BEFORE THE

KANSAS CORPORATION COMMISSION

PREPARED DIRECT TESTIMONY OF

H. EDWIN OVERCAST

ON BEHALF OF

MIDWEST ENERGY, INC.

Prepared Direct Testimony of H. Edwin Overcast

Q. Please state your name and occupation.

A. H. Edwin Overcast, I am a Director of the Energy Management Solutions group of Black & Veatch.

Q. Please provide a summary of your educational and professional qualifications.

A. A detailed summary of my educational and professional experience is provided in Appendix A to this testimony. I have a B. A. degree in economics from King College and a Ph.D. degree in economics from Virginia Polytechnic Institute and State University. I have been employed in the energy industry for over 33 years in various rate, regulatory and planning positions. In my various positions, I have testified before state and federal regulatory bodies, Canadian provincial regulatory bodies, state and federal legislative bodies and in various courts. My testimony has addressed a variety of issues including cost allocation, rate design, regulatory policy, open access and unbundling, bypass economics, forecasting, gas supply planning, and a number of other issues. In addition, I have been a lecturer in a number of energy industry sponsored training programs including: the Edison Electric Institute Rate Fundamentals Course and the Advanced Rate Course; the American Gas Association Rate Course and the Advanced Rate School; and the Southern Gas Association Intermediate Rate Course. Specifically, I have lectured on the principles of electric cost of service for both retail and wholesale jurisdictions.

Q. On whose behalf are you providing testimony?

A. I am appearing on behalf of Midwest Energy, Inc. ("Midwest Energy" or the "Company").

Q. Have you testified before the Kansas Corporation Commission ("KCC" or the "Commission") before?

A. Yes. I appeared before the Commission in a Western Resources, Inc. proceeding, Docket No. 01 WSRE-436-RTS in 2001.

Q. What is the purpose of your testimony in this proceeding?

A. I am recommending that the KCC adopt a formula transmission rate for the Company. In addition, I am supporting the design and content of the formula rate and the implementation steps contained in the rate. Exhibit__(HEO-1) provides a blank template of the formula transmission rate for Midwest Energy.

Q. Why has the Company proposed a formula rate?

A. For some time, the Federal Energy Regulatory Commission (FERC) has approved formula rates for transmission operators (TO) as part of a national program to encourage new investment in transmission infrastructure. Consistent with the formula approaches adopted by other transmission providers in the Southwest Power Pool (SPP) and elsewhere, Midwest Energy seeks to have a comparable approach to recovery of its transmission costs. SPP is a Regional Transmission Organization (RTO) subject to regulation by the FERC. SPP provides a variety of services to its members, including the Company. One of those services includes the administration of transmission services and billing for the service under Schedules 1 through 12 of the SPP Tariff as applicable using the Annual Transmission Revenue Requirement (ATRR) contained in the formula rate

exhibits (Exhibit_HEO-1 thru 3). Currently, the ATRR for Midwest Energy is a fixed value of almost $4.2 million and that amount does not change with cost changes absent a rate filing. The use of a formula rate will permit the Midwest Energy ATRR to change on an annual basis to reflect the actual costs of its transmission system. A formula rate permits timely recovery of the actual costs without the cost of annual rate filings based on the approved formula.

Q. Why is a formula rate appropriate for Midwest Energy?

A. There are several reasons that a formula rate is appropriate for Midwest Energy. First, as discussed below, the only source of equity capital to support system expansion is from retained earnings. Failure to recover costs in a timely fashion reduces this source of equity contribution and results in less favorable financial condition and flexibility. Second, to the extent that the Midwest Energy system is used by customers other than the retail customers, it is appropriate for these customers to bear the actual cost of the system in as close to real time as possible to provide appropriate economic price signals. These price signals result in more efficient and economic decisions relative to the sources and types of capacity that customers acquire. Finally, Midwest Energy must replace aging infrastructure to maintain system reliability. The cost of transmission (and for that matter distribution) equipment is rising and that implies a growing rate base as equipment is replaced. The formula rate permits replacement without significantly reducing the return of and on new capital.

Q. How has the formula rate been developed?

A. The FERC has authorized a number of formula rate options for transmission owners. The basic model follows the fundamental equation for revenue requirements as follows:

$$ATRR = O + M + D + T + (GP - AD + ORB)\, r$$

Where O is the transmission related operating expense, including applicable overheads; M is the transmission related maintenance expense, including applicable overheads; D is the annual depreciation expense for transmission and allocated general plant; T is the applicable taxes, GP is the gross plant, including both transmission plant and general plant allocated to transmission service less accumulated depreciation; ORB is the net of other rate base items including working capital, deferred taxes and other rate base adjustments and; r is the rate of return.

Q. What is the source of data for the formula rate?

A. Data for the formula comes primarily from the FERC Form 1 filed annually by the Company (except in this initial filing which is based on a test year ended June 30, 2007). Certain information is supplied by the Company as part of the formula. Other data, such as the rate of return, will be provided by the Commission in the rate order accepting the formula rate.

Q. Please describe the formula template in Exhibit_(HEO-1).

A. Appendix A consists of nine major sections. In addition there are five additional pages that provide supporting calculations for various parts of the formula specifically applicable to Midwest Energy. Appendix A calculates the ATRR and the associated Network Service Rate. Each of the first seven sections provides the

basic data for calculation of the ATRR. The first section entitled Allocators provides three allocation factors:

1. A wages and salary allocator;
2. A gross plant allocator; and
3. A net plant allocator.

These allocation factors are used in other parts of the formula to allocate costs to transmission service as discussed below.

Q. Please describe the use of the three allocation factors.

A. The wages and salary allocator is used to allocate general plant and common plant components, including depreciation expense and accumulated depreciation in the formula. The net plant allocation factor is used to allocate certain other rate base items. The gross plant allocation factor is used to allocate certain taxes and construction work in progress.

Q. Please describe the second section of Appendix A.

A. The second section provides the plant calculations, including the gross plant in service and the total net plant in service associated with providing transmission service. This includes an allocation of general and common plant as well as the transmission related plant held for future use. The gross plant amount is reduced by the applicable accumulated depreciation to produce the net transmission related plant. In addition, the plant in service includes the applicable CWIP as discussed below.

Q. Please describe the third section of Appendix A.

A. Section three provides the calculations for the adjustments to rate base. These adjustments include: prepayments, materials and supplies, cash working capital, construction work in progress, and an entry for network credits should those apply. The calculation of cash working capital uses the FERC 1/8th of operation and maintenance expense as the basis for working capital. This calculation is used to simplify the calculation of the formula.

Q. Please describe the fourth section of Appendix A.

A. Section four calculates the transmission related operation and maintenance expense. The calculation includes transmission operation and maintenance expenses, an allocated portion of general and common expenses and a portion of directly assigned administrative and general expenses.

Q. Please describe the fifth section of Appendix A.

A. The fifth section calculates the depreciation and amortization expense associated with the transmission related plant, including the allocated general plant.

Q. Please describe the sixth section of Appendix A.

A. The sixth section identifies the taxes other than income tax. The calculation of these taxes is taken from the page entitled other taxes that serves as a workpaper for Appendix A.

Q. Please describe the seventh section of Appendix A.

A. The seventh section calculates the capitalization and the rate of return. The calculation includes the actual capital structure and the weighted cost of capital.

Q. Please describe the eighth section of Appendix A.

A. The eighth section calculates the revenue requirement for transmission service. As discussed by Mr. Dowling, the transmission service is based on the assets that provide transmission service for other customers and reflects the classification of assets under the FERC seven factor test. The section also calculates the applicable system rate using the 12 coincident peak (12CP) allocation methodology.

Q. Please describe the ninth section of Appendix A.

A. The ninth section consists of a series of notes that provide additional information and support for certain portions of the Appendix.

Q. Please describe the additional pages in the formula rate calculation.

A. Attachment one (sheet 5 of 13 on Exhibits_HEO-1 thru 3) provides the calculation of taxes other than income taxes. Attachment two (sheet 6 of 13) provides cost support data for various elements of the calculation. Attachment three (sheet 9 of 13) is not used in the initial filing. It is the estimation and true-up worksheet for use in subsequent filings. Attachment four (sheet 12 of 13) is the calculation of the 12 CP allocation factor. Attachment five is the transmission enhancement worksheet used to develop costs for new projects that will be subject to additional incentives.

Q. Does the FERC provide incentives for new investment in transmission facilities?

A. Yes. The FERC, beginning with Order 679 issued in July of 2006, adopted certain incentives designed to encourage investment in transmission

infrastructure. These incentives responded to legislative requirements in the Energy Policy Act of 2005. The approved incentives include the following:

1. An incentive return on equity
2. Construction work in progress and pre-commercial expenses
3. Hypothetical capital structures
4. Accelerated depreciation
5. Recovery of costs of abandoned facilities
6. Deferred cost recovery

In this request, Midwest Energy seeks approval of only two of these incentives. Midwest Energy asks that the KCC allow the inclusion of construction work in progress and pre-commercial expenses as the first incentive. Second, Midwest Energy requests the approval of the recovery of costs of abandoned facilities. Both of these incentives would be recognized in the formula rate. At this time, the deferred cost recovery incentive is not applicable to Midwest Energy. Further, the incentive ROE, hypothetical capital structures and accelerated depreciation do not seem necessary for the Midwest Energy transmission program at this time. Since these incentives comply with federal mandates, Midwest Energy believes that it is appropriate for them to be included as part of its filing in this case. Further, these proposals appear to be consistent with Kansas legislation as well.

Q. Does the FERC inclusion of these incentives require certain standards of proof?

A. Yes, the incentives require proof that they are needed to promote transmission investment. The FERC historically has permitted recovery of 50 percent of CWIP

in rate base prior to Order 679. In allowing 100 percent of CWIP for transmission, the FERC found that this policy furthers the public interest by "providing up-front regulatory certainty, rate stability and improved cash flow for applicants thereby easing the pressures on their finances caused by transmission development programs." The FERC requires that there be a nexus between the transmission projects and the inclusion of CWIP in rate base. In the case of Midwest Energy, in order to maintain its capital structure and issue debt, it must grow its equity through retained earnings. Midwest Energy has no common stock to sell to maintain its equity ratio. Undertaking capital programs to provide transmission infrastructure requires additional retained earnings to support the capital structure. Retained earnings to support construction must come from a higher earned return or from CWIP included in rate base. Using CWIP for transmission projects permits Midwest Energy to maintain its ability to finance such projects on reasonable terms. Further, the ability to include CWIP and to expense pre-commercial costs means lower future rates over long-lived transmission facilities. Thus, there is a clear nexus between the inclusion of CWIP and the cost effective and timely additions of transmission infrastructure on the Midwest Energy system. The second incentive, recovery of costs of abandoned facilities requires that the cost recovered be prudently incurred. In the case of Midwest Energy, this incentive is critical to support transmission investment because the customers are the only source for abandoned cost recovery. By including this provision in the formula rate, in the event of an

abandoned project, these costs will be included in the ATRR and borne by users of the transmission system.

