Participants; (D) notes of Protected Materials; and (E) copies of Protected Materials. The Participant producing the Protected Materials shall physically mark them on each page as "PROTECTED MATERIALS" or with words of similar import as long as the term "Protected Materials" is included in that designation to indicate that they are Protected Materials. If the Protected Materials contain Critical Energy Infrastructure Information, the Participant producing such information shall additionally mark on each page containing such information the words "Contains Critical Energy Infrastructure Information – Do Not Release".

(ii) The term "Notes of Protected Materials" means memoranda, handwritten notes, or any other form of information (including electronic form) which copies or discloses materials described in Paragraph 3(b)(1). Notes of Protected Materials are subject to the same restrictions provided in this order for Protected Materials except as specifically provided in this order.

(iii) Protected Materials shall not include (A) any information or document contained in the files of the Commission, or any other federal or state agency, or any federal or state court, unless the information or document has been determined to be protected by such agency or court, or (B) information that is public knowledge, or which becomes public knowledge, other than through disclosure in violation of this Protective Order, or (C) any information or document labeled as "Non Internet Public" by a Participant, in accordance with Paragraph 30 of FERC Order No. 630, FERC Stat. & Reg. ¶ 31,140. Protected Materials do include any information or document contained in the files of the Commission that has been designated as Critical Energy Infrastructure Information.

(c) The term "Non-Disclosure Certificate" shall mean the certificate annexed hereto by which Participants who have been granted access to Protected Materials shall certify their understanding that such access to Protected Materials is provided pursuant to the terms and restrictions of this Protective Order, and that such Participants have read the Protective Order and agree to be bound by it. All Non-Disclosure Certificates shall be served on all parties on the official service list maintained by the Secretary in this proceeding.

(d) The term "Reviewing Representative" shall mean a person who has signed a Non-Disclosure Certificate and who is:

(i) Commission Trial Staff designated as such in this proceeding;

(ii) an attorney who has made an appearance in this proceeding for a Participant;

(iii) attorneys, paralegals, and other employees associated for purposes of this case with an attorney described in Subparagraph (2);

(iv) an expert or an employee of an expert retained by a Participant for the purpose of advising, preparing for or testifying in this proceeding;

(v) a person designated as a Reviewing Representative by order of the Presiding Judge or the Commission; or

(vi) employees or other representatives of Participants appearing in this proceeding with significant responsibility for this docket.

4. Protected Materials shall be made available under the terms of this Protective Order only to Participants and only through their Reviewing Representatives as provided in Paragraphs 7-9.

5. Protected Materials shall remain available to Participants until the later of the date that an order terminating this proceeding becomes no longer subject to judicial review, or the date that

any other Commission proceeding relating to the Protected Material is concluded and no longer subject to judicial review. If requested to do so in writing after that date, the Participants shall, within fifteen days of such request, return the Protected Materials (excluding Notes of Protected Materials) to the Participant that produced them, or shall destroy the materials, except that copies of filings, official transcripts and exhibits in this proceeding that contain Protected Materials, and Notes of Protected Material may be retained, if they are maintained in accordance with Paragraph 6, below. Within such time period each Participant, if requested to do so, shall also submit to the producing Participant an affidavit stating that, to the best of its knowledge, all Protected Materials and all Notes of Protected Materials have been returned or have been destroyed or will be maintained in accordance with Paragraph 6. To the extent Protected Materials are not returned or destroyed, they shall remain subject to the Protective Order.

6. All Protected Materials shall be maintained by the Participant in a secure place. Access to those materials shall be limited to those Reviewing Representatives specifically authorized pursuant to Paragraphs 8-9. The Secretary shall place any Protected Materials filed with the Commission in a non-public file. By placing such documents in a non-public file, the Commission is not making a determination of any claim of privilege. The Commission retains the right to make determinations regarding any claim of privilege and the discretion to release information necessary to carry out its jurisdictional responsibilities. For documents submitted to Commission Trial Staff ("Staff"), Staff shall follow the notification procedures of 18 C.F.R. § 388.112 before making public any Protected Materials. .

