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OPPD.WAUE
A Benefit and Cost Analysis

A Thesis

Presented to the

Department of Business Administration

and the

Faculty of the Graduate College

University of Nebraska

In Partial Fulfillment

of the Requirements for the Degree

Master of Business Administration

University of Nebraska at Omaha

By

Thomas James Sandoz

May 2005

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THESIS ACCEPTANCE

Acceptance for the faculty of the Graduate College,
University of Nebraska, in partial fulfillment of the
Requirements for the degree Masters of Business Administration
University of Nebraska at Omaha.

Committee

Graham R. Mitenko, Ph.D.

Richard G. File, Ph.D.

David A. Volkman, Ph.D.

Chairperson Graham R. Mitenko, Ph.D.

Date MAY 11, 2005
Month, Day, Year

OPPD.WAUE

A Benefit/Cost Analysis

Thomas James Sandoz, MBA

University of Nebraska, 2005

Advisor: Dr. Graham R. Mitenko

The purpose of this thesis is to study the benefit and cost of constructing a 161, 230, or 345 kilovolt (kV)[1] transmission line between Omaha Public Power District (OPPD)[2], a political subdivision of the State of Nebraska, and OPPD's northern Control Area neighbor, Western Area Power Administration (WAPA),[3] a division of the U.S. Department of Energy.[4]

Seven transmission construction project options will be analyzed, and a description of the individual characteristics of each option will be discussed. The characteristics of each option include the option specific assumed benefits, costs, right of ways, environmental impacts, and transmission system impact studies. The scope of the analysis also will include discussion of the legal ramifications for OPPD to own transmission assets outside of the borders of the State of Nebraska, and the legality for

[1] Kilovolt is 1000 volts. Acronym Appendix is located on page 123 and Definitions Appendix is located on page 126.

[2] *Omaha Public Power District, Who We Are,* web site on 11/11/04. http://ww1.oppd.com/who/index.cfm

[3] *Western Area Power Administration, Home*, web site on 11/12/04. http://www.wapa.gov/

[4] *U.S. Department of Energy, Offices and Facilities*, web site on 11/11/04. http://www.energy.gov/engine/content.do?BT_CODE=OF_PMAWESTERNAREA

companies established outside of Iowa (the targeted construction State) to own transmission assets within the borders of Iowa. A side by side benefit and cost analysis of the options will be compared and a final recommendation will be suggested by the author.

ACKNOWLEDGEMENTS

Grateful appreciation is due my fellow Omaha Public Power District co-workers Kent Herzog and Dr. Qian Zhang for taking time out of their extremely busy schedules to answer specific and detailed questions regarding the content of this Thesis.

Dr. Michael O'Hara has been a critical cog in the content and scope of this effort. Dr. O'Hara's input was paramount because of his past experience as a former Board Member at Omaha Public Power District, his doctoral dissertation on Nebraska's Power Review Board, and for his grasp of the legal landscape surrounding Public Power.

My wife, Janie Sandoz, is recognized for reasons which would merit a separate and stand alone thesis. I will spare you.

I would like to recognize Dr. Richard File, and Dr. David Volkman, for providing me support and guidance, especially during the 'final miles' of this marathon effort.

Dr. Graham Mitenko is acknowledged for rekindling the flames of my academic pursuits. In Mitenko's Financial Management graduate MBA class, the student is introduced to hundreds of financial equations, concepts, terms, and ratios. The student comes away with many equations including: Mitenko = Value.

And finally, I say "thanks" to my sister Mary Koziel, for supporting me and my various pursuits for the past forty years.

TABLE OF CONTENTS

Chapter 1: Introduction

Omaha Public Power District

Omaha Public Power District (OPPD), a political subdivision of the State of Nebraska, is an electric utility serving all or some of the 13 counties of southeastern Nebraska.[5] Established on December 2, 1946 from the merging of Nebraska Power Company and Eastern Nebraska Public Power District, OPPD currently serves over 312,000 customers and a population of 705,000 persons.[6] (For a list of acronyms, refer to Appendix 1, starting at page 123. For a list of definitions, refer to Appendix 2, starting at page 126.)

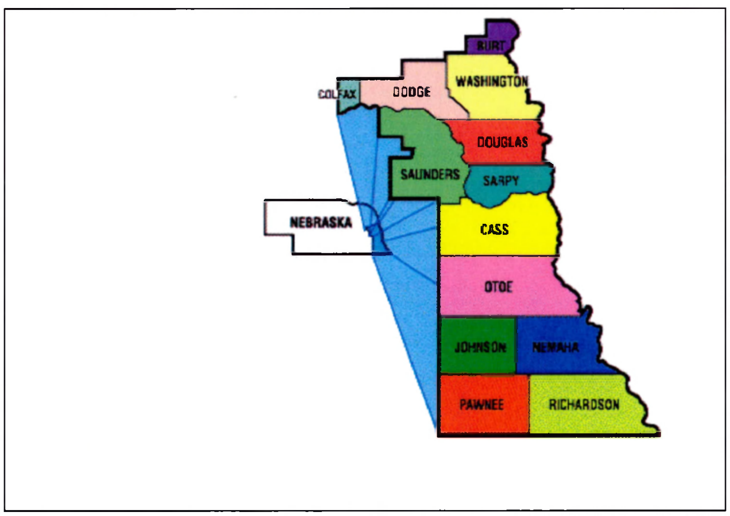

Figure 1. OPPD service area (Highlighted by county) [7]

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[5] *OPPD History* web site on 8/11/04.
http://ww1.oppd.com/who/history/index.cfm

[6] *OPPD History* web site on 8/21/04.
http://ww1.oppd.com/who/history/index.cfm

[7] *OPPD Service Territory* web site on 8/15/04.
http://ww1.oppd.com/who/svcterritory.cfm

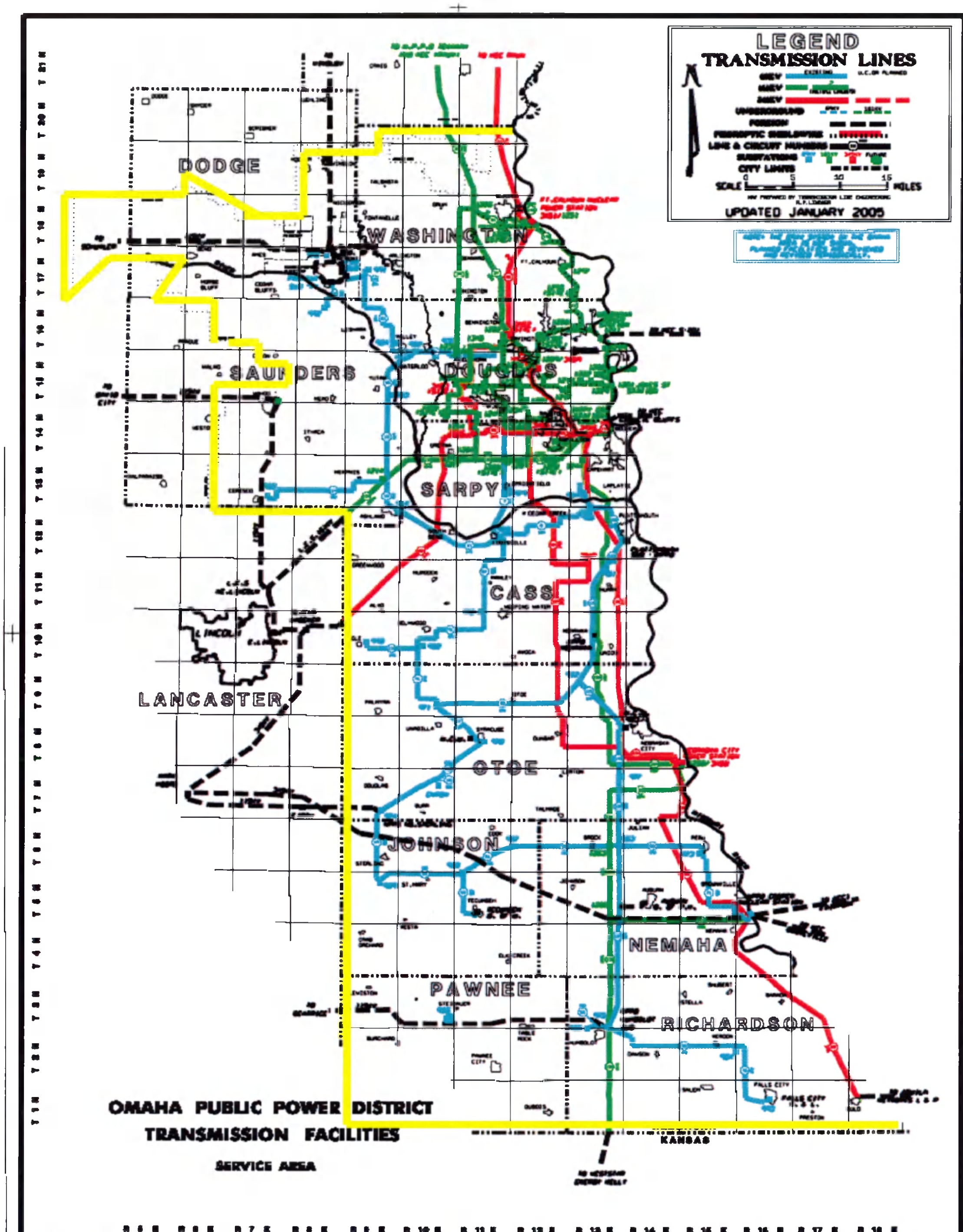

Figure 2. Detail of OPPD Transmission Facilities and Service Area (Yellow line is approximate border and Missouri River is Eastern border) [8]

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[8] Source of map is OPPD Transmission and Distribution Planning Department.

OPPD's Geographic Location

Control Area

OPPD is a Control Area (CA). A Control Area is defined as:

"An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s).
(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and
(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice."[9]

Control Areas are linked to one another via direct interconnects, in which the transmission lines of Control Area "A" connect to a substation of Control Area "B".

Prior to being a Control Area, OPPD existed as a service area.

"LB 220 (1963) created the Nebraska Power Review Board (PRB). The Board's principal tasks were to foster and authorize the creation of legitimized service areas and to review and approve additions to the generation and transmission systems. LB 220 (1963) specifically changed the policies of the state of Nebraska with respect to its electric utilities. Cost minimization was retained as a policy, but cooperation replaced competition, and state control constrained local control on matters affection generation and transmission.[10]

---

[9] *MAPP Schedule F: Open-Access Transmission Tariff, Common Service Provisions, Definitions, at: Business Practices, Transmission Tariffs and Service Schedules, MAPP SERVICE SCHEDULE F* web site, pg. 8 on 9/27/04. http://toinfo.oasis.mapp.org/oasisinfo/

[10] Michael J. O'Hara, "*The Nebraska Power Review Board: Regulating a Publicly-Owned Electric Utility Industry*" (Ph.D. diss., University of Nebraska, 1983), pg. 95.

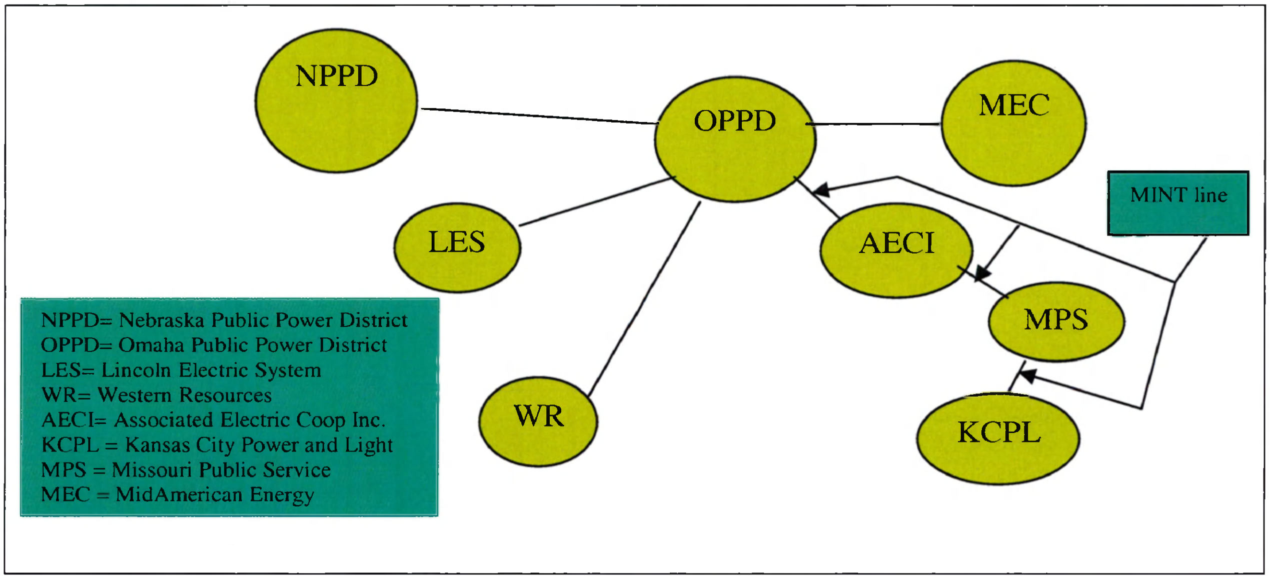

Figure 3. OPPD's and its seven direct interconnecting Control Areas[11]

Interconnect	Acronym	Headquarters
Nebraska Public Power District	NPPD	Columbus, NE
Lincoln Electric System	LES	Lincoln, NE
Westar Energy	WR	Topeka, KS
Associated Electric Cooperative	AECI	Springfield, MO
Aquila Networks*	AN**	Kansas City, MO
Kansas City Power and Light	KCPL	Kansas City, MO
MidAmerican Energy	MEC	Des Moines, IA

Figure 4. OPPD direct interconnects.

* Formally St. Joseph Light and Power (SJLP)

** Formally Missouri Public Service (MPS)

Currently, OPPD has no direct interconnects north of Nebraska.

[11] Nebraska Public Power District (NPPD) web site on 11/11/04. http://www.nppd.com/
Lincoln Electric System (LES) web site on 11/11/04. http://www.les.com/
Westar Energy (WR) web site on 11/11/04. http://www.westarenergy.com
Associated Electric Cooperative Incorporated (AECI) web site on 11/11/04. http://www.aeci.org/
Aquila Networks (AN) web site on 11/11/04. http://www.aquila.com/
Kansas City Power and Light (KCPL) web site on 11/11/04 at: http://www.kcpl.com/
MidAmerican Energy (MEC) web site on 11/11/04. http://www.midamericanenergy.com/

Regional Reliability Regions/Power Pools

Mid-Continent Area Power Pool (MAPP)

Control Areas are further grouped into larger pools. OPPD, a Control Area, is a member of the Mid-Continent Area Power Pool (MAPP) headquartered in Minneapolis, MN.

> "Power pooling is not a new concept ... In the latter part of the 1963 to1983 time-frame, the public power districts also pursued power-pooling. NPPD was the most active district, pursuing the construction of an extra-high voltage (EHV) transmission line to Canada to permit seasonal exchanges of power … The 1969 federal encouragement of transmission system interconnections and creation of reliability councils, following brown- and black-outs of the 1960's greatly expanded the potential for competition at the wholesale level. The efforts to reduce reserve ratios, assemble diverse demands, and engage in power pooling were accentuated by the energy crisis of the 1970s ... The reliability council, of which Nebraska is a part, is the Mid-Continent Area Reliability Coordination Agreement (MARCA) … a sister organization was formed actually to perform the power transfers … The sister organization, which includes the area of Nebraska is the Mid-Continent Area Power Pool (MAPP).[12]

MAPP's geographic footprint extends from Saskatchewan and Manitoba along its northern border to Nebraska and Iowa along its southern border. (See, MAPP map below on page 6) These larger pools exist to

> "perform three core functions:
> 1) Reliability Councils, responsible for the safety and reliability of the bulk electric system under NERC guidelines;
> 2) Regional transmission groups, responsible for facilitating open access of the transmission system; and
> 3) Facilitators of power and energy markets, where MAPP Members and non-members may buy and sell electricity."[13]

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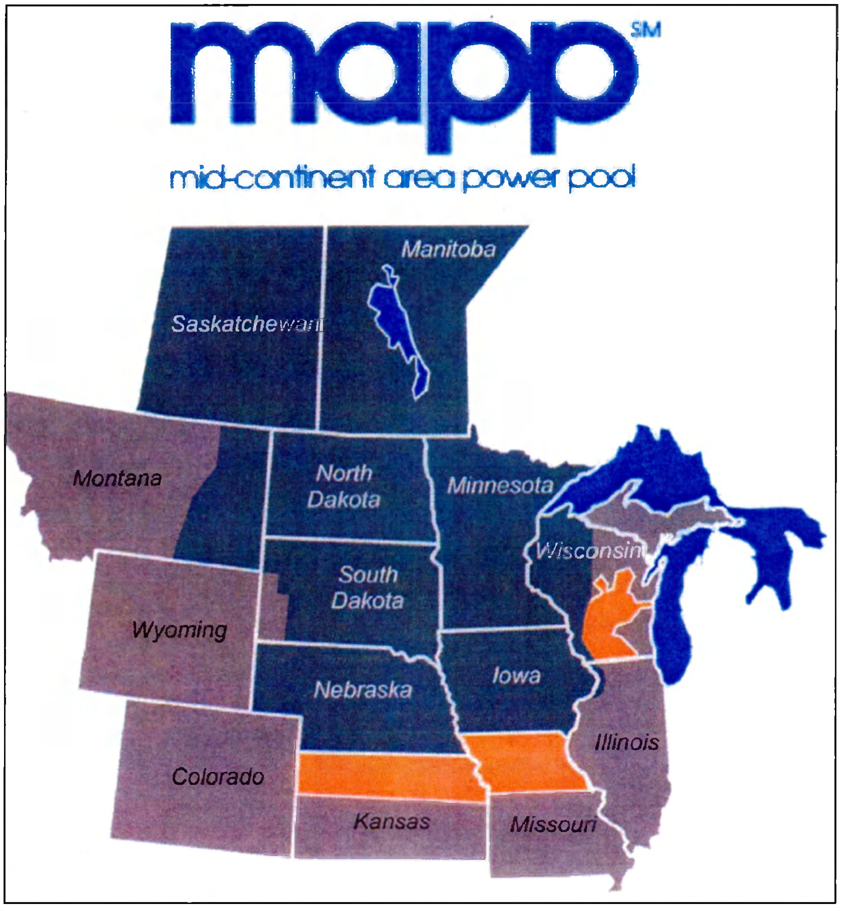
[12] Michael J. O'Hara, "*The Nebraska Power Review Board: Regulating a Publicly-Owned Electric Utility Industry*" (Ph.D. diss., University of Nebraska, 1983), pgs. 136-137.

[13] *MAPP About* web site on 8/30/2004. http://www.mapp.org/content/about_mapp.shtml



= MAPP Reliability and Regional Transmission Members
= MAPP Regional Transmission Members Only
= non-MAPP Members

Figure 5. MAPP region[14]

[14] MAPP Committee Directory Cover web site on 9/24/2004.
http://www.mapp.org/assets/pdf/Committee%20Directory.pdf

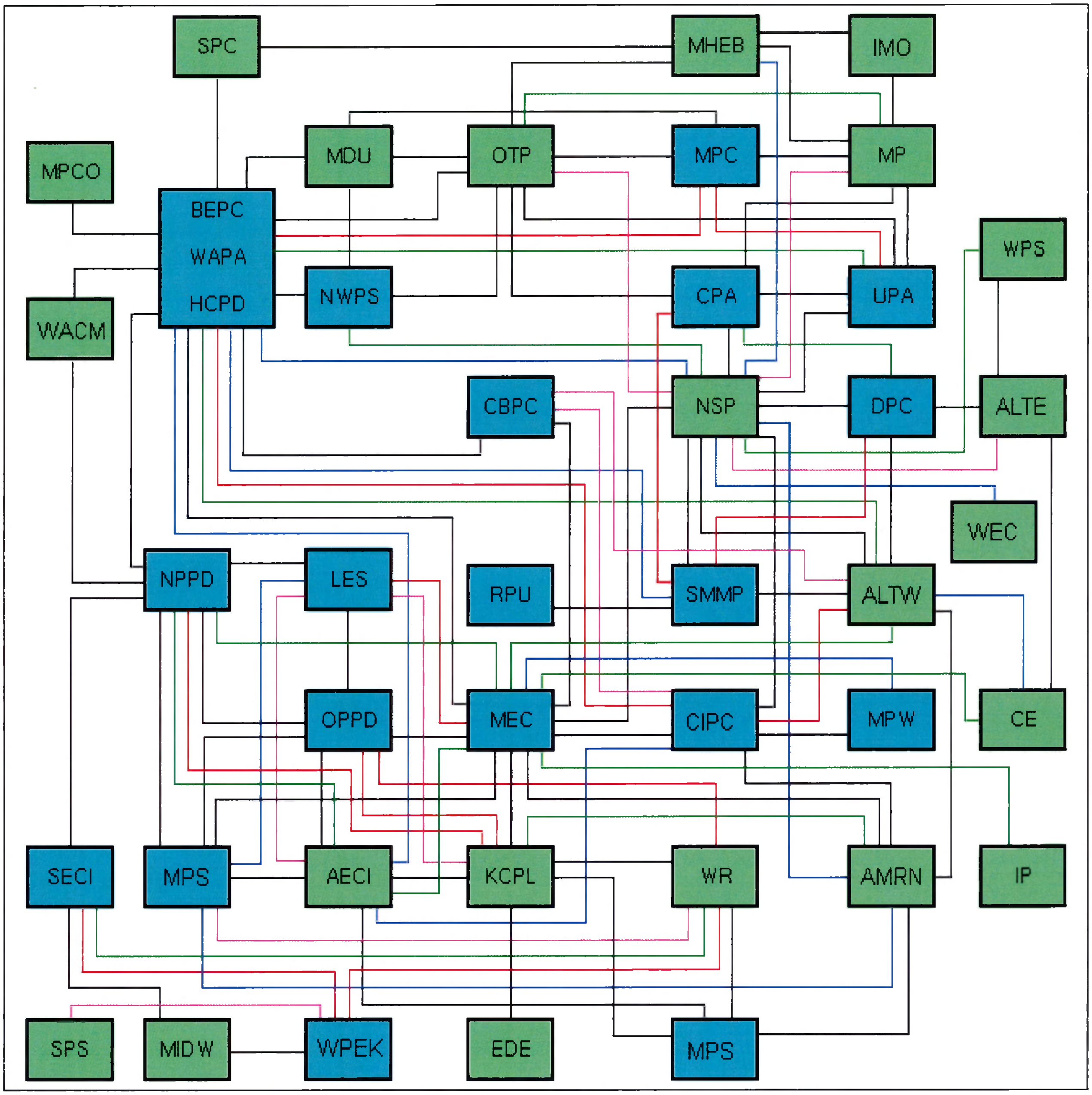


Figure 6. MAPP detailed Control Area Interconnects [15]

[15] *MAPP map* on 9/10/04 web site. (The significance of the colored interconnect lines serve to enhance interconnect viewing only. The various colored interconnect lines have no other significant meaning.) http://mapp.oasis.mapp.org/OASIS/NODE

Southwest Power Pool

OPPD is geographically located on the southern border of MAPP. The Regional Reliability Regions south of OPPD's Control Area is Southwest Power Pool (SPP). Reliability Regions are connected via interconnects between their respective Control Areas. For example, OPPD is interconnected to WR, and this Control Area interconnect also serves as an interconnect between Reliability Regions, MAPP and SPP.

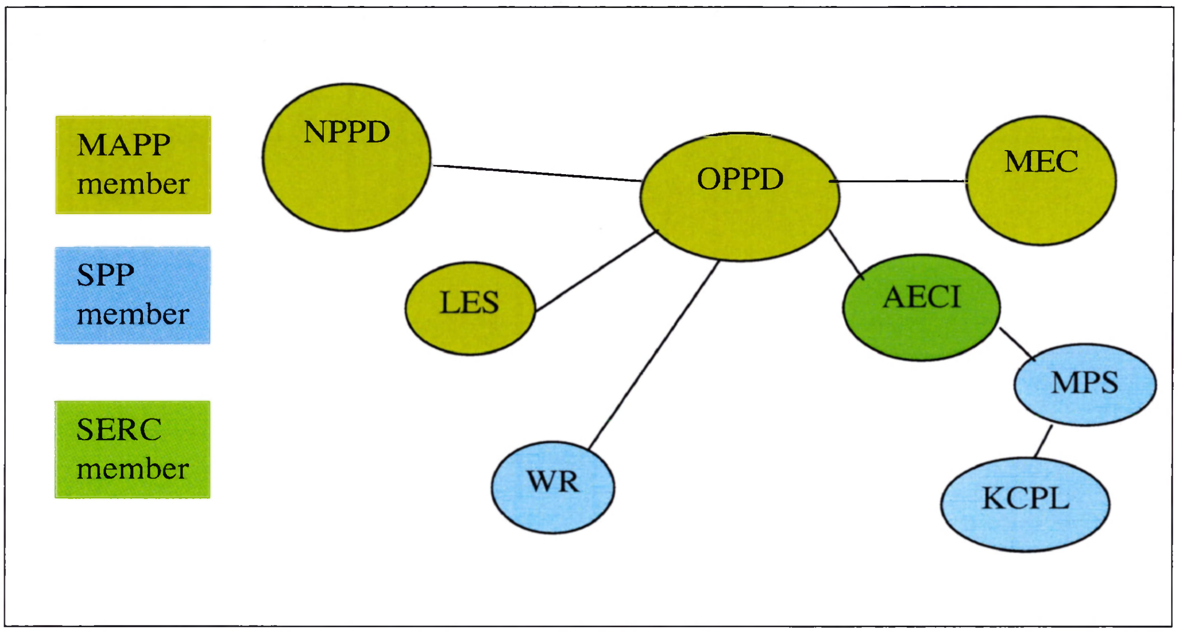


Figure 7. MAPP and SPP interconnected via OPPD.WRI, OPPD.KCPL and OPPD. MPS. MAPP and AECI are interconnected via OPPD.AECI.[16]

[16] AECI is a member of Southeastern Electric Reliability Council (SERC) headquartered in Birmingham, Alabama, for the reliability functions (Reserve Sharing) associated to a Reliability region; however, SERC does not administer a transmission tariff, so AECI uses its own tariff and provides open access to its transmission system. Transmission is "wheeled" through SERC from Control Area to Control Area. For more discussion of "wheeling" see pg. 56.

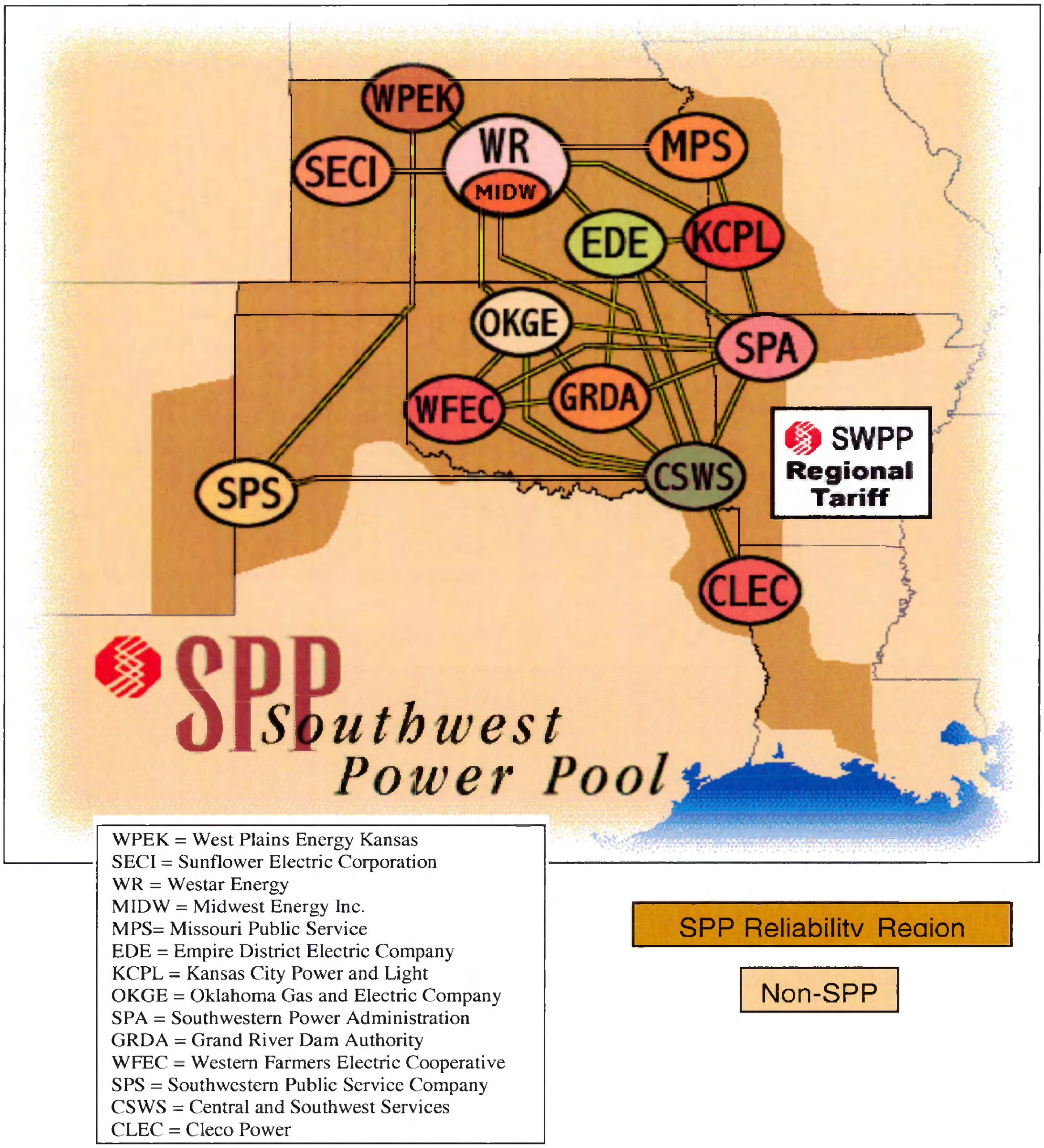


Figure 8. Southwest Power Pool (SPP) Regional Reliability Map[17]
(Control Area color differentiation has no significance)

[17] SPP MAP on 9/12/2005 at secured web site. https://sppoasis.spp.org/OASIS/NODE

MINT line

The MINT line highlighted above is a jointly owned 345 kV transmission line from OPPD to KCPL, contracted on March 5, 1990 with 7 participants: NPPD, OPPD, LES, MEC, (formally Iowa Power Incorporated), AECI, MPS (Aquila Networks, formally St. Joseph Power and Light), and KCPL. MINT is an acronym for Missouri-Iowa-Nebraska Transmission. The purpose of the discussion on the MINT line is two-fold; first to illustrate OPPD interconnects in the above diagram, and to demonstrate precedence in jointly owned transmission assets. An option analyzed will involve jointly owned transmission assets, and the MINT line is an example of prior commitment to such an endeavor.

> "The Participants have agreed to finance, construct, and operate the Interconnection in order to (1) enhance the reliability of their systems through the provision of additional sources of emergency support, (2) increase the reliability of the interconnected regional transmission network, and (3) achieve operating efficiencies through the purchase and sale of power and/or energy among the Participants.[18]

The impetus behind the construction of the MINT line came from AECI. Prior to the MINT line, there was a "weak-link" between MAPP and SPP, with considerable congestion in this corridor. AECI saw the value in establishing the line to have access to the relatively less expensive coal generation in the MAPP region as compared to the higher cost gas generation which is more prevalent in the SPP and other southern Reliability Regions. The seven participants also believed the added capacity would

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[18] *Coordinating Agreement By and Among Associated Electric Cooperative, Inc., Kansas City Power and Light Company, St. Joseph Light and Power Company, Nebraska Public Power District, Omaha Public Power District, City of Lincoln, Iowa Power Inc., For the Cooper-Fairport-St. Joseph 345 Kilovolt Interconnection*, Article III, Use of Interconnection, section 3.1, pg. 6.

bolster reliability in that corridor. The capacity of the MINT line is 1000 MW, so each of the 7 members is allocated 1/7 of 1,000 MW or 142 MW.[19]

> "The Point of Interconnection for NPPD, OPPD, IOWA POWER and LES shall be the Terminal Facilities at the Cooper Substation."[20] "The Point of Interconnection for AECI shall be the 345 kV breaker at the Fairport Substation."[21] "The Point of Interconnection for SJLP and KCPL shall be the Terminal Facilities at the St. Joseph Substation."[22] "The Participants agree to schedule delivery and receipt of power and/or energy to and from the Interconnection only at their respective Points of Interconnection."[23]
>
> "The financial responsibility for all the construction costs and all costs for the operation and maintenance, including ad valorem taxes, of all Joint Facilities shall be shared equally among the Participants. To meet this obligation, each Participant shall (1) bear financial responsibility for one-seventh of the total cost of construction of the Joint Facilities ... and (2) pay a one-seventh share of

---

[19] Interview with Dan Witt, OPPD Manager Transmission Engineering, November 12, 2004.

[20] *Coordinating Agreement By and Among Associated Electric Cooperative, Inc., Kansas City Power and Light Company, St. Joseph Light and Power Company, Nebraska Public Power District, Omaha Public Power District, City of Lincoln, Iowa Power Inc., For the Cooper-Fairport-St. Joseph 345 Kilovolt Interconnection*, Article VIII, Points of Interconnection, section 8.1, pg. 12.

[21] *Coordinating Agreement By and Among Associated Electric Cooperative, Inc., Kansas City Power and Light Company, St. Joseph Light and Power Company, Nebraska Public Power District, Omaha Public Power District, City of Lincoln, Iowa Power Inc., For the Cooper-Fairport-St. Joseph 345 Kilovolt Interconnection*, Article VIII, Points of Interconnection, section 8.2, pg. 12.

[22] *Coordinating Agreement By and Among Associated Electric Cooperative, Inc., Kansas City Power and Light Company, St. Joseph Light and Power Company, Nebraska Public Power District, Omaha Public Power District, City of Lincoln, Iowa Power Inc., For the Cooper-Fairport-St. Joseph 345 Kilovolt Interconnection*, Article VIII, Points of Interconnection, section 8.3, pg. 12.

[23] *Coordinating Agreement By and Among Associated Electric Cooperative, Inc., Kansas City Power and Light Company, St. Joseph Light and Power Company, Nebraska Public Power District, Omaha Public Power District, City of Lincoln, Iowa Power Inc., For the Cooper-Fairport-St. Joseph 345 Kilovolt Interconnection*, Article VIII, Points of Interconnection, section 8.4, pg. 12.