Q. Does the provision of CWIP in rate base and abandonment cost recovery protect Midwest Energy from prudence review?

A. No. Both of these provisions require that Midwest Energy act in a prudent manner to be allowed cost recovery. A central feature of the regulatory compact is the recovery of prudently incurred costs. Thus, Midwest Energy only expects that prudently incurred costs would be included in rates.

Q. Have you prepared examples of the formula rate?

A. Yes. Exhibit_(HEO-2) presents the formula rate using the 2006 Form 1 data and serves as an example of the process that is drawn from FERC Form 1. Exhibit_(HEO-3) provides the rate consistent with the test year revenue requirements sought in this case. The formula will be updated each year as the Form 1 data becomes available.

Q. What rate does the Company ask the Commission to approve?

A. The Company seeks approval of the rate contained in Exhibit_(HEO-3).

Q. Please describe the process for filing changes to the formula rate.

A. There are two types of filings relative to the formula rate. The first type of filing is to amend the actual formula. To alter the formula in a substantive way (other than to reflect differences in the line numbers for various accounts), Midwest Energy would file a rate proceeding and propose a revised formula. The second type of filing is the annual filing to implement the formula for the new costs included in the most recent FERC Form 1 report.

Q. Please describe the filing process to update the ATRR under the formula.

A. The filing process is explained in the formula itself. Attachment three (beginning at sheet 9 of 13 of Exhibits_HEO-1 thru 3) of the formula contains the estimate and true-up worksheet that spells out the steps for annual filings. Once the data becomes available with the filing of FERC Form 1, Midwest Energy as the transmission owner will populate the formula with data. No later than the last business day of April, Midwest Energy will file a copy of the formula with the KCC and post the formula rate on the SPP website with an effective date as to retail rates (Effective Date) of June 1. During this thirty-day period, the KCC Staff may review and audit the formula. If the KCC Staff proposes changes, Midwest Energy may either accept those changes and repost the updated formula or reject those changes subject to the FERC provisions for review and protest. The tariff contained in Exhibit_(HEO-4) provides for the details associated with the FERC filing and procedures.

Q. Given that the Formula Rate is subject to the KCC jurisdiction, does the limitation of the review period to the thirty days prior to the Effective Date provide adequate opportunity for affected parties to seek review?

A. Yes. The rate may be approved and made effective subject to refund in the event that parties have concerns about the costs or other data used in the formula.

Q. Is it reasonable to delay the Effective Date of the formula rate to resolve issues related to the annual filing?

A. No. Any further delay beyond the June 1 Effective Date creates unreasonable delay in the recovery of costs and frustrates the use of the formula rate concept.

Q. How will the formula rate be incorporated in retail rates for the Company?

A. Mr. Volker has prepared a rider- The Transmission Service Charge Adjustment Rider- that incorporates the change in the net retail obligation for the ATRR in rates for each class of customer. Under the provisions of the rider, the ATRR is reduced by the actual transmission related revenues received by the Company from transactions other than to retail customers. The adjustment calculates the new Retail Annual Transmission Revenue Requirement (RATRR) as the change in the average RATRR for all customers and adds that increase to the unbundled rate for each rate schedule as determined in the current proceeding.

Q. Please summarize your recommendations.

A. I recommend approval of a formula rate consistent with those approved by the FERC. Under the formula rate, changes in transmission costs will be reflected in an annual filing and take effect thirty days after the filing. The formula rate will also reflect two specific incentives that Midwest Energy requests the KCC approve as part of the formula. The requested incentives include (1) CWIP and expensing pre-commercial expenses and (2) the recovery of cost of abandoned facilities. The FERC adopted these two incentives and provided the standards for their inclusion. In both cases, Midwest Energy meets the criteria for approval of incentives. Further, Midwest Energy meets the criteria for other incentives such as a higher equity return, a theoretical capital structure and others but does not request approval at this time.

Q. Does this complete your testimony?

A. Yes.

DR. H. EDWIN OVERCAST

Educational Background and Professional Experience

Dr. Overcast graduated cum laude from King College with a Bachelor of Arts Degree in Economics. He received the Doctor of Philosophy Degree in Economics from Virginia Polytechnic Institute and State University. His principal fields of study included Economic Theory, Public Finance and Industrial Organization, with supporting fields of study in Econometrics and Statistics. He has taught courses at both the graduate and undergraduate level in Microeconomic Theory, Managerial Economics and Public Finance. In addition, he has taught courses in Mathematical Economics, Economics of Regulation and Money and Banking. While a faculty member at East Tennessee State University, he was appointed to the Graduate Faculty and subsequently directed thesis programs for graduate students.

In 1975, he joined the Tennessee Valley Authority (TVA) as an Economist in the Distributor Marketing Branch. He held successively higher positions as an Economist in the Rate Research Section of the Rate Branch and was ultimately Supervisor of the Economic Staff of the Rate Branch.

In May of 1978, he joined Northeast Utilities as a Rate Economist in the Rate Research Department and was promoted to Manager of Rate Research in November 1979. In that position, he was responsible for the rate activities of each of the operating companies of Northeast Utilities: Western Massachusetts Electric Company, Holyoke

Water Power Company, Holyoke Power and Electric Company, The Connecticut Light and Power Company, and the Hartford Electric Light Company.

In March 1983, Dr. Overcast became Director of the Rates and Load Research Department of the Consumer Economics Division of Northeast Utilities. In this position, Dr. Overcast directed the planning of analyses and implementation of system-wide pricing and costs for regulated and unregulated products and services of Northeast Utilities. As part of that responsibility, Dr. Overcast represented the system companies before state and federal regulators, legislative bodies and other public and private forums on matters pertaining to rate and cost-of-service issues.

Dr. Overcast represented Northeast Utilities as a member of the Edison Electric Institute (E.E.I.) Rate Committee and the American Gas Association (A.G.A.) Rate Committee. While serving on those committees, he was the Rate Training Subcommittee Chairman of the A.G.A. Rate Committee. He has been an instructor on cost-of-service and federal regulatory issues for the E.E.I. Rate Fundamentals Course and the E.E.I. Advanced Rate Course. Dr. Overcast also represented Northeast Utilities as a member of the Load Research Committee of the Association of Edison Illuminating Companies.

In March 1989, he joined Atlanta Gas Light Company as Director - Rates and was promoted to Vice President - Rates in February 1994. In November 1994 he became Vice President - Corporate Planning and Rates and was subsequently elected Vice President - Strategy, Planning and Business Development for AGL Resources, Inc.,

the parent company of Atlanta Gas Light Company. His responsibilities in the various rate positions included: designing an administering the Company's tariffs, including rates, rules and regulations and terms of service. He represented the Company before regulatory commissions on rate and regulatory matters and oversaw the preparation of the Company's forecast of natural gas demand. He was responsible for planning activities relating to the regulated businesses of the Company. He developed strategy for both regulated and unregulated business units, monitored markets for new products and services and identified potential new business opportunities for the Company.

Dr. Overcast has previously testified in rate cases and other proceedings before the Connecticut Department of Public Utility Control, the Massachusetts Department of Public Utilities, the Georgia Public Service Commission, the Montana Public Service Commission, the Missouri Public Service Commission, the Kansas Corporation Commission, the Ohio Public Utilities Commission, the New York Public Service Commission, the New Jersey Board of Public Utilities, the Michigan Public Service Commission and the Tennessee Regulatory Authority and the Federal Energy Regulatory Commission. He has also testified before the subcommittee on Energy and Power of the U.S. House of Representatives and various committees of the Georgia General Assembly.

Dr. Overcast joined R. J. Rudden Associates, Inc. as Vice President in September 1999. R. J. Rudden Associates became a unit of Black and Veatch in January of 2005.

At that time he became a Principal of the division, and is currently a Director. He is responsible for the open access and unbundling practice area and provides economic and regulatory consulting to clients of the firm.

Dr. Overcast has served as an instructor in the A.G.A. Rate Fundamentals Course, the AGA Advanced Rate Course and the S.G.A. Intermediate Level Rates Course.

Appendix A

Utility Name: MIDWEST ENERGY Formula Rate	Notes	FERC Form 1 Page # or Instruction	Year
Shaded cells are input cells			
Allocators			
Wages & Salary Allocation Factor			
1 Transmission Wages Expense		p354.21.b	0
2 Total Wages Expense		p354.28b	0
3 Less A&G Wages Expense		p354.27b	0
4 Total		(Line 2 - 3)	0
5 **Wages & Salary Allocator**		(Line 1 / 4)	**0.0000%**
Plant Allocation Factors			
6 Electric Plant in Service	(Note B)	p207.104g	0
7 Common Plant In Service - Electric		(Line 24)	0
8 Total Plant In Service		(Sum Lines 6 & 7)	0
9 Accumulated Depreciation (Total Electric Plant)		p219.29c	0
10 Accumulated Intangible Amortization	(Note A)	p200.21c	0
11 Accumulated Common Amortization - Electric	(Note A)	p356	0
12 Accumulated Common Plant Depreciation - Electric	(Note A)	p356	0
13 Total Accumulated Depreciation		(Sum Lines 9 to 12)	0
14 Net Plant		(Line 8 - 13)	0
15 Transmission Gross Plant		(Line 29 - Line 28)	0
16 **Gross Plant Allocator**		(Line 15 / 8)	**0.0000%**
17 Transmission Net Plant		(Line 39 - Line 28)	0
18 **Net Plant Allocator**		(Line 17 / 14)	**0.0000%**
Plant Calculations			
Plant In Service			
19 Transmission Plant In Service	(Note B)	p207.58.g	0
20 For True up only - remove New Transmission Plant Additions for Current Calendar Year	For True Up Only	Attachment 6	0
21 New Transmission Plant Additions for Current Calendar Year (weighted by months in service)		Attachment 6	0
22 **Total Transmission Plant In Service**		(Line 19 - 20 + 21)	**0**
23 General & Intangible		p205.5.g & p207.99.g	0
24 Common Plant (Electric Only)	(Notes A & B)	p356	0
25 Total General & Common		(Line 23 + 24)	0
26 Wage & Salary Allocation Factor		(Line 5)	0.00000%
27 **General & Common Plant Allocated to Transmission**		(Line 25 * 26)	**0**
28 **Plant Held for Future Use (Including Land)**	(Note C)	p214	**0**
29 **TOTAL Plant In Service**		**(Line 22 + 27 + 28)**	**0**
Accumulated Depreciation			
30 Transmission Accumulated Depreciation	(Note B)	p219.25.c	0
31 Accumulated General Depreciation		p219.28.c	0
32 Accumulated Intangible Amortization		(Line 10)	0
33 Accumulated Common Amortization - Electric		(Line 11)	0
34 Common Plant Accumulated Depreciation (Electric Only)		(Line 12)	0
35 Total Accumulated Depreciation		(Sum Lines 31 to 34)	0
36 Wage & Salary Allocation Factor		(Line 5)	0.00000%
37 **General & Common Allocated to Transmission**		(Line 35 * 36)	**0**
38 **TOTAL Accumulated Depreciation**		**(Line 30 + 37)**	**0**
39 **TOTAL Net Property, Plant & Equipment**		**(Line 29 - 38)**	**0**

