

CURTIS, HEINZ, GARRETT & O'KEEFE, P. C.

ATTORNEYS AT LAW

130 SOUTH BEMISTON, SUITE 200

ST. LOUIS, MISSOURI 63105

(314) 725-8788

FAX (314) 725-8789

CARL J. LUMLEY
PRINCIPAL

CLUMLEY@LAWFIRMEMAIL.COM

RECEIVED

April 22, 2008

APR 24 2008

Adjudication Division
Public Service Commission

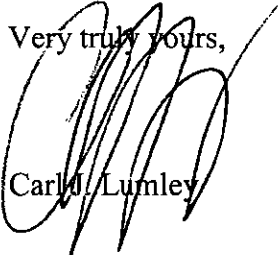
Honorable Nancy Dippell
Missouri Public Service Commission
200 Madison Street
P.O. Box 360
Jefferson City, MO 65102-0360

Re: *Case No. EM-2007-0374*

Dear Judge Dippell:

We were unable to verify whether or not we previously provided a copy of Exhibit 700, the Rebuttal Testimony of Dogwood Energy, LLC's witness Robert Janssen in the above-referenced matter to the Court Reporter at the start of the hearing last December. Accordingly, a copy is enclosed herewith. Thank you.

Very truly yours,


Carl J. Lumley

CJL:dn
Enclosure
cc. Parties of Record (W/O Enclosure)

FILED

APR 25 2008

**Missouri Public
Service Commission**

Exhibit No.: 700
Issue: RTO Membership and Combined
Balancing Authority Area
Witness: Robert Janssen
Sponsoring Party: Dogwood Energy, LLC
Type of Exhibit: Rebuttal Testimony
Case No.: EM-2007-0374

BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION

In the Matter of the Joint Application of Great Plains)
Energy Incorporated, Kansas City Power & Light)
Company, and Aquila, Inc., for Approval of the Merger) Case No. EM-2007-0374
of Aquila, Inc., with a Subsidiary of Great Plains)
Energy Incorporated and for Other Related Relief.)

**REBUTTAL TESTIMONY OF
ROBERT JANSSEN ON BEHALF OF
DOGWOOD ENERGY, LLC**

Carl J. Lumley, #32869
Leland B. Curtis, #20550
CURTIS, HEINZ, GARRETT & O'KEEFE, P.C.
130 S. Bemiston, Suite 200
Clayton, Missouri 63105
(314) 725-8788
(314) 725-8789 (Fax)
clumley@lawfirmemail.com
lcurtis@lawfirmemail.com

ATTORNEYS FOR DOGWOOD ENERGY, LLC

STATE OF District of Columbia)
)
COUNTY OF _____) SS.

BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION

In the Matter of the Joint Application of Great Plains)
Energy Incorporated, Kansas City Power & Light)
Company, and Aquila, Inc., for Approval of the Merger) Case No. EM-2007-0374
of Aquila, Inc., with a Subsidiary of Great Plains)
Energy Incorporated and for Other Related Relief.)

AFFIDAVIT OF ROBERT JANSSEN

COMES NOW Robert Janssen, of lawful age, sound of mind and being first duly sworn, deposes and states:

1. My name is Robert Janssen, I am Vice President for Kelson Energy, Inc., the corporate parent of Dogwood Energy, LLC.

2. Attached hereto and made a part hereof for all purposes is my Rebuttal Testimony in the above-referenced case.

3. I hereby swear and affirm that my statements contained in the attached testimony are true and correct to the best of my knowledge, information and belief.

Robert J Janssen

Robert Janssen

SUBSCRIBED AND SWORN to before me, a Notary Public, this 9th day
of October, 2007

Graciela V. Baten
Notary Public

My Commission Expires:
(SEAL)

GRACIELA V. BATEN
Notary Public District of Columbia
My Commission Expires October 15, 2008

REBUTTAL TESTIMONY OF
ROBERT JANSSEN ON BEHALF OF
DOGWOOD ENERGY, LLC

1 **Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND TITLE.**

2 A. My name is Robert Janssen. My business address is 6700 Alexander Bell Drive,
3 Suite 360, Columbia, MD 21046. I have held the position of Vice President for
4 Kelson Energy Inc. ("Kelson") since February 2007. From October 2005 to
5 February 2007, I was a Director with Kelson. I also hold the position of President
6 of Redbud Energy, L.P., which is a 1,200 MW generating facility wholly owned
7 by Kelson and located in Oklahoma.

8 **Q. ON WHOSE BEHALF ARE YOU TESTIFYING?**

9 A. I am testifying on behalf of Dogwood Energy, LLC ("Dogwood").

10 **Q. WHAT IS THE RELATIONSHIP BETWEEN DOGWOOD AND KELSON**
11 **ENERGY?**

12 A. Kelson is a power generation holding company that wholly owns Dogwood and
13 the Dogwood 600 MW combined cycle generating facility located in Aquila's
14 Missouri Public Service ("MPS") service territory.

15 **Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND**
16 **PROFESSIONAL EXPERIENCE.**

1 A. I have attached a copy of my resume as Schedule RJ1, which outlines my relevant
2 background and experience. In brief, my experience includes (a) development
3 and management of generating facilities, (b) analysis of electricity markets and
4 transmission systems, (c) analysis of, and development of testimony regarding,
5 utility rates and other filings before federal and state regulatory commissions, (d)
6 due diligence analysis of power purchase agreements and fuel contracts, (e)
7 financial analysis of utility and independent power producer assets such as power
8 plants and water supply systems, and (f) monitoring and reviewing the results of
9 power supply Requests for Proposals.

10 Q. **WHAT ARE YOUR RESPONSIBILITIES?**

11 A. In my current position, I am responsible for, among other things, the operations of
12 the Redbud Energy generating facility, representing Kelson and its subsidiaries at
13 the Southwest Power Pool ("SPP") Regional Transmission Organization
14 ("RTO"), state and federal regulatory affairs, power market development, and
15 North American Electric Reliability Corporation ("NERC") compliance for
16 approximately 4,000 MW of Kelson's generating capacity within the United
17 States, including Dogwood's Missouri facility. This includes coordinating
18 Dogwood's potential future participation in electricity markets in SPP.

1 **Q. HAVE YOU TESTIFIED IN OTHER REGULATORY PROCEEDINGS?**

2 A. Yes, I have submitted written testimony in eight prior proceedings before the
3 Federal Energy Regulatory Commission, the Louisiana Public Service
4 Commission, the Oklahoma Corporation Commission, the Public Service
5 Commission of Wisconsin, the City Council of New Orleans, and the Public
6 Utility Commission of Texas.

7 **Q, DO YOU HOLD THE OPINIONS YOU EXPRESS IN THIS TESTIMONY**
8 **TO A REASONABLE DEGREE OF CERTAINTY AS AN EXPERT**
9 **REGARDING ELECTRICAL POWER GENERATION AND**
10 **TRANSMISSION?**

11 A. Yes.

12 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

13 A. In this testimony, I recommend that the Commission condition its approval of the
14 proposed acquisition of Aquila, Inc. by Great Plains Energy ("GPE") and
15 resulting merger of Aquila with KCPL so as to require Aquila to join SPP with
16 KCPL and to require that Aquila and KCPL consolidate their Balancing Authority
17 ("BA") areas.¹

¹ The term "Balancing Authority" refers to an entity, such as a utility or an RTO, that is responsible for maintaining a balance between loads and resources within a particular area. Specifically, this entity integrates resource plans ahead of time, maintains load-interchange-generation balance within an area defined by metered boundaries, and supports Interconnection frequency in real-time.

1 **Q. WHAT IS AT STAKE FOR DOGWOOD IN THIS PROCEEDING?**

2 A. Aquila and KCP&L are potential customers of Dogwood's generating capacity.
3 Dogwood's ability to serve both companies future generation supply needs will be
4 enhanced if their BAs are consolidated, which should benefit the customers of
5 both utilities. Further, Dogwood's generating facility will "move" with Aquila's
6 transmission facilities into whichever RTO Aquila ultimately joins, so Dogwood
7 believes that its interests are aligned with those of Aquila and its customers in
8 ensuring robust access to both transmission and power supplies in the region.
9 Finally, as a potential transmission customer of Aquila, Dogwood benefits from
10 Aquila's transmission facilities being operated in the most efficient manner
11 possible under a consolidation with KCP&L under the SPP RTO.

12 **Q. AT PAGES 7-9 OF HIS DIRECT TESTIMONY, GPE/KCP&L WITNESS**
13 **RICHARD SPRING DESCRIBES THE PURPOSES, BENEFITS AND**
14 **FUNCTIONS OF RTOS. DO YOU AGREE WITH HIS TESTIMONY IN**
15 **THIS REGARD?**

16 A. Yes. Mr. Spring correctly describes how RTOs facilitate open and non-
17 discriminatory electric transmission access and pricing, with regional open access
18 tariffs, planning, and coordinated reliability operations. In particular, regarding
19 regional transmission expansion planning, KCPL provided the following
20 additional information in response to Dogwood Data Request 2-14:

1 KCPL is a SPP RTO member and SPP currently performs the Planning
2 Coordinator function for KCPL on a regional basis. KCPL participates in
3 the SPP regional planning process which includes an annual transmission
4 reliability assessment of the SPP RTO footprint. The SPP Transmission
5 Expansion Plan (STEP) analyzes the transmission system for compliance
6 with NERC Reliability Standards and SPP Criteria. Where standard or
7 criteria violations exist, SPP and Transmission Owners (i.e. KCPL) work
8 together to develop mitigation plans that eliminate problems. These
9 mitigation plans may include new or upgraded transmission facilities. The
10 STEP also performs a screening analysis of potential economic
11 transmission projects. These assessments do not study individual control
12 area transfer capability but rather projects that may improve transmission
13 congestion across the SPP footprint. These projects are ranked based on a
14 cost/benefit analysis of generation dispatch cost savings compared to the
15 cost of the potential project. These projects are typically bulk
16 transmission projects (345kV and above) not required by standards or
17 criteria that cross multiple control areas and/or states and would require
18 project sponsors to actually agree to fund and construct.

19 As part of the planning process, SPP also performs an Aggregate Study
20 three times per year that collectively analyzes specific transmission
21 service requests, including service associated with generation
22 interconnection requests, across the SPP footprint. These service
23 reservations are modeled based on control area to control area transfers.
24 The transmission system is assessed with these potential service requests
25 and, where needed, transmission improvements are identified that would
26 enable the service to occur without standard or criteria violations. Once
27 the customer that has made the service request agrees to the conditions of
28 the system improvement the project is included in the STEP.

29 **Q. WHAT IS YOUR UNDERSTANDING OF THE CURRENT STATUS OF**
30 **KCP&L AND AQUILA REGARDING RTO PARTICIPATION?**

31 **A.** As Mr. Spring testifies, KCP&L is a member of the SPP and has turned over
32 functional control of its transmission facilities to SPP (see my answer to the
33 previous question for additional detail), whereas Aquila is a conditional member
34 of the Midwest Independent Transmission System Operator (MISO). (Spring

1 Direct, p. 7, 9). However, according to Aquila's response to Dogwood Data
2 Request 2-11, "Aquila is in the transmission footprint of SPP and all point to
3 point service requests are processed through SPP."

4 **Q. WHAT IS YOUR UNDERSTANDING OF THE PLAN FOR THE**
5 **MERGED KCP&L/AQUILA REGARDING RTO PARTICIPATION?**

6 A. I am uncertain as to the plan, as there is conflicting information available. On the
7 one hand, Mr. Spring seems to testify that there is a strong desire to operate the
8 combined entities in a single RTO. He describes the "proposed action plans for
9 combining the Aquila transmission operations and facilities into KCPL once the
10 merger is completed", including that both entities will be run out of a single
11 transmission control center. (Spring Direct, p. 6). He also testifies that "there are
12 significant benefits for operating the resulting combined organization within a
13 single RTO structure." (Spring Direct, p. 9). He lists various benefits that
14 KCP&L would expect to realize from a single RTO membership, including:

- 15 - avoidance of transmission seam issues, with reduced flowgates,
16 simplified management of transmission capacity, and increased
17 flexibility of power transactions;
- 18 - reduced costs to support activities in governance, market development,
19 transmission planning and expansion, reliability standards development,
20 and tariff administration;

- 1 - savings related to participation in a single regional transmission tariff,
- 2 with simplified administration and minimized proceedings with FERC;
- 3 - maintenance of consistency across both companies, coordinated
- 4 transmission cost sharing, lower administrative costs, and more
- 5 congruent investment structures;
- 6 - facilitation of consistent retail rate structures;
- 7 - more effective transmission planning and expansion and avoidance of
- 8 inefficient, redundant or even conflicting solutions; and
- 9 - ensured consistent development and adherence to bulk power reliability
- 10 standards and criteria. (Spring Direct, p. 10-11).²

11 Mr. Marshall touts combined RTO membership as an aspect of transmission
12 synergy. (Marshall Supplemental Direct, p. 13). Witness Crawford testifies that
13 the companies will not realize the additional savings that would result from joint
14 dispatching of KCPL and Aquila generating resources unless Aquila joins the SPP
15 with KCPL. (Crawford Direct, p. 5-6).

16
17 On the other hand, Mr. Spring acknowledges that there is a “potential of KCPL
18 and Aquila having membership in separate RTOs.” (Spring Direct, p. 9). Further,
19 in Case No. EO-2008-0046, Aquila has applied to the Commission for authority
20 to transfer operational control of transmission assets to MISO. Dogwood requests

² KCPL has not yet quantified these benefits of single RTO participation in testimony, but discovery is pending and Dogwood or other parties may provide supplemental testimony in this regard.

1 that the Commission take notice of the proceedings in EO-2008-0046 in this case.

2 A copy of the Application from that case (without appendices) is attached hereto

3 as Schedule RJ2. A copy of the Direct Testimony of Dennis Odell submitted by

4 Aquila in that case (without attachments) is attached hereto as Schedule RJ3.

5 **Q. HOW DO KCP&L AND AQUILA PROPOSE TO RESOLVE THE ISSUE**
6 **OF APPROPRIATE RTO MEMBERSHIP?**

7 A. Again, the picture is murky. Mr. Spring indicates a desire by KCPL to evaluate
8 the strategy of RTO membership when the merger is completed. (Spring Direct, p.
9 9). Witness John Marshall makes the same statement. (Marshall Direct, p. 7).
10 However, as indicated above, Aquila has actively petitioned the Commission to
11 authorize it to join MISO, which would seem to effectively preclude any post-
12 merger evaluation, at least for a significant period of time. In my opinion, it is not
13 a simple matter for a company to jump in and out of RTO membership even
14 within a matter of years. The information contained in Schedules RJ2 and RJ3
15 demonstrates that there would be contractual limitations on the timing of an exit
16 from an RTO.

17 **Q. WHAT IS DOGWOOD'S POSITION CONCERNING THE PROPOSED**
18 **MERGER?**

19 A. Based on its current understanding of the materials that have been made available
20 to it, Dogwood generally supports the merger as being in the best interests of both

1 Aquila and KCPL, as well as customers. However, we believe that conditions
2 should be imposed concerning RTO membership and consolidation of the two
3 companies' Balancing Authority areas. We do not currently take a position on
4 other issues raised by the parties.

5 **Q. WHAT CONDITION SHOULD BE IMPOSED REGARDING RTO**
6 **MEMBERSHIP?**

7 **A.** The Commission should require Aquila to join the SPP RTO with KCPL as soon
8 as practicable.

9 Without question, Aquila needs to join an RTO. In light of the significant
10 benefits that would attend membership in a single RTO by Aquila and KCPL, and
11 in light of KCPL's established membership in SPP, Aquila needs to join SPP. I
12 agree with Mr. Spring's description of the various benefits of membership in a
13 single RTO, as summarized above. Also, as described below, the net financial
14 benefits of Aquila joining the SPP are substantially higher than any benefits of it
15 joining MISO (even before the benefits of a merged entity with a single RTO
16 membership are considered).

17 Aquila seems to have applied for authority to join MISO to fulfill what have
18 become stale commitments rather than to address the public interests at stake in
19 the new opportunities presented by the merger application. In its application in

1 Case No. EO-2008-0046, Aquila describes how it agreed to join MISO in 2001 in
2 connection with a merger application to FERC, when MISO was the only
3 approved RTO in existence accessible to Aquila and when Aquila expected
4 AmerenUE to function as if it were a part of MISO. Aquila also describes how
5 there were subsequent delays in AmerenUE joining MISO, which resulted in
6 Aquila withdrawing pending applications to join MISO due to its dependence
7 upon AmerenUE for physical connection to the MISO area. In its Application,
8 Aquila describes additional starts and stops in its process of attempting to join
9 MISO, including dismissal of a pending application by this Commission to allow
10 for completion of comparative cost/benefit studies regarding joining SPP versus
11 MISO.

12 With its application in Case No. EO-2008-0046, Aquila submitted a copy of the
13 comparative cost/benefit analysis as Appendix G. A copy is attached hereto as
14 Schedule RJ4. The study demonstrates that there would be a \$66 million (or four
15 times) greater benefit for Aquila to join SPP (again, even before considering the
16 benefits of a merged entity being in a single RTO). The study describes in detail
17 how those greater benefits flow from Aquila's greater involvement and connection
18 with SPP.

1 For these reasons, Dogwood has intervened in Case No. EO-2008-0046 to oppose
2 Aquila's request in that case for authority to transfer operational control of
3 transmission assets to MISO.

4 In my opinion, the Commission should not be constrained by any prior
5 commitment that Aquila may have made to MISO and should require Aquila to
6 join the SPP in light of all the benefits that would flow from such membership.
7 Furthermore, RTO membership is too important to leave unresolved in this
8 merger proceeding as KCPL seems to propose.

9 **Q. WHAT CONDITION SHOULD BE IMPOSED REGARDING**
10 **BALANCING AUTHORITY?**

11 A. The Commission should require Aquila and KCPL to promptly begin operating
12 out of a combined balancing authority as soon as practicable after the merger.
13 Mr. Marshall testifies that if the two companies "align operations in a single
14 control area, there are likely to be numerous benefits in areas such as load
15 following, outage planning, and spinning reserves." (Marshall Supplemental
16 Direct, p. 6). He indicates that Energy Resource Management savings will be
17 realized when "the combined companies are able to operate from a single control
18 area." (Marshall Supplemental Direct, p. 18). KCPL elaborates on this point in the
19 response to Dogwood Data Request 2-21, as follows:

1 A portion of the ERM synergies are planned to be realized on day one.
2 These are mainly in the back office functions of power sales accounting,
3 in the Energy Resource Management analysis area and in the fuels areas
4 where there is modest redundancy. Additional savings are possible with
5 consolidation of control area operations.³ Consolidation would eliminate
6 redundant functions such as the need for two sets of control operators. To
7 the extent the companies can consolidate control area operations, benefits
8 could be gained without SPP control area consolidation. There is
9 currently a significant amount of uncertainty surrounding Aquila's RTO
10 participation. It is uncertain when or even what RTO Aquila will
11 ultimately participate in. There is also significant uncertainty surrounding
12 the design and timing of future phases of the SPP market structure.
13 Discussions are currently underway with SPP and their membership to
14 consolidate control areas under the SPP. Timing of this is also uncertain.
15 KCP&L anticipates that in 2010 SPP may evolve into a fully functional
16 RTO. If the SPP market evolves sooner than this, possibly in late 2009,
17 the benefits may be able to be recognized sooner.

18 As Witness Crawford testifies, combining control area operations (Balancing
19 Authority area operations) is necessary to achieve the savings associated with
20 joint dispatching of generating resources.⁴ (Crawford Direct, p. 5-6). In response
21 to Dogwood Data Request 2-5, KCP&L explains that:

22 In theory, control area consolidation would reduce the amount of
23 regulating capacity needed to maintain NERC control performance
24 standards. This would reduce the cost of regulation. Potential benefits
25 from reduced regulating capacity needs have not been quantified.

26 The Commission should ensure that the benefits of BA consolidation will be
27 realized in connection with the merger.

³ In this context, Control Area is synonymous with Balancing Authority area. The term Control Area predates NERC's recent revisions to its functional model, wherein it developed the term Balancing Authority to more precisely define certain functions associated with a Control Area.