7. Protected Materials shall be treated as confidential by each Participant and by the Reviewing Representative in accordance with the certificate executed pursuant to Paragraph 9. Protected Materials shall not be used except as necessary for the conduct of this proceeding, nor shall they be disclosed in any manner to any person except a Reviewing Representative who is engaged in the conduct of this proceeding and who needs to know the information in order to carry out that person's responsibilities in this proceeding. Reviewing Representatives may make copies of Protected Materials, but such copies become Protected Materials. Reviewing Representatives may make notes of Protected Materials, which shall be treated as Notes of Protected Materials if they disclose the contents of Protected Materials.

8. (a) If a Reviewing Representative's scope of employment includes the marketing of energy, the direct supervision of any employee or employees whose duties include the marketing of energy, the provision of consulting services to any person whose duties include the marketing of energy, or the direct supervision of any employee or employees whose duties include the marketing of energy, such Reviewing Representative may not use information contained in any Protected Materials obtained through this proceeding to give any Participant or any competitor of any Participant a commercial advantage.

(b) In the event that a Participant wishes to designate as a Reviewing Representative a person not described in Paragraph 3(d) above, the Participant shall seek agreement from the Participant providing the Protected Materials. If an agreement is reached that person shall be a Reviewing Representative pursuant to Paragraphs 3(d) above with respect to those materials. If no agreement is reached, the Participant shall submit the disputed designation to the Presiding Judge for resolution.

9. (a) A Reviewing Representative shall not be permitted to inspect, participate in discussions regarding, or otherwise be permitted access to Protected Materials pursuant to this Protective Order unless that Reviewing Representative has first executed a Non-Disclosure Certificate; provided that if an attorney qualified as a Reviewing Representative has executed such a certificate, the paralegals, secretarial and clerical personnel under the attorney's instruction, supervision or control need not do so. A copy of each Non-Disclosure Certificate shall be provided to counsel for the Participant asserting confidentiality prior to disclosure of any Protected Material to that Reviewing Representative.

(b) Attorneys qualified as Reviewing Representatives are responsible for ensuring that persons under their supervision or control comply with this order.

10. Any Reviewing Representative may disclose Protected Materials to any other Reviewing Representative as long as the disclosing Reviewing Representative and the receiving Reviewing Representative both have executed a Non-Disclosure Certificate. In the event that any Reviewing Representative to whom the Protected Materials are disclosed ceases to be engaged in these proceedings, or is employed or retained for a position whose occupant is not qualified to be a Reviewing Representative under Paragraph 3(d), access to Protected Materials by that person shall be terminated. Even if no longer engaged in this proceeding, every person who has executed a Non-Disclosure Certificate shall continue to be bound by the provisions of this Protective Order and the certification.

11. Subject to Paragraph 17, the Presiding Administrative Law Judge shall resolve any disputes arising under this Protective Order. Prior to presenting any dispute under this Protective Order to the Presiding Administrative Law Judge, the parties to the dispute shall use their best efforts to resolve it. Any participant that contests the designation of materials as protected shall notify the party that provided the protected materials by specifying in writing the materials the designation of which is contested. This Protective Order shall automatically cease to apply to such materials five (5) business days after the notification is made unless the designator, within said 5-day period, files a motion with the Presiding Administrative Law Judge, with supporting affidavits, demonstrating that the materials should continue to be protected. In any challenge to the designation of materials as protected, the burden of proof shall be on the participant seeking protection. If the Presiding Administrative Law Judge finds that the materials at issue are not entitled to protection, the procedures of Paragraph 17 shall apply. The procedures described above shall not apply to protected materials designated by a Participant as Critical Energy Infrastructure Information. Materials so designated shall remain protected and subject to the provisions of this Protective Order, unless a Participant requests and obtains a determination from the Commission's Critical Energy Infrastructure Information Coordinator that such materials need not remain protected.