> operating and maintenance expenses associated with the Joint Facilities ... each Participant shall also bear financial responsibility for a share of the cost of the Terminal Facilities (including operating and maintenance expenses) at the Point of Interconnection identified in Article VIIII ..."[24]

The Participants were responsible for varying degrees of construction responsibilities. NPPD designed and constructed the Nebraska Segment, including the Cooper Substation Terminal Facilities and Missouri river crossing. SJPL designed and constructed the St. Joseph Transformer, and Substation Terminal Facilities. AECI designed, constructed, owns, operates and maintains the Missouri Segment, including the Fairport Substation Terminal Facilities.[25]

The costs associated to these constructions served as credits towards the constructing participants 1/7th obligation to the overall cost of the project. A Coordinating Committee consisting of a representative from each Participant, established interchange accounting and billing procedures to audit the projects equitable allocation of

---

[24] *Coordinating Agreement By and Among Associated Electric Cooperative, Inc., Kansas City Power and Light Company, St. Joseph Light and Power Company, Nebraska Public Power District, Omaha Public Power District, City of Lincoln, Iowa Power Inc., For the Cooper-Fairport-St. Joseph 345 Kilovolt Interconnection*, <u>Article IV, Construction, Ownership, Financing and Operating Responsibilities for the Interconnection</u>, section 4.2, pg. 8.

[25] *Coordinating Agreement By and Among Associated Electric Cooperative, Inc., Kansas City Power and Light Company, St. Joseph Light and Power Company, Nebraska Public Power District, Omaha Public Power District, City of Lincoln, Iowa Power Inc., For the Cooper-Fairport-St. Joseph 345 Kilovolt Interconnection*, <u>Article IV, Construction, Ownership, Financing and Operating Responsibilities for the Interconnection</u>, section 4.4-4.10, pgs. 8-10.

costs amongst the Participants. Various methods of payment included credits for construction, monies paid, and energy in lieu of money swaps.[26]

[26] *Coordinating Agreement By and Among Associated Electric Cooperative, Inc., Kansas City Power and Light Company, St. Joseph Light and Power Company, Nebraska Public Power District, Omaha Public Power District, City of Lincoln, Iowa Power Inc., For the Cooper-Fairport-St. Joseph 345 Kilovolt Interconnection*, Article IV, Construction, Ownership, Financing and Operating Responsibilities for the Interconnection, section 4.2, pgs. 8-10.

Customer Types

OPPD power customers are classified into one of two primary groups, Retail and Off-System customers. (Off-System customers also are referred to as Wholesale customers, and these two terms are interchangeable.) Retail customers are further subdivided into Residential,[27] Industrial,[28] Commercial,[29] and Street and Highway Lighting.[30] Off System or Wholesale is subdivided into two categories, Wholesale Towns[31] and simply Wholesale customers. Wholesale customer power is the excess power available after Retail customer and Wholesale Town demand has been met. Off-System or Wholesale revenues have averaged 16.97% ($96.52 million) of total operating revenues over a five year period starting in 1999 and ending in 2003.

---

[27] Residential Service is defined as a single-family home, trailer apartment, flat, or unit of a multi-family dwelling that is individually metered and equipped with cooking facilities as defined in an email from David Hayden, Rate Planning Analyst, Planning and Budgeting Services Division of OPPD on 12/30/2004.

[28] Industrial Service is defined as Non-residential services having metered demand of 1,000 KW or more per 15 minute period in 6 of the past 12 months as defined in an email from David Hayden, Rate Planning Analyst, Planning and Budgeting Services Division of OPPD on 12/30/2004.

[29] Commercial Service is defined as Non-residential services not qualifying as Industrial Service as defined in an email from David Hayden, Rate Planning Analyst, Planning and Budgeting Services Division of OPPD on 12/30/2004.

[30] Street and Highway Lighting is defined as street lights and traffic signal demand from government entities including states, cities, schools, counties, and SIDs as defined in an email from David Hayden, Rate Planning Analyst, Planning and Budgeting Services Division of OPPD on 12/30/2004.

[31] Wholesale Towns are four municipalities of Greenwood, Elk City, Syracuse and Tecumseh, Nebraska which OPPD serves. These municipalities then serve their customers as retail service in an email from David Hayden, Rate Planning Analyst, Planning and Budgeting Services Division of OPPD on 12/30/2004.

($1,000's)	2003	2002	2001	2000	1999	Average
Retail	452,738	468,411	463,019	442,651	435,187	452,401
Wholesale[32]	124,262	73,256	91,045	110,300	78,741	95,521
Other	11,541	11,357	14,731	14,238	9,802	12,334
	588,541	**553,024**	**568,795**	**567,189**	**523,730**	**560,256**

% Analysis	2003	2002	2001	2000	1999	Average
Retail	76.93	84.70	81.40	78.04	83.09	80.83
Wholesale	21.11	13.25	16.01	19.45	15.03	16.97
Other	1.96	2.05	2.59	2.51	1.87	2.20
Total	100.00	100.00	100.00	100.00	100.00	100.00

Figure 9. OPPD Retail and Wholesale Sales [33]

Facilitating the movement of Wholesale power is the primary purpose of this thesis.

[32] Includes Wholesale Towns and Wholesale power.

[33] *OPPD's 2003 Annual Report* web site on 12/28/3004 at: http://ww1.oppd.com/who/financial/annualrept/pdf/page26_42.pdf

Western Area Power Administration

OPPD's northern Control Area non-interconnected neighbor,

"Western Area Power Administration is one of four power marketing administrations within the U.S. Department of Energy whose role is to market and transmit electricity from multi-use water projects. WAPA markets and delivers reliable, cost-based hydroelectric power and related services within a 15-state region of the central and western U.S. WAPA's transmission system carries electricity from 55 hydropower plants operated by the Bureau of Reclamation, U.S. Army Corps of Engineers and the International Boundary and Water Commission. Together, these plants have a capacity of 10,600 megawatts."[34]

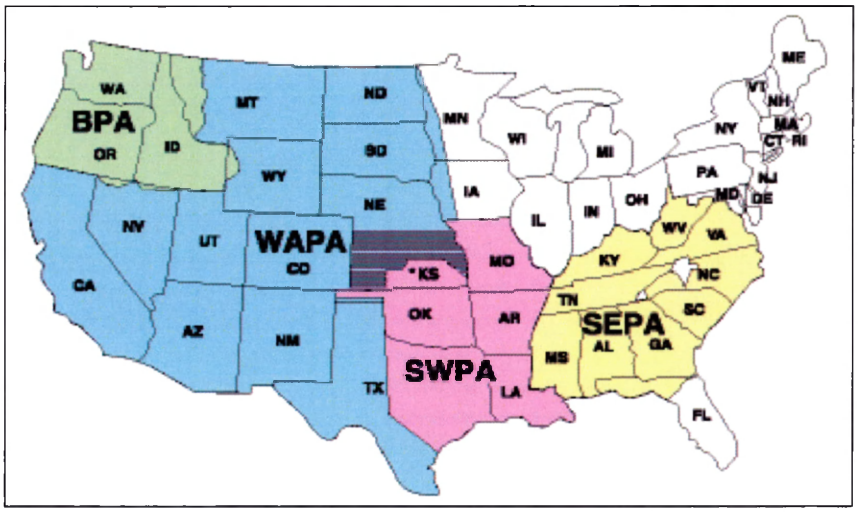

Figure 10. Four Power Marketing Administrations within the US Dept. of Energy[35]

"This map shows the four power marketing administrations within the U.S. Department of Energy. Bonneville Power Administration's service territory covers Washington, Oregon, and small pieces of western Montana and western Wyoming. Western Area Power Administration covers California, Nevada, Utah, Arizona, New Mexico, Utah, most of Montana, most of Wyoming, west Texas, North and South Dakota, Nebraska, western and southern Kansas, and the western edges of Minnesota and Iowa. the Southwestern Power Adminsitration serves the rest of Kansas, Missouri, Oklahoma, the rest of Texas, Arkansas, and Louisiana. The Southeastern Power Administration serves West Virginia, Kentucky,

[34] *About Western* web site on 7/28/2004. http://www.wapa.gov/geninfo/whatwho.htm

[35] *What is Western?* web site on 9/28/04. http://www.wapa.gov/geninfo/mappma.htm

> Tennessee, Mississippi, Alabama, Georgia, the Florida panhandle, South Carolina, North Carolina, and Virginia."[36]

"Alaska Power Administration (APA), consisting of two dams, Eklutna and Snettishham, was privatized in 1995 by the Alaska Power Administration Sale Act."[37] "Hawaii is 100% private power and private power is not eligible for Power Adminsitration allocations."[38]

WAPA is further divided into four regions, Upper Great Plains, Rocky Mountain, Desert Southwest, and Sierra Nevada Regions

---

36 *What is Western?* web site on 9/28/04. http://www.wapa.gov/geninfo/pmadesc.htm

37 *104th Congress Report 104-187 House of Representatives* web site on 12/04/04. http://thomas.loc.gov/cgi-bin/cpquery/0?&&dbname=cp104&&&r_n=hr187p1.104&&sel=DOC&

38 Correspondence with Dr. Michael J. O'Hara, University of Nebraska at Omaha.

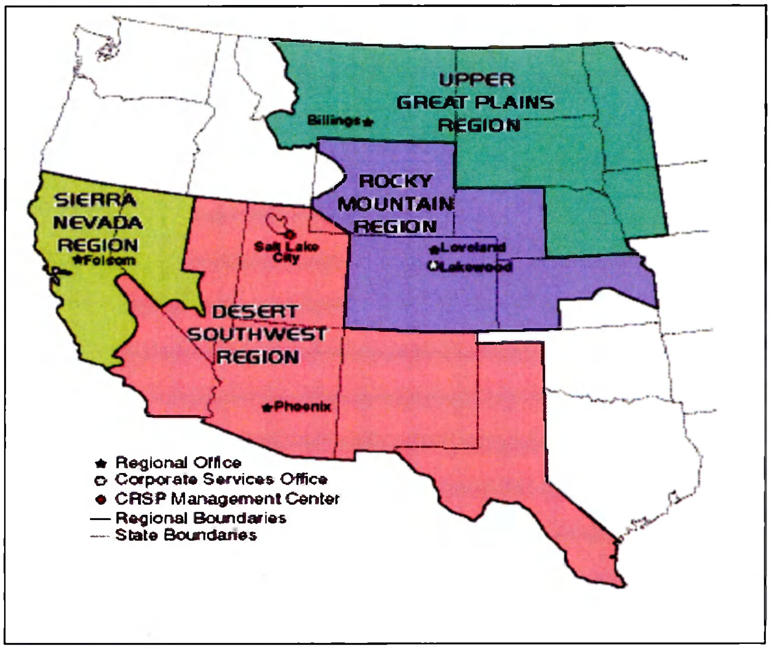

Figure 11. Western's Regional Offices.[39]

[39] *Western's Regional Offices* web site on 9/28/04.
http://www.wapa.gov/regions.htm

WAPA's Upper Great Plains Regional office covers maintenance, operation and transmission facilities in most of Montana, all of North Dakota, western Minnesota, all of South Dakota, eastern Nebraska, and western Iowa.[40]

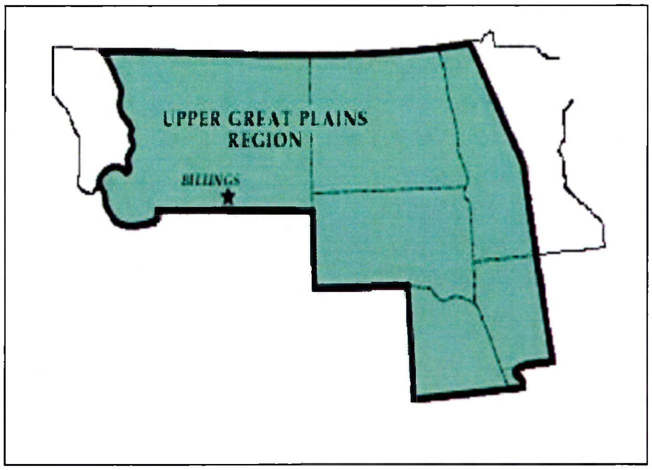

Figure 12. Upper Great Plains Region[41]

[40] *UGPR Home Page* web site on 9/28/04. http://www.wapa.gov/ugp/

[41] *UGPR Home Page* web site on 9/28/04. http://www.wapa.gov/ugp/

WAPA Firm Allocation

OPPD is allocated power from WAPA/UGPR through the Missouri River basin project.

> "The Missouri River basin project is a comprehensive plan authorized in 1944 for the coordinated development of water resources of the Missouri River and its tributaries, draining an area of about 513,300 sq mi in Nebraska, Montana, South Dakota, North Dakota, Wyoming, Kansas, Missouri, Colorado, Iowa, and Minnesota. The program provided for the construction of 112 dams with a storage capacity of almost 35 million gal; 4,300,000 acres of irrigated land; 2.6 million kilowatts of hydroelectric generating capacity; a 9-ft navigable channel on the Missouri River from Sioux City to its mouth; control of floods and sedimentation; protection of fish and wildlife; and development of recreational facilities and industrial and municipal water supplies. Seven main-stem dams on the Missouri were completed (Fort Peck, Garrison, Oahe, Big Bend, Fort Randall, Gavins Point, and Canyon Ferry), and 80 other dams were built on tributaries."[42]

This allocated power is commonly known as the "WAPA firm allocation." In addition to providing OPPD with an allocation up to 47.9 Megawatts/hr (MWh) for OPPD's own customer base, WAPA provides additional allocations to other governmental entities and municipalities also receiving electric service from OPPD. The OPPD customers receiving WAPA allocations via OPPD's transmission and distribution lines are: Offutt Air force Base (as much as 33.55 MWh), University of Nebraska at Omaha (as much as 1.30 MWh), Peru State College (as much as 0.53 MWh), and the Nebraska cities of Nebraska City (as much as 8.30 MWh), Fremont (as much as 4.80 MWh), Auburn (as much as 3.10 MWh), Falls City (as much as 3.10 MWh), Tecumseh (as much as 0.95 MWh), and Syracuse (as much as 0.26 MWh), The total maximum

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[42] *Infoplease, US Encyclopedia*, Missouri River Basin Project web site on 9/27/04. http://www.infoplease.com/ce6/us/A0833428.html

current allocation equals up to about 104 MWh.[43] OPPD power transacted with WAPA, both bilateral and firm allocation is considered Off-System or Wholesale power. (See pg. 14 for a description of customer types.)

This allocation amount is subject to change.

> "It is WAPA's intent to promote the most widespread use of WAPA generated power. In January of 2001, OPPD's allocation dropped 4% due to an addition of several Native American Tribes and 11 municipalities. In January of 2006, the OPPD allocation will drop less then ¼ of 1% and in January of 2011, OPPD's allocation could drop up to an additional 1%. The allocation is a function of the number of qualified customers and is subject to a rebalancing every five years."[44]

Under the contract terms per the UNITED STATES DEPARTMENT OF ENERGY WESTERN AREA POWER ADMINISTRATION Pick-Sloan Missouri Basin Program-Eastern Division <u>CONTRACT FOR FIRM ELECTRIC SERVICE TO OMAHA PUBLIC POWER DISTRICT</u>, number 01-UGPR-28, dated December 20, 2002, specifically, section 2.5 in its entirety states:

> "Western (WAPA) currently has in place a contract, Contract No. 89-BAO-337 dated January 18, 1989 (MidAmerican Contract), with MidAmerican Energy Company for transmission service from the system of Western to OPPD. The MidAmerican Contract expires on December 31, 2008. After such time as that contract expires or is otherwise terminated, **OPPD and OPPD's customers who are also firm power customers of Western will be required to make their own transmission arrangements for delivery of power and energy from the system of Western to OPPD."[45]**

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[43] Email from Terry Norton (OPPD Transmission Services Engineer) to TJ Sandoz on June 11, 2004.

[44] Phone conversation with WAPA Contract Administrator, WAPA on December 28th, 2004.

[45] *UNITED STATES DEPARTMENT OF ENERGY WESTERN AREA POWER ADMINISTRATION Pick-Sloan Missouri Basin Program-Eastern Division CONTRACT FOR FIRM ELECTRIC SERVICE TO OMAHA PUBLIC POWER DISTRICT, number 01-UGPR-28 dated December 20th, 2002*, section 2, (emphasis added).

Section 7.2.4 continues reading:

> "If increases in rates of charge for transmission service and transmission losses, either or both, are made during the term of this Contract, Western shall notify OPPD of the effective date of such increase. OPPD may elect to make its own transmission arrangements or may terminate this Contract by written notice to Western at any time within one hundred eighty (180) days after the effective date of such increase.[46]

Furthermore, upon the expiration of transmission service contract 889-BAO-337, "WAPA will not renegotiate a transmission contract with MEC on behalf of OPPD's allocation, and OPPD will be responsible for procuring the necessary transmission to receive the WAPA allocation."[47]

This places OPPD and our customers, Offutt Air force Base, UNO, Peru State College, and the cities of Nebraska City, Fremont, Auburn, Falls City, Tecumseh and Syracuse into the precarious scenario of unknown transmission availability, reliability and cost.

OPPD's neighboring Control Area Lincoln Electric System currently receives their WAPA allocation via the NPPD transmission system. LES has a total of 132 MW of WAPA allocations.[48] One construction option pursued in this thesis involves the

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[46] *UNITED STATES DEPARTMENT OF ENERGY WESTERN AREA POWER ADMINISTRATION Pick-Sloan Missouri Basin Program-Eastern Division CONTRACT FOR FIRM ELECTRIC SERVICE TO OMAHA PUBLIC POWER DISTRICT, number 01-UGPR-28 dated December 20th, 2002*, section 7.2.4.

[47] Phone conversation with WAPA Contract Administrator, WAPA on December 28th, 2004.

[48] Phone interview with Lincoln Electric System personnel, Lincoln Electric System, 11/15/2004 and further confirmed by NPPD transmission OASIS request

partnering of OPPD and LES to build a jointly owned line, (continuing a planned line from Nebraska City to LES in Southeast Lincoln) from Southeast Lincoln to WAPA's 345 kV substation at Grand Island, NE. In this option's analysis, the economic benefit derived (cost savings) will be the sum of NPPD's currently posted transmission rate tariff cost (multiplied by LES's 132 MW allocation) and MEC's currently posted transmission rate tariff cost (multiplied by OPPD's 103 MW allocation.)

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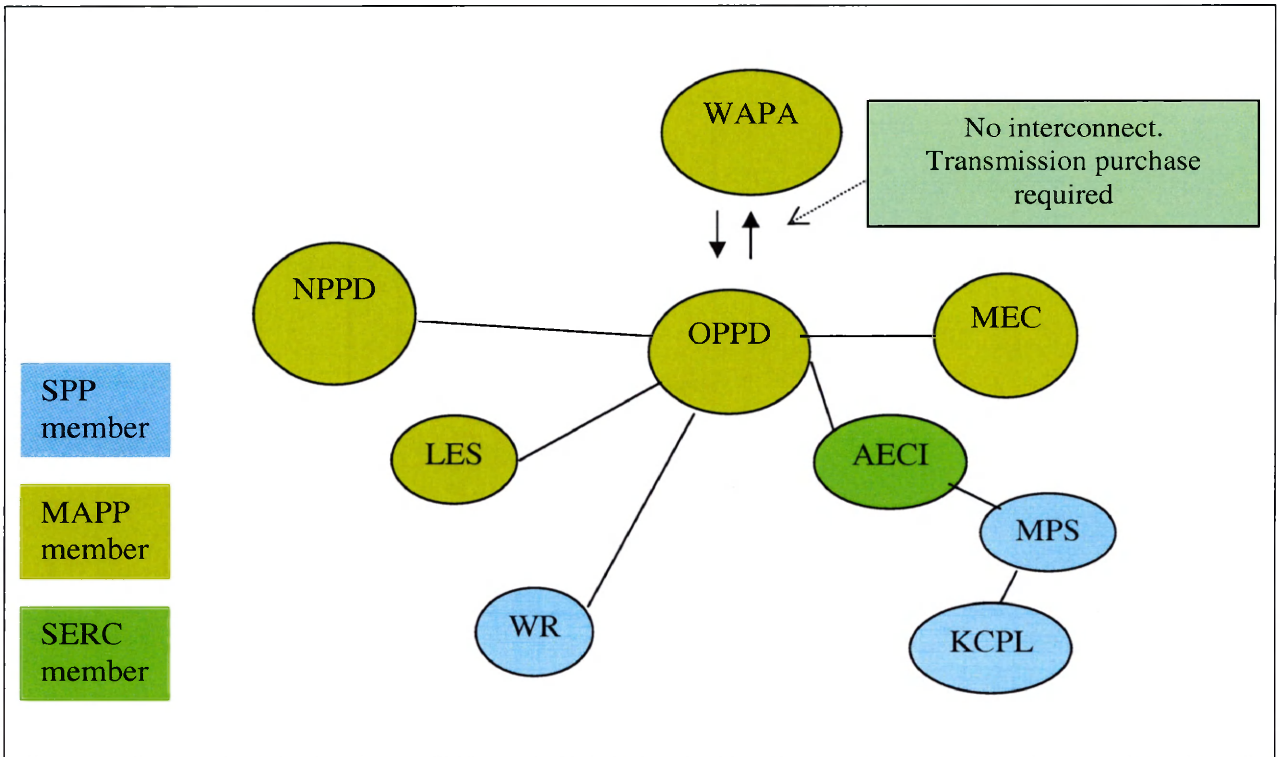
numbers 178299 (75 MWh through 12/31/2020) and 178297 (59 MWh through 12/31/2020) on secured web site on 12/27/2004.
https://mapp.oasis.mapp.org/OASIS/NPPD/data/transstatusdetails?ASSIGNMENT_REF=178297&RETURN_TZ=CD

OPPD.WAUE: A Benefit and Cost Analysis

The purpose of this thesis is to analyze the benefits and costs of establishing a direct interconnect between Omaha Public Power District and Western Area Power Administration, an interconnect point to be identified as OPPD.WAUE. The purpose of OPPD.WAUE is to facilitate the WAPA firm allocation and additional bilateral power transactions between WAPA and OPPD, as well as between OPPD and other impacted counterparties. This proposed interconnect could increase transmission capacity, reliability, stability and simultaneously reduce transmission expenditures for OPPD's (and possibly LES's) customers, both retail and wholesale, and reduce costs for Western's bilateral transactions with OPPD, benefiting WAPA's economic, stability and reliability interests.



MAPP = Mid-Continent Area Power Pool
SPP = Southwest Power Pool
WAPA = Western Area Power Administration
NPPD= Nebraska Public Power District
OPPD= Omaha Public Power District
MEC = MidAmerican Energy
LES= Lincoln Electric System
WR= Western Resources
AECI= Associated Electric Coop Inc.
MPS = Missouri Public Service
KCPL = Kansas City Power and Light

Figure 13. Proposed Interconnect Between OPPD and WAPA

The analysis also will include a discussion of the legal ramifications for OPPD to own transmission assets outside of Nebraska's borders, and the legality for companies established outside of the targeted States to own transmission assets within the borders of the targeted States. Additional consideration will include environmental impact studies, right of way feasibility (ROW), system impact studies, and finally a discussion of WAPA's policies regarding the allowance of interconnects into their system. A comprehensive analysis of each of these items is beyond the scope of this thesis. Instead, each of these items will be imported into this thesis, either in the form of professional estimates, given known constraints, or in the form of professionally completed studies. This thesis will focus on assembling all the relevant pieces needed for a thorough analysis of OPPD.WAUE.

Chapter 2: LITERATURE REVIEW

FERC Orders 888 and 889

On April 24th, 1996 the Federal Energy Regulatory Committee (FERC) issued a pair of landmark orders:[49] 888 and 889. FERC order 888 regards "Transmission Open Access. Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities." In summary, FERC order 888 states:

> "The Federal Energy Regulatory Commission is issuing a Final Rule requiring all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to have on file open access non-discriminatory transmission tariffs that contain minimum terms and conditions of non-discriminatory service. The Final Rule also permits public utilities and transmitting utilities to seek recovery of legitimate, prudent and verifiable stranded costs associated with providing open access and Federal Power Act section 211 transmission services. The Commission's goal is to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the Nation's electricity consumers."[50]

"Public Utilities" is mentioned in FERC order 888 and in FERC order 889. But the term "Public Utilities" can be a misconstrued term in the context of FERC order 888 and FERC order 889. FERC defines "Public Utilities" as:

> "Utilities, typically investor owned through publicly-held stock, and are referred to in this document by the FERC definition as either FERC Jurisdictional or Public utilities. The public utility term can be confused with the Public Power term often used to describe members of the American Public Power Association,

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[49] Landmark orders are those which have a continuing and significant impact on the industries the FERC regulates as defined at *Federal Energy Regulatory Commission, Legal Resources, Landmark Orders* on web site on 1/1/2005. http://www.ferc.gov/legal/ferc-regs/land-ord-elec.asp

[50] *Federal Energy Regulatory Commission, Legal Resources, Landmark Orders* on web site on 1/1/2005. http://www.ferc.gov/legal/ferc-regs/land-ord-elec.asp

such as Lincoln Electric System (LES). However, the FERC term used here for these government or ratepayer owned utilities is Non-Jurisdictional or Non-Public Utilities; LES, being a municipal corporation created under Nebraska law, is exempt from the provisions of the FERC order as a non-jurisdictional or non-public utility."[51]

Like LES, OPPD and WAPA are exempt from FERC orders 888 and 889 regarding Jurisdictional or Public Utilities.

FERC order 889 focuses on OASIS standards. OASIS is the acronym for Open Access Same-Time Information, whose purpose is to promote competition through deregulation of the wholesale Electric Power Industry.[52] OASIS is an electronic internet node which allows potential power customers to purchase transmission service. In summary FERC order 889 states:

> "Under this final rule, each public utility (or its agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce will be required to create or participate in an OASIS that will provide open access transmission customers and potential open access transmission customers with information, provided by electronic means, about available transmission capacity, prices, and other information that will enable them to obtain open access non-discriminatory transmission service. This final rule requires (1) each public utility subject to the rule to implement standards of conduct to functionally separate transmission and wholesale power merchant functions and (2) the creation of a basic OASIS system. In addition, some of the standards and formats for OASIS nodes are prescribed in a document entitled OASIS Standards and Communication Protocols that is being issued with the final rule."[53]

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[51] *Lincoln Electric System* web site on 1/1/2005. http://www.les.com/business/tariff.asp

[52] *Energy Information Administration, Wholesale Power Markets and Restructuring the U.S. Power Transmission System*, web site on 9/24/04. http://www.eia.doe.gov/cneaf/electricity/chg_stru_update/chapter7.html

[53] *Federal Energy Regulatory Commission, Legal Resources, Landmark Orders* web site on 1/1/2005. http://www.ferc.gov/legal/ferc-regs/land-ord-elec.asp

Although exempt from the FERC order 889, OPPD, LES and WAPA have created OASIS nodes where customers can obtain open access non-discriminatory transmission service.

FERC Order 2000

FERC Order 2000 was implemented on December 20, 1999. In summary, the Order states:

> "The final rule requires all public utilities that own, operate or control interstate electric transmission to file by October 15, 2000, a proposal for a Regional Transmission Organization (RTO), or, alternatively, a description of any efforts made by the utility to participate in an RTO, the reasons for not participating and any obstacles to participation, and any plans for further work toward participation. The RTOs will be operational by December 15, 2001. The Commissions goal is to promote efficiency in wholesale electricity markets and to ensure that electricity customers pay the lowest price possible for reliable service."[54]

OPPD, WAPA and LES are exempt from FERC order 200, and OPPD and WAPA have yet to join an RTO. Regional RTOs forming include SPP and the MidWest Independent Systems Operator (MISO). OPPD and WAPA have not joined an RTO but LES has committed to joining MISO if the MISO network footprint becomes contiguous to LES's Control Area. (See MISO map on pg. 33)

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[54] *Federal Energy Regulatory Commission, Legal Resources, Landmark Orders* web site on 1/1/2005. http://www.ferc.gov/legal/ferc-regs/land-ord-elec.asp

MISO and RTO's

MISO has acquired most of MAPP's assets, including the building and software used to administer the MAPP Model and with these assets MISO will be overseeing transmission, generation and marketing activities formally administered by MAPP.

The Midwest Reliability Organization (MRO) will replace the

> " ... MAPP Regional Reliability Council of the North American Electric Reliability Council ("NERC") and will result in a more effective and efficient reliability organization that will administer and enforce reliability standards across a broader geographical region.[55]
>
> "The MRO replaces the regional reliability councils and functions of MAPP. Specifically, the MRO will set organizational standards, adopt NERC standards, revise standards as a region, and set its own regional standards. The MRO will monitor and enforce compliance with standards. The MRO will also provide education and training for its members, assess adequacy and performance, collect reliability information and data, provide an appeals and dispute resolution process, and participate in NERC as a regional reliability council."[56]

MISO is literally being implemented in phases as this Thesis is being composed. On April 1, 2005, MISO plans to implement its final phase and will begin operating several marketing tasks, including Locational Marginal Pricing (LMP)[57] and Financial Transmission Rights (FTR)[58].

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[55] *MAPP Midwest Reliability Organization* web site on 3/15/2005. http://www.mapp.org/content/mro.shtml

[56] *Midwest Reliability Organization, Frequently Asked Questions* web site on 3/15/2005. http://www.midwestreliability.org/FAQ.html

[57] LMP pricing is fundamentally a mechanism for using market prices, rather than administrative restrictions, for managing transmission congestion by determining prices that are consistent with the system operators redispatch as defined in Scott Harvey's

LMP and FTR are two power flow management tools which attempt to automatically and judiciously manage the generation and flow of power within the MISO footprint. MISO will have control of each generator within the footprint.

Midwest Market Initiative presentation on Consumer Impact of LMP Pricing, October 20, 2003, slide 33, on web site on 1/1/2005.
http://www.midwestiso.org/meeting_agendas/Consumer%20Impact%20of%20LMP%20Pricing.pdf

[58] Locational pricing provides a means to allocate the short-term use of the transmission grid but does not allocate the right to use the transmission grid (without paying congestion) among those who are paying the embedded costs of the grid. When there is transmission congestion, 1) the right to use the transmission grid is valuable, 2) locational pricing will cause the ISO to collect congestion rents (the difference between payments by load and payments to generators), 3) the price of transmission use can be very volatile and 4) actual redispatch costs are not known until generators provide bids for redispatch and transmission schedules are set.

The uncertainty of congestion charges under a market-based congestion pricing system creates a demand for congestion hedges or transmission rights.

Financial transmission rights (FTRs) enable market participants to "lock-in" a price for transmission prior to the day-ahead market. 1) The owner of a FTR pays or is paid the hourly cost of congestion ($/MWh) between two locations on the transmission system. Thus, the owner of an A to B FTR receives Price at B-Price at A. 2) If the FTR owner's net injections and withdrawals match the FTR quantities, then the FTR is financially equivalent to a traditional firm transmission right. 3) FTRs provide the financial equivalent of firm transmission for market participants that use their FTRs to support bilateral transactions, as defined in Scott Harvey's Midwest Market Initiative presentation on Consumer Impact of LMP Pricing, October 20, 2003, slide 83, on web site on 1/1/2005.
http://www.midwestiso.org/meeting_agendas/Consumer%20Impact%20of%20LMP%20Pricing.pdf

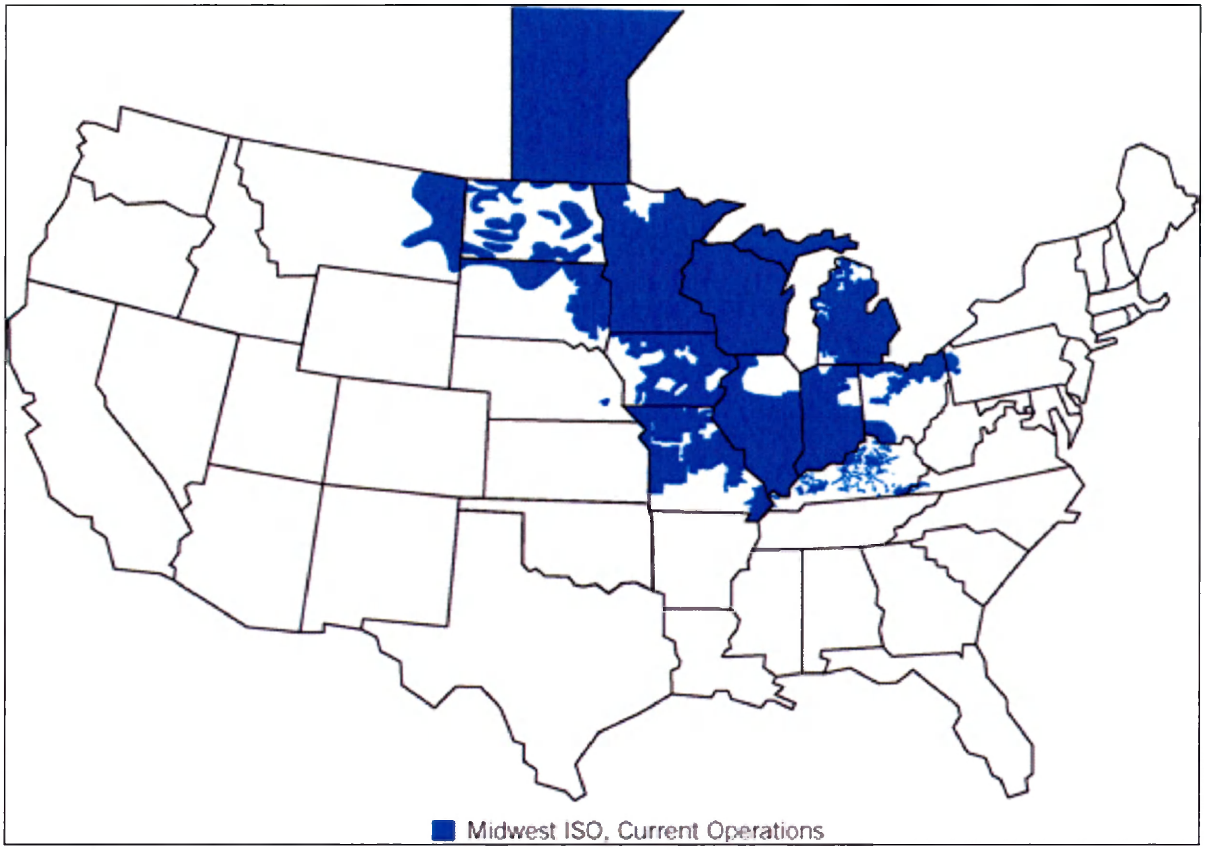

Figure 14. Midwest Independent System Operators Current Members[59]

"LMP prices recognize the Locational differences in the cost of meeting incremental load that are a result of the need to redispatch generation to avoid exceeding transmission limits. LMP pricing supports system reliability by providing generators and load with financial incentives to respond to real-time dispatch instructions. LMP pricing is a form of market-based pricing, since prices are determined by the bids and offers of market participants and all suppliers are paid the market clearing price at their location."[60]

"FTR recognizes that the uncertainty of congestion charges under a market-based congestion pricing system creates a demand for congestion hedges or transmission

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[59] *MISO Home: Our Members* web site on 1/1/2005. http://www.midwestiso.org/about_signatories.shtml

[60] *Midwest Market Initiative* web site on 1/1/2005. http://www.midwestiso.org/meeting_agendas/Consumer%20Impact%20of%20LMP%20Pricing.pdf

rights. Financial transmission rights enable market participants to obtain long-term transmission price certainty, just like yesterday's physical transmission rights. Financial transmission rights are designed to hedge congestion costs without undermining open access or the incentive of generators to respond to dispatch instructions and LMP prices. Financial transmission rights also provide the mechanism for disposing of the congestion rents collected by the ISO under locational pricing."[61]

(For an in-depth discussion of LMP and FTRs see MISO website:

http://www.midwestiso.org/meeting_agendas/Consumer%20Impact%20of%20LMP%20

Pricing.pdf).