⁴ Dogwood has not been able to review cost and benefit information on this point at this time, because it has been required to review that information at applicant's premises pursuant to Dogwood Data Request 2-1.

1 **Q. ARE YOU AWARE OF THE ONGOING DISCUSSIONS WITHIN SPP**
2 **REGARDING THE CONSOLIDATION OF BALANCING AUTHORITIES**
3 **WITHIN THE SPP FOOTPRINT?**

4 A. Yes. These discussions have been going on for many years, but are finally
5 reaching fruition. During February 2005 in Docket Nos. RT01-4 and ER04-48,
6 SPP filed a report with FERC on the potential for BA consolidation associated
7 with the development of the Energy Imbalance Service ("EIS") Market in SPP. In
8 that filing, SPP asserted that the benefits of consolidation would outweigh the
9 costs, and the consolidation would be pursued after the start-up of the EIS
10 Market.⁵ Consistent with that obligation, SPP BAs are currently engaged in a
11 discussion regarding this consolidation, and it is my understanding that these
12 discussions are moving forward in a positive manner and many of the SPP BAs
13 are in favor of it. Contrary to statements by KCP&L witnesses in testimony, SPP
14 Staff has targeted 2008 as the year for the consolidation to be completed.⁶

15

⁵ SPP successfully started up its EIS Market on February 1, 2007. This market is designed to allow all participating generating facilities within SPP to be centrally dispatched on an economic basis by SPP to serve the load following needs of the load serving entities within the SPP Market footprint. Aquila is not currently in the SPP Market footprint, and as a result, does not receive the benefits of common centralized economic generation dispatch with the rest of SPP to meet its load following needs.

⁶ See Schedule RJ5 for a presentation from SPP Staff to its Board of Directors, wherein SPP Staff states that the target date for BA consolidation in the SPP footprint is mid- to late-2008.

1 **Q. WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION?**

2 A. On behalf of Dogwood Energy, in order for Aquila's and KCP&L's customers to
3 more fully receive the potential benefits of the proposed merger, I recommend
4 that the Commission approve the proposed merger with the following conditions
5 (in addition to such other conditions as the Commission reasonably decides to
6 impose based on the recommendations of other parties):

7 (1) Aquila should be required to join and operate its generation and
8 transmission facilities under the auspices of the SPP RTO with
9 KCPL within four months after approval of the merger⁷; and

10 (2) Aquila and KCPL should be required to consolidate their BAs within
11 six months of approval of the merger. The Commission should
12 allow KCP&L and Aquila to exceed this deadline only in the event
13 that KCP&L and Aquila provide a definite schedule and
14 commitment to the Commission, prior to the six month post-merger
15 deadline, for the two companies' participation in an overall
16 consolidation of SPP BAs to be completed no later than January 1,
17 2009.

18 **Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?**

19 A. Yes.

⁷ The standard EIS Market registration timeframe for new participants is four to six months after submission of registration materials to the SPP. However, it is possible that Aquila's participation could be accommodated more quickly since its information is already included in SPP's Energy Management System and planning models.

ROBERT J. JANSSEN

6700 Alexander Bell Drive, Suite 360 • Columbia, MD 21046 • (202) 249-0215 •
rob.janssen@kelsonenergy.com

SUMMARY OF QUALIFICATIONS

- Energy professional with a technical background and thirteen years of experience in the electricity and natural gas industries, including power plant management, acquisition, development, and financial analysis; electricity market analysis, design and monitoring; utility rate analysis and development; and expert testimony and litigation support.

EXPERIENCE

Kelson Energy, Baltimore, MD

October 2005 - Present

Vice President, Kelson and President, Redbud Energy
Vice President, Kelson and Vice President, Redbud Energy
Director, Kelson and Vice President, Redbud Energy
Director, Kelson

6/07 – Present
2/07 – 6/07
1/06 – 2/07
10/05 – 1/06

Primary Areas of responsibility include:

- Redbud Energy operations and maintenance
- NERC reliability standards compliance
- State and Federal regulatory and legislative affairs
- Market development and participation

Southwest Power Pool Committee Memberships on behalf of Redbud Energy:

- Members Committee
- Strategic Planning Committee
- Corporate Governance Committee
- Market Operations and Policy Committee

Boston Pacific Company, Inc., Washington, DC

October 1997 – September 2005

Project Director
Project Manager
Senior Consultant

10/01 – 9/05
10/98 – 10/01
10/97 – 10/98

Consulting practice focusing on three primary areas:

- Power Plant Development, Acquisition and Sale Support
- Electricity Market Analysis, Design and Monitoring
- Expert Testimony and Litigation Support

UGI Utilities, Inc., Reading, PA

July 1994 – October 1997

Commercial Engineer II
Industrial & Commercial Marketing Engineer I

5/96 – 10/97
7/94 – 5/96

Served as a technical expert and program manager for the Industrial and Commercial marketing department.

EDUCATION

University of Pennsylvania: GPA 3.39 / 4.00
B.S. in Mechanical Engineering with a Minor in Economics

1990-1994

Johns Hopkins University: GPA 4.00 / 4.00
Finance and Accounting Graduate Level Classes:

2000-2002

- Financial Accounting
- Managerial Finance
- Corporate Financial Theory

**BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI**

In the Matter of the Application of)	
Aquila, Inc., d/b/a Aquila)	
Networks – MPS and Aquila)	
Networks – L&P for Authority to)	Case No.
Transfer Operational Control of)	
Certain Transmission Assets)	
to the Midwest Independent)	
Transmission System Operator, Inc.)	

APPLICATION

COMES NOW Aquila, Inc., d/b/a Aquila Networks – MPS and Aquila Networks – L&P (“Aquila”) in accordance with § 393.190 RSMo. 2000 and 4 CSR 240-3.110, and for its Application to transfer operational control of certain transmission assets to the Midwest Independent Transmission System Operator, Inc. (“MISO”), states to the Missouri Public Service Commission (“Commission”) as follows:

The Applicant

1. Aquila is a Delaware corporation with its principal office and place of business at 20 West Ninth Street, Kansas City, Missouri 64105. Aquila is authorized to conduct business in Missouri through its Aquila Networks – MPS and Aquila Networks – L&P operating divisions and, as such, is engaged in providing electrical and heating utility services in Missouri in those areas certificated to it by the Commission. A certified copy of Aquila's amended Certificate of Authority to do business in this state as a foreign corporation was filed with the Commission in Case No. EU-2002-1053 and said documents are incorporated herein by reference in accordance with 4 CSR 240-2.060(1)(G).

Likewise, copies of the Registrations of Fictitious Name of Aquila Networks – MPS and Aquila Networks – L&P were filed in Case No. EU-2002-1053 and said documents are incorporated herein by reference in accordance with 4 CSR 240-2.060(1)(G).

2. Aquila is an “electrical corporation,” a “heating company,” and a “public utility” as those terms are defined in §386.020 RSMo. 2000. Consequently, it is subject to the jurisdiction and supervision of the Commission as provided by law.

3. Other than as set forth in the attached **Appendix A**, Aquila has no pending or final judgments or decisions against it from state or federal regulatory agencies or courts which involve customer service occurring within the three (3) years immediately preceding the filing of this Application.

4. Aquila has no overdue Commission annual reports or assessment fees.

5. Pleadings, notices and orders and other correspondence and communications concerning this Application should be addressed to the following individuals:

Gary Clemens, Director of Regulatory Services
Aquila, Inc.
20 West Ninth Street
Kansas City, Missouri 64105
Telephone: (816) 467-3807
Email: gary.clemens@aquila.com

Paul A. Boudreau
Brydon, Swearengen & England, PC
312 East Capitol Avenue
P. O. Box 456
Jefferson City, Missouri 65102-0456
Telephone: (573) 635-7166
Facsimile: (573) 636-6450
Email: paulb@brydonlaw.com

The Midwest Independent Transmission System Operator

6. MISO, founded on February 12, 1996, is the nation's first Regional Transmission Organization ("RTO") to receive the approval of the Federal Energy Regulatory Commission ("FERC"). MISO is based in Carmel, Indiana, and is responsible for monitoring the electric transmission system that delivers power from generating plants to member wholesale power transmitters and load serving entities. MISO's role is to ensure equal access to the transmission system and to maintain or improve electric system reliability in the Midwest. MISO's primary objective is to "direct traffic" on the wholesale bulk electric power lines. In this role, MISO endeavors to ensure that every electric industry participant has access to the lines and that no entity has the ability to deny access to a competitor. MISO also manages the use of the electric transmission lines under its control to make sure that they do not become overloaded. MISO began selling transmission service under its FERC tariff on February 1, 2002. As of April 1, 2005, MISO also operates day-ahead and real-time wholesale energy markets within its region.

Purpose of Filing

7. The purpose of this filing is to obtain the approval of the Commission to transfer to MISO operational control of those same portions of the

Aquila transmission system in Missouri which were the subject of the FERC Application to the extent such approval may be required under § 393.190.1 RSMo. 2000. See, ¶9, *infra*.

Historical Context for Filing

8. In 1999, Aquila (f/k/a UtiliCorp United Inc. (UtiliCorp)) entered into an Agreement and Plan of Merger with St. Joseph Light & Power Company which was subject to various regulatory approvals, including the approval of the Commission¹ and FERC. Aquila's FERC application coincided with the issuance of FERC Order 2000 that embodied, among other things, FERC's expectation that electric utilities join an RTO. Consequently, its order approving the merger contained a requirement that the merged company file a plan to join an RTO. MISO was the only FERC-approved RTO then in existence. Aquila entered into an agreement to join MISO on July 16, 2001. Its decision to join MISO also was based on the understanding that MISO would be operational on December 15, 2001, and that AmerenUE would function as if it were a part of the MISO footprint through its involvement in the Alliance RTO. The Alliance RTO and MISO were parties to an Inter-RTO Coordination Agreement which provided for the two entities to coordinate activities for transmission and transmission-related services in order to eliminate the effect of seams separating the two entities so that the regions would be able to operate as a seamless market. However, on December 20, 2001, FERC issued an order finding that the Alliance entity lacked sufficient scope to be an RTO and, on April 25, 2002, FERC issued an order requiring

¹ The Commission issued a Report and Order approving the merger on December 14, 2000, in its Case No. EM-2000-292. Thereafter, on February 26, 2004, the Commission issued a Second Report and Order upon remand from the Missouri Supreme Court.

AmerenUE and other Alliance participants to join other RTOs. AmerenUE subsequently decided to join MISO through GridAmerica LLC, but such participation was not effective until May 1, 2004.

9. On August 20, 2001, Aquila (then, UtiliCorp) filed with FERC an Application to transfer operational control over certain designated transmission facilities to MISO, pursuant to § 203 of the Federal Power Act, 16 USC §824b, as required by FERC Order 2000. A copy of that filing (the "FERC Application") is attached hereto as **Appendix B**.² The FERC Application requested FERC approval to transfer to MISO operational control for portions of the Aquila transmission system in Missouri, 100 kV and above, and other systems in another state. FERC, in an Order Authorizing Disposition of Jurisdictional Facilities issued September 13, 2001, approved the transfer subject to certain specified conditions. See, 96 FERC ¶ 62,256 (attached hereto as **Appendix C**). On November 14, 2001, Aquila filed with FERC a supplemental application in order to list certain additional facilities that had been inadvertently omitted from the August 20, 2001 application. FERC issued an order on December 13, 2001 approving the supplemental application. A copy of the supplemental FERC application is attached hereto as **Appendix D** and the December 13, 2001 FERC order is attached as **Appendix E**.³

² A map depicting MPS and SJLP transmission facilities as originally supplied to the FERC in Exhibit K has been replaced with a more current map of the Aquila transmission system in Missouri.

³ As a result of a subsequent decision of the United States Court of Appeals for the District of Columbia Circuit, *Atlantic City Electric Co. et al. v. FERC*, 295 F.3d 1 (D.C. Cir. 2002), FERC approval under Section 203 of the Federal Power Act is no longer required for a transmission owner to transfer operational control over its transmission facilities to an RTO.

10. Aquila also filed applications for approval to transfer operational control of certain of its transmission assets with the Kansas Corporation Commission (KCC) and the Commission⁴ on November 8, 2001, and August 29, 2001, respectively. The KCC approved Aquila's request on December 18, 2001.

11. UtiliCorp was one of the original transmission-owning members of Southwest Power Pool (SPP) and historically had obtained security coordination services from SPP. On July 12, 2001, however, FERC rejected SPP's initial application to become an RTO. As a result, Aquila transferred security coordination responsibilities from SPP to MISO on December 15, 2001, in anticipation of the commencement of its operations as an RTO which was to begin that month.

12. Because AmerenUE had withdrawn from membership in MISO⁵, which left Aquila with no physical connection to the MISO control area, Aquila withdrew its application for Commission approval to join MISO on January 2, 2002.

13. On December 20, 2002, Aquila filed with FERC a protest against MISO challenging the reasonableness of certain administrative costs being assessed by MISO pursuant to Schedule 10-B to the MISO tariff. MISO's proposed Schedule 10-B was assigned Docket No. ER02-871-000. That case was resolved by settlement, (hereinafter, the "MISO Settlement"); one of the terms included a commitment by Aquila to re-file for Commission approval to

⁴ Case No. EO-2002-125.

⁵ FERC denied RTO status to the Alliance RTO on December 20, 2001.

transfer to MISO operational control of its transmission facilities by June 22, 2003, and to diligently pursue said approval.

14. In accordance with the terms of the MISO Settlement and Aquila's expectation of an electrical connection to the MISO control area through AmerenUE's participation, Aquila filed with the Commission its second Application to participate in the MISO RTO on June 20, 2003, a case docketed by the Commission as Case No. EO-2003-0566. The proceedings in that case were continued on a number of occasions, initially to assess the outcome of the then-pending Commission Case No. EO-2003-0271, a case concerning AmerenUE's application to transfer operational control of its transmission system to MISO and a companion filing at the FERC level. Subsequent continuances were permitted to allow for the completion of comparative cost/benefit studies being prepared by, or on behalf of, the SPP Regional State Committee and MISO.⁶ That Application was dismissed by the Commission on May 12, 2005, without prejudice to be refiled at such time as additional system cost information became available.

15. The Commission on February 26, 2004, in Case No. EO-2003-0271 approved AmerenUE's participation in MISO for an interim period of five (5) years subject to FERC's approval. On March 25, 2004, FERC approved the Service Agreement between MISO and AmerenUE.

16. The KCC rescinded Aquila's authority to participate in MISO by separate orders dated February 23, 2005 and September 15, 2005. The KCC concluded that "significant changes" concerning the options available to Aquila

⁶ FERC granted the SPP RTO status on January 24, 2005.

had occurred since the issuance of its December 2001 order; specifically, that FERC had approved SPP as an RTO. The KCC concluded its prior order was no longer in the public interest.

17. On September 21, 2005, Aquila announced that Mid-Kansas Electric Company, a coalition of six consumer-owned cooperatives that also own Sunflower Electric Power Corporation, a regional generation and transmission service provider, had agreed to purchase the assets and liabilities of Aquila's electric operations in the State of Kansas. The transaction closed on April 1, 2007.

18. On September 28, 2005, Kansas City Power & Light Company ("KCPL") and The Empire District Electric Company each filed with the Commission separate applications to transfer operational control of their respective electric transmission systems to SPP. Those cases were docketed by the Commission, respectively, as Case Nos. EO-2006-0142 and EO-2006-0141. Those applications both were approved by the Commission on June 13, 2006.

19. On April 4, 2007, Great Plains Energy Incorporated ("GPE"), KCPL and Aquila filed a Joint Application with the Commission requesting authority to undertake a series of transactions whereby Aquila, like KCPL, will become a wholly-owned subsidiary of GPE. That filing was docketed by the Commission as Case No. EM-2007-0374. The Commission subsequently adopted a procedural schedule that set the hearing dates on December 3-14 with post-hearing briefing to be completed by January 11, 2008.

Miscellaneous Filing Requirements

20. As to the material required by 4 CSR 240-3.110 (1)(A), Aquila states that the property involved in the transaction is Aquila's transmission facilities, 100 kV and above, located in the State of Missouri (the "Facilities"). A map showing the involved system is contained in Appendix B, Exhibit K.

21. As to the material required by Commission rule 4 CSR 240-3.110 (1)(B), Aquila states that there is no agreement to "sell" the Facilities. The currently effective version of the agreement that is the subject of the transaction (the Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc. ("MISO Agreement")) is attached hereto as **Appendix F**.⁷ As a transmission-owning member of the MISO Agreement, Aquila is obligated to transfer operational control over its transmission facilities upon receipt of all required regulatory approvals. The MISO Agreement further obligates Aquila to pay annual membership fees to MISO and to follow operational directions of MISO once its transmission facilities are under MISO's control. Pursuant to Article V, Section I to the MISO Agreement, unless otherwise permitted under Article VII, a transmission owner member may withdraw from the MISO Agreement as of December 31 of the year after the year in which a notice of withdrawal is provided, subject to FERC approval and payment of an "exit fee" determined by MISO. Article VII provides that any transmission owner member may withdraw from the MISO Agreement

⁷ A preceding agreement by and between UtiliCorp and MISO appears as Exhibit I to the FERC Application. Appendix F is a subsequent agreement that has been approved by FERC and is now effective.

within 30 days after any regulatory order denying or unreasonably conditioning such member's participation in MISO.

22. As to the material required by 4 CSR 240-3.110 (1)(D), Aquila states that there is no proposed sale. The transfer of operational control of the Facilities is not detrimental to the public interest because it furthers the interest of MISO in accordance with FERC's expressed desire to establish RTOs. FERC Order No. 2000⁸ strongly encouraged all public utilities that own, operate or control interstate transmission facilities to participate in an RTO. Additionally, FERC has found the transfer to be "consistent with the public interest" (see, Appendix C). Finally, Aquila's participation in MISO represents a net benefit of approximately \$21 million over 10 years to Aquila's retail electric customers. A copy of a cost-benefit study prepared by CRA International for Aquila in March of 2007 is attached hereto as **Appendix G**.

23. As to the material required by Commission rule 4 CSR 240-3.110 (1)(E), Aquila states that there is no "purchaser" because there is no sale of the Facilities. Additionally, Aquila does not anticipate that MISO will be subject to the jurisdiction of the Commission.

24. As to the material required by Commission rule 4 CSR 240-3.110 (1)(F), Aquila states that there is no expected impact on the tax revenues of any political subdivision in which the Facilities are located because there will be no transfer of title concerning any such Facilities from Aquila to MISO. Aquila will

⁸ *Regional Transmission Organizations*, Order No. 2000, III FERC Stats & Regs. Regs Preambles ¶ 31,089 (1999), Order on Rehearing, Order No. 2000 – A, III FERC Stats & Regs. Regs Preambles ¶ 31,092 (2000).

continue to be the owner of the Facilities and will continue to be responsible for property taxes levied thereon.

Recovery of Prudently Incurred Costs

25. Aquila anticipates that, as a result of participation in MISO, it will incur costs that generally fall into two categories: (a) FERC-approved costs and fees under the MISO tariff assessed against and paid by Aquila; and (b) other costs of participating in MISO, which Aquila may have some ability to control.⁹ Aquila seeks recognition by the Commission that all FERC-approved costs and fees addressed by item (a) above, and costs prudently incurred by Aquila and included in the description of item (b) above would be included by the Commission in Aquila's retail electric rates when properly requested.

WHEREFORE, Aquila respectfully requests the Commission to issue an order:

A. Authorizing Aquila to perform in accordance with the terms described in the MISO Agreement, and to take any and all other actions which may be reasonably necessary and incidental to Aquila's performance under the MISO Agreement and to include performance under such subsequent agreements as may be approved by FERC;

B. Authorizing Aquila, to the extent such authority is deemed necessary and appropriate, to take network integration transmission services from MISO to serve its retail native load in Missouri;

⁹ This latter category would generally include the cost of internal systems Aquila would be required to install to participate in MISO.