Adjustment To Rate Base				
	Prepayments			
40	Prepayments (Account 165)	(Note A)	p111.57c	0
41	Net Plant Allocation Factor		(Line 18)	0.0000%
42	**Total Prepayments Allocated to Transmission**		(Line 40 * 41)	**0**
	Materials and Supplies			
43	Materials and Supplies	(Note A)	p227.6c & 15.c	0
44	Wage & Salary Allocation Factor		(Line 5)	0.00%
45	Total Transmission Allocated		(Line 43 * 44)	0
46	Transmission Materials & Supplies		p227.8c	0
47	**Total Materials & Supplies Allocated to Transmission**		(Line 45 + 46)	**0**
	Cash Working Capital			
48	Operation & Maintenance Expense		(Line 71)	0
49	1/8th Rule		x 1/8	12.5%
50	**Total Cash Working Capital Allocated to Transmission**		(Line 48 * 49)	**0**
	Construction Work in Progress (CWIP)			
51	Construction Work in Progress		p200.11b	
52	Gross Plant Allocation Factor		(Line 16)	0.0000%
53	**Total Construction Work in Progress**		(Line 51 * 52)	**0**
54	**TOTAL Adjustment to Rate Base**		(Line 42 + 47 + 50 +53)	**0**
55	**Rate Base**		(Line 39 + 54)	**0**
O&M				
	Transmission O&M			
56	Transmission O&M		p321.112.b	0
57	Less Account 565		p321.96.b	0
58	Less Schedule 12 payments applicable to the entire zone if not excluded in line 57 above	(Note O)	MWE Data	-
59	Plus Transmission Lease Payments	(Note A)	P200.4.c	0
60	**Transmission O&M**		(Lines 56 - 57 + 58 + 59)	**0**
	Allocated General & Common Expenses			
61	Common Plant O&M	(Note A)	p356	0
62	Total A&G		p323.197.b	0
63	Less Property Insurance Account 924		p323.185.b	0
64	Less EPRI Dues	(Note D)	p352-353	0
65	**General & Common Expenses**		(Lines 61 + 62) - Sum (63 to 64)	0
66	Wage & Salary Allocation Factor		(Line 5)	0.0000%
67	**General & Common Expenses Allocated to Transmission**		(Line 65 * 66)	**0**
	Directly Assigned A&G			
68	Property Insurance Account 924		p323.156b	0
69	Net Plant Allocation Factor		(Line 18)	0.00%
70	**A&G Directly Assigned to Transmission**		(Line 68 * 69)	**0**
71	**Total Transmission O&M**		**(Line 60 + 67 + 70)**	**0**
Depreciation & Amortization Expense				
	Depreciation Expense			
72	Transmission Depreciation Expense		p336.7b&c	**0**
73	General Depreciation		p336.10.b	0
74	Intangible Amortization	(Note A)	p336.1d&e	0
75	Total		(Line 73 + 74)	0
76	Wage & Salary Allocation Factor		(Line 5)	0.0000%
77	**General Depreciation Allocated to Transmission**		(Line 75 * 76)	**0**
78	Common Depreciation - Electric Only	(Note A)	p336.11.b	0
79	Common Amortization - Electric Only	(Note A)	p356 or p336.11.d	0
80	Total		(Line 78 + 79)	0
81	Wage & Salary Allocation Factor		(Line 5)	0.0000%
82	**Common Depreciation - Electric Only Allocated to Transmission**		(Line 80 * 81)	**0**
83	**Total Transmission Depreciation & Amortization**		**(Line 72 + 77 + 82)**	**0**
Taxes Other than Income				
84	**Taxes Other than Income**		Exhibit B	**0**
85	**Total Taxes Other than Income**		**(Line 84)**	**0**

Return / Capitalization Calculations					
	Long Term Interest				
86	Long Term Interest			p117.62c through 67c	0
87	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8	0
88	**Long Term Interest**			(Line 86)	0
	Common Stock				
89	Proprietary Capital			p112.16c	0
90	Less Account 216.1		enter negative	p112.12c	0
91	**Common Stock**			(Sum Lines 89 to 90)	0
	Capitalization				
92	Long Term Debt			p112.18.d through 21.d	0
93	Less LTD on Securitization Bonds	(Note P)	enter negative	Attachment 8	0
94	Total Long Term Debt			(Line 92 - 93)	0
95	Common Stock			(Line 91)	0
96	**Total Capitalization**			(Sum Lines 94 to 95)	0
97	Debt %	Total Long Term Debt		(Line 94 / 96)	0%
98	Common %	Common Stock		(Line 95 / 96)	0%
99	Debt Cost	Total Long Term Debt		(Line 88 / 94)	0.0000
100	Common Cost	Common Stock	(Note J)	Fixed	0.1235
101	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 97 * 99)	0.0000
102	Weighted Cost of Common	Common Stock		(Line 98 * 100)	0.0000
103	**Total Return (R)**			(Sum Lines 101 to 102)	**0.0000**
104	**Investment Return = Rate Base * Rate of Return**			**(Line 55 * 103)**	**0**
REVENUE REQUIREMENT					
	Summary				
105	Net Property, Plant & Equipment			(Line 39)	0
106	Adjustment to Rate Base			(Line 54)	0
107	**Rate Base**			(Line 55)	**0**
108	O&M			(Line 71)	0
109	Depreciation & Amortization			(Line 83)	0
110	Taxes Other than Income			(Line 85)	0
111	Investment Return			(Line 104)	0
112	**Gross Revenue Requirement**			**(Sum Lines 108 to 111)**	**0**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
113	Transmission Plant In Service			(Line 19)	0
114	Excluded Transmission Facilities		(Note M)	Attachment 5	0
115	Included Transmission Facilities			(Line 113 - 114)	0
116	Inclusion Ratio			(Line 115 / 113)	0.00%
117	Gross Revenue Requirement			(Line 112)	0
118	**Adjusted Gross Revenue Requirement**			(Line 116 * 117)	**0**
119	**Net Revenue Requirement**			**(Line 118)**	**0**
	Net Plant Carrying Charge without New Investment Incentive				
120	Net Revenue Requirement			(Line 119)	-
121	Net Transmission Plant			(Line 19 - 30)	-
122	Net Plant Carrying Charge without New Investment Incentive			(Line 120 / 121)	**0.0000%**
123	Net Plant Carrying Charge without New Investment Incentive without Depreciation			(Line 120 - 72) / 121	**0.0000%**
124	**Net Revenue Requirement**			(Line 119)	-
125	True-up amount			Attachment 6	
126	**Net Zonal Revenue Requirement**			(Line 124 - 126)	-
	Network Zonal Service Rate				
127	12 CP Peak		(Note L)	Midwest Data	0
128	Rate ($/KW-Year)			(Line 126 / 127)	0
129	**Network Service Rate ($/KW/Year)**			**(Line 128)**	**0**

Notes

A Electric portion only

B Exclude Construction Work In Progress and leases that are expensed as O&M (rather than amortized). New Transmission plant included in the SPP Regional Transmission Expansion Plan (RTEP) which is expected to be placed in service in the current calendar year weighted by number of months it is expected to be in-service. New Transmission plant expected to be placed in service in the current calendar year that is not included in RTEP must be separately detailed on Attachment 5. For the true-up, new transmission plant which was included in the SPP RTEP actually placed in service weighted by the number of months it was actually in service

C Transmission Portion Only

D All EPRI Annual Membership Dues

J ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.

L Network or Point to Point transactions of over one year for which the full revenue is received by the transmission owner

M Amount of transmission plant excluded from rates, includes investment in generation step-up transformers to the extent included in Plant in Service.

O Payments made under Schedule 12 of the SPP OATT are excluded in Transmission O&M on line 58 since they are already assessed under Schedule 12

P Appropriate adjustments to the capital structure may be made to reflect state authorized issuances of securitized bonds. Any such adjustments must be supported in the Section 205 filing seeking application of this formula .

END

Utility Name: MIDWEST ENERGY

Attachment 1 - Taxes Other Than Income Worksheet

Other Taxes	*Page 263 Col (i)*	*Allocator*	*Allocated Amount*
Plant Related		***Gross Plant Allocator***	
Property Taxes	0		
Total Plant Related	0	0.0000%	0
Labor Related		***Wages & Salary Allocator***	
Total Labor Related	0	0.0000%	0
Other Included		***Gross Plant Allocator***	
Total Other Included	0	0.0000%	0
Total Included			0
Currently Excluded			
Total as reported on p. 263(i)	0		

Utility Name: MIDWEST ENERGY

Attachment 2 - Cost Support

Electric / Non-electric Cost Support

	SPP Formula Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Electric Portion	Non-electric Portion	Details
	Plant Allocation Factors						
10	Accumulated Intangible Amortization	(Note A)	p200.21c				
11	Accumulated Common Amortization - Electric	(Note A)	p356				
12	Accumulated Common Plant Depreciation - Electric	(Note A)	p356				
	Plant In Service						
24	Common Plant (Electric Only)	(Notes A & B)	p356				
	Prepayments						
40	Prepayments (Account 165)	(Note A)	p111.57c				
	Materials and Supplies						
43	Materials and Supplies	(Note A)	p227.6c & 15.c	0	0	0	
	Allocated General & Common Expenses						
59	Plus Transmission Lease Payments	(Note A)	P200.4.c				
61	Common Plant O&M	(Note A)	p356				
	Depreciation Expense						
74	Intangible Amortization	(Note A)	p336.1d&e				
78	Common Depreciation - Electric Only	(Note A)	p336.11.b				
79	Common Amortization - Electric Only	(Note A)	p356 or p336.11.d				

Transmission / Non-transmission Cost Support

	SPP Formula Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Transmission Related	Non-transmission Related	Details
28	**Plant Held for Future Use (Including Land)**	(Note C)	p214				Specific identification based on plant records
							1
							2
							3
							4
							5

CWIP & Expensed Lease Worksheet

	SPP Formula Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	CWIP in Form 1 Amount	Expensed Lease in Form 1 Amount	Details
	Plant Allocation Factors						
6	Electric Plant in Service	(Note B)	p207.104g				See Form 1
	Plant In Service						
19	Transmission Plant In Service	(Note B)	p207.58.g				See Form 1
24	Common Plant (Electric Only)	(Notes A & B)	p356				See Line 24
	Accumulated Depreciation						
30	Transmission Accumulated Depreciation	(Note B)	p219.25.c				See Form 1

EPRI Dues Cost Support

	SPP Formula Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	EPRI Dues	Details
	Allocated General & Common Expenses					
64	Less EPRI Dues	(Note D)	p352-353			EPRI Dues payed by Holding company