[61] *Midwest Market Initiative* web site on 1/1/2005. http://www.midwestiso.org/meeting_agendas/Consumer%20Impact%20of%20LMP%20 Pricing.pdf

Costs of Joining MISO

MISO membership benefits and costs are a hotly contested topic. Some companies are joining MISO only to later realize the cost burdens are not offset by the marginal benefits.

> "State regulators will soon consider whether to allow Louisville Gas & Electric Co. and Kentucky Utilities to pull out of a regional utility organization that charges millions of dollars a year in membership fees but, in the companies' view, provides modest benefits.
>
> "Testimony concluded this week in the case, which pits LG&E and KU against an organization they helped found in 1996, the Midwest Independent Transmission System Operator (MISO).
>
> "The first regional transmission organization approved by the Federal Energy Regulatory Commission, MISO monitors the electric transmission system over 1.1 million square miles from Manitoba, Canada, to Kentucky.
>
> "MISO was founded to manage electric transmission through the region more efficiently. Since then, according to the Kentucky power companies, the not-for-profit organization has taken on the job of running a wholesale electricity market, expected to begin in December. Annual assessments to LG&E and KU now total $7 million to $8 million a year and are expected to balloon toward $20 million annually when the wholesale market launches.
>
> "The Kentucky Public Service Commission, which opened an investigation into MISO membership last July, could rule on withdrawal in the next few months. LG&E and KU have stipulated that they will pull out if the commission allows them to charge customers for exit fees and if FERC allows them to operate as stand-alone utilities. FERC has pushed utilities to join regional transmission organizations since the mid-1990s.
>
> "Even after paying MISO a $23.8 million exit fee, the utilities would save more than $65 million over the next five years by leaving, officials at parent company LG&E Energy have told the PSC.
>
> "'Over the long term, LG&E's and KU's customers will fare better economically if the companies withdraw from MISO,' Paul Thompson, LG&E Energy senior vice president, energy services, said in filings with the state regulators.

“MISO officials argue that the utilities have enjoyed significant benefits under MISO, including cost savings and greater reliability of the transmission grid.

“Belonging to the regional organization also gives utilities ‘a bigger free-trade zone,’ MISO vice president and general counsel Stephen Kozey said in an interview yesterday. ‘You can move power around more than just in your one area for one charge.’

“Broad system oversight from a regional organization ‘prevents the grid from being oversold,’ he said.

“MISO calculates that LG&E and KU would actually come out $279 million ahead over the next five years by remaining in the organization.

“The MISO figures, however, take credit for all of the savings LG&E and KU have seen and continue to enjoy after their 1998 merger, because FERC required the companies to join the transmission organization before it would approve the deal. Through the end of 2003, MISO said, retail customers had received about $140 million in billing credits and payments because of the merger. Merger also helped the company save $36 million in fuel costs, MISO maintains.

"’LG&E and KU's retail ratepayers have received enormous benefits from the merger of the two companies,’ James Torgerson, MISO's president and chief executive, said in PSC testimony. Without MISO membership, he said, the merger might never have happened.

"’MISO has done and will do nothing — through the provision of services or otherwise — to bring about these merger-related benefits,’ countered Michael Beer, vice president of rates and regulatory for LG&E and KU. The benefits came from ‘wise regulation, strong company leadership and sound business initiatives,’ Beer testified.

“The savings are ‘not a unique benefit of MISO membership and would not disappear if the utilities leave,’ he said.

“LG&E and KU particularly object to a fee that goes to pay for the wholesale energy market. Since the companies' power rates are among the lowest in the nation, and they have plenty of generating capacity, they're unlikely to import more costly supplies from neighboring utilities, the companies argue.

“Torgerson said in testimony Thursday that he was ‘a little shocked’ by the request to pull out, and that if the companies left, it would raise costs to other members. He maintained that the companies and their customers would benefit from continued participation.

> "He also ruled out an LG&E/KU proposal that the utilities be allowed to withdraw from MISO while maintaining some coordination of transmission grids. 'We have made a corporate decision not to provide services to anybody who is not a member,' he said.
>
> "The Kentucky utilities had proposed to pay MISO for any associated costs, but to be exempt from the wholesale market expenses. MISO expects the final bill for establishing the market to hit about $190 million.
>
> "LG&E and KU have also questioned what they see as MISO's free-spending ways. 'MISO can, and apparently does, spend whatever it thinks it needs to ... with little or no meaningful review' by the companies that ultimately bear the costs, Thompson said in a filing.
>
> "MISO says its expenditures are under the control of a board of directors that oversees all its operations."[62]

Additionally, Margot Lutzenhiser, associate economist with Public Power Council, has argued the excessive MISO membership cost increase forecasts versus load increase forecasts do not justify a rational membership commitment to MISO.

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[62] Louisville, KY newspaper, *Courier Journal* of April 10, 2004 website on 1/7/05. http://www.courier-journal.com/business/news2004/04/10/F1-PSC10-6472.html

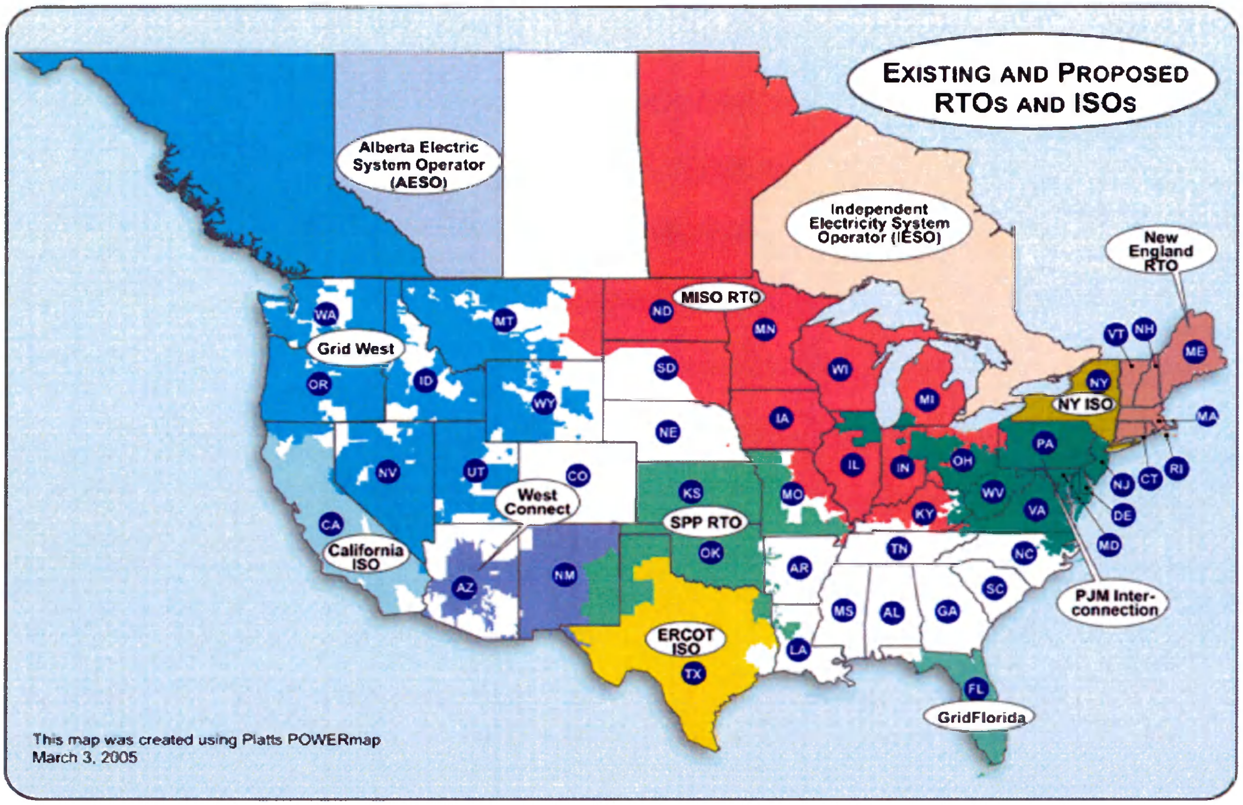

Figure 15. Existing and Proposed RTO Configurations[63] (White = No ISO/RTO)

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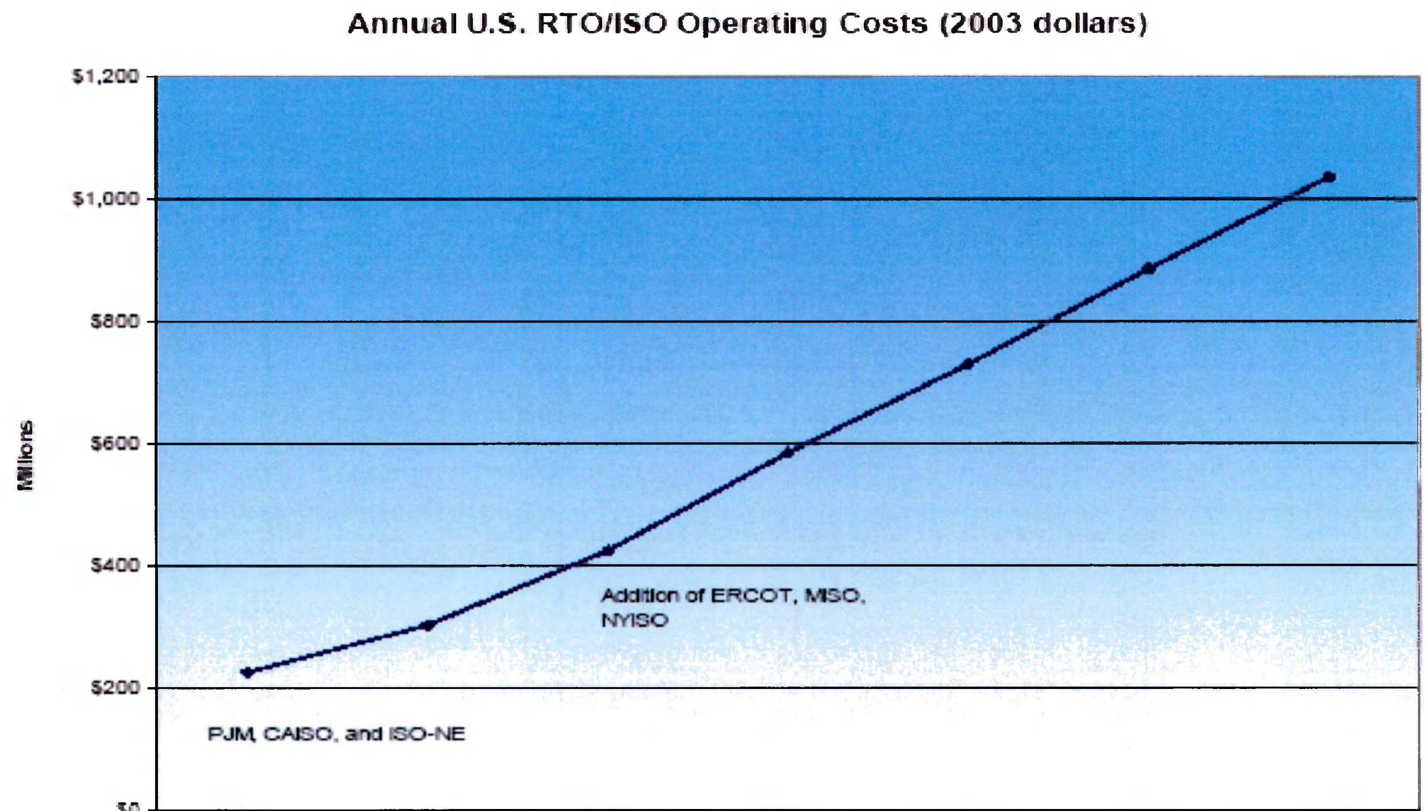
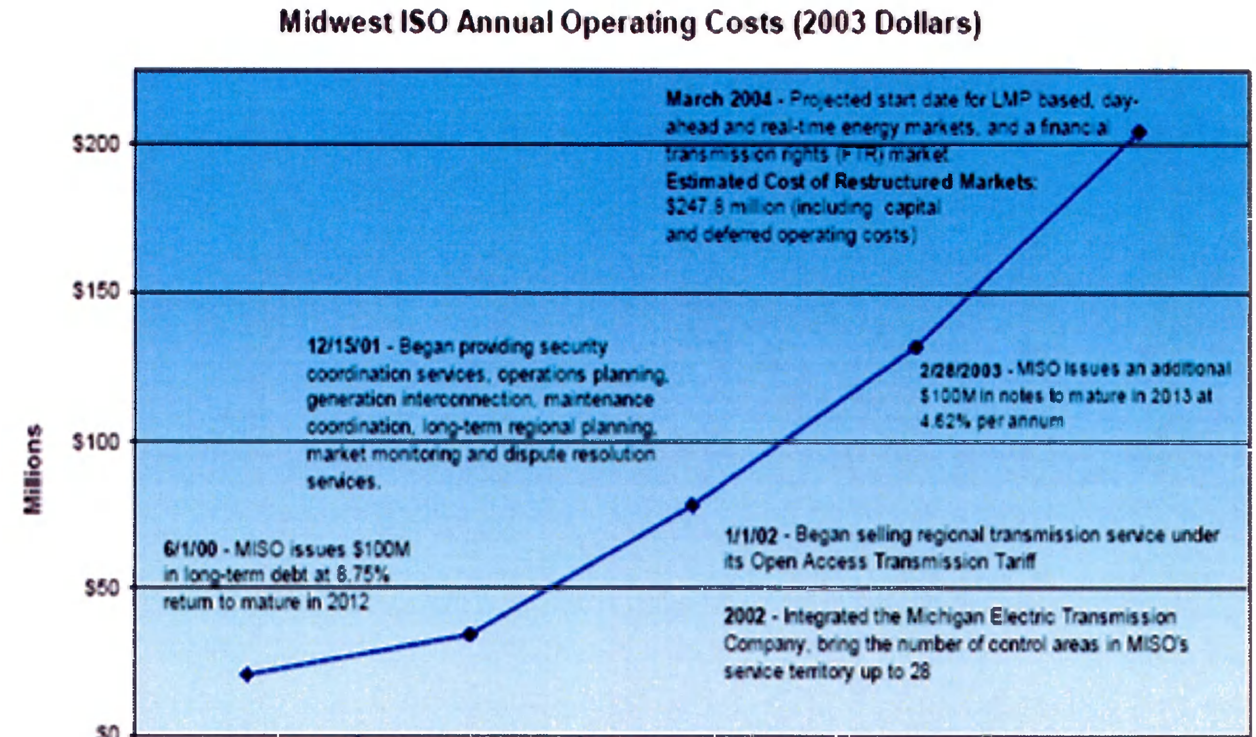
[63] *Federal Energy Regulatory Commission*, on web site on 2/16/2005. http://www.ferc.gov/industries/electric/indus-act/rto/rto-map.asp



	1998	1999	2000	2001	2002	2003	2004
RTO Expenses	$226,771,863	$302,836,246	$424,926,009	$584,279,480	$730,160,074	$885,701,442	$1,035,338,562

Figure 16. Annual U.S. RTO/ISO Operating Costs (2003 dollars)[64]

[64] Lutzenhiser, Margot, Associate Economist, Public Power Council, "Cooperative Analysis of RTO/ISO Operating Costs," 17 August 2004, slide 3 on web site on 1/16/2005. http://www.ppcpdx.org/ComparativeAnalysisTWO.FINAL.pdf



	2000	2001	2002	2003	2004
Op Cost	$20,726,446	$34,095,882	$78,029,133	$131,642,000	$204,592,593
% Increase		64.50%	128.85%	68.71%	55.42%
Staffing	80	146	218	373	465
% Increase	-	82.58%	49.25%	71.10%	24.66%

Figure 17. Midwest ISO Annual Operating Costs (2003 Dollars)[65]

[65] Lutzenhiser, Margot, Associate Economist, Public Power Council, “Cooperative Analysis of RTO/ISO Operating Costs,” 17 August 2004, slide 10 on web site on 1/16/2005. http://www.ppcpdx.org/ComparativeAnalysisTWO.FINAL.pdf

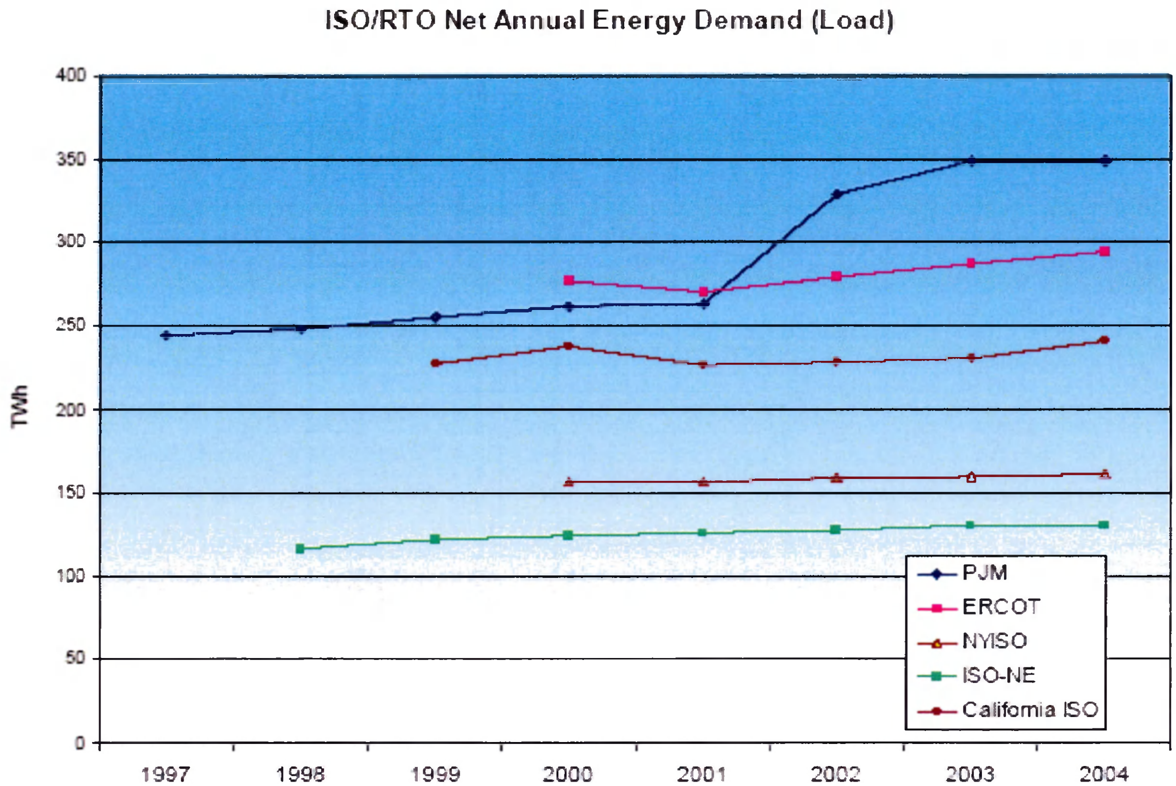


Figure 18. ISO/RTO Net Annual Energy Demand (Load)[66]

OPPD hired consulting group Christensen Associates in April of 2005 to conduct a cost-benefit analysis for OPPD to join MISO. Christensen forecasted a participation cost of $4.928 Million in 2005 with an average annual increase of 2.7% for the ensuing four years. This nearly $5M annual expenditure does not include increased staffing (estimated at $250,000/yr), software ($750,000 capital expenditure plus $150,000/yr support) and legal/regulatory costs ($750,000/yr). Christensen's benefit analysis assumed a 25% increase in wholesale sales volume for OPPD, yet OPPD sold 91.94% of

[66] Lutzenhiser, Margot, Associate Economist, Public Power Council, "Cooperative Analysis of RTO/ISO Operating Costs," 17 August 2004, slide 5, on web site on 1/17/2005. http://www.ppcpdx.org/ComparativeAnalysisTWO.FINAL.pdf

available base load power in 2004, so only 8.09% (100%-91.94%) headroom exists, under perfect marketing conditions. Also Christensen assumed a 15% increase in wholesale prices yet MISO claims that RTO participation results in lower energy prices for member participants.[67]

It is this author's current opinion that OPPD has postponed commitment to this MISO market because of three reasons. First, OPPD is exempt from mandatory participation so OPPD is afforded the luxury to "wait and see". Second, costs do not justify the current foreseen benefits and MISO administrative fees would be allocated to not only OPPD's Wholesale customers as (MAPP currently subscribes), but also to OPPD's retail customers, possibly resulting in higher retail rates. Third, the MISO model appears on the surface to benefit FTR participants in lieu of generation owners. This FTR benefit exists because the market delta between marginal generation offering price and marginal load bid price is a benefit to the FTR holder, not the generation unit owner, as is currently the scenario. OPPD assets are heavily skewed towards generation versus FTR ownership.

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[67] Morey, Mathew J. Ph.D., Senior Consultant, Christensen Associates Energy Consulting LLC, "The Costs and Benefits for OPPD of Membership in the Midwest ISO," 29 April 2005, Afternoon Session slides 37-40.

Transmission

Overview

"Transmission Provider (TP) is the public utility (or its designated agent) that owns or controls facilities used for the transmission of electric energy in interstate commerce."[68] OPPD is a TP. The customers within the OPPD Control Area (CA) are "Native Load Customers." Native Load Customers are defined as "the wholesale and retail customers on whose behalf the Transmission Provider, (OPPD), by statute, franchise, regulatory requirements, or contract, has undertaken an obligation to construct and operate the Transmission Provider's system to meet the reliable electric needs of such customers."[69] OPPD provides transmission services to its Native Load Customers via transmission lines. "Network Integration Transmission Service, allows a Transmission Provider to integrate, plan, economically dispatch and regulate its resources (Transmission System) to serve its Native Load Customers."[70] Network Integration Transmission Service will be referred to as "Network Service" for the remainder of this thesis.

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[68] *Glossary of terms, FERC Glossary* web site on 12/04/2004. http://www.tsin.com/gloss.html

[69] *Glossary of terms, FERC Glossary* web site on 12/04/2004. http://www.tsin.com/gloss.html

[70] *Glossary of terms, FERC Glossary* web site on 12/04/2004. http://www.tsin.com/gloss.html

Load

"Load is any device to which power is delivered."[71] Examples of load include appliances, street lights, and heating/ventilation/air conditioning (HVAC) units. The instantaneous summation of a CA's load is defined as "Native Load." A CA's native load is changing every moment of the day as Native Load Customers turn on and turn off loads. Forecasting loads becomes even more complicated due to weather changes, which can be sudden and unpredictable. For example, especially given OPPD's Great Plains location, changes in cloud cover or moving barometric pressure high and low lines can result in thunderstorms instantly materializing. Abrupt changes in weather conditions instantly affect HVAC load resulting in volatile load swings.

There are times when CA's have greater capacity to generate power (i.e., supply) than native load (i.e., demand): that is, the CA has a surplus. Conversely, there are times when CA's have more native load (i.e., demand) than generation capacity (i.e., supply): that is, a deficit.[72] When imbalances occur between supply and demand within a CA, marketing staffs of the power companies purchase or sell power to rebalance the supply and demand. The selling of surplus power or purchasing to cover a deficit of power, and

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[71] *GuruNet* website on 12/04/2004. http://www.gurunet.com/query;jsessionid=2m4kop7vwn5iu?s=load

[72] MAPP requires members to carry excess Operating Reserves sufficient to account for such factors as errors in forecasting, generation and transmission equipment unavailability, number and size of generating units, system equipment forced outage rates, maintenance schedules, regulating requirements, and Regional and system load diversity. Load Serving Entities have the option to purchase their reserves through the market, through bilateral contracts, multilateral arrangements, or self-supply as defined by the MAPP Generation Reserve Subcommittee presentation on December 19, 2002, as seen at website on 3/25/2004. http://www.mapp.org/assets/pwrpnt/PEMwrkshp/Poff%20Trence%20Beuning.ppt

thus, rebalance a CA, is conducted by transporting power from surplus CAs into deficit CAs. When Control Areas transact wholesale power between one another, then the CAs must purchase a transmission path to facilitate the flow of the power.

MAPP Service Schedule F Regional Tariff

The governing agreement for transmission transactions within the MAPP region is MAPP Service Schedule F. The regional tariff is administered at the MAPP Center.[73] MISO is under contract to administer the tariff for MAPP. The transmission service is referred to as Point-to-Point, meaning, "The reservation and transmission of capacity and energy on either firm or non-firm basis from the Point(s) of Receipt to the Points(s) of Delivery under Part II (which describes specific details of the tariff) of the Tariff."

[73] The MAPP Center is located at Energy Park Drive, St. Paul, MN 55108 as stated at the MAPP Contact US web site on 11/20/2004. http://www.mapp.org/content/contact_us.shtml

Degrees of "Firmness"

Within MAPP, there are seven different levels of "firmness" of transmission to purchase. NERC Level 1, Secondary Point-to-Point Non-Firm Service (NS1), is the weakest level[74] of transmission firmness and NERC Level 7, Firm Service (F7), is the firmest level of transmission. Firm transmission (F7) is a preferred reliability factor to non-firm transmission. If a transmission requestor is denied Level 7, then the requester may initiate a follow-up request at a lower level of firmness. Pricing of transmission is highest for Level 7 and lowest for Level 1. When an unexpected change in the operational limits of transmission are exceeded on the grid[75] usually caused by generating units[76] shutting down or transmission lines being severed, then transmission flows change instantly and the MAPP Security Coordinator Operator[77] will implement a Transmission

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[74] Transmission service type refers to the NERC defined levels of transmission service reliability: Level 1 is Secondary Point-to-Point Non-Firm Service; Level 2 is Hourly Non-Firm; Level 3 is Reserve Non-Firm Daily, Level 4 is Reserve Non-Firm Weekly, Level 5 is Reserve Non-Firm Monthly, level 6 is Network Non-Firm Service, and Level 7 is Firm Service, either daily, weekly, or monthly as defined in *MAPP Policies and Procedures*, pg, 29.

[75] Grid is defined as the aggregate transmission network.

[76] Generating unit is defined as an electromechanical device to convert mechanical energy into electrical energy as defined in *Illustrated Encyclopedic Dictionary of Electronics*, pg. 256.

[77] MAPP Security Coordinator Operator is defined as the overseer of the operation of the bulk transmission system in the MAPP region. They monitor the status of the power system to verify the system is within the operating limits and guides. Through coordination of the transmission provider, the Security Coordinator may curtail schedules to eliminate an operating limit by using the NERC TLR procedure as defined in *MAPP Regional Security Plan* on web site on 2/23/2005. http://www.mapp.org/assets/pdf/2000REGIONALSEC.PDF

Line Loading Relief (TLR)[78] procedure to relieve the overloaded lines. The dispatched energy is reduced sequentially from Level 1 through Level 7. Level 7 is the last to be curtailed.[79] It can therefore be concluded that, if there are several legs in a transaction, then the reliability of the transaction is only as strong as the weakest link.

[78] TLR- Transmission Line Loading Relief- the procedure whereby MAPP Schedule F service is curtailed using NERC Transmission Loading Relief Procedures.

[79] Curtailment is a reduction in firm or non-firm transmission service in response to a transmission capacity shortage or as a result of system reliability conditions as defined in Party as defined in: Common Service Provisions, Definitions, Section 1.7 in the *Mid-Continent Area Power Pool FERC Electric Tariff.*

Three Step Transmission Purchasing Process

The process of purchasing transmission has three steps. First, the purchasing entity requests to purchase the transmission path. The request is made via a secured internet portal from the Transmission Provider's (TP) OASIS web site.[80] Each Transmission Provider maintains its unique OASIS site.

Secondly, the OASIS simultaneously prompts MISO to run the requested transmission purchase through the "MAPP model", which is a robust computer program that assesses the request, and its impacts on Available Transmission Capability (ATC).[81] ATC is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. An in-depth derivation of the MAPP Model algorithms can be found in the *MAPP Procedures Manual*.[82] The MAPP Model generates an "ACCEPTED" response or "REFUSED" response. The response is automatically sent to the requesting party via email. The time consumed by the MAPP Model in formulating its reply is directly related to the amount of requested transmission: short time period requests (i.e., one hour) receive a MAPP Model response within minutes, but a multi-year request may take several weeks or

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[80] OPPD OASIS at secured web site on 11/15/05. https://mapp.oasis.mapp.org/OASIS/OPPD

[81] ATC is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses as defined at *The Energy and Power Risk Management Glossary* web site on 2/15/2005. http://www.riskwaters.com/guides/engloss/eprmglosa.htm

[82] *MAPP Policies and Procedures for Transmission Operations*, Appendix F, MAPP Request Evaluation Process on secured web site on 11/07/2004. https://webmail.oppd.com/exchweb/bin/redir.asp?URL=http://toinfo.oasis.mapp.org/oasisinfo/info.htm?page=/oasisinfo/polproc.htm

months to evaluate before responding.

Third, if the MAPP Model response to the purchasing entity is "ACCEPTED" the purchaser has to respond within a certain time period, (i.e., within five minutes on a "next hour" request, versus, twenty-four hours on a six month request[83]) with a "CONFIRM" response or a "WITHRAWN" response. If the time limit for response is exceeded, then the MAPP Model responds with a "WITHDRAWN" status and the transmission request is annulled. If the response to the purchasing entity is "REFUSED" because of insufficient ATC, then the requestor must either abandon their efforts for the requested path, or adjust the submitted parameters in combination or singularly of Start Date and Time, Stop Date and Time, Capacity Requested[84], Point or Receipt (POR)[85], Point of Delivery (POD)[86], Source[87], Sink[88] or Service Type[89] and resubmit the request. If a TP

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[83] *MAPP Schedule F: Open-Access Transmission Tariff*, Schedule 1: Scheduling and Tariff Administration Service, pg 97 on web site on 9/27/04. http://toinfo.oasis.mapp.org/oasisinfo/

[84] The amount of energy requested to be transmitted in units of MWh.

[85] Point of Receipt (POR) is a Point of interconnection on the Transmission System where capacity and energy will be made available to the Transmission Providers by the Delivering Party as defined in: Common Service Provisions, Definitions, Section 1.27 in the *Mid-Continent Area Power Pool FERC Electric Tariff.*

[86] Point of Delivery (POD) is the Point on the Transmission System where capacity and energy transmitted by the Transmission Providers will be made available to the Receiving Party as defined in the defined in: Common Service Provisions, Definitions, Section 1.26 in the *Mid-Continent Area Power Pool FERC Electric Tariff.*

[87] Source is Control Area of the POR

[88] Sink is the Control Area of the POD

mistakenly "ACCEPTED" a transmission request which was later "CONFIRMED" by a customer, then the TP will "ANNUL" the request.

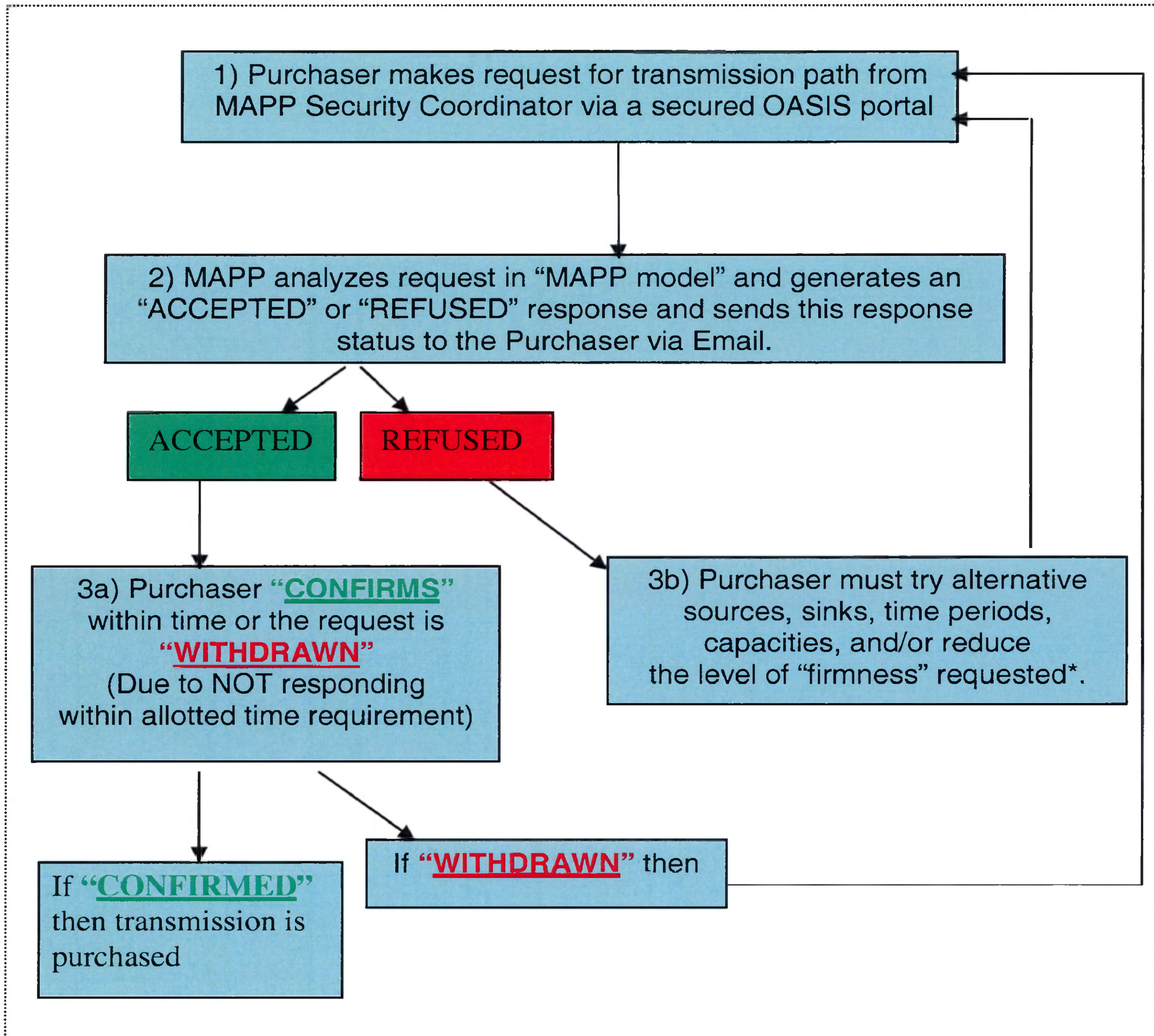

Figure 19. Three-step transmission request process

[89] Service type refers to the Level of Transmission type requested, Level 1 through Level 7.