C. Acknowledging that if the Commission approves this Application, the Commission would consider as prudently incurred expenses, all of the FERC-approved administrative fees Aquila is assessed and all costs Aquila incurs from MISO to make prudent purchases of capacity and/or energy to serve its bundled retail load under the agreement and, thus, that those fees and costs will be included by the Commission in the cost of service for rate-making purposes for bundled retail customers in Aquila's next general electric rate case when the Commission determines the price to be charged for electricity after consideration of all relevant factors; and

D. Granting such other relief as may be deemed necessary and appropriate which is not inconsistent with the foregoing pleading.

Respectfully submitted,

/s/ Paul A. Boudreau

Paul A. Boudreau MO Bar # 33155
Brydon, Swearingen & England, P.C.
312 East Capitol Avenue
P. O. Box 456
Jefferson City, Missouri 65102-0456
Telephone: (573) 635-7166
Facsimile: (573) 636-6450
Email: paulb@brydonlaw.com

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the above and foregoing document was delivered by first class mail, electronic mail or hand delivery, on the 20th day of August, 2007, to the following:

Missouri Public Service Commission
200 Madison Street, Suite 800
P.O. Box 360
Jefferson City, MO 65102-0360

Office of the Public Counsel
Governor Office Building
200 Madison Street, Suite 650
P.O. Box 2230
Jefferson City, MO 65102-2230

/s/ Paul A. Boudreau
Paul A. Boudreau

**BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI**

**DIRECT TESTIMONY OF
DENNIS ODELL
ON BEHALF OF AQUILA, INC.
D/B/A AQUILA NETWORKS-MPS AND AQUILA NETWORKS-L&P
CASE NO. EO-2008-0046**

1 **Q. Please state your name and business address.**

2 A. My name is Dennis Odell, and my business address is 10700 E. 350 HWY, Kansas City,
3 MO 64138

4 **Q. By whom are you employed and what is your position?**

5 A. I am Senior Director, Business Planning for Aquila, Inc. ("Aquila").

6 **Q. What is your educational and professional background?**

7 A. I graduated from the University of Nebraska – Omaha with a Bachelor of Science in
8 Business Administration degree in 1992. I received a Master of Business Administration
9 degree from the same institution in 1996.
10 I joined Aquila (then UtiliCorp United, Inc.) in 1993 as a Rate Analyst. Since then I have
11 been continuously employed at Aquila in a number of positions, including Federal
12 Regulatory Manager, Director of Gas Supply Services and Director, Regulatory Services.
13 I have been in my current position since April, 2006.

14 **EXECUTIVE SUMMARY**

15 **Q. What is the purpose of your testimony?**

1 A. The purpose of my testimony is to twofold; first, to present the historical context
2 regarding Aquila's consideration and analysis of regional transmission organization
3 ("RTO") membership; second, to explain Aquila's request for Missouri Public Service
4 Commission ("MPSC") approval to become a full member of, and to turn over
5 operational control of Aquila's Missouri electric transmission system to, the Midwest
6 Independent Transmission System Operator, Inc. ("MISO").

7 **HISTORICAL CONTEXT**

8 **Q. Please describe Aquila's Missouri transmission system.**

9 A. The Aquila electric transmission system in the state of Missouri consists of 1,257 miles
10 of 345 KV, 161 KV and 69 KV transmission lines extending over an area from the
11 northwest corner of Missouri as far south as Lamar, and as far east as Sedalia, except for
12 the central Kansas City area. The system is interconnected with neighboring utilities at a
13 number of points. The interconnected utility systems are Kansas City Power & Light,
14 City of Independence Power & Light, Associated Electric Cooperative, Ameren, Westar,
15 Mid-America Electric Co., Omaha Public Power District, Nebraska Public Power District
16 and The Empire District Electric Co ("Empire"). The retail native load on the
17 transmission system consists of around 1,960 MW, and in addition Aquila provides
18 transmission service for seven municipal customers that are connected to the system.
19 Aquila also provides transmission wheeling service over the system for a number of
20 wholesale power marketing entities. The system is operated from an operations center
21 located in Lee's Summit, Missouri.

1 **Q. Please provide some historical context regarding Aquila's consideration of RTO**
2 **membership.**

3 A. In 1999, Aquila entered into an Agreement and Plan of Merger with St. Joseph Light &
4 Power Company which was subject to various regulatory approvals, including the
5 approval of the MPSC and FERC. FERC's order approving that merger contained a
6 requirement that the merged company file a plan to join an RTO. At that time, MISO
7 was the only FERC-approved RTO in the area. Consequently, Aquila entered into an
8 agreement to join MISO on July 16, 2001. A copy of the current MISO Transmission
9 Owner Agreement on file with FERC is attached to my testimony as Schedule DO-1.

10 **Q. What did Aquila do next?**

11 A. On August 20, 2001, Aquila filed with FERC an application to transfer operational
12 control over certain designated facilities to MISO. This application requested that FERC
13 approve the transfer of operational control of the Aquila transmission system in Missouri,
14 100 kV and above, as well as systems in another state, to MISO. FERC approved this
15 transfer on September 13, 2001. On November 14, 2001, Aquila filed with FERC a
16 supplemental application in order to list certain additional facilities that had been
17 inadvertently omitted from the August 20, 2001 application. FERC issued an order on
18 December 13, 2001 approving the supplemental application. Copies of these FERC
19 orders are attached to my testimony as Schedule DO-2.

20 **Q. Did Aquila also seek approval from the MPSC for this transfer?**

1 A. Aquila filed an application with the MPSC for approval to transfer operational control of
2 these facilities on August 29, 2001.

3 **Q. Was Aquila's application approved?**

4 A. No, it was not. Aquila withdrew this application on January 2, 2002.

5 **Q. Why did Aquila withdraw its application?**

6 A. Aquila was (and still is) dependent on AmerenUE for its physical connection to the
7 MISO control area. In other words, the only physical connection that Aquila has with
8 MISO is through AmerenUE. AmerenUE had withdrawn from MISO, leaving Aquila
9 with no physical connection to the RTO.

10 **Q. Did AmerenUE's withdrawal from MISO sever any relationship between Aquila**
11 **and MISO?**

12 A. No. In anticipation of turning over operational control of its Missouri transmission
13 system to MISO, Aquila had already transferred security coordination responsibilities
14 from the Southwest Power Pool ("SPP"). These security coordination responsibilities are
15 still performed for Aquila by MISO. However, on December 20, 2002, Aquila made a
16 filing with FERC challenging the reasonableness of certain administrative costs proposed
17 by MISO to be assessed against Aquila pursuant to Schedule 10-B to the MISO tariff.
18 Aquila and MISO subsequently settled that case. One of the provisions of that settlement
19 was that Aquila would file again for MPSC approval to transfer operational control of
20 these facilities to MISO and would diligently pursue that approval.

21 **Q. Did Aquila file this application?**

1 A. Yes. On June 20, 2003, Aquila filed its second application with the MPSC to join MISO.
2 This case was continued a number of times, including once to allow AmerenUE's case
3 for the transfer of control of its transmission facilities to progress. Additional
4 continuances were permitted to allow for the completion of cost/benefit studies.

5 **Q. Was this application approved by the MPSC?**

6 A. No. It was ultimately dismissed by the MPSC on May 12, 2005, without prejudice to be
7 refiled at such time as additional system cost information became available.

8 **Q. What other relevant activities have taken place over the last few years?**

9 A. AmerenUE was granted approval by the MPSC to become a member of MISO. This
10 enables Aquila to become a MISO member by providing a physical connection into the
11 MISO control area. Also, FERC granted SPP RTO status on February 10, 2004. The
12 MPSC granted Kansas City Power & Light ("KCPL") and Empire approval to become
13 members of SPP. Finally, Aquila sold its Kansas operations and has filed with the MPSC
14 to transfer control over its Missouri operations.

15 **Q. Please describe the sale of Aquila's Kansas operations.**

16 A. On September 21, 2005, Aquila announced that Mid-Kansas Electric Company, a
17 coalition of six consumer-owned cooperatives that also own Sunflower Electric Power
18 Corporation, a regional generation and transmission service provider, had agreed to
19 purchase the assets and liabilities of Aquila's electric operations in the State of Kansas.
20 The transaction closed on April 1, 2007.

21 **Q. Please describe the proposed transaction regarding Aquila's Missouri operations.**

1 A. On April 4, 2007, Great Plains Energy Incorporated ("GPE"), KCPL and Aquila filed a
2 Joint Application with the MPSC requesting authority to undertake a series of
3 transactions whereby Aquila, like KCPL, will become a wholly-owned subsidiary of
4 GPE. That filing was docketed by the MPSC as Case No. EM-2007-0374. The MPSC
5 subsequently adopted a procedural schedule that sets the hearing dates for December 3-
6 14 and requires the parties to file post-hearing briefs by January 11, 2008.

7 **Q. What is Aquila's current situation regarding RTO membership?**

8 A. As previously stated, Aquila executed a Transmission Owner's Agreement with MISO in
9 2001, and is currently receiving security coordination service from MISO under Schedule
10 10-B. Aquila is receiving other services, including tariff administration, OASIS
11 administration, available transmission capacity and total transmission capacity
12 calculations, scheduling agent, and regional transmission planning from SPP.

13 **REQUEST TO JOIN MISO**

14 **Q. What is Aquila requesting in this Application?**

15 A. Aquila is requesting that the MPSC approve the transfer of operational control of the
16 Aquila transmission system in Missouri, 100 kV and above, to MISO.

17 **Q. Why is Aquila making this request?**

18 A. As described above, Aquila is obligated, as part of its FERC settlement with MISO in
19 2003, to request MPSC approval to transfer operational control of these facilities to
20 MISO and to diligently pursue that approval.

21 **Q. What support do you offer for this request?**

1 A. In 2006, Aquila contracted with CRA International ("CRA") to perform a cost-benefit
2 analysis ("Study") for Aquila Missouri electric utility operations to assess the impact of
3 potential membership in an RTO. CRA was instructed to consider three scenarios:
4 Membership in MISO, membership in SPP, and a move to a stand-alone status in which it
5 performs transmission- and reliability-related functions on its own. The Study was
6 completed on March 28, 2007, a copy of which is attached to my testimony as Schedule
7 DO-3.

8 **Q. Were other parties consulted regarding the manner in which the Study was**
9 **performed?**

10 A. Yes. Aquila held a stakeholder meeting on November 17, 2006, in which representatives
11 from the Office of Public Counsel, MISO, and SPP were present. During this meeting,
12 Aquila and representatives from CRA described the plan for the Study and offered the
13 opportunity for feedback and discussion.

14 **Q. Was the MPSC's staff ("Staff") requested to participate?**

15 A. Yes, a member of Staff was also invited, but at the last minute was unable to attend. That
16 individual subsequently was briefed on the discussion.

17 **Q. Were any additional meetings held with this group?**

18 A. Yes, another meeting with the same group of stakeholders was held after the Study was
19 completed, and additional clarifying material was developed as a result of that meeting.
20 This additional material is included as Schedule DO-4.

21 **Q. What did the Study conclude?**

1 A. The Study concluded that Aquila's membership in either RTO offers significant net
2 benefits as compared to the stand-alone case. Specifically, the net benefits over the 2008
3 – 2017 time period analyzed were over \$21 million for MISO and over \$86 million for
4 SPP. In addition, the net benefits were positive in each individual year during that period
5 for both RTOs. The Study demonstrates that joining MISO provides net benefits for
6 Aquila's customers, and as such, Aquila seeks the approval requested.

7 **Q. What is the basis for the net benefits cited in the Study?**

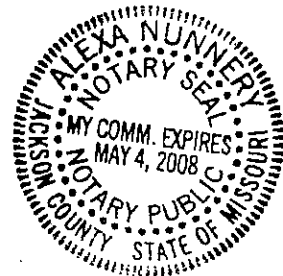
8 A. The net benefits primarily take the form of trade benefits. Trade benefits are the decrease
9 in the cost of serving Aquila's Missouri load, and come as a result of Aquila's ability to
10 displace its own generation with lower cost generation from other sources on a more
11 economical basis as a member of an RTO. There are additional savings as a result of the
12 RTO performing transmission and reliability functions that would otherwise have to be
13 performed by Aquila, but these savings are exceeded by RTO administrative charges.

14 **Q. The Study indicates that the net benefits for joining SPP are greater than the net**
15 **benefits for joining MISO. Why, then, is Aquila requesting approval to join MISO?**

16 A. Aquila is obligated, as part of its settlement with MISO in 2003, to request MPSC
17 approval to transfer operational control of these facilities to MISO and to diligently
18 pursue that approval. This study demonstrates that joining MISO provides net benefits
19 for Aquila's customers, and as such, Aquila seeks the approval requested.

20 **Q. Does this conclude your direct testimony?**

21 A. Yes.





INTERNATIONAL

RTO Cost-Benefit Analysis Aquila Missouri Electric Utility Operations

Prepared By:

CRA International

March 28, 2007

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY	1
1.1. INTRODUCTION	1
1.2. METHODOLOGY	2
1.2.1. Midwest ISO and SPP RTO Modeling	2
1.3. FINDINGS	4
1.3.1. Net Benefits of Joining an RTO	4
1.3.2. Net Benefits of Joining the Midwest ISO or the SPP RTO	5
2. ANALYTIC FRAMEWORK	7
2.1. CASES ANALYZED	7
2.2. COSTS AND BENEFITS	7
2.3. MIDWEST ISO AND SPP RTO MARKETS	8
3. ENERGY MODELING	8
3.1. MODELING ASSUMPTIONS BY CASE	9
4. BENEFITS AND COSTS	11
4.1. METHODOLOGY FOR MEASURING BENEFITS (COSTS)	11
4.2. TRADE BENEFITS	11
4.2.1. Measurement of Aquila Missouri Trade Benefits	12
4.2.2. Trade Benefit Results	13
4.3. ADMINISTRATIVE AND OPERATING COSTS	16
4.3.1. Stand-alone Costs to Provide Current SPP and Midwest ISO Functions	16
4.3.2. RTO Administrative Charges	16
4.3.3. FERC Charges	18
4.3.4. Aquila Internal RTO Market Participation Costs	18
4.4. OVERALL COST-BENEFIT RESULTS	19
4.4.1. High Gas Price Sensitivity	20
5. QUALITATIVE CONSIDERATIONS	21
6. CONCLUSION	22

7.	APPENDIX A: MAPS INPUTS	23
7.1.	TRANSMISSION.....	23
7.2.	LOAD INPUTS	24
7.3.	THERMAL UNIT CHARACTERISTICS	24
7.4.	NUCLEAR UNITS.....	26
7.5.	HYDRO UNITS	26
7.6.	WIND RESOURCES	26
7.7.	CAPACITY ADDITIONS AND RETIREMENTS	27
7.8.	ENVIRONMENTAL REGULATIONS.....	27
7.9.	EXTERNAL REGION SUPPLY	30
7.10.	DISPATCHABLE DEMAND (INTERRUPTIBLE LOAD)	30
7.11.	MARKET MODEL ASSUMPTIONS	31
7.12.	WHEELING RATES	32
7.13.	FUEL PRICES	32
7.14.	NATURAL GAS AND FUEL OIL PRICE FORECAST	33
7.14.1.	Natural Gas Forecast.....	33
7.14.2.	Fuel Oil Price Forecast.....	36
7.15.	NATURAL GAS PRICE SENSITIVITY ASSUMPTION	37
8.	APPENDIX B: AQUILA MISSOURI RESOURCES	38
9.	APPENDIX C: SUPPORTING DETAIL	39
9.1.	ANNUAL RESULTS	39
9.1.1.	Member of Midwest ISO.....	39
9.1.2.	Member of SPP RTO	39
9.2.	ADMINISTRATIVE AND OPERATING COSTS.....	40
9.2.1.	Savings from RTO Provision of Transmission Functions	40
9.2.2.	RTO Administrative Costs	43
9.2.3.	Additional FERC Charges	44

1. EXECUTIVE SUMMARY

1.1. INTRODUCTION

CRA International ("CRA") has conducted a cost-benefit analysis for the Aquila Missouri electric utility operations (collectively, Missouri Public Service and St. Joseph's Light and Power) to assess the impact of potential membership in a Regional Transmission Organization ("RTO"). Other investor-owned utilities with service territories in Missouri¹ are currently members of one of two different RTOs: 1) the Midwest Independent System Operator ("Midwest ISO")² and 2) the Southwest Power Pool ("SPP RTO")³. As such, the Aquila Missouri companies asked CRA to evaluate the costs and benefits that would accrue to the utility and its customers if Aquila Missouri were to join one of these two RTOs.

Currently, Aquila Missouri has a number of its transmission- and reliability-related functions performed by SPP and the Midwest ISO. Aquila Missouri is a transmission owner under the SPP tariff, and the Midwest ISO is the reliability coordinator for Aquila Missouri. While the potential exists for Aquila Missouri to continue this type of relationship with the two RTOs in the near future, this interim-type status is unlikely to be available over the long-term. As such, in this study it is assumed that Aquila Missouri will need to move to full market membership in the Midwest ISO or in the SPP RTO or to move to a "Stand-alone" status in which it performs (or procures) its transmission- and reliability-related functions on its own.⁴

¹ These Missouri utilities include AmerenUE, a member of the Midwest ISO, and Kansas City Power and Light ("KCP&L") and Empire District, members of the SPP RTO. Aquila Missouri is directly interconnected with the Midwest ISO through AmerenUE, and with the SPP RTO through KCP&L and Westar Energy. During the course of the preparation of this study, Aquila announced a transaction under which Great Plains Energy, the parent of KCP&L, would become the parent of Aquila. Potential impacts of this transaction on the cost-benefit results have not been considered in this study.

² The Midwest ISO covers all or part of the Canadian province of Manitoba and 15 Midwestern states, including portions of Missouri and the neighboring states of Iowa and Illinois. The market operated by the Midwest ISO provides a security-constrained unit commitment reflecting the marginal cost of providing for transmission losses, and operates a day-ahead market, a real-time market, and a financial transmission rights market.

³ SPP was originally formed as a reliability council, and covers all or parts of eight south central states, including Missouri and the neighboring states of Arkansas, Kansas, and Oklahoma. Most, but not all, of the load-serving entities in the SPP reliability region are currently members of the market operated by the SPP RTO. The SPP RTO began operation of a real-time market on February 1, 2007.

⁴ Aquila Missouri is a longstanding member of the SPP reliability council. For purposes of this study, Aquila Missouri is assumed to remain in the SPP reliability council in all cases, and thus would continue to pay the SPP annual membership fee and its allocated share of SPP's NERC assessment.

As discussed in further detail below, we have found that joining an RTO is expected to provide net benefits to Aquila Missouri. Subject to certain qualitative considerations and modeling assumptions, we have also found joining the SPP RTO to be more beneficial to Aquila Missouri than joining the Midwest ISO.

1.2. METHODOLOGY

The time horizon for this study is the 10-year period from 2008 through 2017. CRA has performed GE MAPS model runs for this period assuming Aquila Missouri is: 1) Stand-alone, 2) a member of the Midwest ISO, or 3) a member of the SPP RTO. GE MAPS is a detailed economic dispatch and production cost model that simulates the operation of the electric power system taking into account transmission topology. The model determines the security-constrained commitment and hourly dispatch of each modeled generating unit, the loading of each element in the transmission system, and the locational marginal price ("LMP") for each generator and load area. The GE MAPS model was recently used by CRA to support the U.S. Department of Energy in conducting the August 2006 National Electric Transmission Congestion Study required by the Energy Policy Act of 2005.

In comparison to the Stand-alone case, the two RTO cases are modeled in GE MAPS with Aquila Missouri: 1) having no wheeling charges for transactions with fellow RTO members, 2) committing its generating units efficiently through an RTO-wide regional optimization process, and 3) operating flowgates at higher capacity levels through market-based RTO congestion management. These factors serve to decrease impediments to Aquila Missouri trade in the RTO cases and thus yield "trade benefits" to Aquila Missouri. In this study, trade benefits are measured as the decrease in the total cost to serve Aquila Missouri load (Aquila Missouri production costs for owned and contracted capacity plus purchased power costs minus "off-system" sales revenue).⁵ These trade benefits must be compared to the additional administrative charges that Aquila Missouri would incur by being a member of an RTO.