Excluded Plant Cost Support

SPP Formula Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Excluded Transmission Facilities	Description of the Facilities
Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities					
114	Excluded Transmission Facilities	(Note M)	Attachment 5	-	General Description of the Facilities
				$ -	
				-	
					Add more lines if necessary

Load Cost Support

SPP Formula Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				12 CP Peak	Description & PJM Documentation
	Network Zonal Service Rate				
127	12 CP Peak	(Note L)	Midwest Data		SPP Zonal Peak Load per 34.1 of the PJM OATT

Statements BG/BH (Present and Proposed Revenues)

Customer	Billing Determinants	Current Rate	Proposed Rate	Current Revenues	Proposed Revenues	Change in Revenues
				-	-	-
Total				-	-	-

Utility Name: MIDWEST ENERGY

Attachment 3 - Estimate and True-up Worksheet

Step	Month	Year	Action
Exec Summary			
1	April	XXX	TO populates the formula with Prior Year data
2	April	XXX	TO estimates Cap Adds for Current Year weighted based on Months expected to be in service in Current Year
3	April	XXX	TO adds weighted Cap Adds to plant in service in Formula
4	May	XXX	Post on SPP web site
5	June	XXX	Rates go into effect
6	April	XXXX	TO populates the formula with Prior Year data
7	April	XXXX	TO estimates Cap Adds during Current Year (calendar) weighted based on Months expected to be in service in Current Year
8	April	XXXX	True-up - TO calculates true-up by removing from Step 6 the total Cap Adds placed in service that year and adding weighted average Cap Adds in true-up
9	April	XXXX	True-up - TO adds the difference between the true-up in Step 8 and the forecast in Prior Year with interest to the result of Step 7
10	May	XXXX	Post on SPP web site
11	June	XXXX	Rates go into effect
12	June	XXXX	Return to Step 6 for following year

Prior Year
Current Year

Detailed Example

1 April XXX TO populates the formula with Prior Year data

Rev Req based on Prior Year data

2 April XXX TO estimates Cap Adds for Current Year weighted based on Months expected to be in service in Current Year

	Est. In Service Date	Weighting	Amount	One 12th
Jan		12	-	-
Feb		11	-	-
Mar		10	-	-
Apr		9	-	-
May		8	-	-
Jun		7	-	-
Jul		6	-	-
Aug		5	-	-
Sep		4	-	-
Oct		3	-	-
Nov		2	-	-
Dec		1	-	-
Total	-		-	-

New Transmission Plant Additions for Current Calendar Year (weighted by months in service) -

3 April XXX TO adds weighted Cap Adds to plant in service in Formula

$ - Input to Formula Line 21

4 May XXX Post On SPP Web Site Rev Req and Formula with Exhibits

5 June XXX Rates go into effect

$ -

6 April XXXX TO populates the formula with Prior Year data

$ - Rev Req based on Prior Year data

7 April XXXX TO estimates Cap Adds during Current Year (calendar) weighted based on Months expected to be in service in Current Year

	Est. In Service Date	Weighting	Amount	One 12th
Jan	-	12	-	-
Feb	-	11	-	-
Mar	-	10	-	-
Apr	-	9	-	-
May	-	8	-	-
Jun	-	7	-	-
Jul	-	6	-	-
Aug	-	5	-	-
Sep	-	4	-	-
Oct	-	3	-	-
Nov	-	2	-	-
Dec	-	1	-	-
Total	-		-	-

New Transmission Plant Additions for Current Calendar Year (weighted by months in service) - Input to Formula Line 21

8 April XXXX True-up - TO calculates true-up by removing from Step 6 the total Cap Adds placed in service that year and adding weighted average Cap Adds in true-up

Remove all Cap Adds placed in service in Prior Year

For True up only - remove New Transmission Plant Additions for Current Calendar Year - Input to Formula Line 20

Add Cap Adds actually placed in service in Prior Year

	Actual In Service Date	Weighting	Amount	One 12th
Jan	-	12	-	-
Feb	-	11	-	-
Mar	-	10	-	-
Apr	-	9	-	-
May	-	8	-	-
Jun	-	7	-	-
Jul	-	6	-	-
Aug	-	5	-	-
Sep	-	4	-	-
Oct	-	3	-	-
Nov	-	2	-	-
Dec	-	1	-	-
Total	-		-	-

New Transmission Plant Additions for Current Calendar Year (weighted by months in service) - Input to Formula Line 21

- Result of Formula for true-up

9 April XXXX True-up - TO adds the difference between the true-up in Step 8 and the forecast in Prior Year with interest to the result of Step 7

The true-up in Step 8		The forecast in Prior Year		
-	-	-	=	-

Interest on Amount of Refunds or Surcharges

Interest 35.19a for March Current Yr

Month	Yr	1/12 of Step 9	Interest 35.19a for March Current Yr	Months	Interest	Refunds Owed
Jun	2005	-	0.0000%	12	-	-
Jul	2005	-	0.0000%	11	-	-
Aug	2005	-	0.0000%	10	-	-
Sep	2005	-	0.0000%	9	-	-
Oct	2005	-	0.0000%	8	-	-
Nov	2005	-	0.0000%	7	-	-
Dec	2005	-	0.0000%	6	-	-
Jan	2006	-	0.0000%	5	-	-
Feb	2006	-	0.0000%	4	-	-
Mar	2006	-	0.0000%	3	-	-
Apr	2006	-	0.0000%	2	-	-
May	2006	-	0.0000%	1	-	-
Total		-				-

		Balance	Interest	Amort	Balance
Jun	2006	-	0.0000%	-	-
Jul	2006	-	0.0000%	-	-
Aug	2006	-	0.0000%	-	-
Sep	2006	-	0.0000%	-	-
Oct	2006	-	0.0000%	-	-
Nov	2006	-	0.0000%	-	-
Dec	2006	-	0.0000%	-	-
Jan	2007	-	0.0000%	-	-
Feb	2007	-	0.0000%	-	-
Mar	2007	-	0.0000%	-	-
Apr	2007	-	0.0000%	-	-
May	2007	-	0.0000%	-	-
Total with interest				-	

The difference between the true-up in Step 8 and the forecast in Prior Year with interest		-
Rev Req based on Current Year data with estimated Cap Adds for Current Year	$	-
Revenue Requirement for Current Year		-

10 May XXXX Post on SPP web site

$ - Post On SPP Web Site Rev Req and Formula with Exhibits

11 June XXXX Rates go into effect

$ -

Return to Step 6 for following year

UTILITY NAME: Midwest Energy

Attachment 4 - 12 CP Calculation

Month	Year	Monthly Peak Load
July `06		
Aug.		
Sep.		
Oct.		
Nov.		
Dec.		
Jan. `07		
Feb.		
Mar.		
Apr.		
May		
Jun.		
Total		-
12 CP Allocator		-

Utility Name: M 'EST ENERGY

Attachment 5 - Transmission Enhancement Charge Worksheet

New Plant Carrying Charge

FCR if not a CIAC

	Formula Line		
A	123	Net Plant Carrying Charge without New Investment Incentive without Depreciation	0.0000%
B	#REF!	#REF!	#REF!
C		Line B less Line A	#REF!

FCR if a CIAC

D	#REF!	#REF!	#REF!

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years
The Transmission Enhancement Charges assessed projects pursuant to Schedule 12 include any approved incentives, the amounts credited to the Customers in the zone under Schedule 12 do not include any such incentives.

Details		Project A				Project B				Project C						
Life																
CIAC		No				No				Yes						
ROE Incentive (Basis Points)																
FCR W/O incentive		0				0				#REF!						
FCR for This Project		#REF!				#REF!				#REF!						
Investment		-				-				-						
Annual Depreciation Exp																
In Service Month (1-12)																
	Invest Yr	**Beginning**	**Depreciation**	**Ending**	**Revenue**	**Beginning**	**Depreciation**	**Ending**	**Revenue**	**Beginning**	**Depreciation**	**Ending**	**Revenue**	**Total**	**Incentive Charged**	**Revenue Credit**
W/O Incentive	2005	-	-	-	-									$ -		$ -
W Incentive	2005	-	-	-	#REF!									#REF!	#REF!	
W/O Incentive	2006	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2006	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2007	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2007	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2008	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2008	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2009	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2009	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2010	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2010	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2011	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2011	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2012	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2012	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2013	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2013	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2014	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2014	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2015	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2015	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2016	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2016	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2017	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2017	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2018	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2018	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2019	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2019	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2020	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2020	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2021	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2021	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2022	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2022	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2023	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2023	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2024	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2024	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
....	....		....	.....	....	....	....	Page 1 of 1	....	....	....	.....	....			$ -
.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....		$ -	
															#REF!	#REF!

Appendix A

Utility Name: MIDWEST ENERGY			
Formula Rate	**Notes**	**FERC Form 1 Page # or Instruction**	**Year**

Shaded cells are input cells

Allocators				
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		p354.21.b	234,627
2	Total Wages Expense		p354.28b	4,418,032
3	Less A&G Wages Expense		p354.27b	1,256,544
4	Total		(Line 2 - 3)	3,161,488
5	**Wages & Salary Allocator**		(Line 1 / 4)	**7.4214%**
	Plant Allocation Factors			
6	Electric Plant In Service	(Note B)	p207.104g	285,259,225
7	Common Plant In Service - Electric		(Line 24)	14,663,602
8	Total Plant In Service		(Sum Lines 6 & 7)	299,922,827
9	Accumulated Depreciation (Total Electric Plant)		p219.29c	135,443,399
10	Accumulated Intangible Amortization	(Note A)	p200.21c	13,939
11	Accumulated Common Amortization - Electric	(Note A)	p356	0
12	Accumulated Common Plant Depreciation - Electric	(Note A)	p356	6,525,567
13	Total Accumulated Depreciation		(Sum Lines 9 to 12)	141,982,905
14	Net Plant		(Line 8 - 13)	157,939,922
15	Transmission Gross Plant		(Line 29 - Line 28)	68,916,558
16	**Gross Plant Allocator**		(Line 15 / 8)	**22.9781%**
17	Transmission Net Plant		(Line 39 - Line 28)	30,804,575
18	**Net Plant Allocator**		(Line 17 / 14)	**19.5040%**
Plant Calculations				
	Plant In Service			
19	Transmission Plant In Service	(Note B)	p207.58.g	66,667,763
20	For True up only - remove New Transmission Plant Additions for Current Calendar Year	For True Up Only	Attachment 6	0
21	New Transmission Plant Additions for Current Calendar Year (weighted by months in service)		Attachment 6	0
22	**Total Transmission Plant In Service**		(Line 19 - 20 + 21)	**66,667,763**
23	General & Intangible		p205.5.g & p207.99.g	15,637,844
24	Common Plant (Electric Only)	(Notes A & B)	p356	14,663,602
25	Total General & Common		(Line 23 + 24)	30,301,446
26	Wage & Salary Allocation Factor		(Line 5)	7.42141%
27	**General & Common Plant Allocated to Transmission**		(Line 25 * 26)	**2,248,795**
28	**Plant Held for Future Use (Including Land)**	(Note C)	p214	**0**
29	**TOTAL Plant In Service**		**(Line 22 + 27 + 28)**	**68,916,558**
	Accumulated Depreciation			
30	Transmission Accumulated Depreciation	(Note B)	p219.25.c	37,026,663
31	Accumulated General Depreciation		p219.28.c	8,084,663
32	Accumulated Intangible Amortization		(Line 10)	13,939
33	Accumulated Common Amortization - Electric		(Line 11)	0
34	Common Plant Accumulated Depreciation (Electric Only)		(Line 12)	6,525,567
35	Total Accumulated Depreciation		(Sum Lines 31 to 34)	14,624,169
36	Wage & Salary Allocation Factor		(Line 5)	7.42141%
37	**General & Common Allocated to Transmission**		(Line 35 * 36)	**1,085,320**
38	**TOTAL Accumulated Depreciation**		**(Line 30 + 37)**	**38,111,983**
39	**TOTAL Net Property, Plant & Equipment**		**(Line 29 - 38)**	**30,804,575**