Edit Profile

Customer Information

Seller Information

Name
Thomas James Sandoz

Company **Duns**
OPPM

Comments

Status Notification

E-Mail

http://

none

Dates and Times

Start Date and Time
11/20/2004 00:00:00 CS

Stop Date and Time
11/21/2004 00:00:00 CS

Edit Profile

Reference Numbers

Deal **Request**

Sale **Posting**

Related Ref

Service Information

HNF

Capacity Requested
50

Bid Price

Preconfirmed

Path and POR/POD Information (template continued on next page)

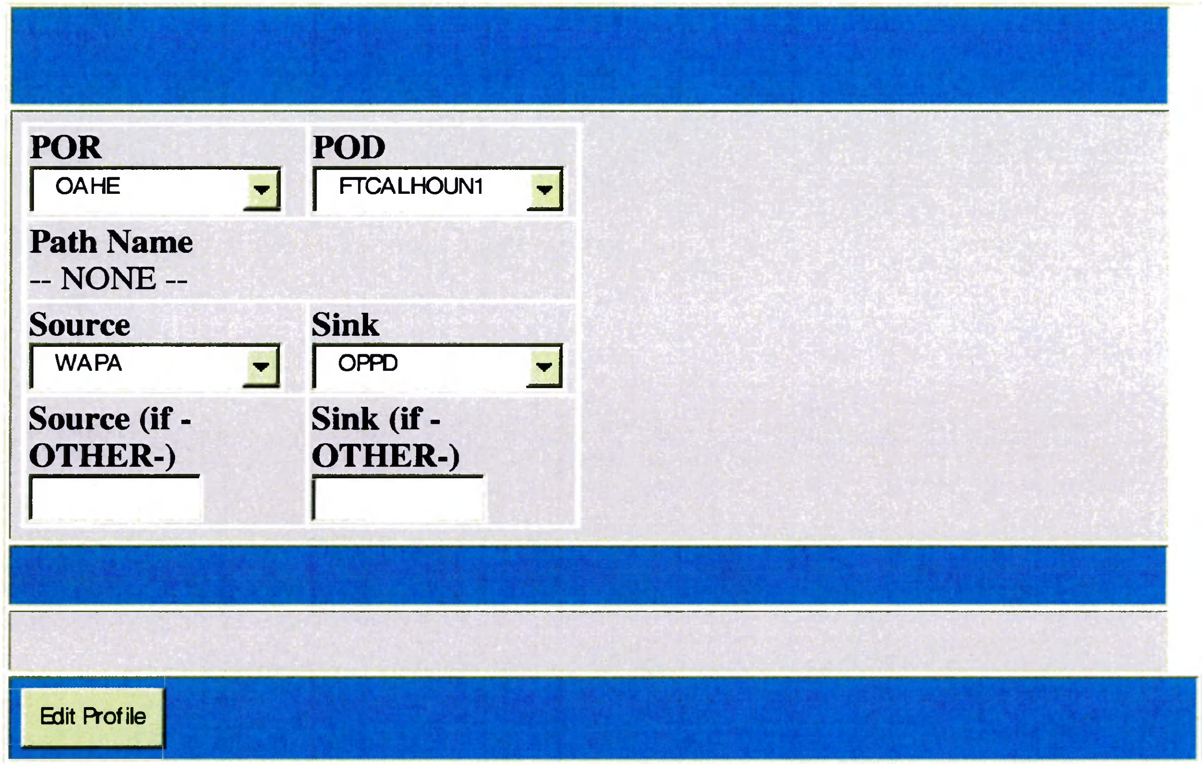

Figure 20. New Transmission request template form from MAPP OASIS

Three Transmission Purchasing Scenarios

There are three different scenarios which dictate the means of acquiring the transmission required for a transaction within MAPP: Network Service, "Wheeling," and MAPP Service Schedule F.

1) Network Service

If the transacting Control Areas are directly interconnected, like OPPD and MEC, then both CAs can use their respective OASIS Tariffs and Network Service to deliver the power from the source CA substation[90] to the substation of the neighboring directly interconnected sinking CA.[91] (Recall, each CA has its own OASIS web portal, and the required transmission is purchased via these secured web sites.) The sinking CA will transmit and distribute the purchased power from its substation to its native load. No money is exchanged for the transmission rights between the two companies because the two companies are using their own assets exclusively (i.e., paying in kind) to facilitate the transaction.

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[90] Substation-an assemblage of equipment for the purpose of switching and/or changing or regulating the voltage of electricity as defined in *Electric Utility Systems and Practices,* pg. 177.

[91] The actual interconnect may exist at a point between the two substations whereby each interconnecting CA would provide a physical meter to measure the flow at the tie point.

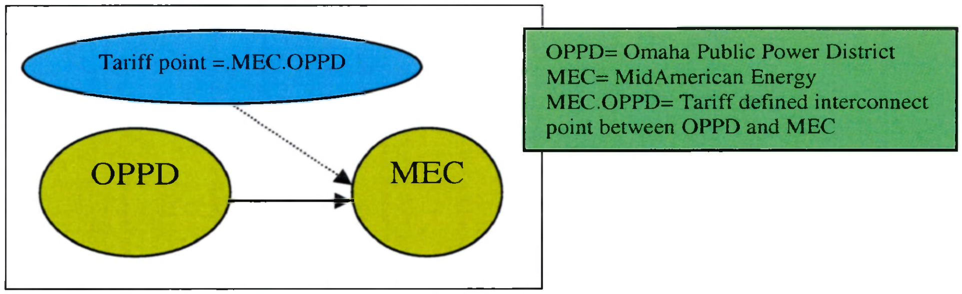

Figure 21. OPPD sale to direct interconnect Control Area MEC

As an example, if OPPD were to sell power "delivered to the border," to MEC, then OPPD marketing would purchase "firm network transmission" from OPPD's OASIS Tariff, (administered by OPPD's transmission division) to deliver power from OPPD to the MEC.OPPD[92] border point. OPPD's financial exchange is between different divisions within OPPD, so all the dollars remain "in-house". Concurrently, MEC marketing would acquire "network service" from MEC's Tariff, administered by MEC's transmission division, from the interconnection point MEC.OPPD to the MEC CA. MEC's financial exchange for transmission also remains "in-house". The net result is power generated at OPPD flows to MEC and neither company incurs any net transmission expenses.

> **"Existing firm service customers (... with a contract term of one-year or more) have the right to continue to take transmission service from the Transmission Provider (OPPD) when the contract expires, rolls over or is renewed. ...** The existing firm service customer must agree to accept a contract term at least equal to a competing request by any new Eligible Customer and to pay the current just and reasonable rate for such service. This transmission reservation priority for existing firm service

[92] OPPD.MEC is the nomenclature used in Tariff administration language to depict a border point between two interconnecting control areas, OPPD and MEC. Arbitrary CAs XXX and YYY, border point would be XXX.YYY, for example OPPD.WAUE.

> customers is an ongoing right that may be exercised at the end of all firm contract terms of one-year or longer."[93] (Bolding added)

This ongoing roll-over right for one-year or longer firm transmission on OPPD's Tariff is a critical advantage to the other transmission options available.

One touted advantage to joining an RTO like MISO or SPP is the "free" access to Network Service as described above. This Network Service is applicable to the entire RTO footprint up to a capacity equal to the CA's Native Load. The only marginal benefit is in the expansion of the RTO's network footprint relative to a CA's footprint. Also, "free" is in addition to Loss re-payments (8%, or about $3.00 per MWh typically), administrative and ancillary service fees (0.50 per MWh), all totaling typical existing Network tariff cost.

2) "Wheeling"

If the CAs are not directly interconnected, then multiple "'legs" of transmission would be purchased to transfer the power from the selling CA to the buying CA. This is termed "wheeling."[94] "Wheeling is the contracted use of electrical facilities of one or more entities to transmit electricity for another entity." For our example, assume WAPA sells power to OPPD and OPPD is to arrange for all the transmission paths (legs) and costs from WAPA to OPPD. But, WAPA and OPPD are not now directly interconnected. (Refer to Figure 13 on page 25).

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[93] *Omaha Public Power District Open Access Transmission Tariff*, Section 2.2: Reservation Priority for Existing Firm Service Customers, pg 23 on web site on 11/6/2994, (Bolding added). http://ww1.oppd.com/prodsvc/pdf/tariff.pdf

[94] *North American Electric Reliability Council (NERC) Glossary of Terms* on website on 12/5/04. ftp://ftp.nerc.com/pub/sys/all_updl/docs/pubs/glossv10.pdf

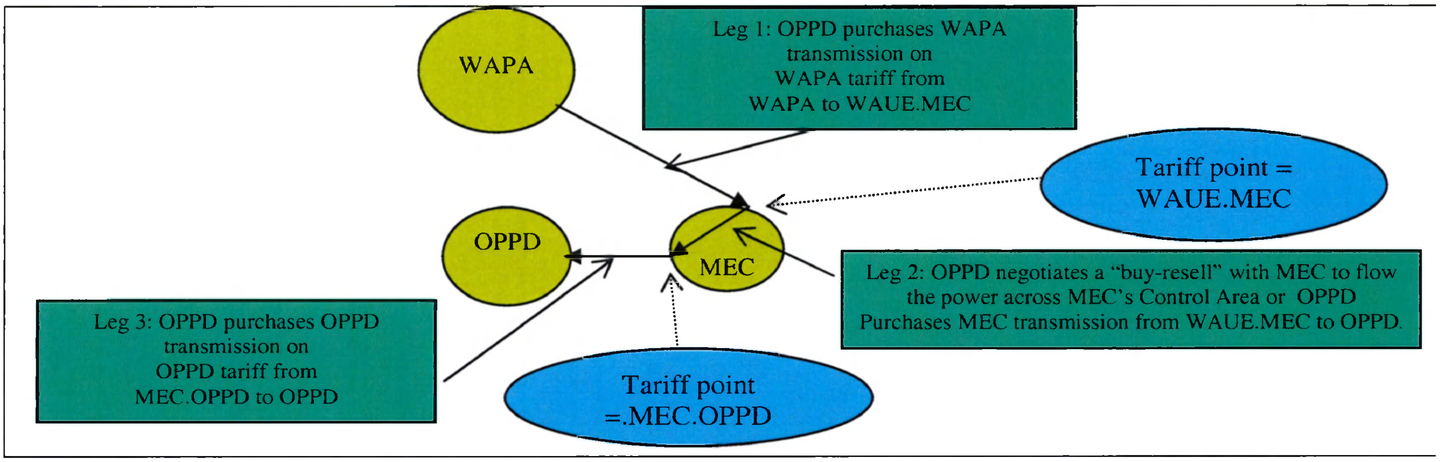

Figure 22. WAPA to MEC to OPPD "Wheeling" example

WAPA = Western Area Power Administration
OPPD= Omaha Public Power District
MEC= MidAmerican Energy
WAUE.MEC= Tariff defined interconnect point between WAPA and MEC
MEC.OPPD= Tariff defined interconnect point between OPPD and MEC

For the first leg, OPPD will purchase WAPA transmission from WAPA to WAUE.MEC, the border point between WAPA and MEC.

The second-leg in the transaction is the wheel. There are two types of wheels. A "buy-resale" involves OPPD selling the WAPA acquired power to MEC at the WAUE.MEC point, then immediately purchasing back an equivalent amount of power at another point in MEC's control area, a point that is capable of flowing to OPPD. OPPD pays MEC a negotiated fee for this service, typically about 10% of market price, but MEC is under no obligation to perform this service and each transaction is negotiated separately, if even allowed to occur. The second type of wheel would be for OPPD to purchase MEC transmission from WAUE.MEC to MEC.OPPD.

Finally, in leg 3, OPPD acquires network service from its own tariff from the OPPD.MEC border point to OPPD.

This cumbersome task of moving power between non-interconnected CA's was simplified by the implementation of MAPP Service Schedule F.

3) MAPP Service Schedule F

In response to FERC Order 888 and FERC Order 889 issued in April 1996, MAPP established a "point to point" tariff called MAPP Service Schedule F. Schedule F serves to evaluate all the legs of a transaction as a single path, so the user, in the request, either [a] could indicate the source generator or Point of Receipt (POR) and the sinking substation/generator; or [b] could indicate the Point of Delivery (POD). MAPP then would evaluate this request as one single request. From the requester's vantage, this was much easier to administer then the wheeling scenario described above in Option 2. Fees for the transmission are paid to MAPP, whereupon MAPP allocates a payment to the transmission owners in a percentage equal to their percent of contribution to the flow of the power.

> 'The MAPP Schedule F tariff can be used for point-to-point transmission service utilizing the MAPP Transmission System that is less than or equal to 6 consecutive months in duration."[95]
>
> **"The MAPP Schedule F Tariff only offers short-term transmission service, therefore no rollover rights are offered."[96]** (Boldness added)

Lack of roll over rights and the short term nature of MAPP Schedule F Service render it an inferior choice for transmission service for OPPD's long-term multi-year WAPA allocation contract. OPPD's tariff allows for multi-year long firm transmission with rollover provisions.

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[95] *MAPP Policies and Procedures.* Sub-section 1.2: Scope, under Section 1: MAPP Schedule F Regional Tariff. Version July 1, 2004, on web site on 11/6/2004. http://toinfo.oasis.mapp.org/oasisinfo/

[96] *MAPP Polices and Procedures.* Sub-section 1.17.5: Rollover Rights, under Section 1.17 Changes in MAPP Schedule F Transmission Service, Version July 1, 2004 on web site on 11/6/2004. (Boldness added) http://toinfo.oasis.mapp.org/oasisinfo/

The Drought Impact

The recent increases in bilateral sales from OPPD to WAPA can be attributed to the corresponding drought conditions in the geographic area which supplies water to the WAPA dams.

The six main stem power plants (Fort Peck, Garrison, Oahe, Big Bend, Fort Randall and Gavins Point) generated a record low 0.31 terawatt hours (TWh) of electricity in October of 2004. This is an output 36% of normal. The forecast for 2004 energy production is 6.50 TWh, compared to a normal of 10.0 TWh. This 2004 forecast is 65% of normal.[97]

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[97] Paraphrased from *Water Management Monthly News Release*, US Army Corps of Engineers, Northwestern Division Public Affairs Office, November 12, 2004: "The six main stem power plants (Fort Peck, Garrison, Oahe, Big Bend, Fort Randall and Gavins Point) generated a record low 310 million kilowatt hours (kWh) of electricity in October 2004, 36% of normal. The forecast for 2004 energy production is 6.5 billion kWh, compared to a normal of 10 billion kWh (65% of normal)."

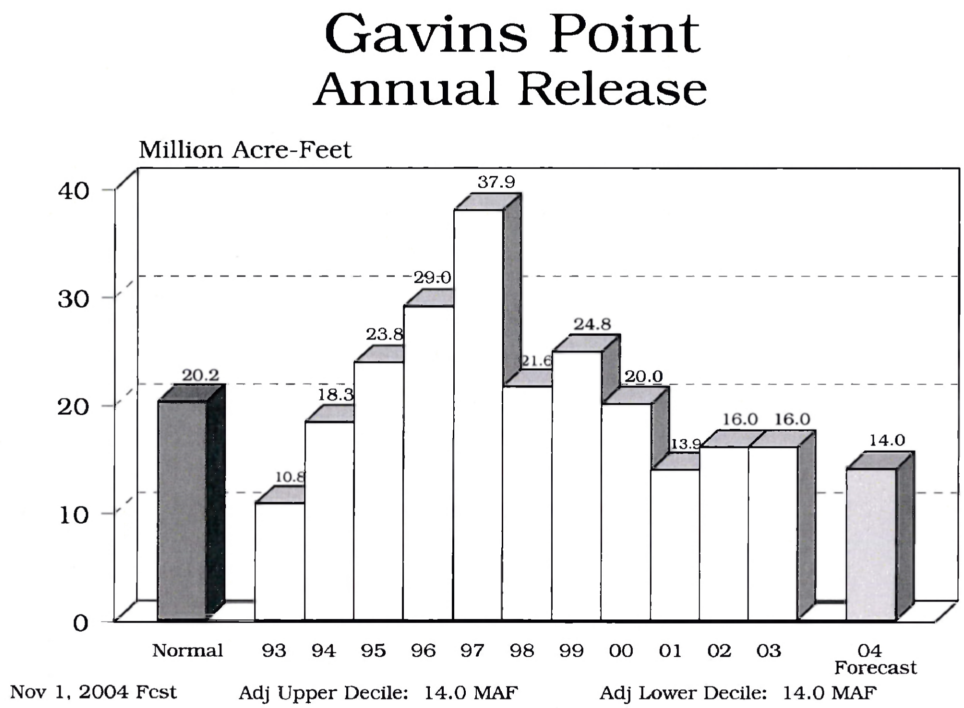

Figure 23. Gavins Point Annual Water release in Million Acre-Feet. [98]

[98] Bob Keasling, Missouri River Basin Water Management Division.

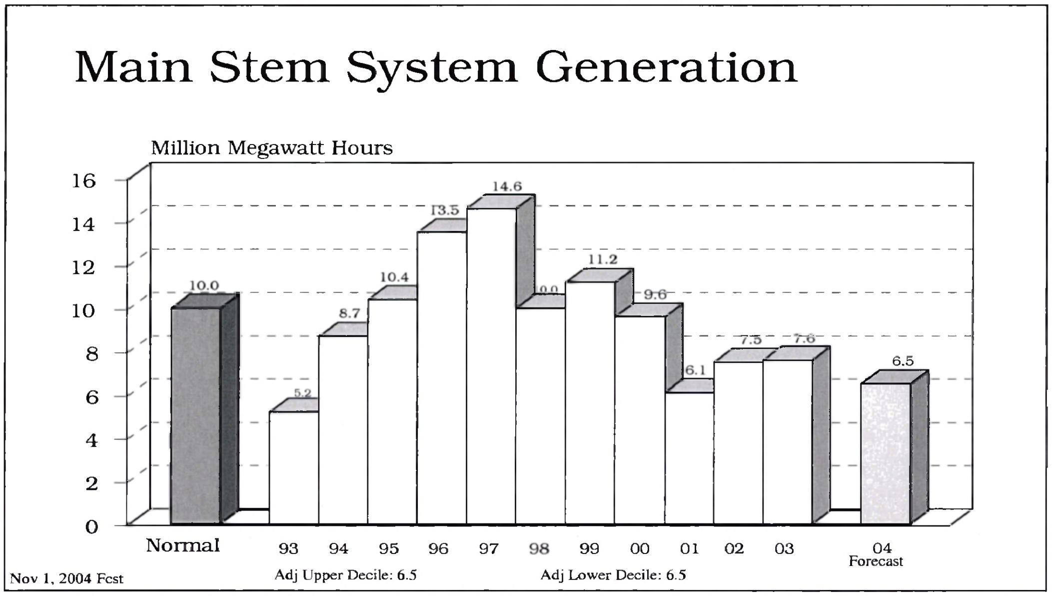

Figure 24. Main Stem System (Fort Peck, Garrison, Oahe, Big Bend, Fort Randall and Gavins Point) Generation[99]

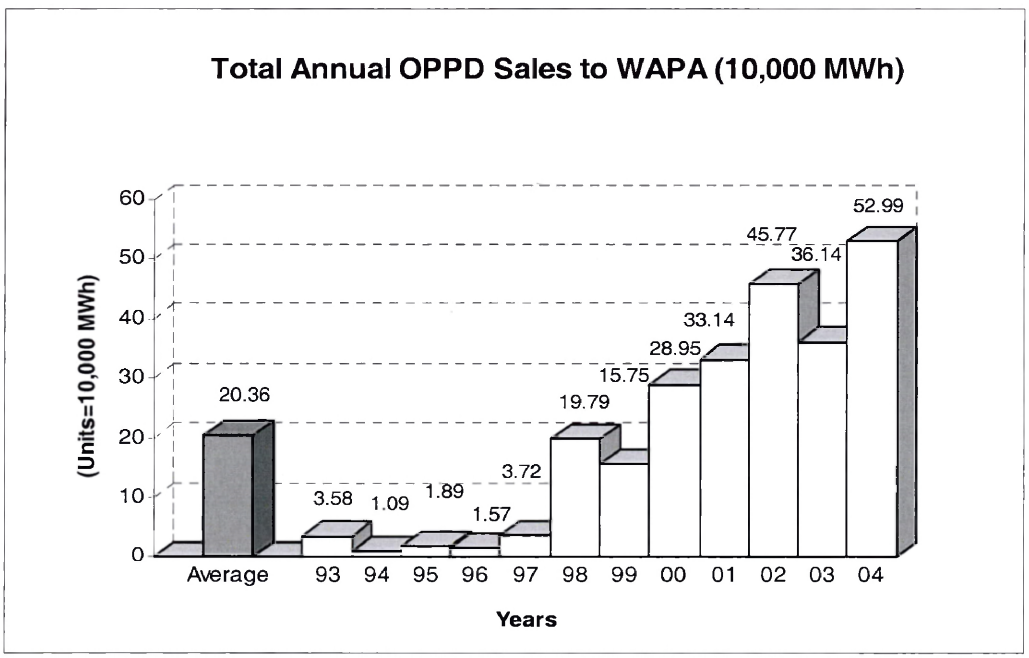

Figure 25. Total Annual OPPD Sales to WAPA (10,000 MWh)[100]

[99] Bob Keasling, Missouri River Basin Water Management Division.

[100] Source is OPPD Accounting, Gretchen Lax, Programmer Analyst, Business Unit Systems Support.

As the data suggests, there appears to be an inverse relationship between WAPA System Generation and OPPD Sales to WAPA. If the current drought cycle eventually subsides, then the bilateral sales to WAPA could decrease significantly. Additionally, as OPPD's Native Load expands, the remaining Wholesale energy available to sell will decrease until OPPD increases base load generation.[101] As a result of unknown bilateral Wholesale transactions between OPPD and WAPA, a worse case scenario (no bilateral transactions) also will be considered when later analyzing the data in this thesis.

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[101] OPPD is currently planning the construction of a 600+ MW base load coal plant at Nebraska City. The plant is named Nebraska City 2, as it is being situated next to OPPD's existing Nebraska City 1 plant. The plant is forecasted to be on-line in Spring of 2009. Approximately half of the generation is committed in long term contracts with other public utilities, leaving OPPD with a net increase of about 300+ MW.

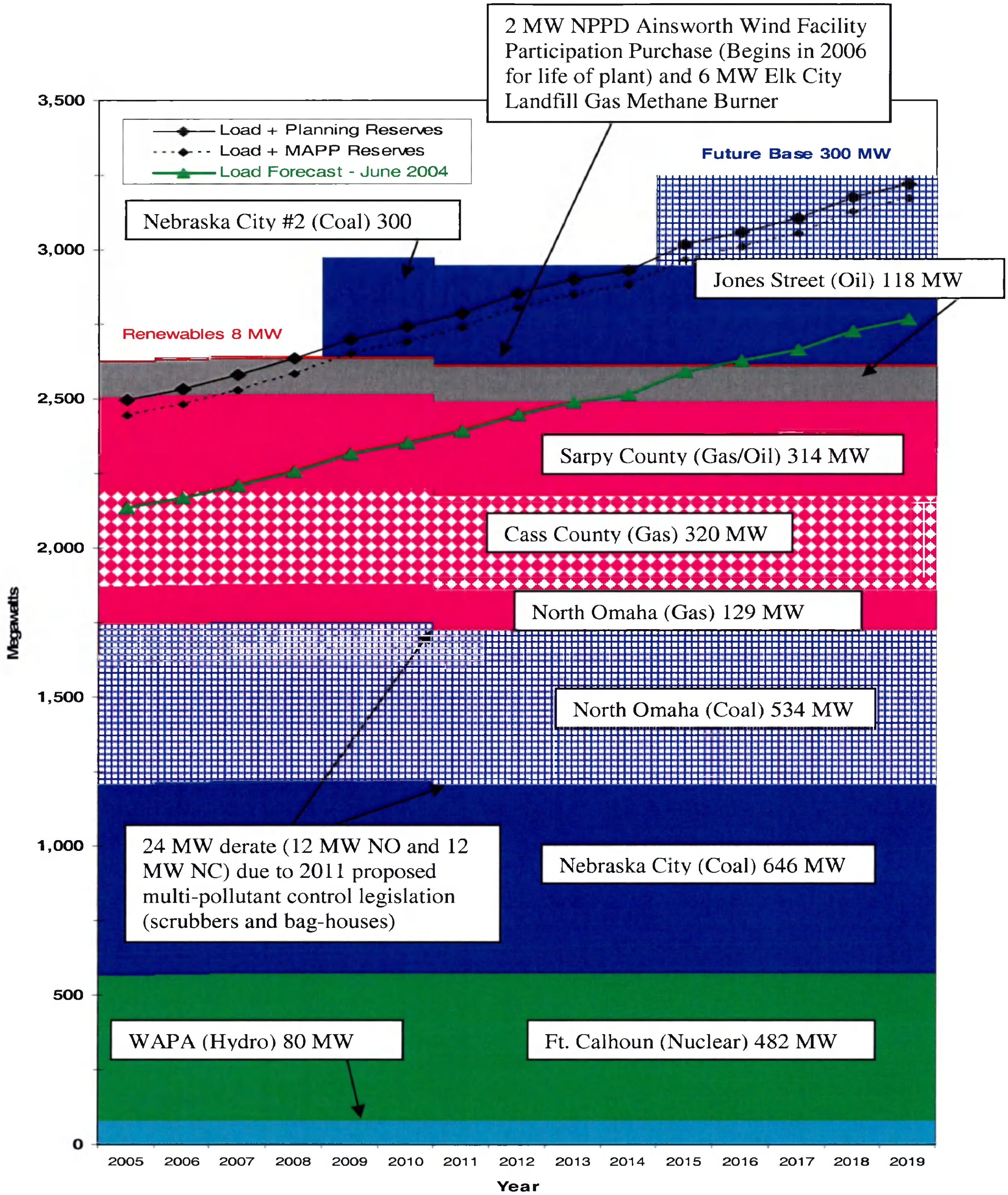

Figure 26. OPPD Load and Capability[102]

[102] Chart source is Jon Iverson, Senior Resource Planning Engineer. MAPP Reserves are the required 15% peak load installed reserves margin. Planning Reserves are OPPD's self imposed 50 MW "safety margin." For a detailed table of the source data used to generate this chart, Appendix 7 on page 153

Nebraska Power Review Board

"The Nebraska Power Review Board is a state agency created in 1963 to regulate Nebraska's publicly owned electrical utility industry. Nebraska is unique in that it is the only state in the country served entirely by publicly owned power entities. These utilities include public power districts, cooperatives, and municipalities.

"The Power Review Board consists of five members appointed by the Governor and confirmed by the legislature. Board members serve four-year terms and cannot serve more than two consecutive terms. No more than three Board members may belong to the same political party as the Governor. The Board must include an engineer, an attorney, an accountant, and two laypersons, with no geographic boundary restrictions. The Board is a cash-funded agency and therefore receives no funds from general tax revenues. The Board's operating funds are received entirely from assessments levied on power suppliers operating in the State of Nebraska. The executive director is appointed by the Board.

"The Board's duties and responsibilities are set out in Chapter 70, article 10 of the Nebraska Revised Statutes (Neb. Rev. Stat. §§ 70-1001 through 70-1027). One of the Board's primary responsibilities is the creation and certification of retail and wholesale service area agreements between electric utilities operating in Nebraska. Any amendments to existing agreements must be approved by the Board. The Board maintains the official records pertaining to these agreements, which establish the geographic territory in which each utility operating in Nebraska has the exclusive right to serve customers. There are approximately 390 such agreements maintained by the Board.

"Another primary function of the Board is to approve the construction of new electric generation facilities in Nebraska and the construction or acquisition of transmission lines or related facilities carrying more than 700 volts. Board approval is not required for the construction or acquisition of transmission line extensions located within a supplier's own certified service area.

"In addition, the Board can hold hearings to address disputes between a utility and its customers under limited circumstances, approves microwave communication facilities built by public power districts, oversees the preparation and filing of a coordinated long-range power supply plan, approves the petitions for creation of public power districts and amendments to the petitions for creation (also called "charters") of public power districts, and prepares a biennial report for the Governor and Legislature which includes such information as a list of all power suppliers in Nebraska, the assessment paid by each supplier, electrical supply and demand statistics, and a summary of the Board's activities."[103] (Bolding added).

The Power Review Board wields considerable influence. Transmission and Generation construction endeavors in the State of Nebraska must meet the approval[104] of

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[103] Nebraska Power Review Board web site on 12/31/2004, (bolding added.). http://www.nprb.state.ne.us/

[104] 70-1011 **Suppliers; service outside area; application for approval; when granted; applicability of section.** Except by agreement of the suppliers involved, no supplier shall offer electric service to additional ultimate users outside its service area or construct or acquire a new electric line or extend an existing line into the service area of another supplier for the purpose of furnishing service to ultimate users therein without first applying to the board and receiving approval thereof, after due notice and hearing under rules and regulations of the board. Such approval shall be granted only if the board finds that the customer or customers proposed to be served cannot or will not be furnished adequate electric service by the supplier in whose service area the customer is located, or that the provision thereof by such supplier would involve wasteful and unwarranted duplication of facilities. This section shall not apply to agreements referred to in subsection (2) of section 70-1002.

70-1012 **Electric generation facilities and transmission lines; construction or acquisition; application; approval; when not required.** Before any electric generation facilities or any transmission lines or related facilities carrying more than seven hundred volts are constructed or acquired by any supplier, an application, filed with the board and containing such information as the board shall prescribe, shall be approved by the board, except that such approval shall not be required (1) for the construction or acquisition of a transmission line extension or related facilities within a supplier's own service area or for the construction or acquisition of a line not exceeding one-half mile outside its own service area when all owners of electric lines located within one-half mile of the extension consent thereto in writing and such consents are filed with the board, (2) for any generation facility when the board finds that: (a) Such facility is being constructed or acquired to replace a generating plant owned by an individual municipality or registered group of municipalities with a capacity not greater than that of the plant being replaced, (b) such facility will generate less than twenty-five thousand kilowatts of electric energy at rated capacity, and (c) the applicant will not use the plant or transmission capacity to supply wholesale power to customers outside the applicant's existing retail service area or chartered territory, or (3) for acquisition of transmission lines or related facilities, within the state, carrying one hundred fifteen thousand volts or less, if the current owner of the transmission lines or related facilities notifies the board of the lines or facilities involved in the transaction and the parties to the transaction.

the Power Review Board. Of note in this analysis, "a construction project must demonstrate a **lack of duplication** of facilities."[105] (Bolding added). These criteria will be within the scope of the author's final recommendation. (See Appendix 5 on page 139 citing relevant excerpts from the *Power Review Board's Revised Rules of Practice and Procedure Manual* specifically relating to transmission construction)

Nebraska Statute 70-1014: **Electric generation facilities and transmission lines; approval or denial of application; findings required.** After hearing, the board shall have authority to approve or deny the application. Except as provided in section 70-1014.01 for special generation applications, before approval of an application, the board shall find that the application will serve the public convenience and necessity, and that the applicant can most economically and feasibly supply the electric service resulting from the proposed construction or acquisition, without unnecessary duplication of facilities or operations.

Nebraska Statutes and Constitution, chap. 70, sec. 101; available 2/28/2005 at http://statutes.unicam.state.ne.us/corpus/chapall/chap70.html.

[105] *State of Nebraska Power Review Board, Revised Rules of Practice and Procedures*, Appendix B, Section 11, as seen in Appendix 5 on page 145, (bolding added).

Legal Issues

Seven interconnect options are analyzed in this thesis. Five of the seven analyzed options involve OPPD constructing, owning and maintaining transmission outside of the geographical borders of Nebraska. This section conducts due diligence on the feasibility of OPPD conducting business outside of Nebraska by referencing Nebraska statuary law.

Conversely, this section also will investigate the feasibility of transmission being constructed, owned and maintained in the targeted State (i.e., Iowa) by entities incorporated outside the targeted State.

Nebraska's Policy Regarding Ownership of Transmission Assets by Public Power Districts, Outside of Nebraska Borders

Nebraska statute 70-604.09 enacted in 1971 by LB 276, provides in whole:

"A public power district may exercise its powers and engage in business either in the State of Nebraska or in any other state subject to any limitations in the petition for its creation and to the laws of such other state. In order to exercise its powers or engage in business in another state, a public power district shall have power and be authorized to comply with the laws of that state."[106]

Nebraska statute 70-625 enacted and revised from 1933 to 2001, provides in part:

"Subject to the limitations of the petition for its creation and all amendments to such petition, a public power district has all the usual powers of a corporation for public purposes and may purchase, hold, sell, and lease personal property and real property reasonably necessary for the conduct of its business."[107]

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[106] *Nebraska Statutes and Constitution*, chap. 70, sec. 604.09; available on web site on 2/28/2005 at http://statutes.unicam.state.ne.us/Corpus/statutes/chap70/R700600409.html.

[107] *Nebraska Statutes and Constitution*, chap. 70, sec. 625; available on web site on 2/28/2005 at http://statutes.unicam.state.ne.us/Corpus/statutes/chap70/R7006025.html.

Nebraska public power districts already own assets outside the State's boundaries. The MINT line (see page 10) resides in Missouri. OPPD also serves load in Carter Lake, IA. The terms of the service are found in the Carter Lake Franchise Agreement, last agreed upon on May 21, 2002 for a period of twenty-five years. Franchise agreements serve as the legal document and process used for establishing long term transmission agreements. The Carter Lake agreement is a two page document consisting of eight sections: Franchise Granted, Construction Maintenance and Indemnification, Metering and Service Lines, Emergency Procedures, System Requirement, Non-exclusivity Clause, Services Provided, and Term of Franchise.

Therefore, it is this author's opinion that OPPD can own transmission assets outside of the State's boundaries through State Statutes, and because OPPD currently has transmission assets outside of Nebraska's boundaries.

Transmission Asset Ownership Rights for Entities Incorporated Outside of Iowa

As mentioned above, The State of Iowa requires a franchise agreement as stated in detailed language via Chapter 478, Section 1:

> "A person shall not construct, erect, maintain, or operate a transmission line, wire, or cable that is capable of operating at an electric voltage of sixty-nine kilovolts or more along, over, or across any public highway or grounds outside of cities for the transmission, distribution, or sale of electric current **without first procuring from the utilities board within the utilities division of the department of commerce a franchise granting authority** as provided in this chapter."[108]

Furthermore, Chapter 478 Section 15, Eminent domain; procedures; states:

> "Any person, company, or corporation having secured a franchise as provided in this chapter, shall thereupon be vested with the right of eminent domain to such extent as the utilities board may approve, prescribe and find to be necessary for public use, not exceeding one hundred feet in width for right of way and not exceeding one hundred sixty acres in any one location, in addition to right of way, for the location of electric substations to carry out the purposes of said franchise; provided however, that where two hundred K V lines or higher voltage lines are to be constructed, the person, company, or corporation may apply to the board for a wider right of way not to exceed two hundred feet, and the board may for good cause extend the width of such right of way for such lines to the person, company, or corporation applying for the same. The burden of proving the necessity for public use shall be on the person, company or corporation seeking the franchise. A homestead site, cemetery, orchard or schoolhouse location shall not be condemned for the purpose of erecting an electric substation. If agreement cannot be made with the private owner of lands as to damages caused by the construction of said transmission line, or electric substations, the same proceedings shall be taken as provided for taking private property for works of internal improvement.
>
> Any person, company or corporation proposing to construct a transmission line or other facility which involves the taking of property under the right of eminent domain and desiring to enter upon the land, which it proposes to appropriate, for

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[108] *Iowa Legislature General Assembly, Iowa Code 2003 and Merged Supplement*, chap. 478, sec. 1; available on web site on 12/15/04, (emphasis added) at http://www.legis.state.ia.us/IACODE/Current/.