1.2.1. Midwest ISO and SPP RTO Modeling

Currently, the Midwest ISO and SPP RTO markets are in different stages of development. The Midwest ISO has in operation a real-time market, a day-ahead market, and financial transmission rights ("FTRs"). In addition, the Midwest ISO has formal plans and budgeting to

⁵ Fixed costs that do not change between cases, such as depreciation for owned-generating units are not included in this measure. The cost to serve Aquila Missouri load has not been further separated between wholesale and retail jurisdiction in this study.

institute an ancillary services market. The Midwest ISO projects total administrative costs of roughly 36 cents per MWh of market member net energy for load over the next few years.⁶

The SPP RTO commenced operation of a real-time market on February 1, 2007. Subject to cost-benefit consideration, the SPP RTO is evaluating plans to move ahead with establishing a day-ahead market, financial transmission rights and an ancillary services market. Before consideration of these additional market developments, the SPP RTO projects administrative costs over the next few years that are approximately 20% lower per MWh of market member net energy for load than that of the Midwest ISO.

The costs and benefits of RTO market development require formal and complex study and evaluation. It is anticipated that the SPP RTO will institute additional market development if cost-benefit studies indicate that the projected benefits exceed the costs. Such analyses are beyond the scope of the type of study that can be easily performed on behalf of a non-RTO utility such as Aquila Missouri.

As such, for purposes of this cost-benefit study, it is assumed that the SPP RTO market will be similar in overall design to that of the Midwest ISO over the long-term time frame evaluated in this study. While it is unlikely that SPP would implement by 2008 the additional market developments in place at the Midwest ISO, the administrative charges charged to SPP RTO members likely will be lower than those charged to Midwest ISO members until such time as the markets become similar in design.

We have further assumed that, under base conditions, the SPP RTO administrative charges per MWh including incorporation of these additional market developments will be similar to those projected by the Midwest ISO. PJM, an RTO with markets in place similar to those of the Midwest ISO, projects administrative charges per MWh of member load similar to those projected by the Midwest ISO. With market development comparable to that of the Midwest ISO, SPP estimates, on a preliminary basis, administrative charges per MWh of market member load in roughly the same range as the Midwest ISO. SPP is currently significantly smaller in terms of market member load than the Midwest ISO and PJM. All else equal, the resulting reduction in economies of scale in operations could result in SPP administrative costs per MWh, with a comparable level of market development, being higher than those incurred by the Midwest ISO and PJM.

⁶ Administrative charges per MWh of net energy for the load of RTO market members is used in this study as a reasonable approximation for determining Aquila Missouri's administrative charges if a member of an RTO market. In practice, the RTO administrative charges are assessed using a variety of metrics. Market member load distinguishes between members participating in the RTO markets from those that are solely reliability members.

1.3. FINDINGS

1.3.1. Net Benefits of Joining an RTO

As shown in Table 1, the quantitative findings indicate a net benefit to Aquila Missouri in joining an RTO relative to Stand-alone operations. The results are the mid-2007 present value of net benefits over the 2008 to 2017 period.⁷

Table 1
2008-2017 Benefits (Costs) to Aquila Missouri of RTO Membership
in comparison to Stand-alone Status
(in millions of 2007 present value dollars; positive numbers are benefits)

	Member of Midwest ISO	Member of SPP RTO
Trade Benefits: Decrease in Cost to Serve Aquila Missouri Load	29.9	95.7
Savings from RTO Providing Reliability/Transmission Functions	16.0	16.0
RTO Administrative Charges	(23.5)	(23.5)
FERC Charges	(1.3)	(1.3)
Total Benefits (Costs)	21.1	86.9

As shown in Table 1, the trade benefits of joining an RTO, i.e., the savings in the net cost to serve Aquila Missouri load, are positive and range from \$30 to \$96 million over the 10-year study period. The savings that Aquila incurs by having the RTO perform transmission and reliability functions rather than performing or procuring these functions on a Stand-alone basis are \$16.0 million over the 10-year study period. The administrative charges that Aquila would incur for being a member of the RTO market are \$23.5 million over the 10-year study period. This is an additional cost and thus is shown as a negative benefit in Table 1. And finally, the charges paid to FERC that Aquila would be assessed as a member of an RTO would be \$1.3 million higher than if Aquila were Stand-alone over the study period.

The overall net benefit to Aquila of RTO membership is projected to be \$21 to \$87 million over the 10-year study period. In addition, the annual net benefits are projected to be positive for each year of the study period.⁸

⁷ GE MAPS runs were performed for the calendar years 2008, 2012 and 2017 with results for intervening years interpolated. A present value rate of 8.0% was applied, consistent with Aquila Missouri's after-tax cost of capital. An underlying inflation rate of 2.5% was assumed.

⁸ These quantitative results are a projection based on a number of modeling assumptions that in practice will deviate from the estimates used herein. As such, the results should be viewed as indicative of the direction of the net benefits rather than a specific computation of the precise level of net benefits that will incur with RTO entry.

A key risk factor in joining an RTO is the amount of RTO administrative charges that could be incurred. However, even if the \$23.5 million of RTO administrative charges shown in Table 1 increased by 50% from those projected in this study, there would still be considerable benefits for Aquila Missouri joining an RTO. Moreover, qualitative considerations for factors not directly addressed in the quantitative modeling, such as increased price transparency and reduced reliance on Transmission Loading Relief ("TLR") events as a member of an RTO, provide further support for the benefits of Aquila Missouri joining an RTO.

1.3.2. Net Benefits of Joining the Midwest ISO or the SPP RTO

With respect to whether it would be more economic to join the Midwest ISO or the SPP RTO, the quantitative results in Table 1 indicate a \$66 million greater benefit for Aquila Missouri being a member of the SPP RTO. As noted above, this benefit is premised on the SPP RTO having in place additional market development that it does not yet have in place, and operating these markets at costs comparable to the Midwest ISO.⁹

The greater benefits for membership in the SPP RTO appear to be primarily the result of Aquila Missouri's location and the nature of its transmission inter-ties with adjoining control areas. Aquila Missouri is located on the western side of Missouri and is heavily interconnected with KCP&L in particular. The total tie-line capacity in MVA on the transmission lines that interconnect Aquila Missouri with SPP RTO members (KCP&L and Westar Energy) is more than five times as large as the capacity on the tie-lines that interconnect Aquila Missouri with Midwest ISO market members (AmerenUE).¹⁰

Moreover, regardless of Aquila Missouri status (Stand-alone, in the Midwest ISO, or in the SPP RTO) the magnitude of the Aquila Missouri power flow to and from the SPP RTO over the tie-lines in the GE MAPS model runs is significantly higher than that to and from Midwest ISO market members. These physical inter-ties between Aquila Missouri and the SPP RTO exist regardless of whether Aquila Missouri is in the SPP RTO or the Midwest ISO. However, placing cost impediments (e.g., wheeling charges for transactions between Aquila and the SPP RTO) on these inter-ties, as would be the case if Aquila Missouri were in the Midwest ISO, provides a substantial impediment to Aquila Missouri trade.

As a result, the GE MAPS runs indicate that Aquila Missouri is able to displace control area generation, particularly gas-fired generation, with less expensive market purchases to a greater extent in the SPP RTO case. As shown in Table 2, Aquila Missouri generation, which

⁹ A high natural gas price sensitivity analysis was performed for the year 2012, and indicated that with higher gas prices, the net benefits to Aquila from joining an RTO would increase, and the net benefits of joining the SPP RTO would increase more in dollar terms than the benefits of joining the Midwest ISO.

¹⁰ NERC Multi-regional Modeling Working Group ("MMWG") 2005 series 2010 summer peak loadflow.

is roughly equal to Aquila Missouri load in the Stand-alone case, is reduced in the RTO cases, but is reduced significantly more in the SPP RTO case.¹¹

Table 2
Decrease in Aquila Missouri Generation in RTO in comparison to Stand-alone Status

	Decrease in Generation (GWh)			Decrease as Share of Net Aquila Load		
	2008	2012	2017	2008	2012	2017
In Midwest ISO	94	258	381	1%	3%	3%
In SPP RTO	1,324	2,173	2,562	15%	22%	23%

Table 2 indicates that additional economic purchases are displacing Aquila Missouri generation in the SPP RTO case through the unit commitment process and through the elimination of wheeling charges with SPP RTO members, and thereby providing additional net benefits. In particular, the gas-fired Aries combined-cycle unit is committed and generates significantly more often in the Stand-alone and Midwest ISO cases than in the SPP RTO case.¹²

Given the smaller size, in terms of market member load, of the SPP RTO, economies of scale could result in higher administrative costs per MWh for the SPP RTO with further market development. However, given the differences in Aquila Missouri net benefits found in the MAPS modeling, even a 50% greater administrative charges per MWh for the SPP RTO would not alter the quantitative advantage found in this study for Aquila Missouri being a member of the SPP RTO.

Again, however, the SPP RTO does not yet have the same level of RTO market development as the Midwest ISO and as modeled in this study. As such, uncertainty exists as to the timing of any future SPP RTO market developments and the costs that would be incurred in putting in place those developments.

¹¹ Aquila Missouri generation as used here includes generation in the Aquila Missouri control area including the merchant Aries unit, plus Aquila Missouri's share of jointly-owned units and unit purchases located outside of the Aquila Missouri control area.

¹² The Aries generation is assumed to be purchased by Aquila Missouri at prevailing market prices in all cases. The 580 MW Aries unit owned by Calpine was auctioned to Kelson Energy for \$235 million in December 2006 over Aquila Missouri's competing bid of \$230 million. To the extent that Aries output becomes contracted to entities outside of the Aquila Missouri control area, Aquila Missouri likely would need to make additional purchases and/or commit and generate more energy from the gas-fired South Harper peaking unit or other units. The additional amount needed would be greater in the Stand-alone and Midwest ISO cases and likely would further increase the relative benefit of joining the SPP RTO.

2. ANALYTIC FRAMEWORK

In this study, it is assumed that Aquila Missouri will need to move to full market membership in the Midwest ISO or in the SPP RTO or to move to a "Stand-alone" status in which it *performs (or procures) its transmission- and reliability-related functions on its own.*

2.1. CASES ANALYZED

CRA modeled three alternative cases for Aquila Missouri in this study:

- **Stand-alone case.** Aquila Missouri does not join an RTO, and performs (or procures) its transmission- and reliability-related functions on its own.
- **RTO Cases:**
 1. **Midwest ISO case.** Aquila Missouri joins the Midwest ISO as a full member of the RTO participating in all markets and paying all applicable administrative costs.
 2. **SPP RTO case.** Aquila Missouri joins the SPP RTO as a full member of the RTO participating in all markets and paying all applicable administrative costs.

In this study, the Stand-alone case is used as the reference case from which changes in costs and benefits are measured. Aquila Missouri is a longstanding member of the SPP reliability council. For purposes of this study, Aquila Missouri is assumed to remain in the SPP reliability council in all cases, and thus would continue to pay the SPP annual *membership fee and its allocated share of SPP's NERC assessment.*

2.2. COSTS AND BENEFITS

The evaluation of the costs and benefits has two basic components:

- **Trade benefits**, which are estimated using energy modeling to obtain the Aquila Missouri cost to supply its load under each case. The energy market simulation uses General Electric's MAPS tool.
- **Administrative costs**, the Aquila Missouri costs to perform transmission-related functions on its own or alternatively to pay administrative charges to the Midwest ISO or SPP RTO and interface with the RTOs.

The time horizon for the study consists of the 10-year period from 2008 through 2017. Detailed energy model simulations were performed for 2008, 2012 and 2017, and

interpolation was used to obtain energy modeling results for the other years in the study horizon.¹³ A natural gas price sensitivity is performed for the year 2012 only.

2.3. MIDWEST ISO AND SPP RTO MARKETS

For purposes of this cost-benefit study, it is assumed that the SPP RTO market will be similar in overall design to that of the Midwest ISO over the long-term time frame used in this study. Currently the Midwest ISO and SPP RTO are in different stages of market development. The Midwest ISO has in operation a real-time market, a day-ahead market, and financial transmission rights (FTRs). In addition, the Midwest ISO has formal plans and budgeting to institute an ancillary services market. The Midwest ISO had not yet formalized plans for the formation of a capacity market. The Midwest ISO projects total administrative costs of roughly 36 cents per MWh of market member load over the next few years.¹⁴

The SPP RTO commenced operation of a real-time market on February 1, 2007. Subject to cost-benefit consideration, the SPP RTO is evaluating plans to move ahead with establishing a day-ahead market, financial transmission rights and an ancillary services market. Before consideration of these additional market developments, the SPP RTO projects administrative costs per MWh of market member load roughly 20% below that of the Midwest ISO.

The costs and benefits of RTO market development require formal and complex study and consideration. It is anticipated that the SPP will institute additional market development if cost-benefit studies indicate that the projected benefits exceed the costs. Such analyses are beyond the scope of the type of study easily performed on behalf of a non-RTO utility such as Aquila Missouri. While it is unlikely that SPP would implement the additional market developments instituted by the Midwest ISO by 2008, the administrative charges charged to SPP RTO members likely will be lower than those charged to Midwest ISO members until such time as the markets become similar in design. We will further consider the ramifications of this assumption in subsequent sections.

3. ENERGY MODELING

The energy modeling in this study was performed using General Electric's MAPS tool. GE MAPS is a detailed economic dispatch and production costing model that simulates the operation of the electric power system taking into account transmission topology. The GE MAPS model determines the security-constrained commitment and hourly dispatch of each

¹³ The results for the intervening years were interpolated on a straight-line basis using the MAPS results in 2005 dollars, and then an annual inflation rate of 2.5% was applied.

¹⁴ Midwest ISO, Recommended Capital and Operating Budget, Section IV, Projected Average Administrative Cost per MWh, December 14, 2006.

modeled generating unit, the loading of each element of the transmission system, and the locational marginal price (LMP) for each generator and load area.

In this study, GE MAPS was set up to model the Eastern Interconnection of the United States and Canada. Other than Aquila Missouri, current RTO membership was assumed to continue in all cases. CRA used its current GE MAPS data base to perform the analysis, as well as its current projection of fuel prices and emission allowance prices. In order to assess the impact of future new entry, CRA used its proprietary *National Energy & Environmental Model (NEEM)* model to develop a capacity expansion forecast. CRA included currently planned or under construction resources throughout the Eastern Interconnect, including latan 2 in 2010. Potential CO₂ policies were not considered in this study. A full description of the GE MAPS inputs is contained in Appendix A.

3.1. MODELING ASSUMPTIONS BY CASE

In distinguishing among the three scenarios, CRA worked with three categories of modeling assumptions: 1) wheeling charges, 2) effective flowgate capacity and 3) commitment region. Table 3 illustrates how these assumptions were applied in each case.

Table 3
Modeling Assumptions by Case

Case	Aquila MO Wheeling Charges to/from:			Effective Flowgate Capacity	Aquila MO Commitment Pool
	Midwest ISO	SPP RTO	Others		
Stand-alone	Yes	Yes	Yes	90%	Aquila MO
Member of Midwest ISO	No	Yes	Yes	100%	Midwest ISO
Member of SPP RTO	Yes	No	Yes	100%	SPP

Wheeling Charges: Wheeling charges are charges for moving energy from one control area to another in an electric system. In GE MAPS, wheeling rates are applied on a "per MWh" basis to net interregional power flows and are used by the optimization engine in determining the most economically efficient dispatch of generating resources to meet load in each model hour. Wheeling rates are considered for both commitment and dispatch of generating units; however, the rates between any two areas may be different for commitment than for dispatch.

For this study, the wheeling rates for commitment were based on the day-ahead firm transmission rates (which are generally consistent with non-firm hourly on-peak rates) in the Aquila Missouri, Midwest ISO and SPP tariffs, while the rate for dispatch is based on non-firm hourly off-peak rates. This is to take into account that the day-ahead commitment process, in considering reliability, is more conservative in the type of capacity that is expected to be available.

The default assumption applied for wheeling rates on inter-ties in the modeled Eastern Interconnection region, other than between members of the same RTO, was \$2 per MWh for both commitment and dispatch. Based on the Aquila Missouri tariff, the Aquila Missouri wheeling out rate in the Stand-alone case was also set at \$2 per MWh for both dispatch and commitment.¹⁵ Based on the Midwest ISO tariff, the wheeling rate from the Midwest ISO to SPP was set at \$4 per MWh for dispatch and \$6 for commitment.¹⁶ Based on the SPP tariff, the wheeling rate from SPP to the Midwest ISO was set at \$2 per MWh for both commitment and dispatch.¹⁷ No wheeling rates were applied for flows within the SPP RTO or within the Midwest ISO. Given current policies, no wheeling rates were applied between PJM and the Midwest ISO.

Effective Flowgate Capacity: For the Stand-alone case, transfer limits on flowgates in the Aquila Missouri region were decreased by 10% to reflect the inefficiency of congestion management through the Transmission Loading Relief ("TLR") process. Flowgates are combinations of critical transmission elements that have the potential to become overloaded due to power flows on the transmission system. The 10% decrease was applied only to those Aquila Missouri flowgates directly impacted by transmission elements outside of the Aquila Missouri control area. The 10% figure was also applied in the SPP cost-benefit study performed by CRA in 2005 based on an examination of historical SPP tie-line flows during TLR events. Because of the uncertainty in exactly which units will be redispatched under a TLR call, and because of the time lag inherent in the process, it is difficult to achieve full system utilization when congestion is managed through the TLR process.

In contrast, RTO markets use market-based congestion management. Locational pricing is used to provide price signals that disclose congestion, signaling generation to redispatch, and enabling market participants to select alternative purchasing opportunities. This process ultimately relieves congestion more quickly and precisely than the TLR process. As a result, flowgates can be managed closer to their transfer limits under market-based congestion management.

-
- 15 Wheeling rates were rounded to the nearest \$/MWh integer, as is required in MAPS. The Aquila Networks rate is currently \$2.07 per MWh on-peak and \$0.98 per MWh off-peak for 345/161 kV service. SPP OATT, Rate Sheet for Point-To-Point Transmission Service for Aquila Networks – MPS/L&P. The Stand-alone wheeling rates for commitment and dispatch were both set to \$2/MWh to be consistent with the default modeled region assumption for individual control areas.
- 16 Midwest ISO, Updated Discounted Pricing Information, oasis.midwestiso.org/documents/miso/pricing_new.html, as of January 30, 2007.
- 17 SPP through and out rates are based on the zone from which the power exits SPP's transmission system. The \$2 rates are based on the Point-To-Point Transmission Service rates in the SPP OATT for KCP&L and SWPA inter-ties to the Midwest ISO market (i.e., to AmerenUE). For Westar Energy inter-ties to Aquila Missouri in the case when Aquila Missouri is in the Midwest ISO, the Westar Energy wheeling rate was set at \$5 per MWh for commitment and \$3 per MWh for dispatch based on the Westar Energy point-to-point rates in the SPP OATT.

Commitment Region: For the Stand-alone case, the day-ahead commitment of generating units for Aquila Missouri was performed for the Aquila Missouri control area, including jointly-owned units outside of the control area. As a Stand-alone entity, Aquila Missouri must commit its own resources in order to ensure control area reliability, as it would have limited ability to rely on external entities for commitment of their resources absent a contractual arrangement. For the RTO cases, the Aquila Missouri commitment was part of a pool-wide commitment encompassing the RTO, in which the unit commitment is optimized on a regional basis subject to transmission limitations. The ability to rely on the commitment of units across a broader region in the RTO markets allows for a more efficient unit commitment process.

4. BENEFITS AND COSTS

4.1. METHODOLOGY FOR MEASURING BENEFITS (COSTS)

This study assesses the benefits and costs associated with Aquila Missouri participating in the Midwest ISO or SPP RTO relative to Stand-alone status. Welfare for the regulated customers of Aquila Missouri, as measured in this study, is based on the charges to local area load for generation and transmission service, assuming that any benefits and costs to the regulated utility are passed through to its native load. If these charges to local area load decrease, regulated customer welfare increases. To quantify this change, CRA identified and analyzed potential sources of benefits and costs that impact the charges for generation and transmission service, such as generation (production) costs, energy purchases, and O&M expenditures.