12. All copies of all documents reflecting Protected Materials, including the portion of the hearing testimony, exhibits, transcripts, briefs and other documents which refer to Protected Materials, shall be filed and served in sealed envelopes or other appropriate containers endorsed to the effect that they are sealed pursuant to this Protective Order. Such documents shall be marked "PROTECTED MATERIALS" and shall be filed under seal and served under seal upon the Presiding Judge and all Reviewing Representatives who are on the service list. Such documents containing Critical Energy Infrastructure Information shall be additionally marked

"Contains Critical Energy Infrastructure Information – Do Not Release". For anything filed under seal, redacted versions or, where an entire document is protected, a letter indicating such, will also be filed with the Commission and served on all parties on the service list and the Presiding Judge. Counsel for the producing Participant shall provide to all Participants who request the same, a list of Reviewing Representatives who are entitled to receive such material. Counsel shall take all reasonable precautions necessary to assure that Protected Materials are not distributed to unauthorized persons.

13. If any Participant desires to include, utilize or refer to any Protected Materials or information derived therefrom in testimony or exhibits during the hearing in these proceedings in such a manner that might require disclosure of such material to persons other than reviewing representatives, such participant shall first notify both counsel for the disclosing participant and the Presiding Judge of such desire, identifying with particularity each of the Protected Materials. Thereafter, use of such Protected Material will be governed by procedures determined by the Presiding Judge.

14. Nothing in this Protective Order shall be construed as precluding any Participant from objecting to the use of Protected Materials on any legal grounds.

15. Nothing in this Protective Order shall preclude any Participant from requesting the Presiding Judge, the Commission, or any other body having appropriate authority, to find that this Protective Order should not apply to all or any materials previously designated as Protected Materials pursuant to this Protective Order. The Presiding Judge may alter or amend this Protective Order as circumstances warrant at any time during the course of this proceeding.

16. Each party governed by this Protective Order has the right to seek changes in it as appropriate from the Presiding Judge or the Commission.

17. All Protected Materials filed with the Commission, the Presiding Judge, or any other judicial or administrative body, in support of, or as a part of, a motion, other pleading, brief, or other document, shall be filed and served in sealed envelopes or other appropriate containers bearing prominent markings indicating that the contents include Protected Materials subject to this Protective Order. Such documents containing Critical Energy Infrastructure Information shall be additionally marked "Contains Critical Energy Infrastructure Information - Do Not Release."

18. If the Presiding Judge finds at any time in the course of this proceeding that all or part of the Protected Materials need not be protected, those materials shall, nevertheless, be subject to the protection afforded by this Protective Order for three (3) business days from the date of issuance of the Presiding Judge's determination, and if the Participant seeking protection files an interlocutory appeal or requests that the issue be certified to the Commission, for an additional seven (7) business days. None of the Participants waives its rights to seek additional administrative or judicial remedies after the Presiding Judge's decision respecting Protected Materials or Reviewing Representatives, or the Commission's denial of any appeal thereof. The provisions of 18 C.F.R. §§ 388.112 and 388.113 shall apply to any requests under the Freedom of Information Act (5 U.S.C. § 552) for Protected Materials in the files of the Commission.

19. Nothing in this Protective Order shall be deemed to preclude any Participant from independently seeking through discovery in any other administrative or judicial proceeding information or materials produced in this proceeding under this Protective Order.

20. None of the Participants waives the right to pursue any other legal or equitable remedies that may be available in the event of actual or anticipated disclosure of Protected Materials.

21. The contents of Protected Materials or any other form of information that copies or discloses Protected Materials shall not be disclosed to anyone other than in accordance with this Protective Order and shall be used only in connection with this (these) proceeding(s). Any violation of this Protective Order and of any Non-Disclosure Certificate executed hereunder shall constitute a violation of an order of the Commission.

Presiding Administrative Law Judge