> the purpose of examining or surveying the same, shall first file with the utilities board, a written statement under oath setting forth the proposed routing of the line or facility including a description of the lands to be crossed, the names and addresses of owners, together with request that a permit be issued by said board authorizing said person, company or corporation or its duly appointed representative to enter upon the land for the purpose of examining and surveying and to take and use thereon any vehicle and surveying equipment necessary in making the survey. Said board shall within ten days after said request issue a permit, accompanied by such bond in such amount as the board shall approve, to the person, company or corporation making said application, if in its opinion the application is made in good faith and not for the purpose of harassing the owner of the land. If the board is of the opinion that the application is not made in good faith or made for the purpose of harassment to the owner of said land it shall set the matter for hearing and it shall be heard not more than twenty days after filing said application. Notice of the time and place of hearing shall be given by said board, to the owner of said land by registered mail with a return receipt requested, not less than ten days preceding date of hearing.
>
> Any person, company or corporation that has obtained a permit in the manner herein prescribed may enter upon said land or lands, as above provided, and shall be liable for actual damages sustained in connection with such entry. An action in damages shall be the exclusive remedy."[109]

It is this author's opinion that there is nothing in Chapter 478, which explicitly prohibits an out-of-state entity from exercising eminent domain, provided the entity has procured a franchise from the utilities board.

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[109] *Iowa Legislature General Assembly, Iowa Code 2003 and Merged Supplement,* chap. 478, sec. 15; available on web site on 12/15/04, (emphasis added) at http://www.legis.state.ia.us/IACODE/Current/.

MAPP Regional Transmission Committee

The MAPP Regional Transmission Committee (RTC):

> "is charged with planning for the future transmission needs of the region as well as ensuring that all electric industry participants have equal access to the transmission system. Committee members develop a biennial regional transmission plan, establish regional transmission tariffs and establish operating policies and procedures."[110]

A subcommittee of the MAPP RTC is the Design Review Subcommittee (DRS). "The DRS is responsible for granting approval of transmission construction on behalf of MAPP. The DRS reviews the system impact studies to verify that the construction does not lessen the stability, reliability, and capacity of the MAPP Reliability Region."[111] As a result, upon completion of system impact studies, this proposed project must be presented to and approved by the MAPP Regional Transmission Committee's Design Review Subcommittee prior to commencing construction.

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[110] *MAPP Committees* on web site on 1/11/2005. http://www.mapp.org/content/mapp_committees.shtml

[111] Phone interview with Kent Herzog, Transmission and Distribution Project Engineer on 1/12/2005.

Right of Way

Right of way acquisition always is a publicly sensitive issue. Right of way (ROW) acquisition is a process, administered by the State governing bodies, that includes announcements, public hearings, and compromises between land owners and the constructing company (i.e., electric utility). Private property owners usually believe insufficient public notice has been given, and/or insufficient public hearing has been provided, and/or insufficient consideration has been given to their concerns. In American government, taking private property always is a sensitive issue. And, the above does not mention the concerns about "just compensation". The State of Iowa has a detailed Informational Meeting Presentation,[112] outlining the process of acquiring Franchise, Right of Way, and if need be, Eminent Domain (Condemnation). This can be found in its entirety in Appendix 4 on page 131

Below is an excerpt from Appendix 4 at page 131 detailing the typical process for obtaining right of way in Iowa (no such document exists for the state of Nebraska).

> "A typical sequence of events, as it may affect the landowner, is set forth below. You should not attach any rigid significance to the sequence. It is merely an example to aid you in understanding the process.
>
> "1. Company planning determines need for the line between termini.
> "2. Prime route, and possibly alternative routes, are tentatively selected.
> "3. Route landowners and tenant names and addresses collected.
> "4. Informational meeting notices mailed.
> "5. Informational meeting is held.
> "6. Company right of way personnel contact landowners to solicit voluntary easements.

[112] *The State of Iowa's Informational Meeting Presentation* for the process of constructing transmission on website on 12/15/2004. http://www.state.ia.us/government/com/util/Misc/CBEC/MtgPresentation.pdf

"7. The company files petition for franchise with the Utilities Board. Eminent domain may be requested at this same time or later.
"8. Newspaper publishes notices of petition.
"9. Public hearing is held by the Utilities Board.
"10. A Utilities Board decision denying or granting franchise is issued. If the petition requested eminent domain, a ruling granting or denying that right will also be issued.
"11. If the petition and/or eminent domain is denied, the company may petition for rehearing, or appeal the Utilities Board denial to the courts. If the petition is granted, the landowner may petition for rehearing or appeal the Utilities Board decision to the courts. To simplify the balance of this list; it is assumed that the Utilities Board granted the franchise and the right of eminent domain and the decision was not appealed.
"12. The company may commence construction where it has voluntary easement.
"13. If eminent domain actions are taken, the company petitions the chief judge of the judicial district for the county involved to appoint a Compensation Commission. (Iowa Code Chapter 6B)
"14. The Compensation Commission sets compensation amounts, the company pays landowners who will accept; posts payment with the sheriff for those who won't, and may commence construction over the balance of the route.
"15. Either the landowners or the company may appeal the amount determined by the Compensation Commission to the courts.
"16. Line construction and clean up completed.
"17. Company pays voluntary easement amounts, agreed-to construction damages to eminent domain parcel owners, and gives written notice of renegotiation right. See Iowa Code Section 6B.52
"18. If the landowner or tenant and company cannot agree on the amount of construction damages, and there is no provision in the easement or other agreement calling for such disputes to be settled by an arbitrator or other means, the landowner or tenant may petition the county board of supervisors to establish a Compensation Commission to determine the damages.
"19. Either the landowners or the company may appeal the amount determined by the Compensation Commission to the courts.

OPPD is currently planning the construction of a 345kV transmission line to provide an outlet for a planned 600+ MW coal plant named Nebraska City 2, slated for completion in spring 2009.[113] The proposed line will run from Nebraska City to a newly constructed substation in Southeast Lincoln, in LES Control Area.

> "Alison Rider, Manager of Facilities Services and Real Estate, was chosen to develop and coordinate the team that will let the public know what OPPD is planning. The team intends to inform the public about the need for the plant and line. 'We are doing this through personal conversations, letters, public announcements, the news media, a website, community meetings and open houses,' says Alison. A consultant has been hired to identify broad "corridors" in which a line may be routed. Once the corridors have been identified, OPPD will seek public input. 'It doesn't mean the public will design the line, but we need to understand the public perceptions and legitimate concerns about the project and incorporate them into our planning process. It doesn't mean there won't be any conflict or opposition, but it does ensure people will be heard. Taking the time and making the effort to get this input on the front end often saves a lot of money and time in the long run.' The public communication efforts will continue through 2005. Once a final route is selected and approved, the process of acquiring right of way easements begins and engineers can focus on the details of the line design."[114]

Generically, the cost of right of way is between $30,000 and $50,000 per mile, according to OPPD's Right of Way acquisition personnel. In my analysis, I will use $50,000 per mile for all capacities analyzed: 161kV, 230 kV, and 345kV. Of course, the non-ROW costs of different sized physical structures will vary considerably, but the right of way costs can be relatively constant regardless of the capacity of the line. Another justification for using a constant cost of the high end cost of $50,000 per mile for all routes of right of acquisition is that the utility's environmental costs can vary widely and can vary suddenly for each right of way.

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[113] Approximately half of the output from NC2 will be owned by other public power entities.

[114] Hanson, Jeff. *Flash.* OPPD Corporate Communications Division, November 2004, pg 2.

Often existing transmission right of way is pursued as a first option to minimize public effect and reduce costs.

Environmental Impact Analysis

Environmental impact is closely related to right of way. When routing studies are conducted for right of way placement, environmental impact is a driver in the decision criteria. However, "there is no formal funding requirement for environmental studies, at either the State or federal level. OPPD policy is to conduct routing studies, and to try to avoid wetlands, historical sites, and any other environmentally sensitive areas."[115] The routing study costs are allocated in right of way costs.

[115] Phone interview with Lawrence Troutman, Manager of Distribution Engineering on December 15, 2004.

System Impact Analysis Studies

When constructing transmission, it is necessary to conduct system impact studies to analyze the post construction effects on the grid. Impact studies are more critical when constructing new generation to study the best alternatives for dispatching the new generation onto the grid. Adding transmission capacity is generally viewed as a benefit to the grid. The purpose of the impact study is to make known the best option for increasing stability and reliability to the grid. Impact studies are conducted by transmission engineering consulting groups and $150,000 has been allocated in the budget for these studies.

WAPA Policy for Interconnection with Their System

> "Western accepts requests from electric utilities, firm-power customers, private power developers, and independent power generators to interconnect with its transmission system. Interconnection is a separate but parallel process to the transmission service request process detailed in Western's *Open Access Transmission Service Tariff* (63 FR 521), the environmental review process outlined in the U.S. Department of Energy's National Environmental Policy Act Implementing Procedures and Western's land acquisition process. These processes may share steps in order to ensure an efficient interconnection. Western tries to make the separate processes as seamless as possible.
>
> "We evaluate each request for interconnection separately and we're subject to meeting reasonable needs of the requesting entity. Western assumes responsibilities to operate and maintain its interconnected facilities.
>
> "Direct interconnection to Western's facilities does not involve nor guarantee transmission capacity on Western's system. Transmission service requests must be made following Western's *Open Access Transmission Service Tariff.*
>
> "For detailed information on the interconnection process, see the *General Requirements for Interconnections* booklet."[116]

WAPA is accommodating in the transmission interconnection process as demonstrated by the specific literature available regarding interconnect procedures. Appendix 6, on page 148 details the eight step process for interconnect with the WAPA system.

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[116] Western Area Power Administration web site on 1/3/2005. http://www.wapa.gov/interconn/pdf/gri.pdf

General Requirements for Interconnection, from Western Area Power Administration web site on 1/3/2005. http://www.wapa.gov/interconn/pdf/gri.pdf

Open Access Transmission Service Tariff, from Western Area Power Administration web site on 1/3/2005. http://www.wapa.gov/interconn/tariff.htm

OPPD's Forecasted Debt

OPPD is entering a period of rapid capital expansion due to the construction of Nebraska City 2 Coal Plant (NC2), an upgrade of Fort Calhoun Nuclear Station (FCS) and the construction of new 345 kV transmission to facilitate the increased generation. "The District is planning on issuing up to $900 million in Long Term Debt over the next five years."[117]

"Total Debt Service, (principle and interest expense on all debt including bonds, notes, mini-bonds and tax exempt commercial paper), will increase from $78.8 million in 2003 to a forecasted target of about $120 million per year within five years."[118]

"OPPD is required by its bond covenants to maintain a debt service coverage of 1.40 times. The following table reflects the calculation of debt service coverage, indicating OPPD's solid ability to make required debt service payments."[119] As a result consideration must be given to the option selected with regard to capital outlay so as to not impede on this required ratio parameter. With the increased debt obligations associated to the NC2 project, and Fort Calhoun upgrade, debt service must be considered.

[117] Per phone conversation with John Thurber, Manager, Finance and Capital Management, March 24, 2005.

[118] Per phone conversation with John Thurber, Manager, Finance and Capital Management, March 24, 2005.

[119] *OPPD's 2003 Annual Report,* Debt Service Coverage, pg. 19.

Debt Service Coverage (in $1000's)	**2003**	**2002**	**2001**
Operating revenues	588,541	553,024	568,795
Less Operation expenses	(419,507)	(347,121)	(353,767)
Less payments in lieu of taxes	(18,067)	(18,553)	(18,234)
Net operating revenues	150,967	187,350	196,794
Investment income of related reserve fund	1,049	1,411	1,673
Net receipts	152,016	188,761	198,467
Total debt service	78,839	74,688	73,466
Debt service coverage (Net receipts/Total debt service)	**1.92**	**2.52**	**2.70**

Figure 27. OPPD Debt Service Coverage.[120]

"OPPD's debt to equity ratio {total outstanding debt / (total outstanding debt + accumulated reinvested earnings)}, will rise from 40% debt and 60% equity, to about 50% debt and 50% equity."[121]

Consideration should be given to OPPD's forecasted increase in debt leverage and mandated covenants on debt service coverage ratios when considering which construction option would best benefit OPPD.

[120] *OPPD's 2003 Annual Report,* Debt Service Coverage, pg. 19.

[121] Per phone conversation with John Thurber, Manager, Finance and Capital Management, March 24, 2005.

OPPD's Cost of Capital

OPPD's estimated cost of capital is analyzed and updated annually. The District uses a modified Weighted Average Cost of Capital (WACC)[122] as the primary driver in the calculation of the cost of capital. The District references three derivations of WACC, and averages these three results to establish OPPD's cost of capital.

OPPD's modified Weighted Average Cost of Capital is the sum of the products of the weight of debt multiplied by the cost of debt and the weight of equity multiplied by the cost of equity as depicted below.

WACC = (Wd * Kd) + (We * Ke), where:

Wd = weight of debt in capital structure =
(OPPD Outstanding Debt)/(OPPD Outstanding Debt + OPPD Retained Earnings)

Kd = cost of debt capital =
(OPPD Annual Interest Expense)/(OPPD Long Term Outstanding Debt)

We = weight of equity in capital structure =
(OPPD Retained Earnings)/(OPPD Outstanding Debt + OPPD Retained Earnings)

Ke = cost of equity capital

Figure 28. Weighted Average Cost of Capital equation.

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[122] As defined in *Financial Management Theory and Practice*, pg. 435.

WACC = (Wd * Kd)(1-Tax Rate) + (Wps * Kps) + (We * Ke) where Wd is the weight of debt in capital structure, Kd is the cost of debt capital, Tax Rate is Corporate Tax rate, Wps is the weight of preferred stock, Kps is the cost of preferred stock, We is the weight of equity and Ke is the cost of equity. OPPD does not pay corporate income taxes because of its tax exempt status as a public utility. OPPD does not issue preferred stock.

The cost of equity capital (Ke) is measured in three different ways. These three results are entered into the WACC equation above. The three WACC results are averaged and OPPD uses this average as OPPD's cost of capital. The three processes used to calculate equity capital (Ke) are considered proprietary information to OPPD. The average of the three methods rendered a WACC calculation of 7.02%. The District is currently using 7 % for its cost of capital.

Chapter 3: METHODOLOGY

Overview

The analysis for the benefit and cost analysis will be divided into a benefit section and cost section.

The primary cost driver for this capital project is transmission construction. Transmission construction costs are a function of capacity of transfer (i.e., 345 kV versus 230 kV versus 160 kV), distance of transmission constructed, right of way acquisition, and, finally, substation construction and/or modifications. On top of these physical structure costs are transmission system impact studies and legal fees for the acquisition of the right of way.[123]

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[123] All transmission cost estimates are from Kent Herzog, Transmission and Distribution Project Engineer.

Transmission at 161 kV costs about $275,000 per mile, using steel pole construction. Transmission at 230 kV costs about $387,500 per mile and transmission at 345 kV costs about $500,000 per mile, again using steel pole construction.

Percent of allocation	Category	Estimated Cost per Mile
18.18%	Right of Way	$50,000
9.09%	Wire	$25,000
7.27%	Wire Labor	$20,000
36.36%	Steel Poles	$100,000
29.09%	Steel Pole Labor	$80,000
100%	**Total**	**$275,000**

Figure 29. 161 kV Transmission Construction Cost Assumptions (per mile)

Percent of allocation	Category	Est. Cost/Mile
12.9%	Right of Way	$50,000
9.68%	Wire	$37,500
7.74%	Wire Labor	$30,000
38.71%	Steel Poles	$150,000
30.97%	Steel Pole Labor	$120,000
100%	**Total**	**$387,500**

Figure 30. 230 kV Transmission Construction Cost Assumptions (per mile)

Percent of allocation	Category	Est. Cost/Mile
10%	Right of Way	$50,000
10%	Wire	$50,000
8%	Wire Labor	$40,000
40%	Steel Poles	$200,000
32%	Steel Pole Labor	$160,000
100%	**Total**	**$500,000**

Figure 31. 345 kV Transmission Construction Cost Assumptions (per mile)

River crossing costs will be absorbed into the per mile construction rate, so river crossing will not be a separate line item. Substation construction for 345kV capacity costs about $6,500,000 and 161 kV costs about $3,250,000. Modifications to existing substations (adding terminals) cost about $3,000,000 for 345kV modifications and $1,500,000 for 161kV. Transmission impact studies will cost about $150,000 and legal fees for right of way are estimated at less then $5,000.

There are several combinations of interconnect possible between OPPD and WAPA; however, the reasonable options pursued will seek to minimize construction mileage and substation construction/modifications while simultaneously pursuing the maximization of grid reliability and stability.

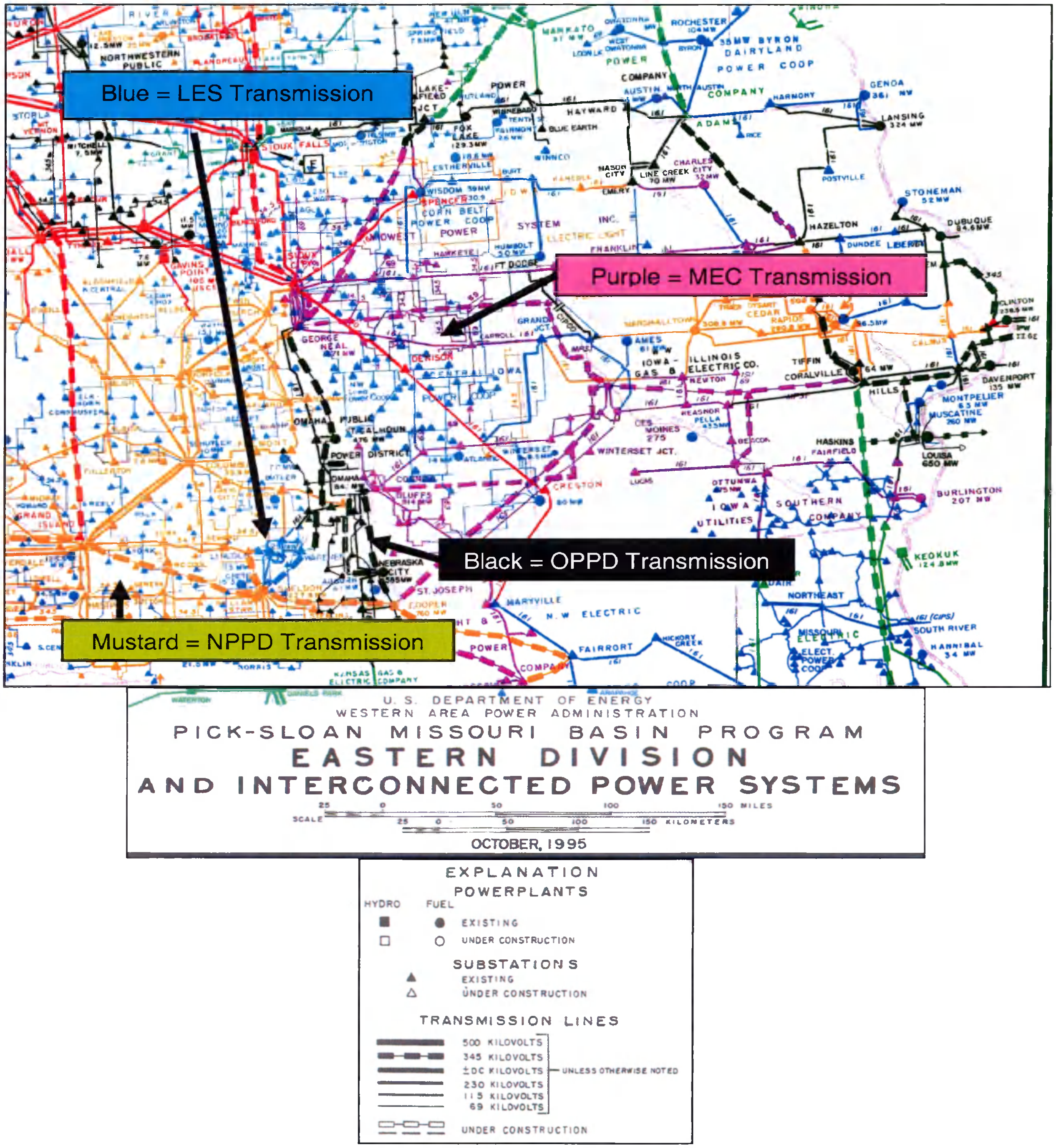

Figure 32. Detailed map of OPPD and surrounding interconnects.[124]

[124] U.S Department of Energy, Western Area Power Administration, Pick-Sloan Missouri Basin Program, Eastern Division and Interconnected Power Systems, October, 1995. Prepared in the Upper Great Plains Office.

The goal in establishing an interconnect is to construct transmission from an existing or new OPPD substation to an existing WAPA substation, so identifying existing WAPA substations near existing OPPD substations is the first selection criteria. The second criteria is to minimize the distance between the interconnecting substations and the third criteria was to try to match similar capacities (i.e. existing 161 kV substation with new 161 transmission) in order to reduce existing substation modification expenses.

These options will then be analyzed over their individual characteristics, challenges, benefits and costs. One option will then be recommended by the author.

Transmission construction costs are primarily variable and a function of distance, so the analysis will begin by inspecting the points of minimal distance between OPPD and WAPA. There are four such points: Sioux City, IA; Grand Island, NE; Denison, IA; and Creston, IA. These four geographic points will be analyzed over mileage, substation construction, substation modifications, and capacity. Additional consideration will include existing right of way, Impact Study results, and Nebraska Power Review Board criteria.

The Seven Options

Option 1: North Omaha to Creston, IA

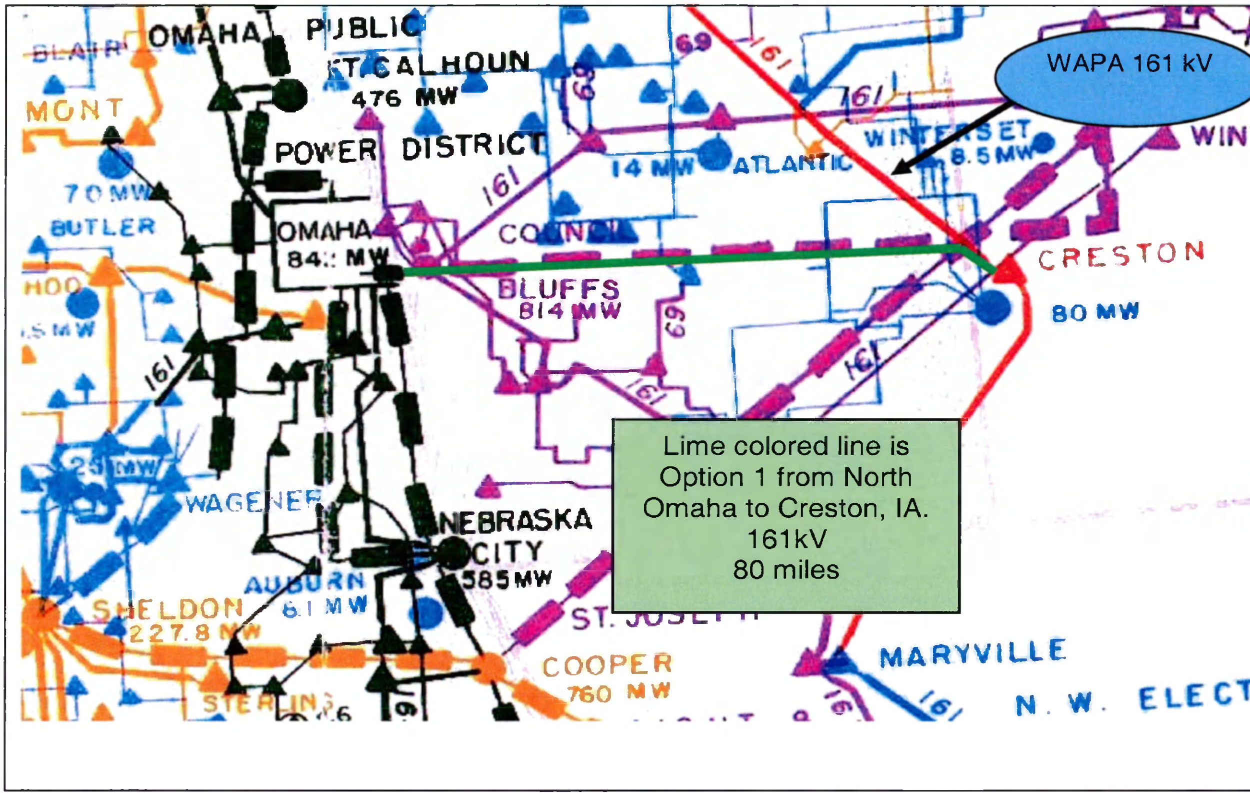

Figure 33. Option 1: North Omaha to Creston, IA (Creston is in MAPP at a WAPA.MEC interface)[125]

Option 1 is to construct 161 kV transmission from the OPPD's North Omaha substation to WAPA's 161 kV substation at Creston, IA. There is existing 345 kV MEC transmission in this corridor. As a result, right of way might encounter less public resistance. This option would involve OPPD constructing transmission in the State of Iowa, so a Franchise would need to be acquired.

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[125] Magnitude of zoom is identical to neither Figure 32 nor the other options' blow ups.

Option 2a and 2b: Lincoln to Grand Island

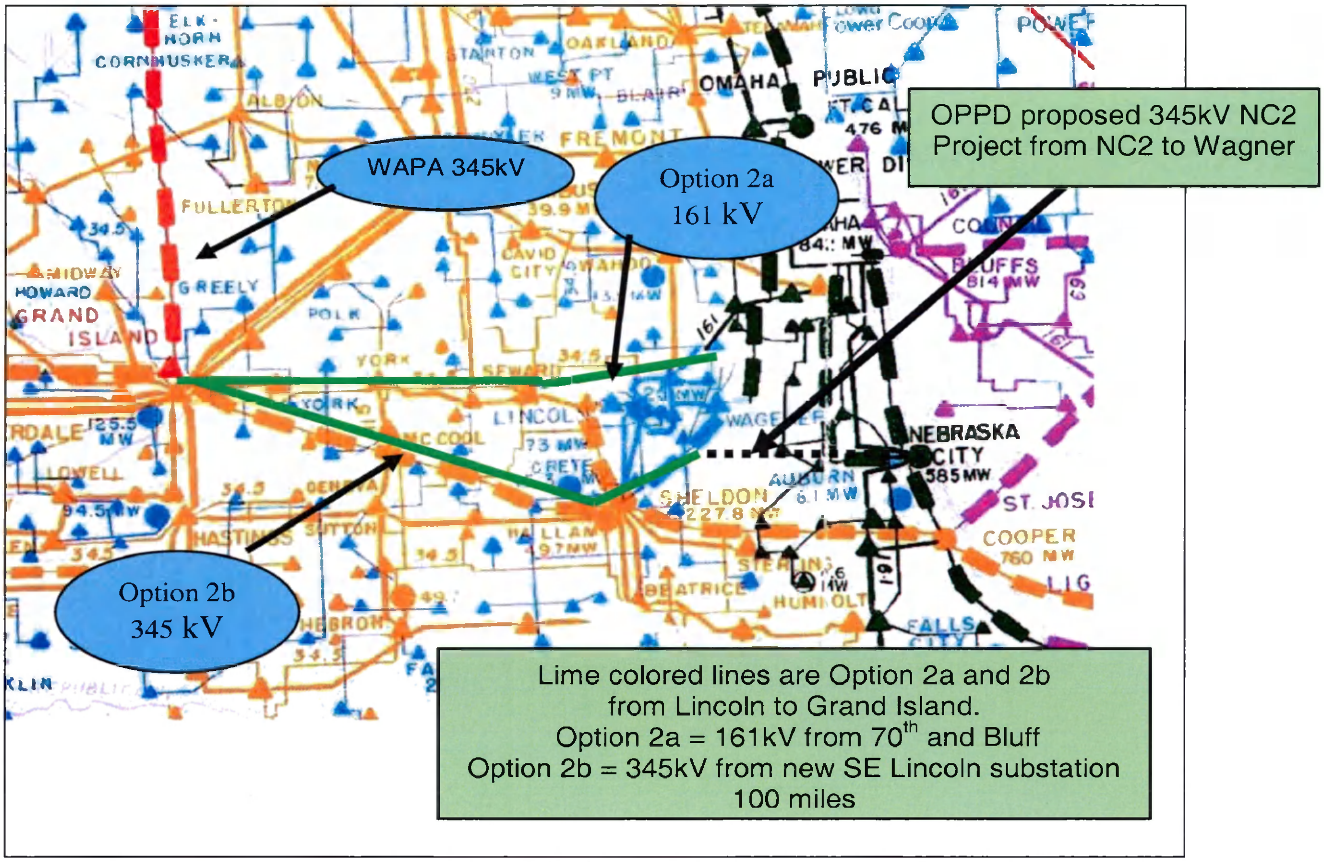

Figure 34. Option 2a and 2b: Lincoln, NE to Grand Island, NE (Grand Island is in MAPP at an NPPD.WAUE interface)[126]

Options 2a and 2b involves transmission construction from Lincoln, NE to Grand Island, NE. Unlike the other proposals, Options 2a and 2b source from unique substations in Lincoln, NE. Option 2a (161 kV) will source from an existing 161 kV substation at 70th and Bluff in Northeast Lincoln. Option 2b (345 kV) will source at the newly proposed Southeast Lincoln substation. Options 2a and 2b propose to form a jointly owned line (OPPD and LES) from one of these two Lincoln substations to WAPA's 345kV substation at Grand Island, NE. This jointly owned line would also

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[126] Magnitude of zoom is identical to neither Figure 32 nor the other options' blow ups.

allow LES to be directly interconnected with WAPA. LES currently has no direct interconnect with WAPA, yet like OPPD, LES receives a WAPA allocation and LES and WAPA conduct bilateral wholesale transactions as evidenced by the Department of Energy's *Energy Information Administration Historical Form EIA-412, Annual Public Electric Utility Data*: http://www.eia.doe.gov/cneaf/electricity/page/eia412/sched6_00.xls. A direct interconnect to WAPA for LES could reduce LES' transmission costs associated to the WAPA allocation and bilateral transactions. Right of way exists along most of these proposed options. Construction of transmission in this scenario would all be contained in the State of Nebraska.

Option 3a and 3b: Raun to Sioux City, IA

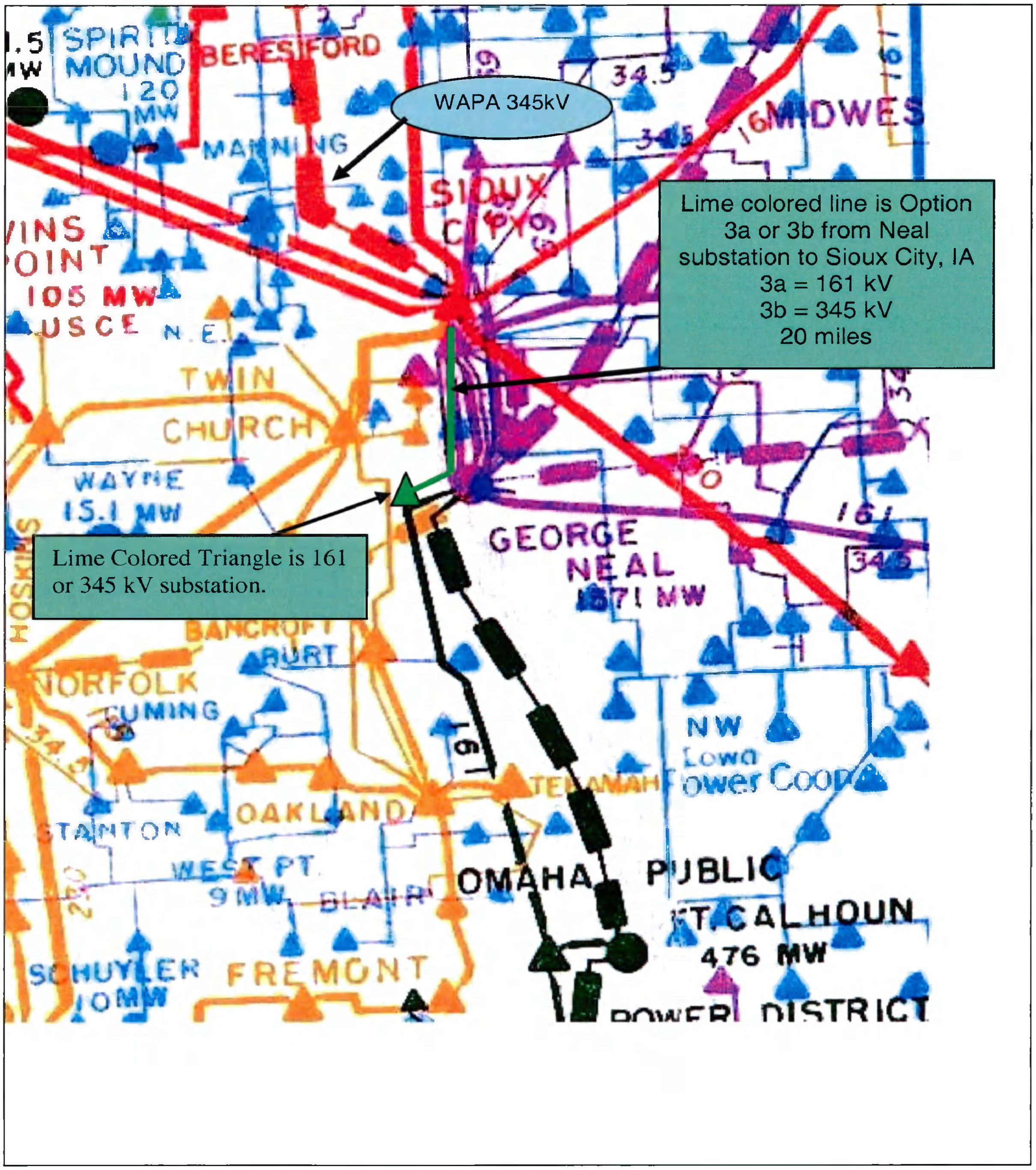

Figure 35. Option 3a and 3b: Raun to Sioux City, IA (Sioux City is in MAPP at a MEC.WAUE interface)[127]

[127] Magnitude of zoom is identical to neither Figure 32 nor the other options' blow ups.

OPPD has an interconnection to MidAmerican Electric Company (MEC) at MidAmerican's Raun substation which serves MEC's George Neal coal plant, just south of Sioux City, IA. Option 3a and 3b propose building a substation near Raun, retaining interconnect with Raun from this new substation, and constructing transmission from this new substation to WAPA's Sioux City, IA 345kV substation. Option 3a and 3b are the only options which include the construction of a new substation. Right of way exists along most of this proposed option. These options include construction in the State of Iowa, so a Franchise will need to be acquired.