The major categories of benefits and costs addressed in this study are trade benefits, RTO administrative costs, and Aquila Missouri internal implementation and operating costs. Trade benefits were computed using the GE MAPS results for each case. The methodology used to estimate the impact of each major category of benefits and costs is discussed below along with the corresponding results.

4.2. TRADE BENEFITS

The cases analyzed in this study (Aquila Stand-alone and Aquila in RTO) reflect varying degrees of impediments to trade between Aquila and surrounding regions. In particular, the wheeling rates and flowgate restrictions between Aquila and the Midwest ISO and SPP RTO in the Stand-alone case result in impediments to trade that are reduced when Aquila is a member of an RTO. Reductions in the impediments to trading should generally result in production cost savings. Generation production costs are actual out-of-pocket costs for operating generating units that vary with generating unit output; they comprise fuel costs, variable O&M costs, and the cost of emission allowances. By decreasing impediments to trading, additional generation from utility areas with lower cost generation replaces higher cost generation in other utility areas. These production cost savings yield the "trade benefits" referred to in this study.

Increases or decreases in production cost in any particular utility area, by themselves, do not provide an indication of welfare benefits for that area, because that area may simply be importing or exporting more power than it did under base conditions. For example, a utility that increases its exports would have higher production costs (because it generates more power that is exported) and would appear to be worse off if the benefits from the additional exports were not considered. Similarly, a utility that imports more would have lower production costs, but higher purchased power costs. In either circumstance – an increase in imports or exports – an accounting of the trade benefits between buyers and sellers must be made in order to assess the actual impact on utility area welfare. Increased trading activity provides benefits to both buying parties (purchases at a lower cost than owned-generation cost) and selling parties (sales at a higher price than owned-generation cost). In practice, the benefits of increased trade are divided between buying and selling parties. For example, the “split-savings” rules that govern traditional economy energy transactions between utilities under cost-of-service regulation result in a 50-50 split of trading benefits.¹⁸

4.2.1. Measurement of Aquila Missouri Trade Benefits

Traditional cost-of-service regulation differs from a fully deregulated retail market, in which individual customers and/or load-serving entities buy all their power from unregulated generation providers at prevailing market prices. In such a deregulated market, benefits to load can be ascertained mostly in terms of the impact that changes to prevailing market prices have on power purchase costs. For the Aquila Missouri region, in which cost-of-service rate regulation is in effect, the energy portion of utility rates reflects the production cost for the utility's owned generating units, plus the cost of “off-system” purchased energy, net of revenues from “off-system” energy sales. In turn, Aquila Missouri's utility customers under cost-of-service regulation pay for the fixed costs of owned-generating units through base rates. Deriving trade benefits for Aquila Missouri thus requires an analysis of both the production cost of operating the Aquila Missouri owned generating plants and the associated Aquila Missouri trading activity (purchases and sales).

The production cost of the Aquila Missouri-owned generating units is derived directly from the MAPS outputs for each case. This includes Aquila Missouri's share of jointly owned units, and its long-term contractual ownership of generating capacity, as shown in Appendix B. Other than its share of Iatan 2, no additional Aquila Missouri owned units were assumed in this study.

18

Consider a simple two-company example. Assume there is a \$16 marginal cost to generate in Company A's control area and a \$20 marginal cost to generate in Company B's control area and there is no trade. Now assume through a reduction in trade impediments that 1 MW can be traded from A to B over the inter-tie between A and B. Company A will generate 1 MW more at a production cost of \$16, while Company B will generate 1 MW less at a production cost savings of \$20. Thus, the total saving in production cost is \$4 (i.e., \$20 – \$16). If the trade price is set, for example, at a 50/50 split savings price, Company A will receive \$18, for a trade benefit of \$2 (\$18 – \$16), and Company B will pay \$18, for a trade benefit of \$2 (\$20 – \$18). The total trade benefit of \$4 (\$2 + \$2) will match the total production cost saving of \$4.

For purposes of deriving the impact of trading with adjoining regions, the net hourly MAPS tie-line flows into and out of Aquila Missouri were used as a proxy for purchase and sale transactions by Aquila Missouri. In each hour, the net interchange was derived using Aquila Missouri tie-line flows to assess whether Aquila Missouri was a net importer (purchaser) or exporter (seller) of power. If a net purchaser in the hour, the net purchase amount was multiplied by the weighted average split-savings price for tie-lines with flows into the Aquila Missouri control area. Similarly, if Aquila Missouri was a net exporter (seller) in the hour, the net sale amount was multiplied by the average split-savings price for tie-lines with outgoing flows. The split-savings prices reflects a 50/50 sharing of the price difference (and trade benefits), adjusted for the applicable wheeling charge, across the MAPS tie lines between Aquila Missouri and adjacent control areas. This also means that to the extent that Aquila Missouri has trade benefits, adjacent control areas are sharing in those trade benefits.

Prior to this hourly net interchange calculation, an adjustment is made to the Aquila Missouri tie-line flows for the power produced by the Aquila Missouri jointly-owned and contracted units located outside of the Aquila Missouri control area. The generation and production costs for Aquila Missouri's share of units located outside of the Aquila Missouri control area are included in Aquila Missouri's total generation and production costs. For purposes of this study, it is assumed that Aquila Missouri purchases the output of the 580 MW Aries combined-cycle unit located in the Aquila Missouri control area at prevailing locational market prices. To the extent that such an arrangement would require an additional capacity-type payment to the merchant unit, it is assumed this payment would be the same in each of the cases. As an intra-control-area unit purchase, these Aries purchases are included in the generation category in the tables in this study along with other Aquila unit purchases.

Wheeling charges on net hourly imports into Aquila Missouri are paid by the native load in Aquila Missouri, and are included in the Aquila Missouri purchase costs in this study. Wheeling charges on net hourly exports from the Aquila Missouri control area are paid by the load in the importing control area to Aquila Missouri (thereby reducing the net Aquila Missouri transmission revenue requirement) and are included in the Aquila Missouri sales revenue in this study.

4.2.2. Trade Benefit Results

Table 4 shows the change in Aquila Missouri generation, purchases and sales for the years 2008, 2012 and 2017 in the RTO cases in comparison to the Stand-alone case. As shown, there is a reduction in generation in the RTO cases. However, the reduction is significantly greater in the SPP RTO case. Aquila Missouri generation as used here includes generation in the Aquila Missouri control area including the merchant Aries unit, plus Aquila Missouri's share of jointly-owned units and unit purchases located outside of the Aquila Missouri control area.

Table 4
Increase in Aquila Missouri Generation, Purchases and Sales in RTO
in comparison to Stand-alone Status (GWh)

	Member of Midwest ISO			Member of SPP RTO		
	2008	2012	2017	2008	2012	2017
Generation	(94)	(258)	(381)	(1324)	(2173)	(2562)
Purchases	348	556	497	959	1788	2330
Sales	254	299	116	(364)	(386)	(232)
Net (G+P-S)	0	0	0	0	0	0

Table 5 lists the trade benefits (i.e., the change in the net cost to serve load) to Aquila Missouri in the RTO cases in comparison to the Stand-alone case. The change in the generation costs, purchase costs and sales revenue correspond to the changes in the GWh of generation, purchases and sales shown in Table 4. As shown, the trade benefits are positive for both RTO cases, but more positive for the SPP RTO case.

Table 5
2008-2017 Trade Benefits to Aquila Missouri of RTO Membership
in comparison to Stand-alone Status
(In millions of 2007 present value dollars; positive numbers are benefits)

	Member of Midwest ISO	Member of SPP RTO
Decrease in Production Costs	45.9	673.4
Decrease in Purchase Costs	(103.5)	(465.5)
Increase in Sales Revenues	87.6	(112.1)
Total Trade Benefits	29.9	95.7

The production costs listed in Table 5 are comprised of the fuel, variable O&M, start-up and emissions costs for Aquila Missouri generating units, including Aquila Missouri's share of jointly-owned units and unit purchases located outside of the Aquila Missouri control area. For purposes of Table 5, the production costs also include the purchase of the output of the merchant Aries unit at prevailing market prices.

The greater trade benefits resulting from membership in the SPP RTO appear to be primarily the result of Aquila Missouri's location and the nature of its transmission inter-ties with adjoining control areas. Aquila Missouri is located on the western side of Missouri and heavily interconnected with KCP&L in particular. The total MVA capacity rating on the transmission lines that interconnect Aquila Missouri with SPP RTO members (KCP&L and Westar Energy) is more than five times as large as the ratings on the lines that interconnect

Aquila Missouri with Midwest ISO market members (AmerenUE).¹⁹ Moreover, regardless of Aquila Missouri status (Stand-alone, in the Midwest ISO, or in the SPP RTO) the magnitude of the Aquila Missouri power flow to and from the SPP RTO over the tie-lines in the GE MAPS model runs is significantly higher than that over the tie-lines to and from Midwest ISO market members. These physical inter-ties between Aquila Missouri and the SPP RTO exist regardless of whether Aquila Missouri is in the SPP RTO or the Midwest ISO. However, placing cost impediments (e.g., wheeling charges for transactions between Aquila and the SPP RTO) on these inter-ties, as would be the case if Aquila Missouri were in the Midwest ISO, provides a substantial impediment to Aquila Missouri trade.

As a result, the GE MAPS runs indicate that Aquila Missouri is able to displace control area generation, particularly gas-fired generation, with less expensive market purchases to a greater extent in the SPP RTO case. As shown in Table 6, Aquila Missouri generation, which is roughly equal to Aquila Missouri load in the Stand-alone case, is reduced in the RTO cases, but is reduced significantly more in the SPP RTO case. This reduction in generation in the SPP RTO case indicates that additional economic purchases are displacing Aquila Missouri generation in the SPP RTO case through the unit commitment process and through the elimination of wheeling charges with SPP RTO members. In particular, the gas-fired Aries combined-cycle unit is committed and generates significantly more often in the Stand-alone and Midwest ISO cases than in the SPP RTO case.

Table 6
Decrease in Aquila Missouri Generation in RTO in comparison to Stand-alone Status

	Decrease in Generation (GWh)			Decrease as Share of Net Aquila Load		
	2008	2012	2017	2008	2012	2017
In Midwest ISO	94	258	381	1%	3%	3%
In SPP RTO	1,324	2,173	2,562	15%	22%	23%

As noted above, the Aries generation is assumed to be purchased by Aquila Missouri at prevailing market prices in all cases. The 580 MW Aries unit owned by Calpine was auctioned to Kelson Energy for \$235 million in December 2006 over Aquila Missouri's competing bid of \$230 million. To the extent that Aries output becomes contracted to entities outside of the Aquila Missouri control area, Aquila Missouri likely would need to make additional purchases and/or commit and generate more energy from the gas-fired South Harper peaking unit or other units. The additional energy needed would be greater in the Stand-alone and Midwest ISO cases and likely would further increase the relative benefit of the SPP RTO case.

¹⁹ NERC Multi-regional Modeling Working Group ("MMWG") 2005 series 2010 summer peak loadflow.

4.3. ADMINISTRATIVE AND OPERATING COSTS

A number of costs must be analyzed in addition to those directly addressed in GE MAPS. These include Aquila implementation and operating costs and RTO administrative charges. The specific categories of costs addressed in this study are discussed in detail below.

4.3.1. Stand-alone Costs to Provide Current SPP and Midwest ISO Functions

In addition to its long-running role as Aquila Missouri's NERC reliability council, SPP performs a number of other reliability/transmission provider functions for Aquila Missouri, namely: 1) tariff administration, 2) OASIS administration, 3) available transmission capacity (ATC) and total transmission capacity (TTC) calculations, 4) scheduling agent, and 5) regional transmission planning. The Midwest ISO performs a sixth needed function, reliability coordination, for Aquila Missouri. As discussed previously, moving to Stand-alone status would require Aquila Missouri to procure these six services from an alternative supplier or provide them internally. In turn, however, Aquila Missouri would avoid payment to SPP and the Midwest ISO for provision of these functions.

Appendix C provides an overview of the analysis performed by Aquila Missouri personnel to estimate the costs to provide or procure these six reliability/transmission provider functions on a Stand-alone basis. The costs were then converted by CRA into annual revenue requirements. The analysis indicates that Aquila Missouri would incur additional costs of \$16.0 million over the 10-year study period to provide these six functions. Since this is an additional cost for the Stand-alone case, the \$16.0 million is counted as a savings (or benefit) to each of the two RTO cases in comparison to Stand-alone status.

4.3.2. RTO Administrative Charges

Both the Midwest ISO and the SPP RTO incur significant capital and operating costs to operate their markets. These costs are recovered through administrative charges that would be payable by Aquila if it were to be an RTO member. The Midwest ISO assesses these charges under Schedules 10, 16 and 17 under its tariff. The Midwest ISO projects the charges under these schedules over the 2007 to 2011 period to average about 36 cents per MWh of member load.²⁰ Of this total, about 13 cents per MWh is for Schedule 10 (ISO Cost Recovery Adder), 2.5 cents is for Schedule 16 (FTR Administrative Service), and 20.5 cents is for Schedule 17 (Energy Markets Support). SPP RTO charges are expected to be about 20% lower on a cents per MWh basis over the next few years, including operation of the real-time imbalance market, than those of the Midwest ISO. The SPP RTO costs do not yet

20

Midwest ISO, Recommended Capital and Operating Budget, Section IV, Projected Average Administrative Cost per MWh, December 14, 2006.

include any administrative charges for a day-ahead market, financial transmission rights, and an ancillary services market.

At the request of CRA, SPP provided a preliminary forecast of charges to be incurred upon development and operation by SPP of a day-ahead market, FTRs, and an ancillary services market. On a preliminary basis, SPP projected costs per MWh of member load roughly equivalent to those of the Midwest ISO upon full institution of these additional markets.

Like the Midwest ISO, the PJM RTO also has day-ahead markets and FTR markets in operation. In 2006, the PJM RTO converted to a system of stated rates that result in projected RTO administrative charges roughly similar to those projected by the Midwest ISO.²¹ For purposes of this study, given that the RTO markets are assumed to have similar markets and operations over the long-term study period, the projected Midwest ISO administrative charges were applied in both the Midwest ISO and SPP RTO cases.²²

We note that the following of best practices and pressure by RTO members to minimize costs will tend to minimize differences in RTO costs. Even so, potential longer-term cost differences between the two RTOs could result from the following:

- At the present time, the Midwest ISO serves a market load roughly three times larger than that of the SPP RTO. Given economies of scale in RTO operations, this likely favors the Midwest ISO having lower administrative charges per unit of energy for load. Of course, new RTO members and any exiting members could alter this relationship.
- SPP has not yet developed market components beyond a real-time market. This provides additional cost uncertainty for SPP. However, the later development could allow SPP to develop these markets using knowledge and systems gleaned from operations at RTOs with these markets in place. This potentially favors lower development costs for SPP, all else equal.
- The Midwest ISO has a number of deferred charges that are being assessed over time to its members. The market-related deferred charges were \$80.8 million as of the end of 2005, and are projected to be recovered by 2011.²³ These deferred charge recoveries are offset by amortization to members of about \$45 million over

²¹ Settlement Agreement and Offer of Settlement, PJM Interconnection, LLC, FERC Docket No. EL05-1181, April 18, 2006. The PJM stated rates will average 30 to 32 cents per MWh from 2006 to 2011, supplemented by an additional rider for the construction and operation of a second control center.

²² The Midwest ISO projected unit charges through 2011. After 2011, the annual RTO administrative charges for Aquila Missouri were assumed to escalate at inflation.

²³ Midwest ISO, Annual Report 2005, pages 29-30.

the 2007 to 2011 period resulting from the exit charges that have been paid to the Midwest ISO.²⁴ SPP does not have similar deferred charges at this time. All else equal, this likely favors SPP having somewhat lower unit administrative charges until these Midwest ISO deferrals are completed.

Using the Midwest ISO projection of administrative costs, the Aquila RTO cases are projected to incur \$23.5 million (2007 present value) in RTO administrative charges over the 10-year study period. See Appendix C for further detail. This is an additional cost to the two RTO cases in comparison to the Stand-alone case.

4.3.3. FERC Charges

All load-serving investor-owned utilities must pay annual FERC charges in order for FERC to recover its administrative costs. Historically, these FERC charges have been assessed to individual investor-owned utilities based only on the quantity of the utility's wholesale transactions (i.e., those related to interstate commerce). However, the annual FERC charges for RTO member load-serving utilities are assessed directly to the RTO, and then in turn assessed by the RTO to member companies. Under FERC regulations, the annual FERC charge is assessed to all RTO energy for load. FERC charges for RTO members are therefore higher for non-RTO members.

As more of the country's utilities join an RTO, the FERC per-unit charges for energy transmitted in interstate commerce are likely to decrease. Nevertheless, as long as only wholesale transactions are assessed the FERC charge under a non-RTO (Stand-alone) basis, there will be higher FERC charges to RTO members than non-RTO members, all else being equal.

For purposes of this study, the difference in the FERC charges between the Stand-alone and RTO cases was estimated by comparing the FERC charges estimated by the Midwest ISO (on a dollars per load served basis) in 2007 to the average inflation-adjusted FERC charges paid by Aquila Missouri in the 2004–2005 period. This annual difference was then escalated at inflation and discounted over the 10-year study period. Using this approach, the increase in FERC fees for Aquila Missouri under the two RTO cases is \$1.3 million (2007 present value) over the study period in comparison to the Stand-alone case. See Appendix C for further detail.

4.3.4. Aquila Internal RTO Market Participation Costs

RTO market participants will incur expenditures to participate in an RTO market over and above the RTO administrative charges. However, in order to interface and trade with surrounding RTOs, Aquila Missouri has already invested in the computer systems and staff

²⁴ Midwest ISO, Recommended 2007–2009 Budget, page 5, December 14, 2006.

training needed to interact with the RTOs. This includes investment in an OATT system. As such, no further additional internal costs have been included for Aquila in the RTO cases.

4.4. OVERALL COST-BENEFIT RESULTS

Table 7 provides the benefits (shown as positive numbers) and costs (shown as negative numbers) discussed above for Aquila membership in the Midwest ISO or SPP RTO in comparison to Stand-alone status. As shown, the quantitative findings indicate a net benefit to Aquila Missouri in joining an RTO relative to Stand-alone operations. The results are the mid-2007 present value of the net benefits over the 2008 to 2017 period.

Table 7
2008-2017 Benefits (Costs) to Aquila Missouri of RTO Membership
in comparison to Stand-alone Status
(in millions of 2007 present value dollars; positive numbers are benefits)

	Member of Midwest ISO	Member of SPP RTO
Trade Benefits: Decrease in Cost to Serve Aquila Missouri Load	29.9	95.7
Savings from RTO Providing Reliability/Transmission Functions	16.0	16.0
RTO Administrative Charges	(23.5)	(23.5)
FERC Charges	(1.3)	(1.3)
Total Benefits (Costs)	21.1	86.9

As shown in Table 7, the trade benefits of joining an RTO, i.e., the savings in the net cost to serve Aquila Missouri load, are positive and range from \$30 to \$96 million over the 10-year study period. The savings that Aquila incurs by having the RTO perform transmission and reliability functions rather than performing or procuring these functions on a Stand-alone basis are \$16.0 million over the 10-year study period. The administrative charges that Aquila would incur for being a member of the RTO market are \$23.5 million over the 10-year study period. This is an additional cost and thus is shown as a negative benefit in Table 7. And finally, the charges paid to FERC that Aquila would be assessed as a member of an RTO would be \$1.3 million higher than if Aquila were Stand-alone over the study period.

The overall net benefit to Aquila of being in an RTO is projected to be \$21 to \$87 million over the 10-year study period. In addition, the annual net benefits are projected to be positive for each year of the study period (see Appendix C).

A key risk factor in joining an RTO is the amount of RTO administrative charges that could be incurred. However, even if the \$23.5 million of RTO administrative charges shown in Table 7 increased by 50% from those projected in this study, there would still be considerable benefits for Aquila Missouri joining an RTO.

With respect to whether it would be more economic to join the Midwest ISO or the SPP RTO, the quantitative results indicate a greater benefit for Aquila Missouri being a member of the SPP RTO. As noted above, this benefit is premised on the SPP RTO having in place additional market development that it does not yet have in place, and operating these markets at costs comparable to the Midwest ISO.