Adjustment To Rate Base				
	Prepayments			
40	Prepayments (Account 165)	(Note A)	p111.57c	401,270
41	Net Plant Allocation Factor		(Line 18)	19.5040%
42	**Total Prepayments Allocated to Transmission**		(Line 40 * 41)	**78,264**
	Materials and Supplies			
43	Materials and Supplies	(Note A)	p227.6c & 15.c	4,928,929
44	Wage & Salary Allocation Factor		(Line 5)	7.42%
45	Total Transmission Allocated		(Line 43 * 44)	365,796
46	Transmission Materials & Supplies		p227.8c	58,585
47	**Total Materials & Supplies Allocated to Transmission**		(Line 45 + 46)	**424,381**
	Cash Working Capital			
48	Operation & Maintenance Expense		(Line 71)	1,394,803
49	1/8th Rule		x 1/8	12.5%
50	**Total Cash Working Capital Allocated to Transmission**		(Line 48 * 49)	**174,350**
	Construction Work in Progress (CWIP)			
51	Construction Work in Progress		p200.11b	5,763,819
52	Gross Plant Allocation Factor		(Line 16)	22.9781%
53	**Total Construction Work in Progress**		(Line 51 * 52)	**1,324,416**
54	**TOTAL Adjustment to Rate Base**		(Line 42 + 47 + 50 +53)	**2,001,411**
55	**Rate Base**		(Line 39 + 54)	**32,805,986**
O&M				
	Transmission O&M			
56	Transmission O&M		p321.112.b	1,177,795
57	Less Account 565		p321.96.b	0
58	Less Schedule 12 payments applicable to the entire zone if not excluded in line 57 above	(Note O)	MWE Data	(92,392)
59	Plus Transmission Lease Payments	(Note A)	P200.4.c	0
60	**Transmission O&M**		(Lines 56 - 57 + 58 + 59)	**1,085,403**
	Allocated General & Common Expenses			
61	Common Plant O&M	(Note A)	p356	0
62	Total A&G		p323.197.b	3,969,082
63	Less Property Insurance Account 924		p323.185.b	122,806
64	Less EPRI Dues	(Note D)	p352-353	0
65	**General & Common Expenses**		(Lines 61 + 62) - Sum (63 to 64)	3,846,276
66	Wage & Salary Allocation Factor		(Line 5)	7.4214%
67	**General & Common Expenses Allocated to Transmission**		(Line 65 * 66)	**285,448**
	Directly Assigned A&G			
68	Property Insurance Account 924		p323.156b	122,806
69	Net Plant Allocation Factor		(Line 18)	19.50%
70	**A&G Directly Assigned to Transmission**		(Line 68 * 69)	**23,952**
71	**Total Transmission O&M**		**(Line 60 + 67 + 70)**	**1,394,803**
Depreciation & Amortization Expense				
	Depreciation Expense			
72	Transmission Depreciation Expense		p336.7b&c	**976,537**
73	General Depreciation		p336.10.b	146,370
74	Intangible Amortization	(Note A)	p336.1d&e	11,622
75	Total		(Line 73 + 74)	157,992
76	Wage & Salary Allocation Factor		(Line 5)	7.4214%
77	**General Depreciation Allocated to Transmission**		(Line 75 * 76)	**11,725**
78	Common Depreciation - Electric Only	(Note A)	p336.11.b	756,797
79	Common Amortization - Electric Only	(Note A)	p356 or p336.11.d	0
80	Total		(Line 78 + 79)	756,797
81	Wage & Salary Allocation Factor		(Line 5)	7.4214%
82	**Common Depreciation - Electric Only Allocated to Transmission**		(Line 80 * 81)	**56,165**
83	**Total Transmission Depreciation & Amortization**		**(Line 72 + 77 + 82)**	**1,044,427**
Taxes Other than Income				
84	**Taxes Other than Income**		Exhibit B	**910,450**
85	**Total Taxes Other than Income**		**(Line 84)**	**910,450**

Return / Capitalization Calculations

	Long Term Interest				
86	Long Term Interest			p117.62c through 67c	7,193,504
87	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8	0
88	**Long Term Interest**			(Line 86)	7,193,504
	Common Stock				
89	Proprietary Capital			p112.16c	97,926,627
90	Less Account 216.1		enter negative	p112.12c	494,573
91	**Common Stock**			(Sum Lines 89 to 90)	98,421,200
	Capitalization				
92	Long Term Debt			p112.18.d through 21.d	128,122,153
93	Less LTD on Securitization Bonds	(Note P)	enter negative	Attachment 8	0
94	Total Long Term Debt			(Line 92 - 93)	128,122,153
95	Common Stock			(Line 91)	98,421,200
96	**Total Capitalization**			(Sum Lines 94 to 95)	226,543,353
97	Debt %	Total Long Term Debt		(Line 94 / 96)	57%
98	Common %	Common Stock		(Line 95 / 96)	43%
99	Debt Cost	Total Long Term Debt		(Line 88 / 94)	0.0561
100	Common Cost	Common Stock	(Note J)	Fixed	0.1239
101	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 97 * 99)	0.0318
102	Weighted Cost of Common	Common Stock		(Line 98 * 100)	0.0538
103	**Total Return (R)**			(Sum Lines 101 to 102)	**0.0856**
104	**Investment Return = Rate Base * Rate of Return**			**(Line 55 * 103)**	**2,808,194**

REVENUE REQUIREMENT

	Summary				
105	Net Property, Plant & Equipment			(Line 39)	30,804,575
106	Adjustment to Rate Base			(Line 54)	2,001,411
107	**Rate Base**			(Line 55)	**32,805,986**
108	O&M			(Line 71)	1,394,803
109	Depreciation & Amortization			(Line 83)	1,044,427
110	Taxes Other than Income			(Line 85)	910,450
111	Investment Return			(Line 104)	2,808,194
112	**Gross Revenue Requirement**			**(Sum Lines 108 to 111)**	**6,157,875**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
113	Transmission Plant In Service			(Line 19)	66,667,763
114	Excluded Transmission Facilities		(Note M)	Attachment 5	2,739,063
115	Included Transmission Facilities			(Line 113 - 114)	63,928,700
116	Inclusion Ratio			(Line 115 / 113)	95.89%
117	Gross Revenue Requirement			(Line 112)	6,157,875
118	**Adjusted Gross Revenue Requirement**			(Line 116 * 117)	**5,904,877**
119	**Net Revenue Requirement**			**(Line 118)**	**5,904,877**
	Net Plant Carrying Charge without New Investment Incentive				
120	Net Revenue Requirement			(Line 119)	**5,904,877**
121	Net Transmission Plant			(Line 19 - 30)	**29,641,100**
122	Net Plant Carrying Charge without New Investment Incentive			(Line 120 / 121)	**19.9212%**
123	Net Plant Carrying Charge without New Investment Incentive without Depreciation			(Line 120 - 72) / 121	**16.6267%**
124	**Net Revenue Requirement**			(Line 119)	**5,904,877**
125	True-up amount			Attachment 6	
126	**Net Zonal Revenue Requirement**			(Line 124 - 126)	**5,904,877**
	Network Zonal Service Rate				
127	12 CP Peak		(Note L)	Midwest Data	248,250
128	Rate ($/KW-Year)			(Line 126 / 127)	**24**
129	**Network Service Rate ($/KW/Year)**			**(Line 128)**	**24**

Notes

A Electric portion only

B Exclude Construction Work In Progress and leases that are expensed as O&M (rather than amortized). New Transmission plant included in the SPP Regional Transmission Expansion Plan (RTEP) which is expected to be placed in service in the current calendar year weighted by number of months it is expected to be in-service. New Transmission plant expected to be placed in service in the current calendar year that is not included in RTEP must be separately detailed on Attachment 5. For the true-up, new transmission plant which was included in the SPP RTEP actually placed in service weighted by the number of months it was actually in service

C Transmission Portion Only

D All EPRI Annual Membership Dues

J ROE will be supported in the original filing and no change in ROE may be made absent a filing with KCC.

L Network or Point to Point transactions of over one year for which the full revenue is received by the transmission owner

M Amount of transmission plant excluded from rates, includes investment in generation step-up transformers to the extent included in Plant in Service.

O Payments made under Schedule 12 of the SPP OATT are excluded in Transmission O&M on line 58 since they are already assessed under Schedule 12

P Appropriate adjustments to the capital structure may be made to reflect state authorized issuances of securitized bonds. Any such adjustments must be supported in the Section 205 filing seeking application of this formula .