Option 4a and 4b: Fort Calhoun to Denison, IA

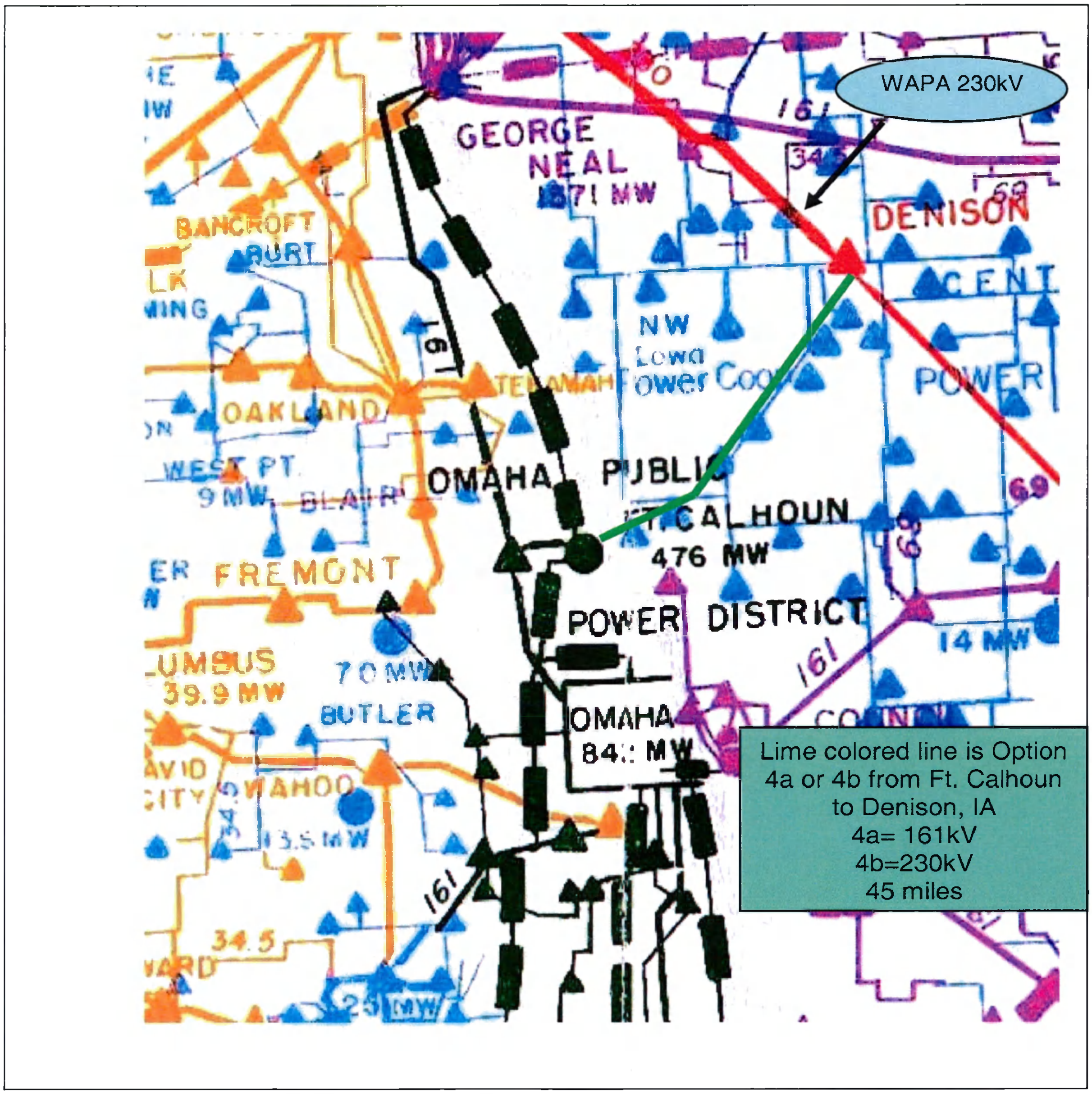

Figure 36. Option 4a and 4b: Ft. Calhoun, NE to Denison IA (Denison is in MAPP at a MEC.WAUE interconnect)[128]

Options 4a and 4b involve the construction of transmission from OPPD's Fort Calhoun Nuclear substation to WAPA's Denison, IA substation. The Denison substation

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[128] Magnitude of zoom is identical to neither Figure 32 nor the other options' blow ups.

is accommodating WAPA's 230 kV line from the northwest and steps down to a 161 kV line to the southeast. This enables OPPD to consider a 161 kV option (Option 4a) or a 230 kV option (Option 4b). OPPD currently has no 230 kV transmission within OPPD's footprint. Right of way on this Option 4a and on Option 4b mostly exists for existing transmission from Fort Calhoun to Denison, IA. Both Option 4a and 4b include construction in the State of Iowa, so a Franchise will need to be acquired.

The Benefits

The benefits from a direct interconnection with WAPA would be four-fold. First, the MAPP tariff transmission expenses currently incurred on bilateral transactions will cease. Second, the MidAmerican transmission expenses incurred in acquiring the WAPA allocation would cease. Third, the direct interconnect could increase bilateral transactions with WAPA by approximately 10% because the transmission cost savings will make each party's power more cost competitive. Finally, the direct interconnect also will increase transmission capacity and stability. Increasing transmission capacity and stability will in turn increase the probability of power flowing; especially if both WAPA and OPPD purchase long-term firm transmission on their respective tariffs to and from OPPD.WAUE.

Bilateral Transmission Savings (Pooled OPPD and WAPA benefit)

OPPD bilateral purchases from WAPA to OPPD (MWh)

On Peak:

Year:	2000	2001	2002	2003	2004
On Peak (MWh)	62,535	9,771	19,341	10,216	28,214
Current MAPP On Peak Cost ($/MWh)	.81	.81	.81	.81	.81
Total On Peak Cost	$50,653.35	$7,914.51	$15,666.21	$8,274.96	$22,853.34

Figure 37. OPPD bilateral On Peak Purchases from WAPA to OPPD (MWh)[129]

Five year average on peak bilateral purchases expenditure is $21,072.47. Standard deviation over the five year period is $17,637.57.

Off Peak:

Year:	2000	2001	2002	2003	2004
Off Peak (MWh)	12,590	4,786	12,945	17,457	10,476
Current MAPP Off Peak Cost ($/MWh)	.46	.46	.46	.46	.46
Total Off Peak Cost	$5,791.40	$2,201.56	$5,954.70	$8,030.22	$4,818.96

Figure 38. OPPD bilateral Off Peak Purchases from WAPA to OPPD (MWh)[130]

Five year average off peak bilateral purchases expenditure is $5,359.37. Standard deviation over the five year period is $2,117.68.

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[129] Source is OPPD Accounting, Gretchen Lax, Programmer Analyst, Business Unit Systems Support.

[130] Source is OPPD Accounting, Gretchen Lax, Programmer Analyst, Business Unit Systems Support .

Total five year average OPPD bilateral purchase expenditure from WAPA to OPPD is $26,431.84

OPPD Bilateral Sales from OPPD to WAPA (MWh)

On Peak:

Year:	2000	2001	2002	2003	2004
On Peak (MWh)	75,497	128,849	147,146	66,501	200,875
Current MAPP On Peak Cost ($/MWh)	.79	.79	.79	.79	.79
Total On Peak Cost	$59,642.63	$101,790.71	$116,245.34	$52,535.79	$158,691.25

Figure 39. OPPD bilateral On Peak Sales from OPPD to WAPA (MWh)[131]

Five year average on peak bilateral sales expenditure is $97,781.14. Standard deviation over the five year period is $43,499.23.

Off Peak:

Year:	2000	2001	2002	2003	2004
Off Peak (MWh)	214,045	202,509	310,514	294,853	369,335
Current MAPP Off Peak Cost ($/MWh)	.45	.45	.45	.45	.45
Total Off Peak Cost	$96,320.25	$91,129.05	$139,731.30	$132,683.85	$166,200.75

Figure 40. OPPD bilateral Off Peak Sales from OPPD to WAPA (MWh)[132]

Five year average off peak bilateral sales expenditure is $125,213.04. Standard deviation over the five year period is $31,397.04.

[131] Source is OPPD Accounting, Gretchen Lax, Programmer Analyst, Business Unit Systems Support.

[132] Source is OPPD Accounting, Gretchen Lax, Programmer Analyst, Business Unit Systems Support.

Total five year average, OPPD bilateral sales transmission expenditure from WAPA to OPPD is $222,994.18.

Total five year average, OPPD bilateral purchases and sales transmission expenditure between OPPD and WAPA is $249,426.02.

In the cash flow analysis, these transmission expenditures were increased at an annual rate of 1.86%, the forecasted MAPP growth rate.[133]

[133] This growth rate was extrapolated from the Forecasted Seasonal System Demand Summary report from *2004 Mid-Continent Area Power Pool Load and Capability Report* on page 468 on web site on 12/28/2004. http://www.mapp.org/assets/pdf/LC_2004_Final.pdf

WAPA Firm Allocation Transmission Savings

In the current MEC-WAPA transmission contract No. 89-BAO-337 dated January 3, 1989 WAPA pays MEC $0.524 per kW-month which equates to $53,972 per month or $647,664 per year. OPPD reimburses WAPA for a portion of this transmission expense. OPPD currently pays MEC $42,623.27 per month (or $511,479.24 per year) for the 103 MW of MEC transmission used to flow the WAPA allocation to OPPD.[134] This is the contracted rate with MEC which expires on December 31, 2008.

MEC's current posted tariff rate could cost OPPD $1,745,384.97 per year if the current tariff rate would be charged when OPPD's current contracted rate expires on December 31, 2008.[135]

In the analysis of cost savings, the posted tariff rate of $1,745,385 will be used, and this rate will remain fixed for the 30 year cash flow analysis.

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[134] As stated in WAPA monthly invoices to OPPD.

[135] MidAmerican Firm Point-to-Point Transmission Service could include (1) Schedule 7 Transmission Service rate of $13,825 per MW year; (2) $0.08 per MWh for Scheduling, System Control and Dispatch Service,(ancillary service Schedule 1); (3) $0.18 per MWh for all energy scheduled to compensate for Reactive Supply and Voltage Control from Generation Sources Service (ancillary service Schedule 2); and (4) losses of 3.23% on website on 12/15/2004.
https://mapp.oasis.mapp.org/documents/MEC/tariffs.html#schedule7rates

The Costs

161 kV Construction Costs

Estimated construction costs of 161 kV capacity is $275,000 per mile and is allocated as follows:

Percent of allocation	Category	Estimated Cost per Mile
18.18%	Right of Way	$50,000
9.09%	Wire	$25,000
7.27%	Wire Labor	$20,000
36.36%	Steel Poles	$100,000
29.09%	Steel Pole Labor	$80,000
99.99%	Total	$275,000

Figure 41. Estimated 161 kV transmission construction costs, per mile.[136]

[136] 99.99% due to .01% rounding error.

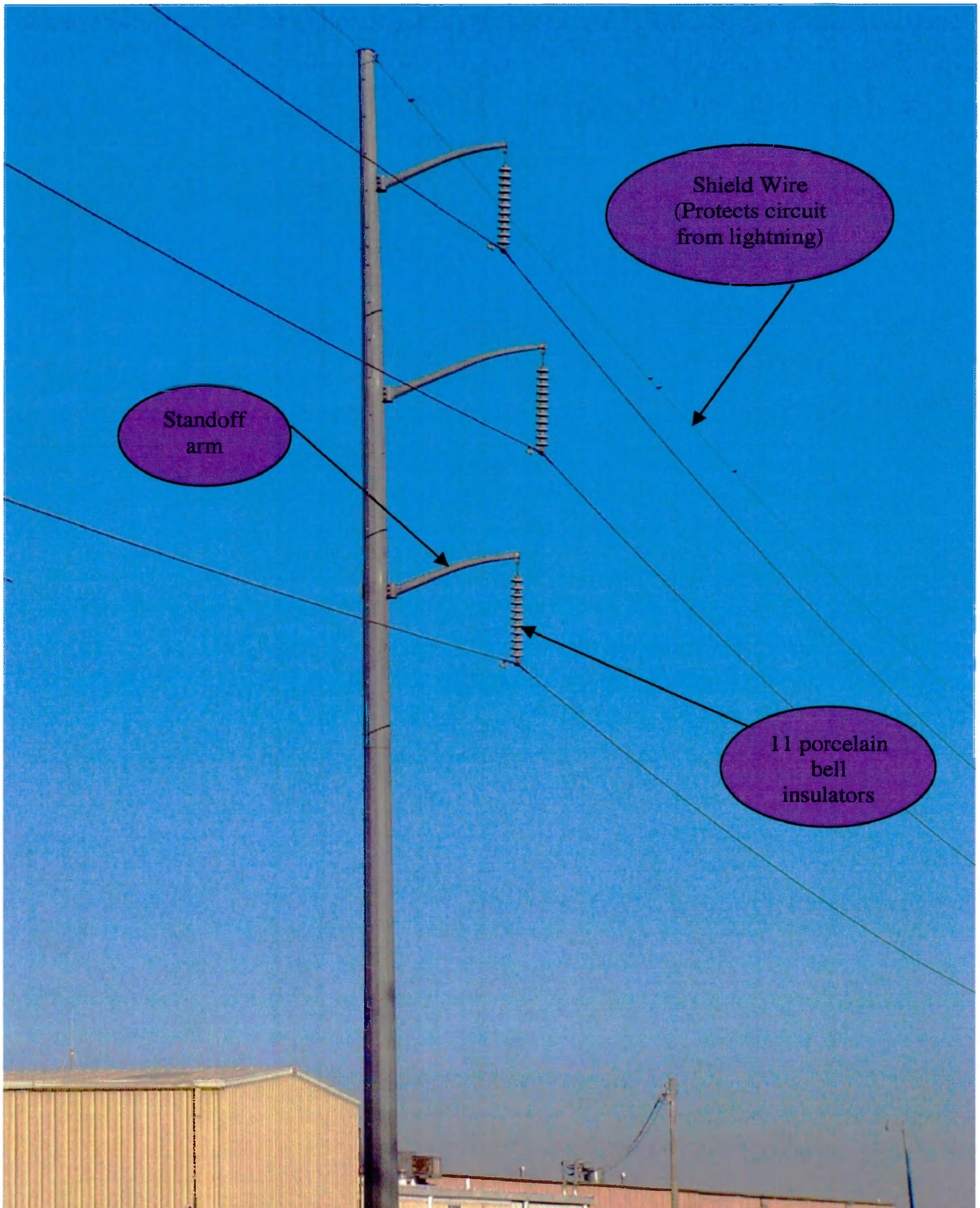

Figure 42. Three phase 161 kV circuit[137]

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[137] OPPD 161 kV transmission line photo taken by the author, east of 144th and Giles Roads in Omaha, NE.

230 kV Construction Costs

Estimated construction of 230 kV capacity is $387,500 per mile and is allocated as follows:

Percent of allocation	Category	Estimated Cost per Mile
12.90%	Right of Way	$50,000
9.68%	Wire	$37,500
7.74%	Wire Labor	$30,000
38.71%	Steel Poles	$150,000
30.97%	Steel Pole Labor	$120,000
100.00%	Total	$387,500

Figure 43. Estimated 230 kV transmission construction costs, per mile.

OPPD currently has no 230 kV transmission erected.

345 kV Construction Costs

Estimated construction costs of 345 kV capacity is $500,000 per mile and is allocated as follows:

Percent of allocation	Category	Estimated Cost per Mile
10.00%	Right of Way	$50,000
10.00%	Wire	$50,000
8.00%	Wire Labor	$40,000
40.00%	Steel Poles	$200,000
32.00%	Steel Pole Labor	$160,000
100.00%	Total	$500,000

Figure 44. Estimated 345 kV transmission construction costs, per mile.

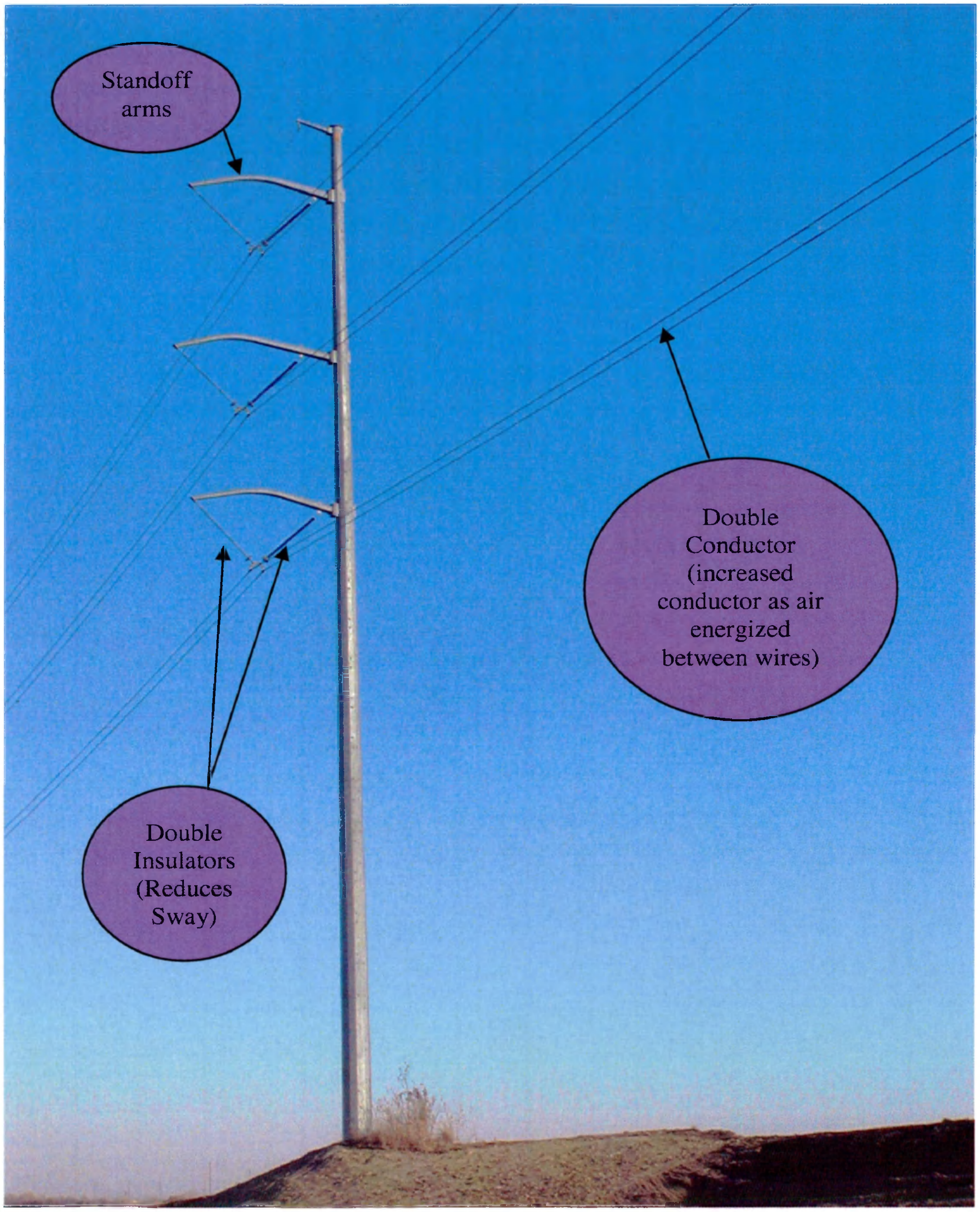

Figure 45. Three phase 345kVcircuit[138]

[138] OPPD 345 kV transmission line photo taken by the author near 156th and Giles Roads in Omaha, NE.

Additional costs varying from option to option:

- 161 kV
  - $3,250,000 = 161 kV Greenfield Substation construction
  - $1,500,000 per substation modified = 161 kV Substation Terminal Modifications

- 230 kV
  - No 230 kV Greenfield Substation construction scenario
  - $2,250,000 per substation modified = 230 kV Substation Terminal Modifications

- 345 kV
  - $6,500,000 = 345 kV Greenfield Substation construction
  - $3,000,000 per substation modified = 345 kV Substation Terminal Modifications

Fixed Project Costs

- Transmission Impact Analysis Consultants Fee = $150,000
- Legal fees associated to Franchise Contracting = $3,000

These costs will be totaled for each of the seven options. The total cost for each project will then be allocated evenly over the estimated four year construction period.

Additional Considerations

Payment In Lieu of Taxes

OPPD is a political subdivision of the State of Nebraska, and therefore, is exempt from paying Federal and State of Nebraska income taxes. However, in Nebraska, OPPD does make a Payment in Lieu of Taxes. Nebraska Article VIII, Section 11 (enacted by the People in 1958) of the Nebraska *Constitution* provides in relevant part:

> "Every public corporation and political subdivision organized primarily to provide electricity or irrigation and electricity shall annually make the same payments in lieu of taxes as it made in 1957, which payments shall be allocated in the same proportion to the same public bodies or their successors as they were in 1957.
>
> "The legislature may require each such public corporation to pay to the treasurer of any county in which may be located any incorporated city or village, within the limits of which such public corporation sells electricity at retail, a sum equivalent to five (5) per cent of the annual gross revenue of such public corporation derived from retail sales of electricity within such city or village, less an amount equivalent to the 1957 payments in lieu of taxes made by such public corporation with respect to property or operations in any such city or village. The payments in lieu of tax as made in 1957, together with any payments made as authorized in this section shall be in lieu of all other taxes, payments in lieu of taxes, franchise payments, occupation and excise taxes, but shall not be in lieu of motor vehicle licenses and wheel taxes, permit fees, gasoline tax and other such excise taxes or general sales taxes levied against the public generally.
>
> "So much of such five (5) per cent as is in excess of an amount equivalent to the amount paid by such public corporation in lieu of taxes in 1957 shall be distributed in each year to the city or village, the school districts located in such city or village, the county in which such city or village is located, and the State of Nebraska, in the proportion that their respective property tax mill levies in each such year bear to the total of such mill levies."[139]

[139] *Nebraska Statutes and Constitution*, art. VIII, sec. 11; available on web site on 2/28/2005 at http://statutes.unicam.state.ne.us/Corpus/chapC/CVIII-11.html

Additionally, Nebraska statute 70-651.03 enacted in 1959 provides in whole:

> "Every public power district or public power and irrigation district owning property with respect to which it made payments in lieu of taxes in the 1957 calendar year, shall, so long as it continues to own such property, continue to pay annually the same amounts in the same manner. The directors of any such district shall not have any personal liability by reason of such payments made either before or after September 28, 1959."[140]

These payments in lieu of taxes are made "from retail sales of electricity within such city or village (emphasis added)." Bilateral transactions and WAPA allocation are considered wholesale power transactions, so these revenues are exempt from payments in lieu of taxes. As a result, payments in lieu of taxes from these wholesale bilateral and WAPA allocation transactions are not applicable for consideration as a cost component in this analysis.

[140] *Nebraska Statutes and Constitution*, chap. 70, sec. 651; available on web site on 2/28/2005 at http://statutes.unicam.state.ne.us/Corpus/statutes/chap70/R700605101.html.

WAPA Allocation Reduction

The reduction in WAPA allocation to OPPD of as much as 0.25% in January 2006 and a potential additional reduction of as much as 1.00% in January 2011 represents a maximum reduction of 1.25% in future WAPA allocation and acquired MEC transmission. This maximum of 1.25% reduction equates with 1.31 MWh (i.e., 1.25% of 105 MWh). The author believes this impact (i.e., maximum of -1.25% over 10 years) is insignificant to this analysis and will result in a minimal impact on relevant cash flow analysis.

MEC Transmission Expense Inflator

This analysis ignores any increases in MEC transmission tariff costs over the 30 year cash flow analysis, lessening the potential benefit depicted from the cash flow analysis.

Chapter 4: ANALYSIS OF DATA

	(Units in $1,000's)	North Omaha to Creston	70th and Bluff to Grand Island (Combined)	70th and Bluff to Grand Island (LES)	70th and Bluff to Grand Island (OPPD)	Southeast Lincoln to Grand Island (Combined)	Southeast Lincoln to Grand Island (LES)	Southeast Lincoln to Grand Island (OPPD)	Raun to Sioux City	Raun to Sioux City	Fort Calhoun to Denison	Fort Calhoun to Denison
		Option 1	Option 2a (Combo)	Option 2a (LES)	Option 2a (OPPD)	Option 2b (Combo)	Option 2b (LES)	Option 2b (OPPD)	Option 3a	Option 3b	Option 4a	Option 4b
Net Cash Outlay		161 kV North O To Creston	161 kV 70th and Bluff to GI (Combo)	161 kV 70th and Bluff to GI (LES)	161 kV 70th and Bluff to GI (OPPD)	345 kV SE Lincoln to GI (Combo)	345 kV SE Lincoln to GI (LES)	345 kV SE Lincoln to GI (OPPD)	161 kV Raun to SC	345 kV Raun to SC	161 kV FC to Den	230 kV FC to Den
	Steel Poles	8,000	10,000	5,738	4,262	20,000	11,475	8,525	2,000	4,000	4,500	6,750
	Conductors (Wire)	2,000	2,500	1,434	1,066	5,000	2,869	2,131	500	1,000	1,125	1,688
	Labor	8,000	10,000	5,738	4,262	20,000	11,475	8,525	2,000	4,000	4,500	6,750
	Right of Way	4,000	5,000	2,869	2,131	5,000	2,869	2,131	1,000	1,000	2,250	2,250
	Substation Construction	0	0	0	0	0	0	0	3,250	6,500	0	0
	Substation Terminal Construction	3,000	3,000	1,721	1,279	6,000	3,443	2,557	1,500	3,000	3,000	4,500
	Transmission Impact Study	150	150	86	64	150	86	64	150	150	150	150
	Legal Fees	3	3	2	1	3	2	1	3	3	3	3
Cash Outlay	4 Yr. Allocation	25,153	30,653	17,587	13,066	56,153	32,218	23,935	10,403	19,653	15,528	22,091

Year	2006	-6,288	-7,663	-4,397	-3,266	-14,038	-8,055	-5,984	-2,601	-4,913	-3,882	-5,523
	2007	-6,288	-7,663	-4,397	-3,266	-14,038	-8,055	-5,984	-2,601	-4,913	-3,882	-5,523
	2008	-6,288	-7,663	-4,397	-3,266	-14,038	-8,055	-5,984	-2,601	-4,913	-3,882	-5,523
	2009	-6,288	-7,663	-4,397	-3,266	-14,038	-8,055	-5,984	-2,601	-4,913	-3,882	-5,523
Opera-tional	2010	2,047	4,802	2,755	2,047	4,802	2,755	2,047	2,047	2,047	2,047	2,047
	2011	2,052	4,808	2,755	2,052	4,808	2,755	2,052	2,052	2,052	2,052	2,052
	2012	2,058	4,813	2,755	2,058	4,813	2,755	2,058	2,058	2,058	2,058	2,058
	2013	2,064	4,819	2,755	2,064	4,819	2,755	2,064	2,064	2,064	2,064	2,064
	Truncated years											
	2036	2,233	4,988	2,755	2,233	4,988	2,755	2,233	2,233	2,233	2,233	2,233
	2037	2,242	4,997	2,755	2,242	4,997	2,755	2,242	2,242	2,242	2,242	2,242
	2038	2,251	5,006	2,755	2,251	5,006	2,755	2,251	2,251	2,251	2,251	2,251
	2039	2,260	5,016	2,755	2,260	5,016	2,755	2,260	2,260	2,260	2,260	2,260
Cost of Capital	**7.00%**											
NPV		**(1,322)**	**20,104**	**11,190**	**8,913**	**(1,490)**	**(1,199)**	**(291)**	**11,168**	**3,335**	**6,828**	**1,271**
IRR		**6.46%**	**12.73%**	**12.63%**	**12.87%**	**6.73%**	**6.61%**	**6.88%**	**15.69 %**	**8.63%**	**10.97 %**	**7.57%**
MIRR	**7.00% Reinvestment**	**6.79%**	**8.88%**	**8.83%**	**8.93%**	**6.90%**	**6.85%**	**6.95%**	**9.69%**	**7.59%**	**8.36%**	**7.21%**
PBP (Yrs)		**12.09**	**6.36**	**11.38**	**11.34**	**11.62**	**11.69**	**11.52**	**5.05**	**9.49**	**7.52**	**10.64**

Figure 46. Comparative Cash Flow Analysis[141]

[141] For a complete analysis of the derivation of each Option's Net Cash Outlay and all resultant Cash Flow years, see Appendix 8 on page 155.

Author's Recommendation

The author's recommendation is based primarily on financial results. But ease of right of way acquisition, the construction time interval, and Nebraska Power Reserve Board approval conditions also are considered. Later consideration should include System Impact Analysis results. Together, all of these results, coupled with the initial financial screenings, ought to be the ultimate criteria for the selection process.

Option 1 and Option 2b both have negative Net Present Values (NPV). Option 1 and Option 2b have Internal Rates of Return (IRR) less then the OPPD's hurdle rate (i.e., cost of capital) of 7.00%, (i.e., 6.46% and 6.73% combined respectively). Both options were hampered by distance, their primary variable cost component. These options are eliminated.

	Option 2a (Combo)	**Option 2a (Lincoln)**	**Option 2a (Omaha)**	**Option 3a**	**Option 3b**	**Option 4a**	**Option 4b**
Net Cash Outlay	30,653	17,587	13,066	10,403	19,653	15,528	22,091
	161 kV	161 kV	161 kV	161 kV	345 kV	161 kV	230 kV
	70th and Bluff	70th and Bluff	70th and Bluff	Raun	Raun	FC	FC
	to GI	to GI	to GI	to	to	to	to
	(Combo)	(LES)	(OPPD)	SC	SC	Den	Den
NPV	**$20,104**	**$11,190**	**$8,913**	**$11,168**	**$3,335**	**$6,828**	**$1,271**
IRR	**12.73%**	**12.63%**	**12.87%**	**15.69%**	**8.63%**	**10.97%**	**7.57%**
MIRR	**8.88%**	**8.83%**	**8.93%**	**9.69%**	**7.59%**	**8.36%**	**7.21%**
Pay Back Period (Yrs)	**6.36**	**11.38**	**11.34**	**5.05**	**9.49**	**7.52**	**10.64**

Figure 47. Five Remaining Options

OPPD currently does not employ any 230 kV transmission. Adding 230 kV transmission would require OPPD to amass segregated 230 kV transmission along with substation backup and redundant inventories of equipment and supplies. If the Option 4b Modified Internal Rate of Return (MIRR)[142] was significantly above the hurdle rate of 7.00%, then Option 4b would be given further consideration. However, with Option 4b's apparently relatively small financial benefit and looming segregated inventory supply issues, the author recommends prompt elimination of Option 4b.

Each of the following options exceed OPPD's hurdle rate (i.e., 7.00%). Options listed from the highest NPV, IRR and MIRR (i.e., most profitable) to the lowest NPV, IRR, and MIRR (i.e., least profitable):

- Option 3a: 161 kV Raun to Sioux City
- Option 2a: Joint ownership 161 kV line with LES from 70th and Bluff to Grand Island
- Option 4a: 161 kV Fort Calhoun to Denison
- Option 3b: 345 kV Raun to Sioux City

[142] Modified Internal Rate of Return (MIRR) is similar to Internal Rate of Return (IRR) with the exception that the cash flows are reinvested at a selected reinvestment rate of 7.00%. IRR reinvests at the returned IRR rate. MIRR is more conservative then IRR if the MIRR reinvestment rate is lower then the IRR rate.

	1st	2nd	3rd	4th
	Option 3a	**Option 2a (Omaha)**	**Option 4a**	**Option 3b**
Net Cash Outlay	**10,403**	**13,066**	**15,528**	**19,653**
	161 kV	161 kV	161 kV	345 kV
	Raun	70th and Bluff	FC	Raun
	to	to	to	to
	SC	Lin	Den	SC
NPV	**$11,168**	**$8,913**	**$6,828**	**$3,335**
IRR	**15.69%**	**12.87%**	**10.97%**	**8.63%**
MIRR	**9.69%**	**8.93%**	**8.36%**	**7.59%**
Pay Back Period (Yrs)	**5.05**	**11.34**	**7.52**	**9.49**

Figure 48. Four Remaining Options

The remaining four options merit System Impact Analysis consideration. The System Impact Analysis results would greatly influence the author's recommendation of the four remaining options. For the sake of continued objective analysis, the author will presume the System Impact Analysis results in neutral impacts for all remaining four options, because System Impact Analysis is beyond the scope of this thesis.

Option 2a is the only remaining alternative involving joint ownership between OPPD and LES. The author is suspect of approval of this option by the Nebraska Power Review Board, due to the fact that the economic benefit to LES will be due to the economic detriment to NPPD and due to duplicity of transmission assets along the Lincoln-Grand Island corridor.[143] However, if the System Impact Study results determine significant congestion relief and if the Power Review Board deems the

[143] *State of Nebraska Power Review Board, Revised Rules of Practice and Procedures*, Appendix B, Section 11, as seen in Appendix 5 on page 145.

combined benefit of an LES direct interconnect with WAPA and an OPPD direct interconnect with WAPA (under a single construction endeavor) exceeds the economic detriment to NPPD, then Option 2a would prevail as a superior alternative.

Options 3b and 4a both involve transmission construction in Iowa (Franchise agreements) and near similar MIRRs, 7.59% to 8.36% respectively. Option 3b (345 kV Raun to Sioux City) is the only remaining 345 kV alternative. The Impact Analysis results should render considerable insight to the superior choice between Option 4a and Option 3b. All options assume a four year construction period; however, Option 3b (Raun to Sioux City) traversing about 20 miles versus Option 4a (Ft. Calhoun to Denison) traversing 45 miles may result in a shorter construction period. Both Option 4a and Option 3b should remain as viable alternatives until System Impact Analysis is concluded.

Option 3a, 161 kV from Raun to Sioux City, with the largest NPV ($11.168 M), largest IRR (15.69%), and largest MIRR (9.69%), coupled with an approximate 20 mile traverse, surfaces as the author's premiere recommendation, assuming relatively neutral System Impact Analysis results. Option 3a also has the least net cash outlay of $10.43 M which may be a significant benefit to the District considering the District's debt to equity ratio increasing from 40% in 2004 and reaching a forecasted 50% in 2008 (see page 82), and the District' policy to maintain a debt service coverage of 1.4 or greater (see page 80). Option 3a has a relatively short distance (i.e., 20 miles) that might result in a construction period of less then 4 years, benefiting cash flow analysis.

Removing bilateral transactions from Option 3a (i.e., considering a decrease in OPPD's wholesale power availability and/or an end to the existing drought conditions thus reestablishing WAPA's generation capacity), and therefore considering WAPA allocation transmission savings as the only benefit in the cash flow analysis, rendered an IRR of 13.44%, NPV of $7.71 M, 9.06% and a Payback Period of 5.96 years.

These results strengthen this author's recommendation of Option 3a, building a 161 kV substation on the Nebraska side of the Missouri River in Northeast Nebraska, near the existing MEC Raun substation thus retaining the existing interconnect with MEC while simultaneously construct a 161 kV transmission line to WAPA's substation in Sioux City, IA.