Given the smaller size, in terms of market member load, of the SPP RTO, economies of scale could result in higher administrative costs per MWh for the SPP RTO with further market development. However, given the differences in Aquila Missouri net benefits found in the MAPS modeling, even a 50% greater administrative charges per MWh for the SPP RTO would not alter the quantitative advantage found in this study for Aquila Missouri being a member of the SPP RTO. Nonetheless, the SPP RTO does not yet have the same level of market development as the Midwest ISO and as modeled in this study. As such, uncertainty exists as to the timing of any future SPP RTO market developments and the costs that would be incurred in putting in place those developments.

4.4.1. High Gas Price Sensitivity

Given historic volatility in natural gas prices, CRA also conducted a one-year sensitivity analysis of the impact that much higher natural gas prices would have on net benefits. The natural gas price forecast used in the GE MAPS modeling (see Figure 1 in Appendix A) declines substantially from 2008 through 2012 in accordance with current natural gas market futures. The average natural gas price projected for the Henry Hub of \$7.60 per MMBtu (2005\$) in 2008 declines to \$5.60 by 2012.

Given this projected decline already included in the base modeling, a relatively large increase in gas prices was tested in the 2012 gas sensitivity model runs to address the potential for 2012 gas prices to be significantly higher than 2008 levels. Specifically, the gas prices applied for 2012 in this sensitivity case were increased from \$5.60 to \$9.00 per MMBtu (2005\$), or to a level about 18% higher than base 2008 gas prices. As shown in Table 8, with these high gas prices, the 2012 trade benefits for the Midwest ISO and SPP RTO cases increase significantly.

Table 8
Impact of Higher Gas prices on 2012 Aquila Missouri Trade Benefits (Costs) from RTO
Membership in comparison to Stand-alone Status
(in millions of dollars; positive numbers are benefits)

2012 Trade Benefits	Member of Midwest ISO	Member of SPP RTO
With Base 2012 Gas Prices	3.7	16.1
With High 2012 Gas Prices	10.6	28.0
Increased Benefits (Costs)	6.1	11.8

Relative to the base gas price case, the high gas price case for 2012 shows a greater percentage increase in trade benefits for membership in the Midwest ISO, but a higher

absolute increase in benefits for membership in the SPP RTO. These results support the finding that with a significantly higher level of gas prices, the decision for Aquila to join an RTO would become even more favorable.

5. QUALITATIVE CONSIDERATIONS

Aside from the specific benefits quantified above, participation in an RTO is likely to provide additional benefits, along with some cost risks, as discussed below.

Regional Transmission Management. Participation in an RTO is likely to assist Aquila Missouri in the regional management of parallel path flows, management of reserve sharing, and the regional coordination/planning of transmission investment. These benefits result from addressing issues at a regional level rather than that of a local control area unable to examine or to be fully cognizant of the actions of surrounding areas that can impact their local control area. The RTO real-time markets should allow for economic redispatch to alleviate the need for TLR events. TLR is a real-time operating procedure that allows reliability coordinators to mitigate violations of reliability limits through curtailments and redispatch actions. The need for a TLR often arises when transaction schedules are not fully-coordinated among control areas in advance of real-time operations. Finally, single region-wide OASIS administration should also provide additional efficiencies relative to Aquila Missouri in Stand-alone status.

Price Transparency. The inclusion of a transmission system in a transparent regional market with locational price signals will provide additional incentives to improve generation availability when economic to do so, and will help in the planning process in placing transmission improvements and new generation capacity in optimal locations. The transparency of the pricing provides an additional tool for regulators to monitor the efficiency of utility purchases and sales.

Costs. Aside from the specific issues identified above, one of the main concerns regarding RTO membership has been the magnitude of the administrative charges, and the perception that individual members may not have enough ability to directly control the underlying RTO expenditures. In response, the Midwest ISO has reduced its budgeted expenditures²⁵ and is projecting relatively stable costs in terms of costs per MWh over the next five years. Moreover, the PJM RTO has moved to a form of stated rates, rather than a direct formula passthrough of all costs. These stated rate are expected be in place through 2011, indicating greater confidence on the part of RTO management in the predictability of costs as RTO markets mature. In addition, FERC has issued reporting rules to allow for greater

²⁵ Midwest ISO Trims Operating Costs, Midwest ISO News Release, June 19, 2006.

transparency in evaluating RTO costs.²⁶ While these trends appear favorable to the stabilization of RTO costs, there continues to be ongoing uncertainty about future RTO market developments and refinements that result in ongoing cost risk to member utilities.

Market Monitoring. Market monitoring and mitigation is an essential function for RTOs and is required by FERC Order 2000. Both the Midwest ISO and SPP have established independent market monitors. In CRA's view, Aquila Missouri's entry into an RTO is unlikely to increase significantly the likelihood of actual exercises of market power in the Aquila Missouri region. This is because most power delivered within Missouri will be subject to the continuation of cost-based retail rates. In addition, it is our understanding that much of the wholesale market is covered by long-term contracts for which a short-term increase in the spot price for power would be immaterial. In these circumstances, generation owners would have little, if any, incentive to withhold generation from the RTO markets for the purpose of increase in the market-clearing price in that market. This is because the output of the generating unit is committed to load under regulatory and contractual arrangements under which it is not possible to earn additional revenue merely because of an increase in the spot market price. Without the incentive to exercise market power, the issue is likely to be a minor consideration in the decision to join an RTO. Nonetheless, it is important that the RTO market monitors review the performance of their markets to FERC as needed. The market monitoring function is an important deterrent to the exercise of whatever residual market power exists in the market.

6. CONCLUSION

The results of the quantitative analysis show a net benefit for Aquila Missouri joining either the Midwest ISO or the SPP RTO. Qualitative considerations further buttress the likelihood of net benefits resulting from RTO entry by Aquila Missouri. The quantitative results indicate a greater benefit for Aquila Missouri to join the SPP RTO than the Midwest ISO. The relative benefits are high enough to offset potentially greater administrative costs at SPP given its smaller size. These quantitative results are premised on additional market developments in the SPP RTO that have not yet been formally proposed or budgeted. Thus, there is uncertainty regarding the timing and cost of these additional SPP market developments.

²⁶ RTO Costs to be Reflected in Accounting Rules, FERC News Release, Docket No. RM04-12-000,, December 15, 2005

7. APPENDIX A: MAPS INPUTS

This appendix summarizes the key inputs to the GE MAPS locational price forecasting model. As formulated for this study, the model's geographic footprint encompasses the U.S. portion of the Eastern Interconnect and the Canadian province of Ontario with the major focus on the SPP, Midwest ISO and surrounding regions. The GE MAPS simulations focus on the ten-year period from 2008 to 2017. The years directly simulated are 2008, 2012 and 2017. Results for intervening years are interpolated.

Primary data sources for the model include the NERC MMWG, the General Electric generation and transmission databases for the Eastern Interconnect, various publications by NERC regions and Independent System Operators, FERC submissions by generation and transmission owners, commercial databases from Platt's and Energy Velocity and CRA in-house analysis of plant operations and market data.

7.1. TRANSMISSION

The CRA model is based on load flow cases provided by the NERC Multiregional Modeling Working Group (MMWG). This analysis uses the modified MMWG 2005 series load flow cases for the summer of 2007 and 2010. The MMWG load flow case encompasses the entire Eastern Interconnect system, including lines, transformers, phase shifters, and DC ties. CRA adds to these load flows the Cross-Sound and Neptune high voltage DC cables. Load flow models were further analyzed against regional transmission planning documents and a number of changes were made to the load flow to reflect future transmission projects (those under construction or having a high probability to be implemented, but not included in the original MMWG models).

Monitored constraints originate from the following sources:

- The NERC flowgate book (November 2005 version).
- The list of flowgates published by the Midwest ISO on its website.
- A list of flowgates provided by the Southwest Power Pool.
- FERC Form 715 filings, seasonal transmission assessment reports, and studies published by NERC regions and Independent System Operators.
- Regional Transmission Expansion Plan (RTEP) reports published by various ISOs.
- The 2004 Intermediate Area Transmission Review published by the New York ISO.
- Contingency analyses performed by General Electric and by CRA.
- Historically binding constraints monitored by CRA.

For constraints monitored for their thermal limit violations, their limits are updated with respect to each load flow to reflect transmission upgrades. For constraints enforced for stability purposes, we use the limits obtained from the sources above.

Reducing the number of constraints monitored in the study reduces the time required for GE MAPS to solve the optimal commitment and dispatch. Therefore, CRA filters out non-significant constraints far away from the study areas to speed up the process. In this study, all

non-duplicate constraints from the above sources within MISO, SPP and Entergy are included. For other study areas, a constraint is included only if it has been binding in our previous studies or it monitors facilities at 500KV or above.

7.2. LOAD INPUTS

For each load serving entity, GE MAPS requires an hourly load shape and an annual forecast of peak load and total energy. CRA uses the latest EIA-411 load forecast data available (2006) for each company within the study region. Ontario data is drawn from the 10-Year Outlook: Ontario Demand Report published by the Independent Electricity Market Operator of Ontario. If study years are to be modeled after the last year for which forecast data is available, CRA uses linear extrapolation to estimate the peak load and annual energy, by company, for the remaining years.

Load shapes are drawn from hourly actual demand for 2002, as published in FERC Form 714 submissions and on the websites of various Independent System Operators (ISOs) and NERC reliability regions. These hourly load shapes, combined with forecasts for peak load and annual energy for each company, are used by GE MAPS to develop a complete load shape by company for each forecast year.

7.3. THERMAL UNIT CHARACTERISTICS

Description. MAPS models the operational characteristics of generation units in detail to predict hourly dispatch and prices. The following characteristics are modeled:

- Unit type (e.g., steam cycle, combined-cycle, simple cycle, cogeneration)
- Heat rate values and curve (based on unit technology)
- Summer and winter capacity
- Variable operation and maintenance costs
- Fixed operation and maintenance costs
- Forced and planned outage rates
- Minimum up and down times
- Quick-start and spinning reserves capabilities
- Startup costs
- Emission rates

CRA's generation database reflects unit-specific data for each generating unit based on a variety of sources. If unit-specific operational data were not available for a particular unit, representative values based on unit type, fuel, and size were used. Table 9 and Table 10 documents these generic assumptions.²⁷ As is the case throughout this MAPS analysis, all costs are in real 2005 dollars.

²⁷ Note that certain data types are specified on a plant-specific basis in CRA's database and therefore do not require corresponding generic data. These include full load heat rates and emissions data.

Table 9: Characteristics for Generic Thermal Units

Unit Type & Size	Variable O&M (\$/MWh)	Fixed O&M (\$/kW-yr)	Minimum Downtime (Hrs)	Minimum Uptime (Hrs)	Heat Rate Shape
Combined Cycle	\$ 2.50	\$ 21.00	8	6	2 Blocks, each 50% at FLHR
Combustion Turbine <100 MW	\$ 7.00	\$ 15.00	1	1	One block
Combustion Turbine >100 MW	\$ 7.00	\$ 15.00	1	1	One block
Steam Turbine [coal] >200 MW	\$ 1.00	\$ 35.00	12	24	4 blocks, 50% @ 106%FLHR, 15% @ 90%, 30% @ 95%, 5% @ 100%
Steam Turbine [coal] <100 MW	\$ 3.00	\$ 45.00	6	8	
Steam Turbine [coal] <200 MW	\$ 3.00	\$ 35.00	8	8	
Steam Turbine [gas] >200 MW	\$ 3.00	\$ 30.00	8	16	4 blocks, 25% @ 118%FLHR, 30% @ 90%, 35% @ 95%, 5% @ 103%
Steam Turbine [gas] <100 MW	\$ 5.00	\$ 34.00	6	10	
Steam Turbine [gas] <200 MW	\$ 4.00	\$ 30.00	6	10	
Steam Turbine [oil] >200 MW	\$ 3.00	\$ 30.00	8	16	4 blocks, 25% @ 118%FLHR, 30% @ 90%, 35% @ 95%, 5% @ 103%
Steam Turbine [oil] <100 MW	\$ 5.00	\$ 34.00	6	10	
Steam Turbine [oil] <200 MW	\$ 4.00	\$ 30.00	6	10	

Table 10: Characteristics for Generic Thermal Units

Unit Type & Size	Quick Start (% of Capacity)	Spinning Reserve (% of Capacity)	Forced Outage Rate (%)	Planned Outage Rate (%)	Typical Outage Length (Days)
Combined Cycle	-	30%	1.81%	7.40%	3
Combustion Turbine <100 MW	100%	90%	2.81%	5.28%	1
Combustion Turbine >100 MW	100%	90%	2.60%	6.94%	1
Steam Turbine [coal] >200 MW	-	10%	3.07%	9.10%	7
Steam Turbine [coal] <100 MW	-	10%	3.78%	8.32%	3
Steam Turbine [coal] <200 MW	-	10%	4.57%	9.43%	3
Steam Turbine [gas] >200 MW	-	10%	3.50%	14.11%	7
Steam Turbine [gas] <100 MW	-	10%	2.62%	6.81%	2
Steam Turbine [gas] <200 MW	-	10%	3.23%	11.11%	2
Steam Turbine [oil] >200 MW	-	10%	2.79%	13.51%	7
Steam Turbine [oil] <100 MW	-	10%	1.46%	8.33%	2
Steam Turbine [oil] <200 MW	-	10%	3.01%	12.16%	2

Data Sources. The primary data source for generation units and characteristics is the NERC Electricity, Supply and Demand (ES&D) 2003 database, which contains unit type, primary and secondary fuel type, and capacity data for existing units. Heat rate data were drawn from prior ES&D databases where available. For newer plants, heat rates were based on industry averages for the technology of each unit. The NERC Generation Availability Data System (GADS) database published in January 2005 (data through 2003) was the source for forced and planned outage rates, based on plant type, size, and age.

Fixed and variable operation and maintenance costs are estimates based on plant type, size, and age. These estimates are supplemented by FERC Form 1 submissions where available. The fixed operations and maintenance cost (FOM) values include an estimate of \$1.50/kW-yr for insurance and 10% of base FOM (before insurance) for capital improvements.

Plants that are known to be cogeneration facilities are either modeled with a low heat rate (6,000 Btu/kWh), or set as must-run units in the dispatch, to reflect the fact that steam demand requires operation of the plant even when uneconomical in the electricity market.

7.4. NUCLEAR UNITS

Description. CRA assumes that all nuclear plants run when available and that they have minimum up and down times of one week. Forced outage rates for each nuclear unit are drawn from the Energy Central database of unit outages. These plants do not contribute to quick-start or spinning reserves. Refueling and maintenance outages for each nuclear plant are also simulated. Outages posted on the NRC website or announced in the trade press for the near future are included. For later years, refueling outages for each plant are projected based on its refueling cycle, typical outage length, and last known outage dates. Since these facilities are treated as must-run units, CRA does not specifically model their cost structure.

Data Sources. Nuclear unit data were obtained from NRC publications, trade press announcements, and the Energy Central database.

7.5. HYDRO UNITS

Description. MAPS has special provisions for modeling hydro units. For conventional or pondage units, CRA specifies a pattern of water flow, i.e., a minimum and maximum generating capability and the total energy for each plant. CRA assumes that hydro plants can provide spinning reserves of up to 50% of plant capacity. CRA assumes that the maximum capacity for each hydro unit is flat throughout the year, that the minimum capacity is zero (i.e., that there are no stream-flow or other constraints that force a plant to generate). Plant monthly energy data is drawn from an average of Form EIA-860 submissions for 1992-1998.

Data Sources. The list of hydro units and their maximum generating capacities is taken from the NERC ES&D database.

7.6. WIND RESOURCES

Description. Individual wind resources were modeled either as zero-cost dispatchable energy resources with high (70%) outage rates or as hourly modifiers based on historical production data. Solar generators are run at 24% annual capacity factor, and restricted to daytime hours.

7.7. CAPACITY ADDITIONS AND RETIREMENTS

The initial set for new entry is based on existing projects in development and on projects with signed interconnection agreements as of December 2006, including Iatan 2 in 2010. For study years 2012 and 2017, CRA added capacity based on economic and/or reliability criteria using CRA's proprietary CRA's North American Electricity & Environment Model (NEEM). Capacity additions are made such that each capacity region complies with its specified reserve margin. New capacity can also be added if the economics of adding new capacity result in lower present value on-system electric sector costs over the time horizon of the model (i.e., reduced operating costs more than offset capital costs). The choice of new capacity will depend on a number of key inputs, but foremost on capital costs of the new capacity and fuel costs. Capital costs used in NEEM are generally based on information included in EIA's Annual Energy Outlook 2006, with adjustments for such factors as the recent run-up in steel prices, additional costs of adding transmission and natural gas pipeline. The natural gas and oil prices described herein that are applied in the MAPS model are also applied in the NEEM model.

The least cost capacity decisions from NEEM are then added to the MAPS database for balancing purposes. Other information from NEEM that is used in MAPS includes: coal choices, delivered coal prices, emission rates for SO₂, NO_x and Hg, allowance prices for SO₂, NO_x and Hg, and unit retirements. NEEM is a process-based model of national US electricity markets (with limited representation of Canada as well). Electricity markets are divided into 27 individual demand regions (based on NERC sub-regions) and interconnected by limited transmission capabilities (also based on NERC data). Units are dispatched to load duration curves within each region so that all loads are met at least cost. Every existing generating unit in the US is represented in the model, with its current emissions control equipment. NEEM was designed specifically to be able to simultaneously model least-cost compliance with all regional and national, seasonal and annual emissions caps for SO₂, NO_x and Hg (and CO₂ if relevant). NEEM has been widely used within the electric sector to analyze the costs, impacts, and allowance prices of multi-pollutant proposals.

The capacity expansion did not vary by case in this study. According to the NEEM results, no capacity was retired in the SPP region during the study period. Taking into account already planned generating additions, no additional capacity was added in the NEEM modeling in this region. The NEEM modeling is designed to provide a consistent basis for estimating capacity expansion throughout the Eastern Interconnect. By necessity, the capacity expansion in the NEEM analyses is a projection based upon generalized input assumptions and will vary from actual future experience, including the size, type and location of specific new units.

7.8. ENVIRONMENTAL REGULATIONS

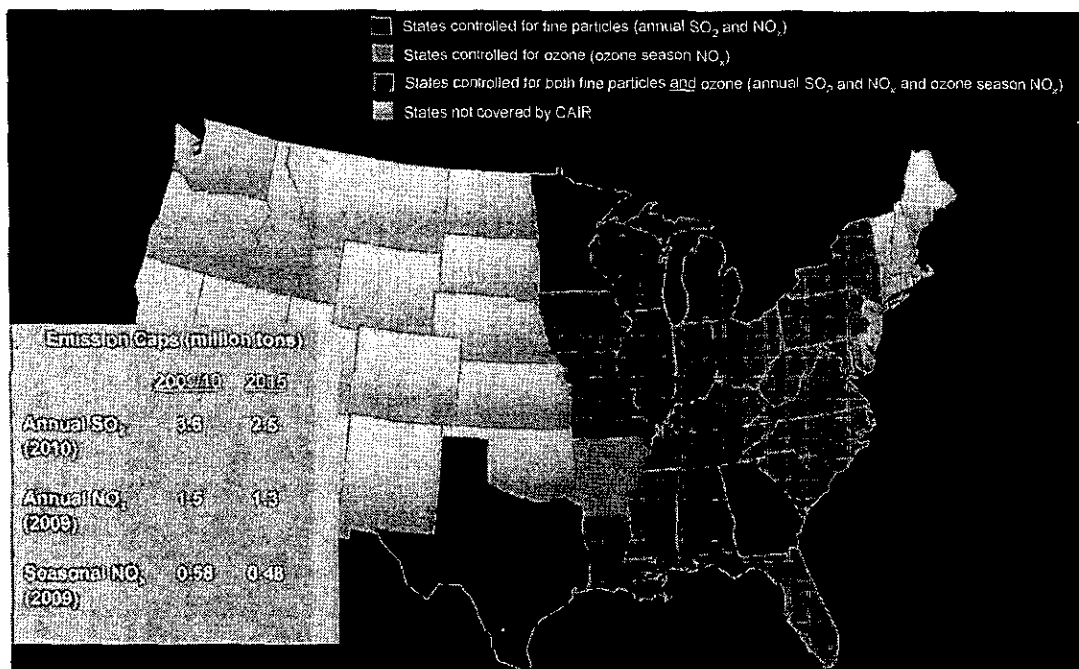
Description. For thermal generating units, variable operating and maintenance costs associated with installed scrubbers (SO₂ reduction) or with Selective Catalytic Reduction (SCR) processes for NO_x reduction are included in the marginal production cost and the unit

energy bids. No fixed or capital costs of these emission control technologies are included in the calculation of marginal cost. CRA tracks industry announcements of units that are planning to install NO_x or SO₂ abatement technologies in the near future and models the resulting changes in emission rates and the variable and fixed costs associated with the new installations.