END

Utility Name: MIDWEST ENERGY

Attachment 1 - Taxes Other Than Income Worksheet

Other Taxes	*Page 263 Col (i)*	*Allocator*	*Allocated Amount*
Plant Related		***Gross Plant Allocator***	
Property Taxes	3,962,253		
Total Plant Related	3,962,253	22.9781%	910,450
Labor Related		***Wages & Salary Allocator***	
Total Labor Related	0	7.4214%	0
Other Included		***Gross Plant Allocator***	
Total Other Included	0	22.9781%	0
Total Included			910,450

Currently Excluded

Total as reported on p. 263(i)	3,962,253

Utility Name: MIDWEST ENERGY

Attachment 2 - Cost Support

Electric / Non-electric Cost Support

	SPP Formula Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Electric Portion	Non-electric Portion	Details
	Plant Allocation Factors						
10	Accumulated Intangible Amortization	(Note A)	p200.21c				
11	Accumulated Common Amortization - Electric	(Note A)	p356				
12	Accumulated Common Plant Depreciation - Electric	(Note A)	p356				
	Plant In Service						
24	Common Plant (Electric Only)	(Notes A & B)	p356				
	Prepayments						
40	Prepayments (Account 165)	(Note A)	p111.57c				
	Materials and Supplies						
43	Materials and Supplies	(Note A)	p227.6c & 15.c	5,476,979	4,928,929	548,050	
	Allocated General & Common Expenses						
59	Plus Transmission Lease Payments	(Note A)	P200.4.c				
61	Common Plant O&M	(Note A)	p356				
	Depreciation Expense						
74	Intangible Amortization	(Note A)	p336.1d&e				
78	Common Depreciation - Electric Only	(Note A)	p336.11.b				
79	Common Amortization - Electric Only	(Note A)	p356 or p336.11.d				

Transmission / Non-transmission Cost Support

	SPP Formula Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Transmission Related	Non-transmission Related	Details
28	**Plant Held for Future Use (Including Land)**	(Note C)	p214				Specific identification based on plant records
							1
							2
							3
							4
							5

CWIP & Expensed Lease Worksheet

	SPP Formula Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	CWIP in Form 1 Amount	Expensed Lease in Form 1 Amount	Details
	Plant Allocation Factors						
6	Electric Plant in Service	(Note B)	p207.104g				See Form 1
	Plant In Service						
19	Transmission Plant In Service	(Note B)	p207.58.g				See Form 1
24	Common Plant (Electric Only)	(Notes A & B)	p356				See Line 24
	Accumulated Depreciation						
30	Transmission Accumulated Depreciation	(Note B)	p219.25.c				See Form 1

EPRI Dues Cost Support

	SPP Formula Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	EPRI Dues	Details
	Allocated General & Common Expenses					
64	Less EPRI Dues	(Note D)	p352-353			EPRI Dues payed by Holding company

Excluded Plant Cost Support

SPP Formula Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Excluded Transmission Facilities	Description of the Facilities
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
114	Excluded Transmission Facilities	(Note M)	Attachment 5	2,739,063	**General Description of the Facilities**
				$ 1,181,059	**S. Hays to Gorham**
				1,558,004	**Great Bend North to Susank, Bunker Hill and Hitschmann**
					Add more lines if necessary

Load Cost Support

SPP Formula Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				12 CP Peak	Description & PJM Documentation
	Network Zonal Service Rate				
127	12 CP Peak	(Note L)	Midwest Data		SPP Zonal Peak Load per 34.1 of the PJM OATT

Statements BG/BH (Present and Proposed Revenues)

Customer	Billing Determinants	Current Rate	Proposed Rate	Current Revenues	Proposed Revenues	Change in Revenues
				-	-	-
Total				-	-	-

Utility Name: MIDWEST ENERGY

Attachment 3 - Estimate and True-up Worksheet

Step	Month	Year	Action
Exec Summary			
1	April	XXX	TO populates the formula with Prior Year data
2	April	XXX	TO estimates Cap Adds for Current Year weighted based on Months expected to be in service in Current Year
3	April	XXX	TO adds weighted Cap Adds to plant in service in Formula
4	May	XXX	Post on SPP web site
5	June	XXX	Rates go into effect
6	April	XXXX	TO populates the formula with Prior Year data
7	April	XXXX	TO estimates Cap Adds during Current Year (calendar) weighted based on Months expected to be in service in Current Year
8	April	XXXX	True-up - TO calculates true-up by removing from Step 6 the total Cap Adds placed in service that year and adding weighted average Cap Adds in true-up
9	April	XXXX	True-up - TO adds the difference between the true-up in Step 8 and the forecast in Prior Year with interest to the result of Step 7
10	May	XXXX	Post on SPP web site
11	June	XXXX	Rates go into effect
12	June	XXXX	Return to Step 6 for following year

Prior Year
Current Year

Detailed Example

1 April XXX TO populates the formula with Prior Year data
Rev Req based on Prior Year data

2 April XXX TO estimates Cap Adds for Current Year weighted based on Months expected to be in service in Current Year

	Est. In Service Date	Weighting	Amount	One 12th
Jan		12	-	-
Feb		11	-	-
Mar		10	-	-
Apr		9	-	-
May		8	-	-
Jun		7	-	-
Jul		6	-	-
Aug		5	-	-
Sep		4	-	-
Oct		3	-	-
Nov		2	-	-
Dec		1	-	-
Total	-		-	-

New Transmission Plant Additions for Current Calendar Year (weighted by months in service) -

3 April XXX TO adds weighted Cap Adds to plant in service in Formula
$ - Input to Formula Line 21

4 May XXX Post On SPP Web Site Rev Req and Formula with Exhibits

5 June XXX Rates go into effect
$ -

6 April XXXX TO populates the formula with Prior Year data

$ - Rev Req based on Prior Year data

7 April XXXX TO estimates Cap Adds during Current Year (calendar) weighted based on Months expected to be in service in Current Year

	Est. In Service Date	Weighting	Amount	One 12th
Jan	-	12	-	-
Feb	-	11	-	-
Mar	-	10	-	-
Apr	-	9	-	-
May	-	8	-	-
Jun	-	7	-	-
Jul	-	6	-	-
Aug	-	5	-	-
Sep	-	4	-	-
Oct	-	3	-	-
Nov	-	2	-	-
Dec	-	1	-	-
Total	-		-	-

New Transmission Plant Additions for Current Calendar Year (weighted by months in service) - Input to Formula Line 21

8 April XXXX True-up - TO calculates true-up by removing from Step 6 the total Cap Adds placed in service that year and adding weighted average Cap Adds in true-up

Remove all Cap Adds placed in service in Prior Year

For True up only - remove New Transmission Plant Additions for Current Calendar Year - Input to Formula Line 20

Add Cap Adds actually placed in service in Prior Year

	Actual In Service Date	Weighting	Amount	One 12th
Jan	-	12	-	-
Feb	-	11	-	-
Mar	-	10	-	-
Apr	-	9	-	-
May	-	8	-	-
Jun	-	7	-	-
Jul	-	6	-	-
Aug	-	5	-	-
Sep	-	4	-	-
Oct	-	3	-	-
Nov	-	2	-	-
Dec	-	1	-	-
Total	-		-	-

New Transmission Plant Additions for Current Calendar Year (weighted by months in service) - Input to Formula Line 21

- Result of Formula for true-up

9 April XXXX True-up - TO adds the difference between the true-up in Step 8 and the forecast in Prior Year with interest to the result of Step 7

The true-up in Step 8		The forecast in Prior Year		
-	-	-	=	-

Interest on Amount of Refunds or Surcharges

Interest 35.19a for March Current Yr

Month	Yr	1/12 of Step 9	Interest 35.19a for March Current Yr	Months	Interest	Refunds Owed
Jun	2005	-	0.0000%	12	-	-
Jul	2005	-	0.0000%	11	-	-
Aug	2005	-	0.0000%	10	-	-
Sep	2005	-	0.0000%	9	-	-
Oct	2005	-	0.0000%	8	-	-
Nov	2005	-	0.0000%	7	-	-
Dec	2005	-	0.0000%	6	-	-
Jan	2006	-	0.0000%	5	-	-
Feb	2006	-	0.0000%	4	-	-
Mar	2006	-	0.0000%	3	-	-
Apr	2006	-	0.0000%	2	-	-
May	2006	-	0.0000%	1	-	-
Total		-				-

		Balance	Interest	Amort	Balance
Jun	2006	-	0.0000%	-	-
Jul	2006	-	0.0000%	-	-
Aug	2006	-	0.0000%	-	-
Sep	2006	-	0.0000%	-	-
Oct	2006	-	0.0000%	-	-
Nov	2006	-	0.0000%	-	-
Dec	2006	-	0.0000%	-	-
Jan	2007	-	0.0000%	-	-
Feb	2007	-	0.0000%	-	-
Mar	2007	-	0.0000%	-	-
Apr	2007	-	0.0000%	-	-
May	2007	-	0.0000%	-	-
Total with interest				-	

The difference between the true-up in Step 8 and the forecast in Prior Year with interest		-
Rev Req based on Current Year data with estimated Cap Adds for Current Year	$	-
Revenue Requirement for Current Year		-

10 May XXXX Post on SPP web site

$ - Post On SPP Web Site Rev Req and Formula with Exhibits

11 June XXXX Rates go into effect

$ -

Return to Step 6 for following year

UTILITY NAME: Midwest Energy

Attachment 4 - 12 CP Calculation

Month	Year	Monthly Peak Load
July `06		357,000
Aug.		349,000
Sep.		248,000
Oct.		249,000
Nov.		229,000
Dec.		220,000
Jan. `07		212,000
Feb.		217,000
Mar.		192,000
Apr.		195,000
May		223,000
Jun.		288,000
Total		2,979,000
12 CP Allocator		248,250

Utility Name: ' 'EST ENERGY

Attachment 5 - Transmission Enhancement Charge Worksheet

New Plant Carrying Charge

FCR If not a CIAC

	Formula Line		
A	123	Net Plant Carrying Charge without New Investment Incentive without Depreciation	16.6267%
B	#REF!	#REF!	#REF!
C		Line B less Line A	#REF!

FCR If a CIAC

D	#REF!	#REF!	#REF!

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years
The Transmission Enhancement Charges assessed projects pursuant to Schedule 12 include any approved incentives, the amounts credited to the Customers in the zone under Schedule 12 do not include any such incentives.

Details		Project A				Project B				Project C						
Life																
CIAC		No				No				Yes						
ROE Incentive (Basis Points)																
FCR W/O Incentive		0.1662671				0.1662671				#REF!						
FCR for This Project		#REF!				#REF!				#REF!						
Investment		-				-				-						
Annual Depreciation Exp																
In Service Month (1-12)																
	Invest Yr	**Beginning**	**Depreciation**	**Ending**	**Revenue**	**Beginning**	**Depreciation**	**Ending**	**Revenue**	**Beginning**	**Depreciation**	**Ending**	**Revenue**	**Total**	**Incentive Charged**	**Revenue Credit**
W/O Incentive	2005	-	-	-	-									$ -		$ -
W Incentive	2005	-	-	-	#REF!									#REF!	#REF!	
W/O Incentive	2006	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2006	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2007	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2007	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2008	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2008	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2009	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2009	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2010	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2010	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2011	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2011	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2012	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2012	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2013	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2013	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2014	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2014	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2015	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2015	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2016	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2016	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2017	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2017	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2018	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2018	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2019	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2019	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2020	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2020	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2021	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2021	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2022	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2022	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2023	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2023	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2024	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2024	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
....	....		....	.....	....	....	....	Page 1 of 1	....	.....	....	.....	....			$ -
....	....	....	.....	.....	....	....	.....	.....	....	.....	.....	.....	....		$ -	
															#REF!	#REF!