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APPENDIX 1: Acronyms Defined

AN	Aquila Networks
ATC	Available Transfer Capability
AECI	Associated Electric Cooperative Incorporated
CA	Control Area
CAPM	Capital Asset Pricing Model
DRS	Design Review Subcommittee
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Committee
F7	Firm NERC level 7 Transmission
GWh	Gigawatt hour
HVAC	Heating, Ventilation, Air Conditioning
IA	Iowa
IOU	Investor Owned Utility
IRR	Internal Rate of Return
Kd	Cost of debt capital
Ke	Cost of equity capital
KS	Kansas
KCPL	Kansas City Power and Light
kV	Kilovolt or 1000 volts
LES	Lincoln Electric Service
MAPP	Mid-Continent Area Power Pool

MEC	MidAmerican Energy Company
MINT	Missouri, Iowa, Nebraska Transmission
MIRR	Modified Internal Rate of Return
MNM	Minnesota
MO	Missouri
MPS	Missouri Public Service
MRO	Midwest Reliability Organization
MWh	Megawatt hour
ND	North Dakota
NEN	Nebraska
NPPD	Nebraska Public Power District
NPV	Net Present Value
NS1	NERC Level 1, Secondary Point-to-Point Non-Firm Service
O&M	Operations and Maintenance expenses
OASIS	Open Access Same-Time Information System
OPPD	Omaha Public Power District
OPPD.MEC	The nomenclature used in Tariff administration language to depict a border point between two interconnecting control areas, OPPD and MEC. XXXX.YYY would be the point between arbitrary control areas XXXX and YYY.
POD	Point of Delivery
POR	Point of Receipt
ROE	Return on Equity
ROW	Right of way

RTC	Regional Transmission Committee
SD	South Dakota
SERC	Southeastern Electrical Reliability Council
SPP	Southwest Power Pool
TLR	Transmission Line Loading Relief
TP	Transmission Provider
TWh	Terrawatt hour
WACC	Weighted Average Cost of Capital
WAPA	Western Area Power Administration
WAUE	Western Administration Upper-Great-Plains Energy
Wd	Weight of debt in capital structure
We	Weight of equity in capital structure
WR	Westar Energy

APPENDIX 2: Definitions

Arithmetic Mean - Sum of observations divided by the number of observations.

Available Transfer Capability - (ATC) a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.

Control Area - An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

1. match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s).
2. maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
3. maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and
4. provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Commercial Customer - Non-residential services not qualifying as Industrial Service

Deficit - A Control Area scenario in which Native Load exceeds Control Area generation.

Demand - Native Load.

Gigawatt hour - 1000 Megawatt hours

Industrial Customer - as Non-residential services having metered demand of 1,000 KW or more per 15 minute period in 6 of the past 12 months

Kilovolt - 1000 volts

Load - any device to which power is delivered.

Native Load – The instantaneous summation of a CA's load

Native Load Customer - wholesale and retail customers on whose behalf the Transmission Provider, by statute, franchise, regulatory requirements, or contract, has undertaken an obligation to construct and operate the Transmission Provider's system to meet the reliable electric needs of such customers

Network Integration Transmission Service – a service provided by a Transmission Provider to integrate, plan, economically dispatch and regulate its resources (Transmission System) to serve its Native Load Customers

Point of Delivery - the Point on the Transmission System where capacity and energy transmitted by the Transmission Providers will be made available to the Receiving Party.

Point of Receipt – a Point of interconnection on the Transmission System where capacity and energy will be made available to the Transmission Providers by the Delivering Party

Residential Customer – a single-family home, trailer apartment, flat, or unit of a multi-family dwelling that is individually metered and equipped with cooking facilities.

Retail Customer – Power customers are classified into one of two primary groups, Retail and Off-System customers. Retail customers consist of four groups: Residential, Industrial, Commercial, and Street and Highway Lighting.

Service Type – the NERC defined levels of transmission service reliability: Level 1 is Secondary Point-to-Point Non-Firm Service; Level 2 is Hourly Non-Firm; Level 3 is Reserve Non-Firm Daily, Level 4 is Reserve Non-Firm Weekly, Level 5 is Reserve Non-Firm Monthly, level 6 is Network Non-Firm Service, and Level 7 is Firm Service, either daily, weekly, or monthly.

Shortage - A Control Area scenario in which Native Load exceeds Control Area generation.

Sink - Control Area of the Point of Delivery (POD)

Source – Control Area of the Point of Receipt (POR)

Street and Highway Lighting Customers - street lights and traffic signal demand from government entities including states, cities, schools, counties, and SIDs.

Surplus - A Control Area scenario in which Control Area generation exceeds Native Load demand.

Terawatt hours – 1000 Gigawatt hours

Transmission Line Loading Relief – (TLR) the procedure whereby MAPP Schedule F service is curtailed using NERC Transmission Loading Relief Procedures.

Transmission Provider - the public utility (or its designated agent) that owns or controls facilities used for the transmission of electric energy in interstate commerce.

Wheeling - the contracted use of electrical facilities of one or more entities to transmit electricity for another entity

Wholesale Power - the excess power available after Retail customer demand has been met.

Wholesale Towns - Four municipalities of Greenwood, Elk City, Syracuse and Tecumseh, Nebraska which OPPD serves. These municipalities then serve their customers as retail service.

Wheeling - the contracted use of electrical facilities of one or more entities to transmit electricity for another entity.

APPENDIX 3: List of Figures

APPENDIX 4: State of Iowa Franchise Process

INFORMATIONAL MEETING PRESENTATION

Electric Transmission Lines

Iowa Code Chapter 478 is the law governing the construction of electric transmission lines in Iowa. In accordance with Iowa Code section 478.2, the following is a summary of electric line franchise process before the Utilities Board, and of the legal rights of affected landowners. The current version of the Iowa Code is the 2003 edition. If you wish to review the laws or rules referenced during this presentation, they can be found at http://www.legis.state.ia.us/IowaLaw.html . The Board's administrative rules may be found under "Iowa Administrative Code"-"Utilities Division [199]"-"Chapter 11."

In addition, information on the proposed electric transmission line is available on the Board's web site at http://www.state.ia.us/government/com/util.

THE FRANCHISE PROCESS

1. Iowa Code Chapter 478 is the law, which governs the construction of electric lines in Iowa. Any electric line which operates at 69,000 volts or more, and which is located outside the boundaries of a city, requires a franchise from the Utilities Board. In this context a "franchise" is a permit authorizing the construction, operation, and maintenance of the line. Lines operating at 69,000 volts or more are defined as electric transmission lines. A company seeking a franchise can also request that the Utilities Board grants the right of eminent domain, or condemnation, to obtain the right of way needed for the project.

2. If an electric transmission line would extend for one mile or more on privately owned real estate, Iowa Code section 478.2 requires that before a franchise can be requested from the Utilities Board, an informational meeting must be held. The company proposing the electric line is required to notify all parties with an ownership interest in possibly affected property of the meeting.

3. At informational meetings, a representative of the Utilities Board presents a summary of the legal rights of affected landowners, and a representative of the company explains the proposed project. The company cannot begin right of way negotiations with landowners until after this meeting, and cannot petition the Utilities Board for a franchise until at least 30 days after this meeting.

4. This informational meeting is not a hearing upon which the Utilities Board will base a decision. At this time, there is no franchise petition before the Utilities Board. The purpose of this meeting is to provide you with information relative to a proposed project,

not to receive evidence on its merits. No formal record of this meeting is made. Anyone wishing to present evidence to the Utilities Board in favor of or opposing this project does not do so at this meeting.

5. After a petition is filed, there are two procedural paths toward a Utilities Board decision. If no objections are on file and the petition does not request eminent domain, a notice is published for two consecutive weeks in a newspaper located in the county. If no objections are filed within 20 days of the second publication, a franchise may be granted without a hearing.

If objections are filed, however, a hearing will be held. If objections are on file, or if eminent domain is requested, a hearing must be held. Notice of the hearing will be published, and objectors and/or owners of eminent domain parcels will receive notice by mail.

6. When the electric line for which the hearing is being held is more than one mile long, Iowa Code section 478.6 requires the hearing be held in the county seat of the county located at the midpoint of the proposed line.

7. In its proceedings, the Utilities Board is not the advocate or protector of any particular landowner, landowners, or any other party. The duty of the Utilities Board is to determine whether a proposed electric line is necessary to serve a public use, represents a reasonable relationship to an overall plan of transmitting electricity in the public interest, and meets all other legal requirements. The Utilities Board cannot serve as a legal advisor to any party. If you believe you have need for a personal advocate, i.e., lawyers, you may retain them at your expense.

8. Utilities Board proceedings are conducted pursuant to Iowa Code Chapters 478 and 17A, and 199 Iowa Administrative Code Chapter 11. The decision whether to grant a franchise and/or the right of eminent domain will be made by the Utilities Board. The Utilities Board may appoint an administrative law judge to preside over the hearing and issue a proposed decision. This proposed decision will become the final decision of the Utilities Board unless it is appealed to the Board by a party to the case within the time limit provided in the proposed decision.
9. When the Utilities Board has decided the case, either initially or on appeal from a proposed decision, any party to the proceeding may file for rehearing within 20 days under Iowa Code Sections 17A.16 and 478.32. Once a final decision has been made, any party may appeal to the District Court within 30 days under Iowa Code sections 17A.19 and 478.32.

OBJECTIONS

1. Under Iowa Code Section 478.5, you have the right to file written objections to the proposed project with the Utilities Board setting forth the nature of your objections.

2. Written objections may be filed at any time but not later than 20 days after the date of last publication of the notice. The Utilities Board may, but is not required to, allow late filed objections, in which case the company must be given reasonable time to respond. Verbal objections, other than statements made on the record during a hearing, will not be part of the official case record.

3. A suggested form of objection is available. By providing this form the Utilities Board is not promoting the filing of objections, and use of this form is not required to file an objection. The form is provided to show the type of information an objection should include. See Attached Objection Form.

4. You have the right to appear before the Utilities Board at any and all hearings, with or without the aid of legal counsel.

5. At formal hearings, objectors will be given reasonable opportunity to cross-examine company witnesses, and to present witnesses on their own behalf. The burden is on the company to prove the necessary elements of its petition.

6. Utilities Board proceedings are quasi-judicial in nature. Hearings are comparable to courtroom proceedings, and follow similar rules of testimony, cross-examination, and presentation of evidence. The person presiding over the hearing will assist participants unfamiliar with such proceedings, but cannot assist any party with presentation of their case.

7. Anyone who files an objection will be presumed to be a party. However, no objector is entitled to party status merely because that person has filed an objection. To qualify as a party, the objector must be able to demonstrate some right or interest that may be affected by the granting of the franchise. An objector's status may be challenged at the hearing.

RIGHT OF WAY

1. To locate an electric line on private property, the company must obtain the necessary rights from the landowner or owners. The legal document providing such rights is called an easement. An easement may be voluntary, or it may be obtained through the use of eminent domain.

2. Generally speaking, an easement is an acquired privilege of the company for the use of a property. The landowner retains ownership, but use of the easement area is restricted by conditions set forth in the easement or by law. The rights sought by the company will be similar whether obtained by voluntary easement or by eminent domain.

3. The Utilities Board does not supervise or control negotiations for the purchase or acquisition of voluntary right of way easements. Once this informational meeting is

completed, negotiations are strictly between you and the company either with or without your use of private counsel.

4. Landowners should read carefully the form of easement provided by the company and be thoroughly aware of the rights the company seeks. The landowner has the right to negotiate with the company over the terms of the easement.

5. If you decide to sign a voluntary easement, you have for a limited time the right under Iowa Code section 478.33 to cancel the agreement. Cancellation must be by certified mail with return receipt requested, mailed to the company's principal place of business. The cancellation must be received by the company within seven days, excluding Saturday and Sunday, of the date the agreement was signed. The company must inform you in writing of your right to cancel, and provide you with a form in duplicate for the notice of cancellation. The right of cancellation may be exercised only once.

6. Iowa Code section 478.15 contains provisions for the reversion of easements which the company obtained but does not use or ceases to use. This applies to easements acquired either voluntarily or by eminent domain.

7. Iowa Code section 478.17 gives the company the right of reasonable access to its lines for purposes of construction, reconstruction, repairs, and maintenance. The company must pay the owner of the land and crops for all damages resulting from such entry and action. The law allows execution of agreements to cover such situations between the owner of the land or crops and the company. Damage settlements are different than, and separate from payment for the easement, although an easement may include provisions dealing with damages.

EMINENT DOMAIN (CONDEMNATION)

1. If the company cannot obtain the rights it seeks by voluntary easement, it may petition the Utilities Board for authority to take those rights by eminent domain, or condemnation.

2. Under federal and state law, private property cannot be taken for public use without:
   a) A need to serve a public use, and
   b) Just compensation.

Under Iowa Code Chapter 478, the Utilities Board determines whether the company has shown a need to serve a public use. The matter of just compensation for property rights taken by eminent domain is not determined by the Utilities Board, but rather it is determined by a "Compensation Commission" appointed from your county under Iowa Code Chapter 6B.

3. At this time, the company does not have the right of eminent domain. In other words, it does not have the right of condemnation. The right of eminent domain may only be granted by the Utilities Board after a public hearing on the eminent domain request.

4. You will receive written notice of the public hearing if the right of eminent domain is requested to acquire rights to locate an electric transmission line on your property.

5. Iowa Code section 478.2 requires that at informational meetings the Utilities Board representative shall distribute and review a Statement of Property Owner's Rights prepared by the Iowa Attorney General. These have been adopted as Administrative Rules in 61 IAC Chapter 34. In these rules, an "acquiring agency" is not limited to government agencies; it can include private entities that by law have the right of eminent domain. The rules primarily address acquisition of property ownership, but some provisions apply to condemnation of easements. If you will please turn to the attached copy of those rules, we will review them.

Attached to this presentation is a summary of events entitled Attachment I. This will not be read, but is provided to give you an overview of the process in the sequence that may occur. Rev. 03/03

Attachment I

NOTE: A typical sequence of events, as it may affect the landowner, is set forth below. You should not attach any rigid significance to the sequence. It is merely an example to aid you in understanding the process.

1. Company planning determines need for the line between termini.
2. Prime route, and possibly alternative routes, are tentatively selected.
3. Route landowners and tenant names and addresses collected.
4. Informational meeting notices mailed.
5. Informational meeting is held.
6. Company right of way personnel contact landowners to solicit voluntary easements.
7. The company files petition for franchise with the Utilities Board. Eminent domain may be requested at this same time or later.
8. Newspaper publishes notices of petition.
9. Public hearing is held by the Utilities Board.
10. A Utilities Board decision denying or granting franchise is issued. If the petition requested eminent domain, a ruling granting or denying that right will also be issued.
11. If the petition and/or eminent domain is denied, the company may petition for rehearing, or appeal the Utilities Board denial to the courts. If the petition is granted, the landowner may petition for rehearing or appeal the Utilities Board decision to the courts. To simplify the balance of this list; it is assumed that the Utilities Board granted the franchise and the right of eminent domain and the decision was not appealed.
12. The company may commence construction where it has voluntary easement.
13. If eminent domain actions are taken, the company petitions the chief judge of the judicial district for the county involved to appoint a Compensation Commission. (Iowa Code Chapter 6B).
14. The Compensation Commission sets compensation amounts, the company pays landowners who will accept; posts payment with the sheriff for those who won't, and may commence construction over the balance of the route.
15. Either the landowners or the company may appeal the amount determined by the Compensation Commission to the courts.
16. Line construction and clean up completed.
17. Company pays voluntary easement amounts, agreed-to construction damages to eminent domain parcel owners, and gives written notice of renegotiation right. <u>See</u> Iowa Code Section 6B.52
18. If the landowner or tenant and company cannot agree on the amount of construction damages, and there is no provision in the easement or other agreement calling for such disputes to be settled by an arbitrator or other means, the landowner or tenant may petition the county board of supervisors to establish a Compensation Commission to determine the damages.
19. Either the landowners or the company may appeal the amount determined by the Compensation Commission to the courts.

Rev. 03/03

MAIL TO: EXECUTIVE SECRETARY
IOWA UTILITIES BOARD
350 Maple Street
Des Moines, IA 50319-0069

Suggested form for written objections to the granting of an electric transmission line franchise.

The use of this form is not required.

A.
(Name of company or utility)

B.
(Date and Location, if known, of Informational Meeting, and/or)
(Docket Number, if known, of the proceeding)

C.
(Statement of the nature of the objection(s))
(Use additional sheets, if necessary)

D.
(A description of the remedy or relief that you seek. If you are proposing an alternate route, please attach map.)

E.
(Name -- typed or printed) (Signature)
(Mailing address) (Date)
(City & Zip Code) (Phone)

F.
(Description of affected property, including Section, Township, Range and County)

G.
(Statement of your property interest: such as owner, contract purchaser, mortgagor, lessee-tenant, holder of mineral rights, etc.)

H. Are you the party in possession?
(yes or no)

If you have property interest in several properties affected by the proposed line you may wish to attach additional
sheets.

CHAPTER 35

ACQUISITION NEGOTIATION STATEMENT OF RIGHTS

61—34.1(78GA,HF476) Statement of property owner's rights. 1999 Iowa Acts, House File 476, section 3, mandates that an acquiring agency provide a statement of rights to owners of record who may have all or a part of their property acquired by condemnation. It also directs the attorney general to adopt rules prescribing a statement of rights which an acquiring agency may use to meet its obligation. Pursuant to that directive, the following statement of property owner's rights is adopted:

STATEMENT OF PROPERTY OWNER'S RIGHTS

Just as the law grants certain entities the right to acquire private property, you as the owner of the property have certain rights. You have the right to:

1. Receive just compensation for the taking of property. (Iowa Constitution, Article I, section 18)
2. An offer to purchase which may not be less than the lowest appraisal of the fair market value of the property. (Iowa Code section 6B.45 as amended by 1999 Iowa Acts, House File 476, section 18; Iowa Code section 6B.54 as amended by 1999 Iowa Acts, House File 476, section 20)
3. Receive a copy of the appraisal, if an appraisal is required, upon which the acquiring agency's determination of just compensation is based not less than ten days before being contacted by the acquiring agency's acquisition agent. (Iowa Code section 6B.45 as amended by 1999 Iowa Acts, House File 476, section 18)
4. An opportunity to accompany at least one appraiser of the acquiring agency who appraises your property when an appraisal is required. (Iowa Code section 6B.54)
5. Participate in good-faith negotiations with the acquiring agency before the acquiring agency begins condemnation proceedings. (1999 Iowa Acts, House File 476, section 3)
6. A determination of just compensation by an impartial compensation commission and the right to appeal its award to the district court if you cannot agree on a purchase price with the acquiring agency. (Iowa Code section 6B.4; Iowa Code section 6B.7 as amended by 1999 Iowa Acts, House File 476, section 8; Iowa Code section 6B.18)
7. A review by the compensation commission of the necessity for the condemnation if your property is agricultural land being condemned for industry. (1999 Iowa Acts, House File 476, section 7)
8. Payment of the agreed upon purchase price or, if condemned, a deposit of the compensation commission award before you are required to surrender possession of the property. (Iowa Code section 6B.25; Iowa Code section 6B.26; Iowa Code section 6B.54(11))
9. Reimbursement for expenses incidental to transferring title to the acquiring agency. (Iowa Code section 6B.33 as amended by 1999 Iowa Acts, House File 476, section 15; Iowa Code section 6B.54(10))
10. Reimbursement of certain litigation expenses: (a) if the award of the compensation commissioners exceeds 110 percent of the acquiring agency's final offer before condemnation; and (b) if the award on appeal in court is more than the compensation commissioners' award. (Iowa Code section 6B.33)
11. At least 90 days' written notice to vacate occupied property. (Iowa Code section 6B.54(4))
12. Relocation services and payments, if you are eligible to receive them, and the right to appeal your eligibility for and amount of the payments. (Iowa Code section 316.9; Iowa Code section 6B.42 as amended by 1999 Iowa Acts, House File 476, section 17)

The rights set out in this statement are not claimed to be a full and complete list or explanation of an owner's rights under the law. They are derived from Iowa Code chapters 6A, 6B and 316. For a more thorough presentation of an owner's rights, you should refer directly to the Iowa Code or contact an attorney of your choice.

61—34.2(78GA,HF476) Alternate statement of rights. Rule 61—34.1(78GA,HF476) is not intended to prohibit acquiring agencies from providing a statement of rights in a different form, a more detailed statement of rights, or supplementary material expanding upon an owner's rights.

These rules are intended to implement 1999 Iowa Acts, House File 476, section 3.

[Filed 9/17/99, Notice 8/11/99—published 10/6/99, effective 11/10/99]

APPENDIX 5: Nebraska Power Review Board, Revised Rules of Practice and Procedure Manual

STATE OF NEBRASKA

NEBRASKA POWER REVIEW BOARD

REVISED RULES OF PRACTICE
AND PROCEDURE

1989

TABLE OF CONTENTS

TITLE 285 - RULES OF PRACTICE AND PROCEDURE

C H A P T E R I I

RULES AND PROCEDURE
FOR
APPLYING FOR AUTHORIZATION FOR
THE CONSTRUCTION OF ELECTRIC
GENERATION FACILITIES, ELECTRIC
TRANSMISSION LINES (in excess of 700 volts)
AND/OR RELATED FACILITIES, WHEELING,
OR COMPLAINTS

Chapter 2 - RULES AND PROCEDURE FOR APPLYING FOR AUTHORIZATION FOR THE CONSTRUCTION OR ACQUISITION OF ELECTRIC GENERATION FACILITIES, ELECTRIC TRANSMISSION LINES (in excess of 700 volts) AND/OR RELATED FACILITIES, WHEELING, OR COMPLAINTS

001 Approval for construction or acquisition of electric facilities shall be secured in all cases. (Except as noted in Section 70-1012, R.R.S., 1943, as amended.)

002 Except as provided by law, approval to construct or acquire electric transmission lines carrying more than 700 volts or related facilities shall be obtained from the Nebraska Power Review Board prior to construction or acquisition.

003 Any electric supplier may construct or acquire a line not to exceed one-half mile in length without Board approval; PROVIDED THAT, the supplier obtains written consent of all owners of electric lines located within one-half mile of the proposed extension and files said consents with the Board. (Applications shall be filed with the consents.) If the space provided in the application is not sufficient for the information, additional sheets should be attached and referred to in the appropriate space provided.

004 An original and one copy of each application and exhibits, "A" and "B" shall be filed. (All copies other than thermofax copies are acceptable.) All necessary forms are available and will be furnished to any party upon request. Exhibit "A" shall be a map on a scale of not less than one inch equals one mile, and it shall show all other transmission lines or other distribution lines within one mile of the proposed extension or related facilities; provided, however, when the proposed transmission line exceeds twenty five (25) miles in length, a smaller scale map may be used as long as all other facilities of the same magnitude owned by the party making the application or owned by other suppliers are shown. Exhibit "B" shall be a succinct statement as to how the applicant will provide service at its "low overall cost as possible consistent with sound business practices". Exhibit "B" also shall contain (a) the cost of the construction and; (b) a statement indicating if the construction price will be paid in part by any contribution by any customer; and (c) if there is a contribution, the amount of the contribution and whether it is in addition to the cost submitted on the application.

005 (1) No latter than six months after substantial completion of a Power Review Board approved facility the petitioner shall file a completion statement: substantial completion occurs upon commercial operation of the facility. The completion statement shall include (a) the PRB application number; (b) the estimated total cost and estimated date of completion as stated in the application; and (c) the date of substantial completion/commercial

operation and the actual total cost (as estimated on the date of filing the completion statement). If the completion statement reveals a significant divergence between the estimated total cost and the actual total cost, then the completion statement also shall include a full explanation of the significant divergence. Significant divergence shall mean a cost overrun of $150,000 on a facility with an estimated total cost of less than $1,000,000; and shall mean cost overrun of 15% or more on a facility with an estimated total cost of $1,000,000 or more. The Board may hold a informational hearing on the cost overrun. (2) In the event that a supplier terminates construction or acquisition of an electric generation or transmission facility after receiving approval for the facilities from the Nebraska Power Review Board, the supplier shall file with the Board within 30 days of the action taken to terminate construction or acquisition, a statement of the factors or reasons relied upon by the supplier for taking such action. (3) If a transmission or distribution line project is not completed within the approximate time stated in the application, the supplier shall file with the Board a statement informing the Board why such project has not been completed in the time stated in the application.

Appendix B: Application for authority to construct or acquire an electric transmission line(s) and/or related facilities.

11-89

NEBRASKA POWER REVIEW BOARD

IN THE MATTER OF THE APPLICATION OF)	Application for authority to construct or acquire an electric transmission lines(s) and/or related facilities.
____________________________________)	
____________________________________)	
____________________________________)	Application No. PRB-______
____________________________________)	Application File No.______

applies to the Nebraska Power Review Board for an order authorizing it to construct or acquire an electric transmission line(s) and/or related facilities in __________ County, Nebraska, as set forth below.

(1) Description of proposed electric transmission line(s):

	Miles	Voltage	Phase
________	________	________	________
________	________	________	________

(2) Engineering Specification:

Applicant MAY attach to this application, as an exhibit, the following information if known:

A. Type of System (Delta, Wye connected)
B. Poles (Type, number per mile)
C. Conductors (Size and Type)
D. Insulators (Size and Type)
E. Type of Construction (H-Frame, etc.)

(3) Purpose of Construction and Description of related facilities:

____

____

____

(4) Name, address, and type of customers to be served:

____

____

____

(5) Attached and designated Exhibit "A" (if more than one exhibit,

number the first "A-1", the second "A-2", etc.) are maps and other related exhibits showing location of proposed transmission line and related facilities, and any other information deemed necessary or useful in the consideration of this application.

(6) Construction or acquisition of the proposed electric transmission facilities, electric transmission line, and/or related facilities is currently estimated to start on or about ______________________________, and to be completed on or about __________________________________.

(7) The estimated cost of construction is _______________________. Is there any financial contribution by the customer: Yes_____ No_____. If there is a financial contribution by the customer, how much was the contribution _______________________________________ and is this contribution included in the estimated construction cost? Yes_____ No_____.

(8) The owners of electric generation facilities, electric transmission lines, and/or related facilities, and any other persons or organizations known to the applicant whom the applicant believes to be interested in the application are:

____

____

(9) Waivers and consents from the following are attached:

____

____

(10) Safety Standards. The design of the transmission line(s) as set out in the foregoing conforms with the standards set forth in the most recent edition of the National Electrical Safety Code.

(11) The proposed electric transmission line, and/or related facilities will serve the public convenience and necessity, and the applicant can most economically and feasibly supply the electric service resulting from the proposed construction or acquisition without unnecessary duplication of facilities or operations.

Dated __________________,19___.

____
By__________________________________
Title_______________________________
Address_____________________________
____

Appendix H: Completion Statement

11-89

NEBRASKA POWER REVIEW BOARD

Pursuant to Nebraska Rev. Statutes, Section 70-1003 (4) (e) this statement is filed to certify completion and cost information of the project(s) set forth below.

PRB-#	Your Application #	Estimated Date of Completion	Date Completed	Estimated Application Cost	Actual Cost

If, it appears that there is significant divergence between the estimated cost in the application and the actual completion costs, the Nebraska Power Review Board will contact the electrical supplier for additional information. The Board may hold an informational hearing concerning any significant divergence.

Significant divergence shall mean a cost overrun of $150,000 on a facility with an estimated total cost of less than $1,000,000; and shall mean a cost overrun of 15% or more on a facility with an estimated total cost of $1,000,000 or more.

____

By______________________________

Title______________________________

Address______________________________

____

Appendix I: Termination Statement

11-89

NEBRASKA POWER REVIEW BOARD

If you terminate construction or acquisition of electric generation or transmission facilities after receiving approval from the Nebraska Power Review Board, you are required to notify the Nebraska Power Review Board within 30 days of the action to terminate and also the factors or reasons relied upon for such action. (Neb. Rev. Stat. Section 70-1012.01.)

PRB-#	Your Application #	Completion Date	Date of Termination
______	____________________	________________	___________________
______	____________________	________________	___________________
______	____________________	________________	___________________
______	____________________	________________	___________________
______	____________________	________________	___________________

Reason for Termination (if necessary, please use additional paper)

____

____

____

____

____

____

____

____

____

APPENDIX 6: The Eight Step WAPA Interconnection Process

The interconnection process

There are eight steps in the interconnection process. Western may modify this process based on specific circumstances of the requested interconnection.

Step 1: Contact Western and submit application

Before submitting an application, discuss the proposed project with a representative at the Western office that controls the area in which the interconnection will occur. It helps us determine what studies are necessary.

Generally, the requesting entity should register with the appropriate reliability council before requesting interconnection with Western. After initial contact, Western will provide interconnection related information, including Western's General Requirements for Interconnection , the Application for Interconnection, the Tariff if applicable, Western's applicable General Power Contract Provisions and other supporting safety, environmental and operations information.

Requesters should submit formal requests for interconnection at least 18 months before equipment or construction specifications are to be issued for bid. This lead time allows Western to develop a proposed plan, designs and specifications for Western-owned, -operated and -maintained facilities, and to review line taps owned by others.

Western may take up to 30 days to process the interconnections request.

If Western denies the request for interconnection, we will provide a summary of reasons and make every reasonable effort to help the requesting entity revise the request.

Submit Application

Provide as much of the following information as possible to help expedite the design or review process. This information is also listed in summary form on the Application for Interconnection (form to be added).

A. Single-line diagram(s) showing the proposed interconnection, including any relaying and metering facilities.

B. Drawing(s) indicating the physical arrangements of existing and proposed facilities.
C. Geographic location of the proposed interconnection, including land ownership pattern, if available. If a tap, indicate adjacent structure numbers.
D. Description of the proposed routing, approximate lengths and conductor size of transmission line additions or modifications, and dimensions and configurations of new structures.
E. Description and ratings of any proposed breakers, switches, metering, associated communications, relaying and other related equipment.
F. Description of transformer voltage and rating, winding connections, impedance if available, and proposed method of protection.
G. Proposed construction schedule.
H. Description of the generating resources or loads to be served by the interconnection and the proposed transmission path(s) and service arrangements between resources and associated loads, where applicable. The description should include:
    1. Power output or load requirements, including 10-year projections, by delivery points, of winter and summer peaks for loads served or generation supplied through the point of interconnection;
    2. Size, type and ratings of large equipment;
    3. Reliability and special operation requirements; and
    4. Impedance, frequency, voltage, reactive power and protective relaying characteristics of the interconnecting resource or load.

I. Appropriate revenue and telemetering equipment specifications. The data should include load control boundary metering, current and potential transformer ratios and register and contact initiator ratios with multipliers.

J. Copies of relevant planning or operational studies.
K. Copies of relevant environmental impact assessments, reports, or projections; or description of anticipated scope of environmental review

Step 2: System impact study

Western will conduct a system impact study that assesses the capability of the transmission system to support the requested interconnection. The study will use the criteria and process detailed in Sections 4 and 5 of Western's Federal Energy Regulatory Commission Form 715 (available upon request) when the request occurs in the WSCC area, and use the MAPP system impact study methodology (available upon request) when the request occurs in the MAPP area.

Within 30 days of receiving the application for interconnection, Western will provide a System Impact Study Agreement in which the requesting entity agrees to advance funds for Western to perform the study. The requesting entity must sign and return the agreement to Western within 15 days or the request is deemed withdrawn.

Western will make every effort to complete the system impact study within 60 days. The study will identify system constraints and redispatch options and any necessary additional direct assignment facilities and network upgrades.

Once the system impact study is complete, Western will provide the requesting entity with a report.

Within 30 days after receiving the results of the system impact study, an entity requesting both interconnection and transmission service may request to enter into an Expedited Service Agreement. This agreement specifies advance compensation requirements. The Expedited Service Agreement provides one contractual agreement for the full interconnection process, from facilities study to operation and maintenance, including transmission service.

Western will provide the requesting entity its best estimate of new facility costs and other charges, but the estimate is not binding. For further information, refer to Section 19.8 of the Tariff, or contact the appropriate Western office.

Step 3: Facilities study and design

The facilities study determines upgrades or modifications needed at the point of interconnection. Within 30 days after Western completes the system impact study, we will provide a Facilities Study Agreement in which the requesting entity agrees to advance funds for Western to perform the study. The requesting entity must sign and return the agreement to Western within 15 days or the request is deemed withdrawn.

Western will make every effort to complete the facilities study within 60 days. The study includes estimates of the cost of facilities design and construction as well as the time required to complete design and construction. We will provide a facilities study to the requesting entity for review.

Step 4: Environmental review

As a Federal agency, Western conducts an environmental review of any action affecting Western's transmission facilities. The environmental review process can range from a categorical exclusion to a comprehensive environmental impact statement complete with the required public process and is conducted simultaneously with other studies.

Requesting entities must advance funds to Western for the environmental review process. The environmental review process uses input from the studies and construction planning processes and may be concluded before or after completion of these technical studies, when applicable. Continuation of the interconnection process at any and every step is contingent upon favorable environmental review.

If the environmental review shows that the interconnection does not satisfy Federal environmental criteria, Western will either deny the request or work with the requesting entity to revise aspects of the interconnection request to meet environmental criteria. Such revisions may occur at various steps during the process.

Step 5: Land acquisition

After the environmental process, negotiations for any necessary land rights begin. Negotiations should be complete and the land rights obtained before construction begins. Requesting entities must advance funds for Western to conduct the necessary land acquisition activities. Western will, unless otherwise agreed to by Western and the requesting entity, perform all land acquisition activities.

Step 6: Design and construction

Once the facilities study is complete, Western will tender a Construction Agreement to the requesting entity, which has 30 days to sign and return the agreements to Western and provide advance payment. Western cannot continue without funding in place. Western will design the interconnection, unless otherwise agreed to by Western and the requesting entity. Western will also, unless otherwise agreed to by Western and the requesting entity, perform all construction.

Step 7: Review and testing, interconnection agreement, and energize

Once construction has been completed—and before energizing the new interconnection—Western will review and test the new facilities. Before energizing, Western must also receive the appropriate as-built drawings, operating instructions and other relevant materials.

When the facilities are found to be in conformance with Western's criteria, we will issue an Interconnection Agreement to the interconnecting entity. The Interconnection Agreement—also termed mutual services, operations and maintenance, control area, or consolidated agreement in some regions—provides for the long-term operation and maintenance of the interconnected facilities. It generally includes sections on licensing, maintenance, operations, special instructions and funding. When to the benefit of Western and the interconnecting entity, the Interconnection Agreement may be tendered at the same time as the earlier Construction Agreement.

The interconnected facilities may be energized following execution of the Interconnection Agreement. If Western does not maintain direct control of the facilities, then we will maintain backup control of all facilities deemed to be vital to system stability.

Step 8: Project close-out

Western will develop a final report with a list of lessons. We invite the interconnecting entity to join in developing a joint final report that benefits Western and the entity.