To account for SO₂ trading under EPA's Acid Rain Program, the model incorporates the opportunity cost of SO₂ tradable permits into the marginal cost bids, based on unit emission rates and forecast allowance trading prices for the time period of the simulation.

CRA models NO_x and SO₂ emission rates for all units where such data is available. In addition, CRA models compliance with various allowance trading programs, and attempts to capture the effect of future environmental regulations. All plant emission rates are drawn from the Emissions Scorecard published by the US Environmental Protection Agency. Emission rates for NO_x and SO₂ are obtained from industry futures, in particular those published by the Cantor Environmental Brokerage. CRA used its in-house NEEM model to forecast NO_x and SO₂ permit prices in the long run following the Clean Air Interstate Rules (CAIR) issued by EPA in March 2005. Implications of CAIR rules vary geographically as shown in Figure 1.

Figure 1. Geography of CAIR rules



Source: EPA

The forecast of emission allowance prices for NO_x and SO₂ are presented in Table 11 below. CRA does not include the impacts of Carbon or Mercury emissions in these simulations.

Table 11: Forecast Emission Allowance Prices

	Non-CAIR SO ₂ (\$/Ton)	CAIR SO ₂ (\$/Ton)	NO _x (\$/Ton)
2008	615	615	1450
2012	397	794	1665
2017	363	1039	2051

Data Sources. The EPA's Clean Air Markets Emissions Scorecard provides plant heat input, NO_x and SO₂ emissions, and emission rates. Capital costs for NO_x abatement technology are obtained from EPA's Regulatory Impact Assessment report for the NO_x Budget Program, originally provided by Bechtel Corporation. 2008 emission permit prices are obtained from a Cantor Fitzgerald on-line resource. Allowance price forecasts for 2012 and 2017 are developed by CRA using the NEEM Model.

7.9. EXTERNAL REGION SUPPLY

CRA explicitly models the US portion of the Eastern Interconnect and the Canadian province of Ontario. Regions outside this study area are modeled as either supply profiles or scheduled interchanges. CRA uses historic flows, combined with expectations of future conditions in these areas to project quantities and prices of power exchanged with the model footprint. In this analysis, flows from New Brunswick to New England, and from Hydro Quebec to New England, New York, and Ontario are modeled as scheduled flows, based on 12 months of historical data.

The DC ties with the WECC and ERCOT interconnections are modeled as price sensitive supply curves. CRA uses historical electricity prices and gas prices near these DC ties to calculate market heat rates for on-peak and off-peak periods, and for summer and winter. These heat rates are multiplied by the appropriate forecast gas price in each scenario, to arrive at a price points for each DC tie. The tie is then modeled as follows:

- When the locational price at the DC tie is within $\pm \$2.50/\text{MWh}$ of the corresponding price point, zero flow is assumed on the tie.
- At locational prices that are between $\$2.50/\text{MWh}$ and $\$7.50/\text{MWh}$ above the price point, the tie is modeled as importing power into the Eastern Interconnect at half its capacity.
- At locational prices that are greater than $\$7.50/\text{MWh}$ above the price point, the tie is modeled as importing power into the Eastern Interconnect at full capacity.
- At locational prices that are between $\$2.50/\text{MWh}$ and $\$7.50/\text{MWh}$ below the price point, the tie is modeled as exporting power from the Eastern Interconnect at half its capacity.
- At locational prices that are greater than $\$7.50/\text{MWh}$ below the price point, the tie is modeled as exporting power from the Eastern Interconnect at full capacity.

7.10. DISPATCHABLE DEMAND (INTERRUPTIBLE LOAD)

Description. The presence of demand response is important to the energy and installed capacity markets. The value of energy to interruptible load caps the energy prices, and the capacity of interruptible load effectively replaces installed reserves and lowers the capacity value. For this study, the size of interruptible load is determined as a percentage of total load, based on Interruptible Demand and Direct Control Load Management as reported in the EIA-411 data. The dispatchable demand for each load area is modeled as a generator with a dispatch price of $\$600/\text{MWh}$ for the first block (50% of the area's dispatchable demand) and $\$800/\text{MWh}$ for the second block. These proxy units rarely run in the model, because the high prices they require indicate a supply shortfall and prompt new entry. Thus they play an insignificant role in the energy market, but they play an important role in the capacity market. If these loads can truly be interrupted during peak hours, they will be paid the capacity market-clearing price. Thus they have strong incentives to make themselves available during peak hours. When interruptible demand is included in the calculation of the required reserve

margin, it reduces the requirement of installed capacity and thus reduces new entry and helps increase energy prices, consistent with market behavior.

Data Sources. Data were drawn from the EIA-411 report data.

7.11. MARKET MODEL ASSUMPTIONS

Marginal Cost Bidding. All generation units are assumed to bid marginal cost (opportunity cost of fuel plus non-fuel VOM plus opportunity cost of tradable emissions permits). To the extent that markets are not perfectly competitive, the modeling results will reflect the lower bound on prices expected in the actual markets.

Operating Reserves Requirement (spinning and standby). Operating reserves are based on requirements instituted by each reliability region. These requirements are based on the loss of the largest single generator, or the largest single generator and half the second largest generator, or a percentage of peak demand. The spinning reserves market affects energy prices, since units that spin cannot produce electricity under normal conditions. Energy prices are higher when reserves markets are modeled. Table 12 shows a list of operating reserves by reliability region, and the fraction met by spinning reserves. The remainder is assumed to be met by quick start reserves.

Table 12: Operating Reserve Requirements

ISO/Region	Operating Reserve	Met by Spin
ISO-NE	1,900 MW	67%
NYISO	1,200 MW	50%
Eastern NY	1,200 MW	25%
Long Island	120 MW	50%
PJM	4,500 MW	67%
Midwest ISO	2,250 MW	65%
MAPP	871 MW	65%
SPP	1,746 MW	65%
MIPU stand alone	85 MW	65%
Entergy	4% of load	65%
Southern	4% of load	65%
TVA	4% of load	65%
VACAR	4% of load	65%
FRCC	853 MW	65%
Ontario	1,600 MW	55%

Transmission Losses. Transmission losses are modeled at marginal rates.

7.12. WHEELING RATES

Wheeling rates are "per MWh" charges for moving energy from one control area to another in an electric system. In MAPS, wheeling rates are applied to net interregional power flows and are used by the optimization engine in determining the most economically efficient dispatch of generating resources to meet load in each model hour. Wheeling rates are considered for both commitment and dispatch of generating units; however, the rates between any two areas may be different for commitment than for dispatch. For the current analysis, the wheeling rates for commitment were based on the day-ahead firm transmission rates in the individual companies' tariffs, while the rate for dispatch was based on the non-firm hourly rates.

Table 13 gives an overview of the wheeling rates between SPP, MISO, Aquila and other neighboring control areas for the Stand-alone and RTO cases

Table 13: Wheel-out Rates for SPP, Midwest ISO and Aquila Missouri

From	To	Commitment	Dispatch
Midwest ISO	SPP	\$6	\$4
SPP (other than Westar)	Non-SPP	\$2	\$2
Westar	Non-SPP	\$5	\$3
Midwest ISO	PJM	\$0	\$0
Midwest ISO	Non-Midwest ISO/Non-SPP/non-PJM	\$2	\$2
Aquila Missouri Stand-alone	All	\$2	\$2
Non-Midwest ISO MAPP companies	All	\$2	\$2
AECI	All	\$2	\$2
TVA	All	\$2	\$2
Entergy	All (including SPP)	\$2	\$2
LG&E	All	\$2	\$2
Cleco	All (including SPP)	\$2	\$2

7.13. FUEL PRICES

Description. MAPS requires monthly fuel prices for each generating unit in the model footprint. The fundamental assumption concerning participant behavior in competitive energy markets is that generators will bid their marginal cost into the energy market, including the marginal cost of fuel, variable operations and maintenance (O&M) and the costs associated with marginal emission of pollutants. The marginal cost of fuel is defined as either the opportunity cost of fuel purchased or the spot price of fuel at a location representative of the plant. If the fuel is purchased on a long term contract, it assumed that the opportunity cost of the fuel is the same as the price of fuel on the locational spot market.

CRA uses forecasts of spot prices at regional hubs, and refines these prices on the basis of historical differentials between price points and their associated hubs. For fuel oil and coal,

CRA uses estimates of the delivered price of fuel to generators on a regional basis. Dual-fuel generators are simulated as follows:

Natural Gas Primary. Units that primarily burn natural gas may burn fuel oil in at most one month of the year. Because natural gas prices are typically highest in January, the model allows the unit to switch to fuel oil for January if the oil price at that location is lower than the natural gas price.

Fuel Oil Primary. Units that primarily burn oil may switch to natural gas whenever it is economically justified. CRA assumes that natural gas shortages prevent this from happening in the winter heating period, defined as November through March. A heat rate degradation of 3% is modeled when the unit switches to natural gas. Thus, the fuel type is switched to natural gas during April through October, whenever the price of natural gas plus 3% is less than the price of fuel oil.

Coal prices are drawn from a database provided by Resource Data International (RDI), which forecasts delivered coal prices, including transportation and handling, for each major coal plant in the United States. Nuclear plants are assumed to run whenever available, so nuclear fuel prices do not impact commitment and dispatch decisions in the market simulation model. CRA therefore does not do a detailed analysis of nuclear fuel prices.

Specific oil and gas price forecasts used in this study are provided in the next section.

7.14. NATURAL GAS AND FUEL OIL PRICE FORECAST

7.14.1. Natural Gas Forecast

Principal Drivers: The principal drivers are the projected prices for natural gas at Henry Hub.

Base Case Forecast: In the near term (through 2012), the Base Case forecast is set equal to NYMEX futures prices for natural gas at Henry Hub as of the closing of December 6, 2006. For 2013 through 2025, CRA uses the EIA Annual Energy Outlook (AEO2006) Reference Case forecast²⁸. CRA Base Case forecast for natural gas prices at Henry Hub is shown in Figure 2.

Regional Prices: CRA forecasts natural gas prices on a regional basis following major pipeline traded pricing points. Regional forecasts are derived by adding two factors, the basis differential by region and local delivery charge by state, to the Henry Hub gas price.

²⁸ AEO 2006 does not forecast Henry Hub Prices, but predicts prices at the wellhead instead. A historical multiplication factor of 1.129 is used to derive the Henry Hub price forecast.

Basis Differentials by Region: CRA recognizes multiple pricing points within each census region, all of which are actual pipeline trading points surveyed and reported by Platt's Gas Daily. Some of these pricing points coincide with the NYMEX Clearport hubs, which include Henry Hub. For the other points, CRA uses a regression model to one or several NYMEX Clearport hubs, calibrated with historical data, to derive a forecast. In the near term (through 2011), the basis forecast is derived from NYMEX Clearport hub futures settlement as of December 6, 2006. The NYMEX Clearport hub futures settlement data are only available for a short period, typically between 12 and 24 months. Within this time frame, CRA derives summer and winter differentials to these hubs using NYMEX data. Beyond this period, CRA scales the basis differentials in proportion to the Henry Hub forecast. Forecast prices at each hub are derived using the Henry Hub forecast and the scaled basis differential for that hub.

Local Delivery Charges: Burner tip prices for natural gas are the sum of the basis differentials by region as derived above and a local component that captures pipeline lateral charges and/or charges to local distribution companies. CRA estimates this local component at \$0.07/MMBtu for all units. For older units CRA estimates extra LDC charges derived from AGA statistics.

Seasonal Pattern: Natural gas prices are varied seasonally based on NYMEX futures data in the near term (through 2012). Beyond 2012, the seasonal pattern shown in 2012 is repeated for each year.

Figure 3 compares the Base Case gas price forecast by region.

Figure 2. Henry Hub Prices, History and Forecast (in real 2005 \$/MMBtu)

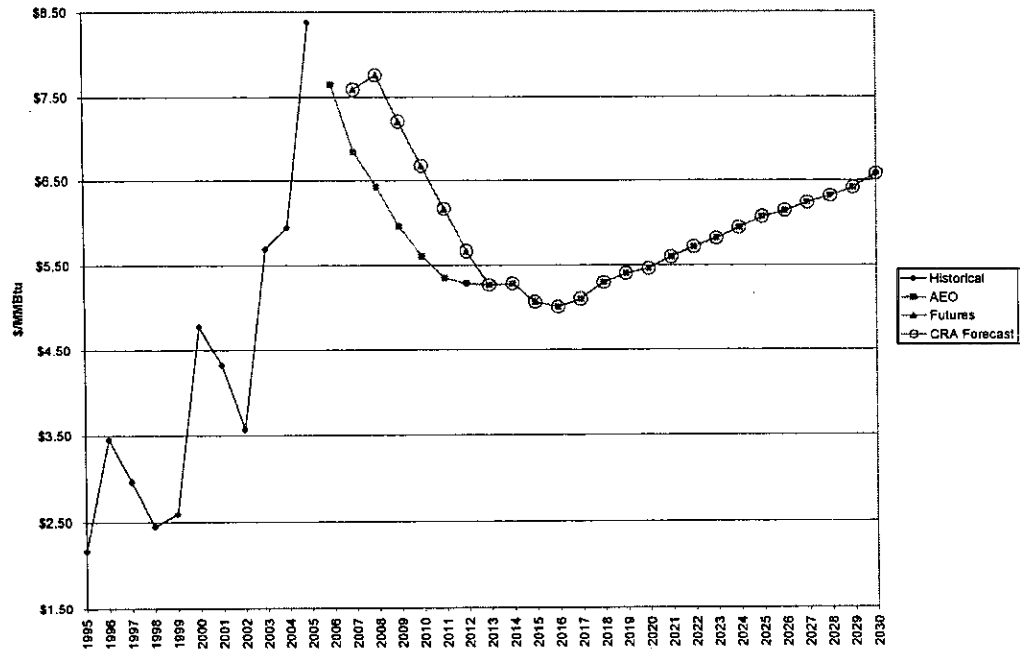
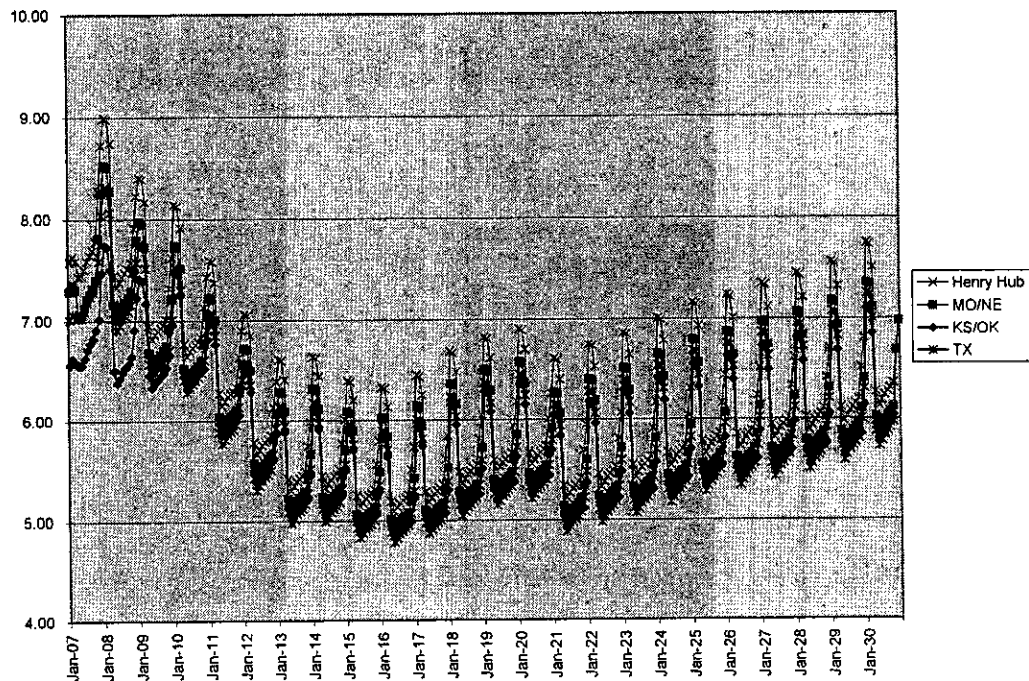


Figure 3. Forecast Regional Natural Gas Prices (Real 2005 \$/MMBtu)



7.14.2. Fuel Oil Price Forecast

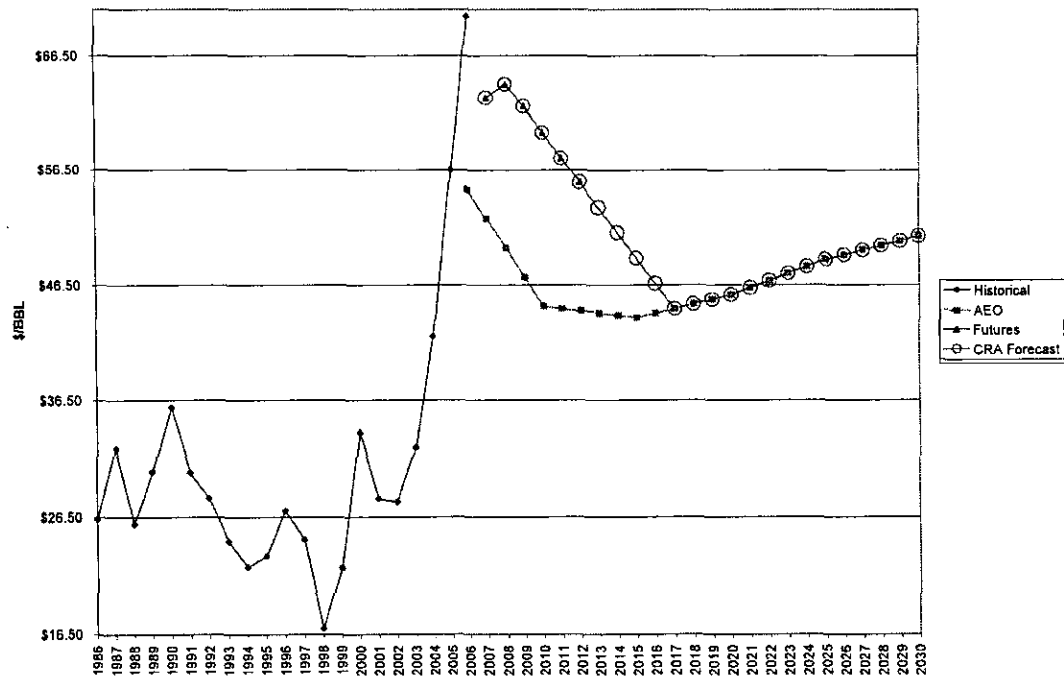
Principal Drivers: The principal drivers underlying this forecast are the projected price for light sweet crude oil at Cushing, Oklahoma.

Base Case Forecast: In the near term (through 2012), the Base Case forecast is derived from the NYMEX futures prices for light sweet crude oil as of the closing of December 6, 2006. For 2013, 2014 and 2015 the forecast is an interpolation between the futures and the AEO2006. Through 2030, CRA uses the AEO2006 Reference Case forecast. CRA Base Case forecast for light sweet crude oil is presented on Figure 2.