Appendix A

Utility Name: MIDWEST ENERGY			
Formula Rate	**Notes**	**FERC Form 1 Page # or Instruction**	**Year**
Shaded cells are input cells			

Aliocators

	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		p354.21.b	266,263
2	Total Wages Expense		p354.28b	4,665,296
3	Less A&G Wages Expense		p354.27b	1,245,519
4	Total		(Line 2 - 3)	3,419,777
5	**Wages & Salary Allocator**		(Line 1 / 4)	**7.7857%**
	Plant Allocation Factors			
6	Electric Plant in Service	(Note B)	p207.104g	356,177,784
7	Common Plant In Service - Electric		(Line 24)	13,490,914
8	Total Plant In Service		(Sum Lines 6 & 7)	369,668,698
9	Accumulated Depreciation (Total Electric Plant)		p219.29c	138,417,810
10	Accumulated Intangible Amortization	(Note A)	p200.21c	15,757
11	Accumulated Common Amortization - Electric	(Note A)	p356	0
12	Accumulated Common Plant Depreciation - Electric	(Note A)	p356	7,105,284
13	Total Accumulated Depreciation		(Sum Lines 9 to 12)	145,538,851
14	Net Plant		(Line 8 - 13)	224,129,847
15	Transmission Gross Plant		(Line 29 - Line 28)	69,126,782
16	**Gross Plant Allocator**		(Line 15 / 8)	**18.6997%**
17	Transmission Net Plant		(Line 39 - Line 28)	30,468,009
18	**Net Plant Allocator**		(Line 17 / 14)	**13.5939%**

Plant Calculations

	Plant In Service			
19	Transmission Plant In Service	(Note B)	p207.58.g	66,905,784
20	For True up only - remove New Transmission Plant Additions for Current Calendar Year	For True Up Only	Attachment 6	0
21	New Transmission Plant Additions for Current Calendar Year (weighted by months in service)		Attachment 6	0
22	**Total Transmission Plant In Service**		(Line 19 - 20 + 21)	**66,905,784**
23	General & Intangible		p205.5.g & p207.99.g	15,035,786
24	Common Plant (Electric Only)	(Notes A & B)	p356	13,490,914
25	Total General & Common		(Line 23 + 24)	28,526,700
26	Wage & Salary Allocation Factor		(Line 5)	7.78568%
27	**General & Common Plant Allocated to Transmission**		(Line 25 * 26)	**2,220,998**
28	**Plant Held for Future Use (Including Land)**	(Note C)	p214	**0**
29	**TOTAL Plant In Service**		**(Line 22 + 27 + 28)**	**69,126,782**
	Accumulated Depreciation			
30	Transmission Accumulated Depreciation	(Note B)	p219.25.c	37,476,664
31	Accumulated General Depreciation		p219.28.c	8,062,072
32	Accumulated Intangible Amortization		(Line 10)	15,757
33	Accumulated Common Amortization - Electric		(Line 11)	0
34	Common Plant Accumulated Depreciation (Electric Only)		(Line 12)	7,105,284
35	Total Accumulated Depreciation		(Sum Lines 31 to 34)	15,183,113
36	Wage & Salary Allocation Factor		(Line 5)	7.78568%
37	**General & Common Allocated to Transmission**		(Line 35 * 36)	**1,182,109**
38	**TOTAL Accumulated Depreciation**		**(Line 30 + 37)**	**38,658,773**
39	**TOTAL Net Property, Plant & Equipment**		**(Line 29 - 38)**	**30,468,009**

Adjustment To Rate Base				
	Prepayments			
40	Prepayments (Account 165)	(Note A)	p111.57d	309,995
41	Net Plant Allocation Factor		(Line 18)	13.5939%
42	**Total Prepayments Allocated to Transmission**		(Line 40 * 41)	**42,140**
	Materials and Supplies			
43	Materials and Supplies	(Note A)	p227.6c & 15.c	5,967,837
44	Wage & Salary Allocation Factor		(Line 5)	7.79%
45	Total Transmission Allocated		(Line 43 * 44)	464,637
46	Transmission Materials & Supplies		p227.8c	49,211
47	**Total Materials & Supplies Allocated to Transmission**		(Line 45 + 46)	**513,848**
	Cash Working Capital			
48	Operation & Maintenance Expense		(Line 71)	1,503,926
49	1/8th Rule		x 1/8	12.5%
50	**Total Cash Working Capital Allocated to Transmission**		(Line 48 * 49)	**187,991**
	Construction Work in Progress (CWIP)			
51	Construction Work in Progress	(Note E)	p200.11b	16,125,037
52	Gross Plant Allocation Factor		(Line 16)	18.6997%
53	**Total Construction Work in Progress**		(Line 51 * 52)	**3,015,327**
54	**TOTAL Adjustment to Rate Base**		(Line 42 + 47 + 50 +53)	**3,759,306**
55	**Rate Base**		(Line 39 + 54)	**34,227,315**
O&M				
	Transmission O&M			
56	Transmission O&M		p321.112.b	1,247,263
57	Less Account 565		p321.96.b	0
58	Less Schedule 12 payments applicable to the entire zone if not excluded in line 57 above	(Note O)	MWE Data	(77,416)
59	Plus Transmission Lease Payments	(Note A)	P200.3.c	0
60	**Transmission O&M**		(Lines 56 - 57 + 58 + 59)	**1,169,847**
	Allocated General & Common Expenses			
61	Common Plant O&M	(Note A)	p356	0
62	Total A&G		p323.197.b	4,197,462
63	Less Property Insurance Account 924		p323.185.b	125,306
64	Less EPRI Dues	(Note D)	p352-353	0
65	**General & Common Expenses**		(Lines 61 + 62) - Sum (63 to 64)	4,072,156
66	Wage & Salary Allocation Factor		(Line 5)	7.7857%
67	**General & Common Expenses Allocated to Transmission**		(Line 65 * 66)	**317,045**
	Directly Assigned A&G			
68	Property Insurance Account 924		p323.156b	125,306
69	Net Plant Allocation Factor		(Line 18)	13.59%
70	**A&G Directly Assigned to Transmission**		(Line 68 * 69)	**17,034**
71	**Total Transmission O&M**		**(Line 60 + 67 + 70)**	**1,503,926**
Depreciation & Amortization Expense				
	Depreciation Expense			
72	Transmission Depreciation Expense		p336.7b&c	1,029,021
73	General Depreciation		p336.10.b	217,483
74	Intangible Amortization	(Note A)	p336.1d&e	11,622
75	Total		(Line 73 + 74)	229,105
76	Wage & Salary Allocation Factor		(Line 5)	7.7857%
77	**General Depreciation Allocated to Transmission**		(Line 75 * 76)	**17,837**
78	Common Depreciation - Electric Only	(Note A)	p336.10.b	1,129,700
79	Common Amortization - Electric Only	(Note A)	p356 or p336.11.d	0
80	Total		(Line 78 + 79)	1,129,700
81	Wage & Salary Allocation Factor		(Line 5)	7.7857%
82	**Common Depreciation - Electric Only Allocated to Transmission**		(Line 80 * 81)	**87,955**
83	**Total Transmission Depreciation & Amortization**		**(Line 72 + 77 + 82)**	**1,134,813**
Taxes Other than Income				
84	**Taxes Other than Income**		Exhibit B	**728,595**
85	**Total Taxes Other than Income**		**(Line 84)**	**728,595**

Return / Capitalization Calculations					
	Long Term Interest				
86	Long Term Interest			p117.58c through 63c	9,387,327
87	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8	0
88	**Long Term Interest**			(Line 86)	9,387,327
	Common Stock				
89	Proprietary Capital			p112.16c	102,278,976
90	Less Account 216.1		enter negative	p112.12d	270,317
91	**Common Stock**			(Sum Lines 89 to 90)	102,549,293
	Capitalization				
92	Long Term Debt			p112.18.d through 21.d	210,031,187
93	Less LTD on Securitization Bonds	(Note P)	enter negative	Attachment 8	0
94	Total Long Term Debt			(Sum Lines 92 to 93)	210,031,187
95	Common Stock			(Line 91)	102,549,293
96	**Total Capitalization**			(Sum Lines 94 to 95)	312,580,480
97	Debt %	Total Long Term Debt		(Line 94 / 96)	67.19%
98	Common %	Common Stock		(Line 95 / 96)	32.81%
99	Debt Cost	Total Long Term Debt		(Line 88 / 94)	0.0447
100	Common Cost	Common Stock	(Note J)	Fixed	0.1239
101	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 97 * 99)	0.0300
102	Weighted Cost of Common	Common Stock		(Line 98 * 100)	0.0407
103	**Total Return (R)**			(Sum Lines 101 to 102)	**0.0707**
104	**Investment Return = Rate Base * Rate of Return**			**(Line 55 * 103)**	**2,419,669**
REVENUE REQUIREMENT					
	Summary				
105	Net Property, Plant & Equipment			(Line 39)	30,468,009
106	Adjustment to Rate Base			(Line 54)	3,759,306
107	**Rate Base**			(Line 55)	**34,227,315**
108	O&M			(Line 71)	1,503,926
109	Depreciation & Amortization			(Line 83)	1,134,813
110	Taxes Other than Income			(Line 85)	728,595
111	Investment Return			(Line 104)	2,419,669
112	**Gross Revenue Requirement**			**(Sum Lines 108 to 111)**	**5,787,003**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
113	Transmission Plant In Service			(Line 19)	66,905,784
114	Excluded Transmission Facilities		(Note M)	Attachment 5	2,739,063
115	Included Transmission Facilities			(Line 113 - 114)	64,166,721
116	Inclusion Ratio			(Line 115 / 113)	95.91%
117	Gross Revenue Requirement			(Line 112)	5,787,003
118	**Adjusted Gross Revenue Requirement**			(Line 116 * 117)	**5,550,089**
119	**Net Revenue Requirement**			**Line 149**	**5,550,089**
	Net Plant Carrying Charge without New Investment Incentive				
120	Net Revenue Requirement			(Line 119)	**5,550,089**
121	Net Transmission Plant			(Line 19 - 30)	**29,429,120**
122	Net Plant Carrying Charge without New Investment Incentive			(Line 120 / 121)	**18.8592%**
123	Net Plant Carrying Charge without New Investment Incentive without Depreciation			(Line 120 - 72) / 121	**15.3626%**
124	**Net Revenue Requirement**			(Line 119)	**5,550,089**
125	True-up amount			Attachment 6	
126	**Net Zonal Revenue Requirement**			(Line 124 - 126)	**5,550,089**
	Network Zonal Service Rate				
127	12 CP Peak		(Note L)	Midwest Data	248,250
128	Rate ($/KW-Year)			(Line 126 / 127)	22
129	**Network Service Rate ($/KW/Year)**			**(Line 128)**	**22**

Notes

A Electric portion only

B Exclude Construction Work In Progress and leases that are expensed as O&M (rather than amortized). New Transmission plant included in the SPP Regional Transmission Expansion Plan (RTEP) which is expected to be placed in service in the current calendar year weighted by number of months it is expected to be in-service. New Transmission plant expected to be placed in service in the current calendar year that is not included in RTEP must be separately detailed on Attachment 5. For the true-up, new transmission plant which was included in the SPP RTEP actually placed in service weighted by the number of months it was actually in service

C Transmission Portion Only

D All EPRI Annual Membership Dues

E Goodmen Energy Service is included in CWIP and should be excluded. See Cost Support for amount that is excluded.