Load and Generation Capability (Summer)

Summer Conditions (May 1 to October 31)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1. Seasonal System Demand																
Base Peak (June 04 LF-50/50)	2169	2227	2266	2310	2357	2421	2461	2501	2566	2609	2637	2711	2748	2787	2850	2889
Less Curtailable Load	-92	-101	-107	-111	-111	-117	-121	-121	-128	-132	-132	-132	-132	-132	-132	-132
Total	2077	2126	2159	2199	2247	2303	2340	2381	2438	2477	2505	2579	2616	2655	2718	2757
2. Annual System Demand	2077	2126	2159	2199	2247	2303	2340	2381	2438	2477	2505	2579	2616	2655	2718	2757
3. Firm Purchases - WAPA	82	82	82	82	82	82	82	**81**	81	81	81	81	81	81	81	81
4. Firm Sales																
Wholesale Towns (a)	11	11	11	11	11	11	11	11	11	11	11	12	12	12	12	12
Total	11	11	11	11	11	11	11	11	11	11	11	12	12	12	12	12
5. Seasonal Adj. Net Demand (1-3+4)	2006	2055	2088	2128	2176	2233	2269	2311	2368	2407	2435	2509	2547	2586	2649	2688
6. Adjusted Net Demand (2-3+4)	2006	2055	2088	2128	2176	2233	2269	2311	2368	2407	2435	2509	2547	2586	2649	2688
7. Net Generating Capability																
Fort Calhoun	476	**483**	**489**	**492**	492	492	492	492	492	492	492	492	492	492	492	492
Nebraska City #1	646	646	646	646	646	646	646	**634**	634	634	634	634	634	634	634	634
Nebraska City #2	0	0	0	0	0	**663**	663	663	663	663	663	663	663	663	663	663
North Omaha	663	663	663	663	663	663	663	**651**	651	651	651	651	651	651	651	651
Sarpy County	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314	314
Jones Street	118	118	118	118	118	118	118	118	118	118	118	118	118	118	118	118
Cass County	320	320	320	320	320	320	320	320	320	320	320	320	320	320	320	320
Douglas County Landfill	3	**3**	**6**	6	6	6	6	6	6	6	6	6	6	6	6	6
Tecumseh (leased)	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Future Baseload Capacity	0	0	0	0	0	0	0	0	0	0	0	**300**	300	300	300	300
Total	2547	2554	2563	2566	2566	3229	3229	3205	3205	3205	3205	3505	3505	3505	3505	3505

8. Participation Purchases																
NPPD Wind Energy	0	0	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Total	0	0	2	2	2	2	2	2	2	2	2	2	2	2	2	2
9. Participation Sales																
Wisconsin Public Service (WPS)	5	5	5	0	0	0	0	0	0	0	0	0	0	0	0	0
Nebraska City #2 Participants	0	0	0	0	0	**332**	332	332	332	332	332	332	332	332	332	332
Total	5	5	5	0	0	332	332	332	332	332	332	332	332	332	332	332
10. Accredited Capability (7+8-9)	2542	2549	2560	2568	2568	2899	2899	2875	2875	2875	2875	3175	3175	3175	3175	3175
11. Net Reserve Capacity Obligation (6 X 15%)	301	308	313	319	326	335	340	347	355	361	365	376	382	388	397	403
12. Total Firm Capacity Obligation (5+11)	2307	2363	2401	2448	2502	2568	2610	2658	2723	2768	2801	2886	2929	2974	3046	3091
13. Surplus or Deficit Capacity (10-12)	236	186	158	120	65	331	289	218	152	107	74	289	246	201	129	84
14. Reserve Margin (10/5)	26.7%	24.0%	22.6%	20.6%	18.0%	29.8%	27.8%	24.4%	21.4%	19.4%	18.1%	26.5%	24.7%	22.8%	19.9%	18.1%

Summer Capability Changes:	**NPPD Wind Plant**	**Ft. Calhoun**	**N Omaha & Neb City #1**	**Nebraska City Station**	**Future Baseload**
	10 MW - Oct 2005	3 MW - May 2005 (Condenser)	12 MW Derate Each Station - 2011	663 MW Unit #2 - May 2009	300 MW - 2015
	Elk City Landfill	4 MW - May 2005 (Moisture Separator)	For proposed MPC Legislation	(Sell 331.5 MW Long-Term)	
	3 MW - May 2006	6 MW - Oct 2005 (Appendix K)			
		3 MW - December 2006 (LP Rotor)			

(a) Consists of the projected demands of the Nebraska municipal utilities of Syracuse, Greenwood, Elk Creek, and Tecumseh. All are served at wholesale by the District.

Appendix 8: Cash Flow Detail

Five year average bilateral transmission expenditure for **purchases** from WAPA to OPPD = $26,431.84
Five year average bilateral transmission expenditure for **sales** from OPPD to WAPA: On Peak = 123,774 MW
Five year average bilateral transmission expenditure for **sales** from OPPD to WAPA: Off Peak = 278,251 MW

5) One time 10% additional increase is sales and purchases due to interconnect in 2010.

Option 1: North Omaha to Creston, IA, 161 kV:

Steel Poles ($100,000/mile * 80 miles)	$	8,000,000
Conductors/Wires ($25,000 *80 miles)	$	2,000,000
Labor ($100,000 * 80 miles)	$	8,000,000
Right of Way ($50,000 * 80)	$	4,000,000
Substation terminal work	$	3,000,000
Transmission Impact Study	$	150,000
Legal Fees	$	3,000
Net Cash Outlay	**$**	**25,153,000**

1) Transmission cost from bilateral purchases increasing at 1.863% per year. $26,431.84*1.863% growth rate

2) Five year average MW sales, both on peak and off peak with a growth rate of 1.863%

4) Net Cash Outlay allocated evenly over four years.

MAPP Rates

On-peak	Off-peak
0.79	0.45

3) MW times respective rate

Year	Initial Capital Investment ($)	WAPA Firm Purchase ($)	Bilateral Purchase ($)	Bilateral Sales ($)	Total Cash Flow ($)	Pay Back Period	Bilateral MW Sales On-peak (MW)	Bilateral MW Sales Off-peak (MW)
2005			26,924	222,944			123,774	278,251
2006	(6,288,250)		27,426	227,149	(6,288,250)	(6,288,250)	126,080	283,435
2007	(6,288,250)		27,937	231,380	(6,288,250)	(12,576,500)	128,428	288,715
2008	(6,288,250)		28,457	235,691	(6,288,250)	(18,864,750)	130,821	294,094
2009	(6,288,250)		28,987	240,082	(6,288,250)	(25,153,000)	133,258	299,573
2010		1,745,385	32,480	269,010	2,046,875	(23,106,125)	149,315	335,670
2011		1,745,385	33,085	274,022	2,052,492	(21,053,633)	152,097	341,923
2012		1,745,385	33,702	279,127	2,058,213	(18,995,419)	154,930	348,293

2013	1,745,385	34,330	284,327	2,064,041	(16,931,378)	157,817	354,782
2014	1,745,385	34,969	289,624	2,069,978	(14,861,400)	160,757	361,391
2015	1,745,385	35,621	295,020	2,076,025	(12,785,375)	163,752	368,124
2016	1,745,385	36,284	300,516	2,082,185	(10,703,190)	166,802	374,982
2017	1,745,385	36,960	306,114	2,088,460	(8,614,730)	169,910	381,968
2018	1,745,385	37,649	311,817	2,094,851	(6,519,879)	173,075	389,084
2019	1,745,385	38,350	317,626	2,101,362	(4,418,518)	176,300	396,333
2020	1,745,385	39,065	323,544	2,107,993	(2,310,524)	179,584	403,717
2021	1,745,385	39,792	329,571	2,114,749	(195,775)	182,930	411,238
2022	1,745,385	40,534	335,711	2,121,630	1,925,855	186,338	418,899
2023	1,745,385	41,289	341,966	2,128,640		189,809	426,703
2024	1,745,385	42,058	348,337	2,135,780		193,345	434,653
2025	1,745,385	42,842	354,826	2,143,053		196,947	442,750
2026	1,745,385	43,640	361,436	2,150,461		200,616	450,999
2027	1,745,385	44,453	368,170	2,158,008		204,354	459,401
2028	1,745,385	45,281	375,029	2,165,695		208,161	467,960
2029	1,745,385	46,125	382,016	2,173,525		212,039	476,678
2030	1,745,385	46,984	389,133	2,181,502		215,989	485,558
2031	1,745,385	47,859	396,382	2,189,626		220,013	494,604
2032	1,745,385	48,751	403,767	2,197,903		224,112	503,819
2033	1,745,385	49,659	411,289	2,206,333		228,287	513,205
2034	1,745,385	50,584	418,951	2,214,920		232,540	522,766
2035	1,745,385	51,526	426,756	2,223,668		236,872	532,505
2036	1,745,385	52,486	434,707	2,232,578		241,285	542,425
2037	1,745,385	53,464	442,806	2,241,655		245,781	552,531
2038	1,745,385	54,460	451,055	2,250,900		250,359	562,825
2039	1,745,385	55,475	459,458	2,260,318		255,024	573,310
		NPV		($1,322,310)			
		IRR		6.46%			
		MIRR	7% Reinv.	6.79%			
		PBP		12.09			

Figure 49. Option 1, North Omaha to Creston, IA, 161 kV

Five year average bilateral transmission expenditure for **purchases** from WAPA to OPPD = $26,431.84
Five year average bilateral transmission expenditure for **sales** from OPPD to WAPA: On Peak = 123,774 MW
Five year average bilateral transmission expenditure for **sales** from OPPD to WAPA: Off Peak = 278,251 MW

Option 2a: Lincoln (70th and Bluff) to Grand Island, 161 kV:

				MAPP Rates	
Steel Poles ($100,000/mile * 100 miles)	$	10,000,000		On-peak	Off-peak
Conductors/Wires ($25,000 *100 miles)	$	2,500,000		0.79	0.45
Labor ($100,000 * 100 miles)	$	10,000,000			
Right of Way ($50,000 * 100)	$	5,000,000			
Substation terminal work	$	3,000,000			
Transmission Impact Study	$	150,000			
Legal Fees	$	3,000			
Net Cash Outlay	**$**	**30,653,000**			

								Bilateral MW Sales	
Year	Initial Capital Investment ($)	LES Firm Purchase ($)	WAPA Firm Purchase ($)	Bilateral Purchase ($)	Bilateral Sales ($)	Total Cash Flow ($)	Pay Back Period	On-peak (MW)	Off-peak (MW)
2005				26,924	222,944			123,774	278,251
2006	(7,663,250)			27,426	227,149	(7,663,250)	(7,663,250)	126,080	283,435
2007	(7,663,250)			27,937	231,380	(7,663,250)	(15,326,500)	128,428	288,715
2008	(7,663,250)			28,457	235,691	(7,663,250)	(22,989,750)	130,821	294,094
2009	(7,663,250)			28,987	240,082	(7,663,250)	(30,653,000)	133,258	299,573
2010		2,755,263	1,745,385	32,480	269,010	4,802,139	(25,850,861)	149,315	335,670
2011		2,755,263	1,745,385	33,085	274,022	4,807,755	(21,043,106)	152,097	341,923
2012		2,755,263	1,745,385	33,702	279,127	4,813,477	(16,229,629)	154,930	348,293
2013		2,755,263	1,745,385	34,330	284,327	4,819,305	(11,410,325)	157,817	354,782
2014		2,755,263	1,745,385	34,969	289,624	4,825,241	(6,585,083)	160,757	361,391

2015	2,755,263	1,745,385	35,621	295,020	4,831,288	(1,753,795)	163,752	368,124
2016	2,755,263	1,745,385	36,284	300,516	4,837,448	3,083,654	166,802	374,982
2017	2,755,263	1,745,385	36,960	306,114	4,843,723		169,910	381,968
2018	2,755,263	1,745,385	37,649	311,817	4,850,114		173,075	389,084
2019	2,755,263	1,745,385	38,350	317,626	4,856,625		176,300	396,333
2020	2,755,263	1,745,385	39,065	323,544	4,863,257		179,584	403,717
2021	2,755,263	1,745,385	39,792	329,571	4,870,012		182,930	411,238
2022	2,755,263	1,745,385	40,534	335,711	4,876,893		186,338	418,899
2023	2,755,263	1,745,385	41,289	341,966	4,883,903		189,809	426,703
2024	2,755,263	1,745,385	42,058	348,337	4,891,043		193,345	434,653
2025	2,755,263	1,745,385	42,842	354,826	4,898,316		196,947	442,750
2026	2,755,263	1,745,385	43,640	361,436	4,905,724		200,616	450,999
2027	2,755,263	1,745,385	44,453	368,170	4,913,271		204,354	459,401
2028	2,755,263	1,745,385	45,281	375,029	4,920,958		208,161	467,960
2029	2,755,263	1,745,385	46,125	382,016	4,928,789		212,039	476,678
2030	2,755,263	1,745,385	46,984	389,133	4,936,765		215,989	485,558
2031	2,755,263	1,745,385	47,859	396,382	4,944,890		220,013	494,604
2032	2,755,263	1,745,385	48,751	403,767	4,953,166		224,112	503,819
2033	2,755,263	1,745,385	49,659	411,289	4,961,596		228,287	513,205
2034	2,755,263	1,745,385	50,584	418,951	4,970,184		232,540	522,766
2035	2,755,263	1,745,385	51,526	426,756	4,978,931		236,872	532,505
2036	2,755,263	1,745,385	52,486	434,707	4,987,842		241,285	542,425
2037	2,755,263	1,745,385	53,464	442,806	4,996,918		245,781	552,531
2038	2,755,263	1,745,385	54,460	451,055	5,006,164		250,359	562,825
2039	2,755,263	1,745,385	55,475	459,458	5,015,581		255,024	573,310
			NPV		$20,103,796			
			IRR		12.73%			
			MIRR	7% Reinv.	8.88%			
			PBP		6.36			

Figure 50. Option 2a: Lincoln (70th and Bluff) to Grand Island, 161 kV

Five year average bilateral transmission expenditure for **purchases** from WAPA to OPPD = $26,431.84
Five year average bilateral transmission expenditure for **sales** from OPPD to WAPA: On Peak = 123,774 MW
Five year average bilateral transmission expenditure for **sales** from OPPD to WAPA: Off Peak = 278,251 MW

Option 2b: Lincoln to Grand Island, 345 kV:

Steel Poles ($200,000/mile * 100 miles)	$	20,000,000
Conductors/Wires ($50,000 *100 miles)	$	5,000,000
Labor ($200,000 * 100 miles)	$	20,000,000
Right of Way ($50,000 * 100)	$	5,000,000
Substation terminal work	$	6,000,000
Transmission Impact Study	$	150,000
Legal Fees	$	3,000
Net Cash Outlay	**$**	**56,153,000**

MAPP Rates	
On-peak	Off-peak
0.79	0.45

Year	Initial Capital Investment ($)	LES Firm Purchase ($)	WAPA Firm Purchase ($)	Bilateral Purchase ($)	Bilateral Sales ($)	Total Cash Flow ($)	Pay Back Period	Bilateral MW Sales On-peak (MW)	Bilateral MW Sales Off-peak (MW)
2005				26,924	222,944			123,774	278,251
2006	(14,038,250)			27,426	227,149	(14,038,250)	(14,038,250)	126,080	283,435
2007	(14,038,250)			27,937	231,380	(14,038,250)	(28,076,500)	128,428	288,715
2008	(14,038,250)			28,457	235,691	(14,038,250)	(42,114,750)	130,821	294,094
2009	(14,038,250)			28,987	240,082	(14,038,250)	(56,153,000)	133,258	299,573
2010		2,755,263	1,745,385	32,480	269,010	4,802,139	(51,350,861)	149,315	335,670
2011		2,755,263	1,745,385	33,085	274,022	4,807,755	(46,543,106)	152,097	341,923
2012		2,755,263	1,745,385	33,702	279,127	4,813,477	(41,729,629)	154,930	348,293
2013		2,755,263	1,745,385	34,330	284,327	4,819,305	(36,910,325)	157,817	354,782
2014		2,755,263	1,745,385	34,969	289,624	4,825,241	(32,085,083)	160,757	361,391

2015	2,755,263	1,745,385	35,621	295,020	4,831,288	(27,253,795)	163,752	368,124
2016	2,755,263	1,745,385	36,284	300,516	4,837,448	(22,416,346)	166,802	374,982
2017	2,755,263	1,745,385	36,960	306,114	4,843,723	(17,572,624)	169,910	381,968
2018	2,755,263	1,745,385	37,649	311,817	4,850,114	(12,722,509)	173,075	389,084
2019	2,755,263	1,745,385	38,350	317,626	4,856,625	(7,865,884)	176,300	396,333
2020	2,755,263	1,745,385	39,065	323,544	4,863,257	(3,002,627)	179,584	403,717
2021	2,755,263	1,745,385	39,792	329,571	4,870,012	1,867,385	182,930	411,238
2022	2,755,263	1,745,385	40,534	335,711	4,876,893		186,338	418,899
2023	2,755,263	1,745,385	41,289	341,966	4,883,903		189,809	426,703
2024	2,755,263	1,745,385	42,058	348,337	4,891,043		193,345	434,653
2025	2,755,263	1,745,385	42,842	354,826	4,898,316		196,947	442,750
2026	2,755,263	1,745,385	43,640	361,436	4,905,724		200,616	450,999
2027	2,755,263	1,745,385	44,453	368,170	4,913,271		204,354	459,401
2028	2,755,263	1,745,385	45,281	375,029	4,920,958		208,161	467,960
2029	2,755,263	1,745,385	46,125	382,016	4,928,789		212,039	476,678
2030	2,755,263	1,745,385	46,984	389,133	4,936,765		215,989	485,558
2031	2,755,263	1,745,385	47,859	396,382	4,944,890		220,013	494,604
2032	2,755,263	1,745,385	48,751	403,767	4,953,166		224,112	503,819
2033	2,755,263	1,745,385	49,659	411,289	4,961,596		228,287	513,205
2034	2,755,263	1,745,385	50,584	418,951	4,970,184		232,540	522,766
2035	2,755,263	1,745,385	51,526	426,756	4,978,931		236,872	532,505
2036	2,755,263	1,745,385	52,486	434,707	4,987,842		241,285	542,425
2037	2,755,263	1,745,385	53,464	442,806	4,996,918		245,781	552,531
2038	2,755,263	1,745,385	54,460	451,055	5,006,164		250,359	562,825
2039	2,755,263	1,745,385	55,475	459,458	5,015,581		255,024	573,310
			NPV		($1,489,676)			
			IRR		6.73%			
			MIRR	7% Rein	6.90%			
			PBP		11.62			

Figure 51. Option 2b: Lincoln to Grand Island, 345 kV

Five year average bilateral transmission expenditure for **purchases** from WAPA to OPPD = $26,431.84
Five year average bilateral transmission expenditure for **sales** from OPPD to WAPA: On Peak = 123,774 MW
Five year average bilateral transmission expenditure for **sales** from OPPD to WAPA: Off Peak = 278,251 MW

Option 3a: Raun to Sioux City, 161 kV:

Steel Poles ($100,000/mile * 20 miles)	$	2,000,000
Conductors/Wires ($25,000 *20 miles)	$	500,000
Labor ($100,000 * 20 miles)	$	2,000,000
Right of Way ($50,000 * 20)	$	1,000,000
Terminal work	$	1,500,000
Greenfield 161 Kv construction	$	3,250,000
Transmission Impact Study	$	150,000
Legal Fees	$	3,000
Net Cash Outlay	**$**	**10,403,000**

MAPP Rates	
On-peak	Off-peak
0.79	0.45

Year	Initial Capital Investment ($)	WAPA Firm Purchase ($)	Bilateral Purchase ($)	Bilateral Sales ($)	Total Cash Flow ($)	Pay Back Period	Bilateral MW Sales On-peak (MW)	Bilateral MW Sales Off-peak (MW)
2005			26,924	222,944			123,774	278,251
2006	(2,600,750)		27,426	227,149	(2,600,750)	(2,600,750)	126,080	283,435
2007	(2,600,750)		27,937	231,380	(2,600,750)	(5,201,500)	128,428	288,715
2008	(2,600,750)		28,457	235,691	(2,600,750)	(7,802,250)	130,821	294,094
2009	(2,600,750)		28,987	240,082	(2,600,750)	(10,403,000)	133,258	299,573
2010		1,745,385	32,480	269,010	2,046,875	(8,356,125)	149,315	335,670
2011		1,745,385	33,085	274,022	2,052,492	(6,303,633)	152,097	341,923
2012		1,745,385	33,702	279,127	2,058,213	(4,245,419)	154,930	348,293
2013		1,745,385	34,330	284,327	2,064,041	(2,181,378)	157,817	354,782
2014		1,745,385	34,969	289,624	2,069,978	(111,400)	160,757	361,391

2015	1,745,385	35,621	295,020	2,076,025	1,964,625	163,752	368,124
2016	1,745,385	36,284	300,516	2,082,185		166,802	374,982
2017	1,745,385	36,960	306,114	2,088,460		169,910	381,968
2018	1,745,385	37,649	311,817	2,094,851		173,075	389,084
2019	1,745,385	38,350	317,626	2,101,362		176,300	396,333
2020	1,745,385	39,065	323,544	2,107,993		179,584	403,717
2021	1,745,385	39,792	329,571	2,114,749		182,930	411,238
2022	1,745,385	40,534	335,711	2,121,630		186,338	418,899
2023	1,745,385	41,289	341,966	2,128,640		189,809	426,703
2024	1,745,385	42,058	348,337	2,135,780		193,345	434,653
2025	1,745,385	42,842	354,826	2,143,053		196,947	442,750
2026	1,745,385	43,640	361,436	2,150,461		200,616	450,999
2027	1,745,385	44,453	368,170	2,158,008		204,354	459,401
2028	1,745,385	45,281	375,029	2,165,695		208,161	467,960
2029	1,745,385	46,125	382,016	2,173,525		212,039	476,678
2030	1,745,385	46,984	389,133	2,181,502		215,989	485,558
2031	1,745,385	47,859	396,382	2,189,626		220,013	494,604
2032	1,745,385	48,751	403,767	2,197,903		224,112	503,819
2033	1,745,385	49,659	411,289	2,206,333		228,287	513,205
2034	1,745,385	50,584	418,951	2,214,920		232,540	522,766
2035	1,745,385	51,526	426,756	2,223,668		236,872	532,505
2036	1,745,385	52,486	434,707	2,232,578		241,285	542,425
2037	1,745,385	53,464	442,806	2,241,655		245,781	552,531
2038	1,745,385	54,460	451,055	2,250,900		250,359	562,825
2039	1,745,385	55,475	459,458	2,260,318		255,024	573,310
		NPV		$11,168,031			
		IRR		15.69%			
		MIRR	7% Reinv.	9.69%			
		PBP		5.05			

Figure 52. Option 3a: Raun to Sioux City, 161 kV

Five year average bilateral transmission expenditure for **purchases** from WAPA to OPPD = $26,431.84
Five year average bilateral transmission expenditure for **sales** from OPPD to WAPA: On Peak = 123,774 MW
Five year average bilateral transmission expenditure for **sales** from OPPD to WAPA: Off Peak = 278,251 MW

Option 3b: Raun to Sioux City, 345 kV:

Steel Poles ($200,000/mile * 20 miles)	$	4,000,000
Conductors/Wires ($50,000 *20 miles)	$	1,000,000
Labor ($200,000 * 20 miles)	$	4,000,000
Right of Way ($50,000 * 20)	$	1,000,000
Terminal work	$	3,000,000
Greenfield 161 Kv construction	$	6,500,000
Transmission Impact Study	$	150,000
Legal Fees	$	3,000
Net Cash Outlay	**$**	**19,653,000**

MAPP Rates	
On-peak	Off-peak
0.79	0.45

Year	Initial Capital Investment ($)	WAPA Firm Purchase ($)	Bilateral Purchase ($)	Bilateral Sales ($)	Total Cash Flow ($)	Pay Back Period	Bilateral MW Sales On-peak (MW)	Bilateral MW Sales Off-peak (MW)
2005			26,924	222,944			123,774	278,251
2006	(4,913,250)		27,426	227,149	(4,913,250)	(4,913,250)	126,080	283,435
2007	(4,913,250)		27,937	231,380	(4,913,250)	(9,826,500)	128,428	288,715
2008	(4,913,250)		28,457	235,691	(4,913,250)	(14,739,750)	130,821	294,094
2009	(4,913,250)		28,987	240,082	(4,913,250)	(19,653,000)	133,258	299,573
2010		1,745,385	32,480	269,010	2,046,875	(17,606,125)	149,315	335,670
2011		1,745,385	33,085	274,022	2,052,492	(15,553,633)	152,097	341,923
2012		1,745,385	33,702	279,127	2,058,213	(13,495,419)	154,930	348,293
2013		1,745,385	34,330	284,327	2,064,041	(11,431,378)	157,817	354,782
2014		1,745,385	34,969	289,624	2,069,978	(9,361,400)	160,757	361,391

2015	1,745,385	35,621	295,020	2,076,025	(7,285,375)	163,752	368,124
2016	1,745,385	36,284	300,516	2,082,185	(5,203,190)	166,802	374,982
2017	1,745,385	36,960	306,114	2,088,460	(3,114,730)	169,910	381,968
2018	1,745,385	37,649	311,817	2,094,851	(1,019,879)	173,075	389,084
2019	1,745,385	38,350	317,626	2,101,362	1,081,482	176,300	396,333
2020	1,745,385	39,065	323,544	2,107,993		179,584	403,717
2021	1,745,385	39,792	329,571	2,114,749		182,930	411,238
2022	1,745,385	40,534	335,711	2,121,630		186,338	418,899
2023	1,745,385	41,289	341,966	2,128,640		189,809	426,703
2024	1,745,385	42,058	348,337	2,135,780		193,345	434,653
2025	1,745,385	42,842	354,826	2,143,053		196,947	442,750
2026	1,745,385	43,640	361,436	2,150,461		200,616	450,999
2027	1,745,385	44,453	368,170	2,158,008		204,354	459,401
2028	1,745,385	45,281	375,029	2,165,695		208,161	467,960
2029	1,745,385	46,125	382,016	2,173,525		212,039	476,678
2030	1,745,385	46,984	389,133	2,181,502		215,989	485,558
2031	1,745,385	47,859	396,382	2,189,626		220,013	494,604
2032	1,745,385	48,751	403,767	2,197,903		224,112	503,819
2033	1,745,385	49,659	411,289	2,206,333		228,287	513,205
2034	1,745,385	50,584	418,951	2,214,920		232,540	522,766
2035	1,745,385	51,526	426,756	2,223,668		236,872	532,505
2036	1,745,385	52,486	434,707	2,232,578		241,285	542,425
2037	1,745,385	53,464	442,806	2,241,655		245,781	552,531
2038	1,745,385	54,460	451,055	2,250,900		250,359	562,825
2039	1,745,385	55,475	459,458	2,260,318		255,024	573,310
		NPV		$3,335,105			
		IRR		8.63%			
		MIRR	7% Reinv.	7.59%			
		PBP		9.49			

Figure 53. Option 3b: Neal to Sioux City, 345 kV

Five year average bilateral transmission expenditure for **purchases** from WAPA to OPPD = $26,431.84
Five year average bilateral transmission expenditure for **sales** from OPPD to WAPA: On Peak = 123,774 MW
Five year average bilateral transmission expenditure for **sales** from OPPD to WAPA: Off Peak = 278,251 MW

Option 4a: Ft. Calhoun to Denison Iowa, 161 kV:

Steel Poles ($100,000/mile * 45 miles)	$	4,500,000
Conductors/Wires ($25,000 *45 miles)	$	1,125,000
Labor ($100,000 * 45 miles)	$	4,500,000
Right of Way ($50,000 * 45)	$	2,250,000
Terminal work	$	3,000,000
Transmission Impact Study	$	150,000
Legal Fees	$	3,000
Net Cash Outlay	**$**	**15,528,000**

MAPP Rates	
On-peak	Off-peak
0.79	0.45

Year	Initial Capital Investment ($)	WAPA Firm Purchase ($)	Bilateral Purchase ($)	Bilateral Sales ($)	Total Cash Flow ($)	Pay Back Period	Bilateral MW Sales On-peak (MW)	Bilateral MW Sales Off-peak (MW)
2005			26,924	222,944			123,774	278,251
2006	(3,882,000)		27,426	227,149	(3,882,000)	(3,882,000)	126,080	283,435
2007	(3,882,000)		27,937	231,380	(3,882,000)	(7,764,000)	128,428	288,715
2008	(3,882,000)		28,457	235,691	(3,882,000)	(11,646,000)	130,821	294,094
2009	(3,882,000)		28,987	240,082	(3,882,000)	(15,528,000)	133,258	299,573
2010		1,745,385	32,480	269,010	2,046,875	(13,481,125)	149,315	335,670
2011		1,745,385	33,085	274,022	2,052,492	(11,428,633)	152,097	341,923
2012		1,745,385	33,702	279,127	2,058,213	(9,370,419)	154,930	348,293
2013		1,745,385	34,330	284,327	2,064,041	(7,306,378)	157,817	354,782
2014		1,745,385	34,969	289,624	2,069,978	(5,236,400)	160,757	361,391
2015		1,745,385	35,621	295,020	2,076,025	(3,160,375)	163,752	368,124
2016		1,745,385	36,284	300,516	2,082,185	(1,078,190)	166,802	374,982

2017	1,745,385	36,960	306,114	2,088,460	1,010,270	169,910	381,968
2018	1,745,385	37,649	311,817	2,094,851		173,075	389,084
2019	1,745,385	38,350	317,626	2,101,362		176,300	396,333
2020	1,745,385	39,065	323,544	2,107,993		179,584	403,717
2021	1,745,385	39,792	329,571	2,114,749		182,930	411,238
2022	1,745,385	40,534	335,711	2,121,630		186,338	418,899
2023	1,745,385	41,289	341,966	2,128,640		189,809	426,703
2024	1,745,385	42,058	348,337	2,135,780		193,345	434,653
2025	1,745,385	42,842	354,826	2,143,053		196,947	442,750
2026	1,745,385	43,640	361,436	2,150,461		200,616	450,999
2027	1,745,385	44,453	368,170	2,158,008		204,354	459,401
2028	1,745,385	45,281	375,029	2,165,695		208,161	467,960
2029	1,745,385	46,125	382,016	2,173,525		212,039	476,678
2030	1,745,385	46,984	389,133	2,181,502		215,989	485,558
2031	1,745,385	47,859	396,382	2,189,626		220,013	494,604
2032	1,745,385	48,751	403,767	2,197,903		224,112	503,819
2033	1,745,385	49,659	411,289	2,206,333		228,287	513,205
2034	1,745,385	50,584	418,951	2,214,920		232,540	522,766
2035	1,745,385	51,526	426,756	2,223,668		236,872	532,505
2036	1,745,385	52,486	434,707	2,232,578		241,285	542,425
2037	1,745,385	53,464	442,806	2,241,655		245,781	552,531
2038	1,745,385	54,460	451,055	2,250,900		250,359	562,825
2039	1,745,385	55,475	459,458	2,260,318		255,024	573,310
		NPV		$6,828,167			
		IRR		10.97%			
		MIRR	7% Reinv.	8.36%			
		PBP		7.52			

Figure 54. Option 4a: Ft. Calhoun to Denison Iowa, 161 kV

Five year average bilateral transmission expenditure for **purchases** from WAPA to OPPD = $26,431.84
Five year average bilateral transmission expenditure for **sales** from OPPD to WAPA: On Peak = 123,774 MW
Five year average bilateral transmission expenditure for **sales** from OPPD to WAPA: Off Peak = 278,251 MW

Option 4b: Ft. Calhoun to Denison Iowa, 230 kV:

Steel Poles ($150,000/mile * 45 miles)	$	6,750,000
Conductors/Wires ($37,500 *45 miles)	$	1,687,500
Labor ($50,000 * 45 miles)	$	6,750,000
Right of Way ($50,000 * 45)	$	2,250,000
Terminal work	$	4,500,000
Transmission Impact Study	$	150,000
Legal Fees	$	3,000
Net Cash Outlay	**$**	**22,090,500**

MAPP Rates	
On-peak	Off-peak
0.79	0.45

Year	Initial Capital Investment ($)	WAPA Firm Purchase ($)	Bilateral Purchase ($)	Bilateral Sales ($)	Total Cash Flow ($)	Pay Back Period	Bilateral MW Sales On-peak (MW)	Bilateral MW Sales Off-peak (MW)
2005			26,924	222,944			123,774	278,251
2006	(5,522,625)		27,426	227,149	(5,522,625)	(5,522,625)	126,080	283,435
2007	(5,522,625)		27,937	231,380	(5,522,625)	(11,045,250)	128,428	288,715
2008	(5,522,625)		28,457	235,691	(5,522,625)	(16,567,875)	130,821	294,094
2009	(5,522,625)		28,987	240,082	(5,522,625)	(22,090,500)	133,258	299,573
2010		1,745,385	32,480	269,010	2,046,875	(20,043,625)	149,315	335,670
2011		1,745,385	33,085	274,022	2,052,492	(17,991,133)	152,097	341,923
2012		1,745,385	33,702	279,127	2,058,213	(15,932,919)	154,930	348,293
2013		1,745,385	34,330	284,327	2,064,041	(13,868,878)	157,817	354,782
2014		1,745,385	34,969	289,624	2,069,978	(11,798,900)	160,757	361,391
2015		1,745,385	35,621	295,020	2,076,025	(9,722,875)	163,752	368,124

2016	1,745,385	36,284	300,516	2,082,185	(7,640,690)	166,802	374,982
2017	1,745,385	36,960	306,114	2,088,460	(5,552,230)	169,910	381,968
2018	1,745,385	37,649	311,817	2,094,851	(3,457,379)	173,075	389,084
2019	1,745,385	38,350	317,626	2,101,362	(1,356,018)	176,300	396,333
2020	1,745,385	39,065	323,544	2,107,993	751,976	179,584	403,717
2021	1,745,385	39,792	329,571	2,114,749		182,930	411,238
2022	1,745,385	40,534	335,711	2,121,630		186,338	418,899
2023	1,745,385	41,289	341,966	2,128,640		189,809	426,703
2024	1,745,385	42,058	348,337	2,135,780		193,345	434,653
2025	1,745,385	42,842	354,826	2,143,053		196,947	442,750
2026	1,745,385	43,640	361,436	2,150,461		200,616	450,999
2027	1,745,385	44,453	368,170	2,158,008		204,354	459,401
2028	1,745,385	45,281	375,029	2,165,695		208,161	467,960
2029	1,745,385	46,125	382,016	2,173,525		212,039	476,678
2030	1,745,385	46,984	389,133	2,181,502		215,989	485,558
2031	1,745,385	47,859	396,382	2,189,626		220,013	494,604
2032	1,745,385	48,751	403,767	2,197,903		224,112	503,819
2033	1,745,385	49,659	411,289	2,206,333		228,287	513,205
2034	1,745,385	50,584	418,951	2,214,920		232,540	522,766
2035	1,745,385	51,526	426,756	2,223,668		236,872	532,505
2036	1,745,385	52,486	434,707	2,232,578		241,285	542,425
2037	1,745,385	53,464	442,806	2,241,655		245,781	552,531
2038	1,745,385	54,460	451,055	2,250,900		250,359	562,825
2039	1,745,385	55,475	459,458	2,260,318		255,024	573,310
		NPV		$1,271,023			
		IRR		7.57%			
		MIRR	7% Reinv.	7.21%			
		PBP		10.64			

Figure 55. Option 4b: Ft. Calhoun to Denison Iowa, 230 kV