Regional Prices: CRA forecasts prices for fuel oil #2 and #6 by US census region. This forecast is prepared in three steps. First CRA uses a regression model calibrated on historical data to derive prices for fuel oil #2 and #6 at New York Harbor from the forecast of crude oil prices. New York Harbor prices for the Base Case forecast are shown in Figure 5. Second, New York Harbor prices (both fuel oil #2 and fuel oil #6) are linked to the AEO Reference Case forecast of US average prices of each type of fuel oil used by electric utilities. This derivation is also based on historical regression. Finally, CRA uses AEO forecast to develop yearly regional multipliers linking national average prices and prices by census region. Petroleum Business Tax of \$0.45/MMBtu for fuel oil #6 and \$0.63/MMBtu for fuel oil #2 is added to oil prices for New York State.

Seasonal Pattern: Both fuel oil #2 and fuel oil #6 prices are varied monthly based on NYMEX futures data in the near term, and based on historical monthly patterns in the longer term.

Figure 4. Crude Oil Prices: History and Projection (Real 2005 \$/BBL)



7.15. NATURAL GAS PRICE SENSITIVITY ASSUMPTION

A natural gas price sensitivity case was performed for the year 2012 in which the Henry Hub natural gas prices shown in Figure 2 were increased to \$9.00 per mmBTU (2005\$). The 2012 generation fuel prices were then recreated using the methodology discussed above. No changes were made to fuel oil, coal or nuclear fuel prices.

8. APPENDIX B: AQUILA MISSOURI RESOURCES

Table 14 lists the Aquila Missouri generation resources for the 2008 to 2017 period. The jointly-owned units and the long-term unit purchases are located outside of the Aquila Missouri control area.

Table 14
Aquila Missouri Generating Capacity
(MW, summer rating)

Existing Units		
Greenwood 1-4	232.0	
Iatan 1	117.7	<i>Jointly-owned</i>
Jeffrey 1-3	175.2	<i>Jointly-owned</i>
KCI 1-2	33.6	
Lake Road 1-7	268.8	
Nevada	20.0	
Ralph Green	71.0	
Sibley 1-3	508.3	
South Harper	315.0	
	<u>1741.6</u>	
Long-term Purchases		
Cooper	75.0	<i>Ends May 2011</i>
Gentleman 1-2	100.0	<i>Ends Jan. 2014</i>
	<u>175.0</u>	
New Capacity		
Iatan 2	153.0	<i>2010 ISD, Jointly-owned</i>
Merchant Capacity in Aquila-Mo Control Area		
Aries	580.0	

9. APPENDIX C: SUPPORTING DETAIL

9.1. ANNUAL RESULTS

9.1.1. Member of Midwest ISO

The projected annual benefits (costs) to Aquila Missouri of being a member of the Midwest ISO for each category of benefits and costs are summarized in Table 15.

Table 15
Annual Benefits (Costs) to Aquila Missouri of Midwest ISO
Membership in comparison to Stand-alone Status
(in millions of dollars; positive numbers are benefits)

	Present Value	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Aquila-MO in Midwest ISO											
+ Production Cost Savings	45.9	2.9	3.6	4.3	5.1	5.9	7.5	9.1	10.8	12.6	14.5
+ Purchase Cost Savings	(103.5)	(11.4)	(12.7)	(14.1)	(15.5)	(17.0)	(17.2)	(17.4)	(17.7)	(17.9)	(18.1)
+ Sales Revenue Increases	87.6	15.3	15.2	15.1	14.9	14.8	13.2	11.6	9.9	8.1	6.2
= Trade Benefits	29.9	6.8	6.1	5.3	4.5	3.7	3.5	3.3	3.0	2.8	2.5
+ Savings Trans/Rel Functions	16.0	2.2	2.2	2.3	2.3	2.4	2.5	2.5	2.6	2.6	2.7
+ RTO Administrative Charges	(23.5)	(3.3)	(3.2)	(3.3)	(3.4)	(3.5)	(3.6)	(3.7)	(3.8)	(3.9)	(4.0)
+ Additional FERC Charges	(1.3)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
= Subtotal Other Charges	(8.8)	(1.3)	(1.2)	(1.2)	(1.3)	(1.3)	(1.3)	(1.4)	(1.4)	(1.4)	(1.5)
Total	21.1	5.5	4.9	4.1	3.3	2.4	2.2	1.9	1.6	1.3	1.0

9.1.2. Member of SPP RTO

The projected annual benefits (costs) to Aquila Missouri of being a member of the SPP RTO for each category of benefits and costs are summarized in Table 16.

Table 16
Annual Benefits (Costs) to Aquila Missouri of SPP RTO
Membership in comparison to Stand-alone Status
(in millions of dollars; positive numbers are benefits)

	Present Value	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Aquila-MO in SPP RTO											
+ Production Cost Savings	673.4	80.2	85.0	90.0	95.2	100.7	105.9	111.4	117.1	123.0	129.1
+ Purchase Cost Savings	(465.5)	(49.4)	(53.3)	(57.3)	(61.5)	(65.8)	(73.1)	(80.7)	(88.7)	(97.0)	(105.7)
+ Sales Revenue Increases	(112.2)	(16.1)	(16.7)	(17.4)	(18.0)	(18.7)	(17.8)	(16.8)	(15.8)	(14.7)	(13.6)
= Trade Benefits	95.7	14.7	15.0	15.4	15.8	16.1	15.0	13.8	12.6	11.2	9.8
+ Savings Trans/Rel Functions	16.0	2.2	2.2	2.3	2.3	2.4	2.5	2.5	2.6	2.6	2.7
+ RTO Administrative Charges	(23.5)	(3.3)	(3.2)	(3.3)	(3.4)	(3.5)	(3.6)	(3.7)	(3.8)	(3.9)	(4.0)
+ Additional FERC Charges	(1.3)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
= Subtotal Other Charges	(8.8)	(1.3)	(1.2)	(1.2)	(1.3)	(1.3)	(1.3)	(1.4)	(1.4)	(1.4)	(1.5)
Total	86.9	13.4	13.8	14.2	14.5	14.8	13.7	12.5	11.2	9.8	8.3

9.2. ADMINISTRATIVE AND OPERATING COSTS

9.2.1. Savings from RTO Provision of Transmission Functions

At the request of CRA, Aquila Missouri staff estimated the additional costs that Aquila Missouri would incur to provide on a Stand-alone basis the six transmission/reliability functions currently provided by SPP and the Midwest ISO on a Stand-alone basis. These costs would be avoided (and replaced by RTO administrative charges) if Aquila Missouri were to join an RTO. The key assumptions behind the cost figures are summarized below.

Function 1. Reliability Coordination

For Aquila Missouri to provide its own reliability functions (the direct actions required to maintain adequate generation capacity, adequate system voltage levels, and transmission system loading within specified limits), five additional FTE system operators would be required along with a \$205,000 investment in additional computer hardware/software. Also there would be approximately \$10,000 per year needed for software licensing/maintenance fees.

Function 2. Tariff Administration

In order to provide tariff administration such as processing long term transmission service requests, performing feasibility and impact studies, managing billing, and handling regulatory issues would require addition of one FTE planning engineer.

Function 3. OASIS Administration

This function comprises administration of transmission service, including provision of qualified staff and supervision for day and night coverage and procurement and maintenance of the necessary telecommunications infrastructure to support the service. Information updated would include ATC, response to service requests, transmission limitations, transmission reservation policy, and various FERC required postings. To maintain the OASIS on a full time basis would require three additional FTE system operators in the system operations area. In addition a capital investment of approximately \$15,000 would be required for additional computer equipment and software.

Function 4. ATC/TTC Calculations

In order to perform required transmission capacity calculations, one FTE planning engineer would be required.

Function 5. Scheduling Agent

For Aquila to perform this service, two clerical FTEs would be required to check out all transactions with customers on a daily basis, and in addition two FTE system operator would be required to track and administer tags on a daily basis.

Function 6. Regional Transmission Planning

The transmission planning function would consist of developing load flow planning models with a 10 year horizon, developing a database and performing stability studies, performing transmission expansion and operating studies, develop transmission pricing models. Part of this work is already performed by Aquila transmission planning personnel. To assume the planning study work now done by SPP would require the addition of one FTE planning engineer.

Aquila Missouri personnel provided O&M (including benefits) and capital addition costs for the years 2008 through 2017. CRA converted the capital additions into revenue requirements, and also applied an A&G adder to the projected wages as shown in Table 17.

Table 17
Annual Costs for Aquila Missouri to Provide Transmission/Reliability Functions
(in thousands of dollars)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
1 Reliability Coordination										
Wages	390	399	409	419	430	441	452	463	475	486
Benefits	195	200	205	210	215	220	226	231	237	243
Other O&M	10	11	11	11	11	12	12	12	12	13
Total O&M	595	609	625	640	656	673	689	707	724	742
Capital Additions	210					238				
2 Tariff Administration										
Wages	72	74	75	77	79	81	83	85	87	90
Benefits	36	37	38	39	40	41	42	43	44	45
Total O&M	108	110	113	116	119	122	125	128	131	134
3 OASIS Administration										
Wages	234	240	246	252	258	264	271	278	285	292
Benefits	117	120	123	126	129	132	136	139	142	146
Other O&M	5	5	5	5	4	6	6	6	5	5
Total O&M	356	365	373	382	391	403	412	422	432	443
Capital Additions	15					15				
4 ATC/AFC/TTC Calculations										
Wages	72	74	75	77	79	81	83	85	87	90
Benefits	36	37	38	39	40	41	42	43	44	45
Total O&M	108	110	113	116	119	122	125	128	131	134
5 Scheduling Agent										
Wages	238	244	250	256	262	269	276	283	290	297
Benefits	119	122	125	128	131	135	138	141	145	148
Total O&M	357	366	375	384	394	404	414	424	435	445
6 Transmission Planning										
Wages	72	74	75	77	79	81	83	85	87	90
Benefits	36	37	38	39	40	41	42	43	44	45
Total O&M	108	110	113	116	119	122	125	128	131	134
TOTAL										
Wages	1076	1103	1131	1159	1188	1218	1248	1279	1311	1344
Benefits	538	552	565	580	594	609	624	640	656	672
Other O&M	16	16	16	16	16	18	18	18	18	18
A&G (a)	473	485	497	510	522	535	549	563	577	591
Total O&M and A&G	2103	2156	2209	2264	2320	2380	2439	2499	2561	2625
<u>Capital Additions</u>										
Capital Additions	225					253				
Rev Requirement	78	71	65	58	52	87	80	72	65	58
Total	2181	2227	2274	2322	2372	2467	2519	2572	2627	2683

(a) Estimated at 44% of Wages based on Aquila-MO 2004/5 FERC Form 1 Ratio of A&G Office Supplies and Expenses to A&G Salaries

9.2.2. RTO Administrative Costs

The annual RTO administrative costs were estimated using the forecast of expenditures per MWh of market member load as projected by the Midwest ISO as shown in Table 18. Aquila Missouri expenditures subsequent to 2011 were assumed to escalate at inflation.

Table 18
Annual RTO Administrative Charges for Aquila Missouri

RTO Administrative Charges			2008	2009	2010	2011
Aquila-MO Net Annual Energy	(GWh)	(a)	8,823	9,074	9,322	9,572
RTO Administrative Charges	(\$/MWh)	(b)	0.373	0.358	0.356	0.356
Aquila-MO RTO Admin Charges	(\$000)		3,291	3,248	3,319	3,408

(a) - SPP 2006 IE-411, page 24.
 (b) - Midwest ISO, Recommended Capital and Operating Budget, December 14, 2006, page 5.

9.2.3. Additional FERC Charges

The annual additional FERC charges in 2007 dollars that would be incurred by Aquila Missouri if a member of an RTO are provided in Table 19. The additional cost was assumed to increase at inflation through the study period.

Table 19: Additional FERC Annual Charges if in RTO
(in thousands of dollars unless noted)

Historical FERC Charges for Aquila-Missouri					
(Source: FERC Form 1, Page 350, Regulatory Commission Expenses)					
	MPS	L&P	Total	2007\$ (c) Multiplier	2007\$ Total
2004	148.8	120.2	269.0	1.0875	292.6
2005	91.5	111.8	203.3	1.0549	214.4
Average					253.5
FERC Charges if in RTO:					
2007 MISO Estimated Schedule 10 FERC Charges (a)					32,333 (a)
2007 MISO Estimated Schedule 10 GWH (load)					650,847
2007 FERC Charges per \$/MWh of load					0.050
Aquila-MO 2007 Estimated Net Energy for Load (GWh)					8,586 (b)
Aquila-MO 2007 Annual FERC Charge if in RTO					426.5
Increase in FERC Charges if in RTO (2007\$)					173.0
(a) - Midwest ISO, Schedule 10 FERC Rate, forecast 2007 dollars for MISO					
(b) - SPP 2006 IE-411, page 24.					
(c) GDP Deflator:					
7/1/2004	109.728				
7/1/2005	113.121				
7/1/2006	116.420				
7/1/2007	119.331 @2.5%				



***Helping our members work together
to keep the lights on...
today & in the future***



Balancing Authority Consolidation

Board of Directors/Members Committee

June 12, 2007

Schedule RJ5

Agenda

- Balancing Authority Responsibilities
- Approach to Consolidation of SPP BAs
- Benefits of BA Consolidation
- BA Consolidation Timeline

Definitions

- **Balancing Authority (BA)** – The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
- **Balancing Authority Area (BAA)** – The collection of generation, transmission, and loads within the metered boundaries of the BA. The BA maintains load-resource balance within this area.

SOUTHWEST POWER POOL

Balancing Authority Responsibilities

SPP.ORG 5

SOUTHWEST POWER POOL

BA Responsibilities/Requirements

- The NERC functional model describes 13 areas of responsibility applicable to the BA function
- NERC Reliability Standards specify approximately 440 requirements for the BA function

SPP.ORG 6

BA Functional Responsibilities

1. Control of at least one of the following combinations
 - Load and generation
 - Load and scheduled interchange
 - Generation and scheduled interchange
 - Generation, load, and scheduled interchange
2. Calculate Area Control Error (ACE)
3. Maintain load-interchange-generation balance

BA Functional Responsibilities

4. Review generation commitments, dispatch, and load forecast
5. Formulate an operational plan for reliability evaluation
6. Approve interchange transactions from ramping ability perspective
7. Implement interchange schedules
8. Support interconnection frequency through tie-line bias

BA Functional Responsibilities

9. Monitor and report control performance and disturbance recovery
10. Provide balancing and energy accounting and administer inadvertent energy paybacks
11. Determine need for reliability-related services
12. Deploy reliability-related services
13. Implement emergency procedures

Approach to Consolidation of SPP BAs

BA Consolidation Approach

- SPP would be responsible to ensure that all BA requirements are met
 - SPP will directly perform most BA tasks
 - SPP may delegate performance of certain BA tasks to Transmission Operators and/or Generation Operators within the SPP BAA
- Appropriate agreements would have to be developed to ensure performance of any tasks to be delegated and/or ensure SPP has necessary data to perform its BA tasks
- Existing BAs would become Regulating Zones
- Detailed consolidation specifications in progress

1. Control of ...Generation and Scheduled Interchange...

- SPP would calculate and send dispatch instructions for each resource in the SPP BAA
- Could rely on existing infrastructure (RSS, MOS, SPP EMS and EMS at existing BAs) for large part of this
- Need to add regulation component based on SPP ACE

2. Calculate ACE

- $ACE = (NAI - NSI) - 10B (FA - FS) - IME$
- SPP already has necessary infrastructure and/or data to determine certain components (NSI, FA, FS)
- Will have to add/acquire data to calculate other components (NAI, B, IME)

3. Maintain Load-Interchange-Generation Balance

- SPP will have to develop a mechanism to allocate the SPP ACE to regulating zones within the SPP BAA
- Although SPP has much of the needed data and displays, SPP will take a more active role in monitoring ACE

4. Review Generation Commitments, Dispatch, and Load Forecasts

- SPP already doing this to a large extent with its Day-Ahead and Hour-Ahead Supply Adequacy and Simultaneous Feasibility Analyses
- SPP currently has infrastructure and is getting most of the data needed to do this
- Will take more active role in instructing commitment of generation

5. Formulate an Operational Plan for Reliability Evaluation

- Generator and Transmission Operators will submit information to SPP by which SPP will formulate an Operational Plan for the SPP BAA and share with the appropriate NERC reliability entities
- Can rely largely on existing infrastructure and analytical tools to receive data and evaluate plans

6. Approve Interchange Transactions

- Can rely on RTOSS infrastructure for approval actions
- Will likely change how schedules are tagged
- Will need to consider development of ramp limits for the SPP BAA

7. Implement Interchange Schedules

- Will be able to rely on existing infrastructure to implement approved schedules
- Will need to change logic to include approved schedules in the SPP BA ACE
- May have to make changes in NERC registry and IDC

8. Support Interconnection Frequency

- SPP already monitors frequency and receives scheduled frequency as an RC
- SPP would need to start calculating frequency bias setting for the SPP BAA based on historical BAA load, initially could use sum of current settings for the Regulating Zones

9. Monitor and Report Control Performance and Disturbance Recovery

- SPP must begin calculating and monitoring the CPS1, CPS2, and DCS measurements for the SPP BAA
- SPP will report these measures to NERC and the SPP reserve sharing group

10. Provide Balancing and Energy Accounting and Administer Inadvertent Energy Paybacks

- SPP currently calculating Inadvertent Energy and administering paybacks on behalf of the market footprint
- Will likely delegate to the Regulating Zones or Transmission Operators the task of checking out interconnect meters

11. Determine Need for Reliability-Related Services

- SPP will need to calculate a regulation requirement for the SPP BAA and for each Regulating Zone
- SPP could continue to calculate reserve requirements for each Regulating Zone much like it does today

12. Deploy Reliability-Related Services

- SPP could either send a regulation instruction to each Regulating Zone or send regulation instructions directly to those resources offering regulation
 - Will likely do the first option initially
 - Second option requires establishment of a regulation market
- Already deploying reserves through schedules in RTOSS

13. Implement Emergency Procedures

- SPP will be responsible for implementing emergency procedures such as insufficient generation, IROL violations, load shedding, and system restoration by coordinating with the Regulating Zones
- SPP will have to take a more active role in communicating, reporting and responding to emergencies

SOUTHWEST POWER POOL

Benefits of BA Consolidation

SPP.ORG 25

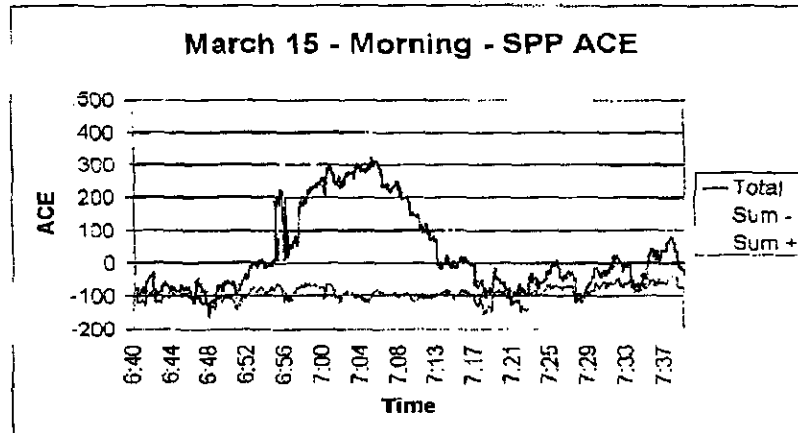
SOUTHWEST POWER POOL

BA Consolidation Benefits

- **Reduced regulation "effort"**
 - Previous studies indicated 30% reduction in energy required to regulate
 - Should also result in capacity savings
- **Better control performance**
- **Transfer of liability from many entities to one**
- **Facilitation of ancillary service markets**
- **Net reductions in training, certification, staffing**

SPP.ORG 26

Example of ACE Diversity Impacts



BA Consolidation Timeline

BA Consolidation Timeline

- Currently drafting business plan that will include a detailed description of how SPP would perform each of the BA responsibilities
- Will present draft business plan to Stakeholders in early July
- Targeting completion of project implementation plan in early November
- Will first target consolidation of BAs within Market footprint by mid- to late-2008