J ROE will be supported in the original filing and no change in ROE may be made absent a filing with KCC.

L Network or Point to Point transactions of over one year for which the full revenue is received by the transmission owner

M Amount of transmission plant excluded from rates, includes investment in generation step-up transformers to the extent included in Plant in Service.

O Payments made under Schedule 12 of the SPP OATT are excluded in Transmission O&M on line 58 since they are already assessed under Schedule 12

P Appropriate adjustments to the capital structure may be made to reflect state authorized issuances of securitized bonds. Any such adjustments must be supported in the Section 205 filing seeking application of this formula .

END

Utility Name: MIDWEST ENERGY

Attachment 1 - Taxes Other Than Income Worksheet

Other Taxes	*Page 263 Col (i)*	*Allocator*	*Allocated Amount*
Plant Related		***Gross Plant Allocator***	
Property Taxes	3,896,301		
Total Plant Related	3,896,301	18.6997%	728,595
Labor Related		***Wages & Salary Allocator***	
Total Labor Related	0	7.7857%	0
Other Included		***Gross Plant Allocator***	
Total Other Included	0	18.6997%	0
Total Included			728,595
Currently Excluded			
Total as reported on p. 263(i)	3,896,301		

Utility Name: MIDWEST ENERGY

Attachment 2 - Cost Support

Electric / Non-electric Cost Support

	SPP Formula Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Electric Portion	Non-electric Portion	Details
	Plant Allocation Factors						
10	Accumulated Intangible Amortization	(Note A)	p200.21c				
11	Accumulated Common Amortization - Electric	(Note A)	p356				
12	Accumulated Common Plant Depreciation - Electric	(Note A)	p356				
	Plant In Service						
24	Common Plant (Electric Only)	(Notes A & B)	p356				
	Prepayments						
40	Prepayments (Account 165)	(Note A)	p111.57d				
	Materials and Supplies						
43	Materials and Supplies	(Note A)	p227.6c & 15.c				
	Allocated General & Common Expenses						
59	Plus Transmission Lease Payments	(Note A)	P200.3.c				
61	Common Plant O&M	(Note A)	p356				
	Depreciation Expense						
74	Intangible Amortization	(Note A)	p336.1d&e				
78	Common Depreciation - Electric Only	(Note A)	p336.10.b				
79	Common Amortization - Electric Only	(Note A)	p356 or p336.11.d				

Transmission / Non-transmission Cost Support

	SPP Formula Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Transmission Related	Non-transmission Related	Details
28	**Plant Held for Future Use (Including Land)**	(Note C)	p214				Specific identification based on plant records
							1
							2
							3
							4
							5

CWIP & Expensed Lease Worksheet

	SPP Formula Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	CWIP in Form 1 Amount	Excluded CWIP	Details
	Plant Allocation Factors						
6	Electric Plant in Service	(Note B)	p207.104g				See Form 1
	Construction Work in Progress						
51	CWIP Adjustment				25,520,330	9,395,293	Goodmen Energy Center Included in CWIP
	Plant In Service						
19	Transmission Plant In Service	(Note B)	p207.58.g				See Form 1
24	Common Plant (Electric Only)	(Notes A & B)	p356				See Line 24
	Accumulated Depreciation						
30	Transmission Accumulated Depreciation	(Note B)	p219.25.c				See Form 1

EPRI Dues Cost Support

	SPP Formula Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	EPRI Dues	Details
	Allocated General & Common Expenses					
64	Less EPRI Dues	(Note D)	p352-353			EPRI Dues payed by Holding company

Excluded Plant Cost Support

	SPP Formula Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Excluded Transmission Facilities	Description of the Facilities
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
114	Excluded Transmission Facilities	(Note M)	Attachment 5	2,739,063	General Description of the Facilities
				$ 1,181,059	S. Hays to Gorham
				1,558,004	Great Bend North to Susank, Bunker Hill and Hitschmann
					Add more lines if necessary

Load Cost Support

SPP Formula Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				12 CP Peak Description & PJM Documentation
Network Zonal Service Rate				
127	12 CP Peak	(Note L)	Midwest Data	SPP Zonal Peak Load per 34.1 of the PJM OATT

Statements BG/BH (Present and Proposed Revenues)

Customer	Billing Determinants	Current Rate	Proposed Rate	Current Revenues	Proposed Revenues	Change in Revenues
				-	-	-
Total				-	-	-

Utility Name: MIDWEST ENERGY

Attachment 3 - Estimate and True-up Worksheet

Step	Month	Year	Action
Exec Summary			
1	April	XXX	TO populates the formula with Prior Year data
2	April	XXX	TO estimates Cap Adds for Current Year weighted based on Months expected to be in service in Current Year
3	April	XXX	TO adds weighted Cap Adds to plant in service in Formula
4	May	XXX	Post on SPP web site
5	June	XXX	Rates go into effect
6	April	XXXX	TO populates the formula with Prior Year data
7	April	XXXX	TO estimates Cap Adds during Current Year (calendar) weighted based on Months expected to be in service in Current Year
8	April	XXXX	True-up - TO calculates true-up by removing from Step 6 the total Cap Adds placed in service that year and adding weighted average Cap Adds in true-up
9	April	XXXX	True-up - TO adds the difference between the true-up in Step 8 and the forecast in Prior Year with interest to the result of Step 7
10	May	XXXX	Post on SPP web site
11	June	XXXX	Rates go into effect
12	June	XXXX	Return to Step 6 for following year

Prior Year
Current Year

Detailed Example

1 April XXX TO populates the formula with Prior Year data

Rev Req based on Prior Year data

2 April XXX TO estimates Cap Adds for Current Year weighted based on Months expected to be in service in Current Year

	Est. In Service Date	Weighting	Amount	One 12th
Jan		12	-	-
Feb		11	-	-
Mar		10	-	-
Apr		9	-	-
May		8	-	-
Jun		7	-	-
Jul		6	-	-
Aug		5	-	-
Sep		4	-	-
Oct		3	-	-
Nov		2	-	-
Dec		1	-	-
Total	-		-	-

New Transmission Plant Additions for Current Calendar Year (weighted by months in service) -

3 April XXX TO adds weighted Cap Adds to plant in service in Formula

$ - Input to Formula Line 21

4 May XXX Post On SPP Web Site Rev Req and Formula with Exhibits

5 June XXX Rates go into effect

$ -

6 April XXXX TO populates the formula with Prior Year data

$ - Rev Req based on Prior Year data

7 April XXXX TO estimates Cap Adds during Current Year (calendar) weighted based on Months expected to be in service in Current Year

	Est. In Service Date	Weighting	Amount	One 12th
Jan	-	12	-	-
Feb	-	11	-	-
Mar	-	10	-	-
Apr	-	9	-	-
May	-	8	-	-
Jun	-	7	-	-
Jul	-	6	-	-
Aug	-	5	-	-
Sep	-	4	-	-
Oct	-	3	-	-
Nov	-	2	-	-
Dec	-	1	-	-
Total	-		-	-

New Transmission Plant Additions for Current Calendar Year (weighted by months in service) - Input to Formula Line 21

8 April XXXX True-up - TO calculates true-up by removing from Step 6 the total Cap Adds placed in service that year and adding weighted average Cap Adds in true-up

Remove all Cap Adds placed in service in Prior Year

For True up only - remove New Transmission Plant Additions for Current Calendar Year - Input to Formula Line 20

Add Cap Adds actually placed in service in Prior Year

	Actual In Service Date	Weighting	Amount	One 12th
Jan	-	12	-	-
Feb	-	11	-	-
Mar	-	10	-	-
Apr	-	9	-	-
May	-	8	-	-
Jun	-	7	-	-
Jul	-	6	-	-
Aug	-	5	-	-
Sep	-	4	-	-
Oct	-	3	-	-
Nov	-	2	-	-
Dec	-	1	-	-
Total	-		-	-

New Transmission Plant Additions for Current Calendar Year (weighted by months in service) - Input to Formula Line 21

- Result of Formula for true-up

9 April XXXX True-up - TO adds the difference between the true-up in Step 8 and the forecast in Prior Year with interest to the result of Step 7

The true-up in Step 8 | The forecast in Prior Year | =

-

Interest on Amount of Refunds or Surcharges

Interest 35.19a for March Current Yr

Month	Yr	1/12 of Step 9	Interest 35.19a for March Current Yr	Months	Interest	Refunds Owed
Jun	2005	-	0.0000%	12	-	-
Jul	2005	-	0.0000%	11	-	-
Aug	2005	-	0.0000%	10	-	-
Sep	2005	-	0.0000%	9	-	-
Oct	2005	-	0.0000%	8	-	-
Nov	2005	-	0.0000%	7	-	-
Dec	2005	-	0.0000%	6	-	-
Jan	2006	-	0.0000%	5	-	-
Feb	2006	-	0.0000%	4	-	-
Mar	2006	-	0.0000%	3	-	-
Apr	2006	-	0.0000%	2	-	-
May	2006	-	0.0000%	1	-	-
Total		-				-

		Balance	Interest	Amort	Balance
Jun	2006	-	0.0000%	-	-
Jul	2006	-	0.0000%	-	-
Aug	2006	-	0.0000%	-	-
Sep	2006	-	0.0000%	-	-
Oct	2006	-	0.0000%	-	-
Nov	2006	-	0.0000%	-	-
Dec	2006	-	0.0000%	-	-
Jan	2007	-	0.0000%	-	-
Feb	2007	-	0.0000%	-	-
Mar	2007	-	0.0000%	-	-
Apr	2007	-	0.0000%	-	-
May	2007	-	0.0000%	-	-
Total with interest				-	

The difference between the true-up in Step 8 and the forecast in Prior Year with interest -

Rev Req based on Current Year data with estimated Cap Adds for Current Year $ -

Revenue Requirement for Current Year -

10 May XXXX Post on SPP web site

$ - Post On SPP Web Site Rev Req and Formula with Exhibits

11 June XXXX Rates go into effect

$ -

Return to Step 6 for following year

UTILITY NAME: Midwest Energy

Attachment 4 - 12 CP Calculation

Month	Year	Monthly Peak Load
July `06		357,000
Aug.		349,000
Sep.		248,000
Oct.		249,000
Nov.		229,000
Dec.		220,000
Jan. `07		212,000
Feb.		217,000
Mar.		192,000
Apr.		195,000
May		223,000
Jun.		288,000
Total		2,979,000
12 CP Allocator		248,250

Utility Name: MIDWEST ENERGY

Attachment 5 - Transmission Enhancement Charge Worksheet

New Plant Carrying Charge

FCR if not a CIAC

	Formula Line		
A	123	Net Plant Carrying Charge without New Investment Incentive without Depreciation	15.3626%
B	#REF!	#REF!	#REF!
C		Line B less Line A	#REF!

FCR if a CIAC

D	#REF!	#REF!	#REF!

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years
The Transmission Enhancement Charges assessed projects pursuant to Schedule 12 include any approved incentives, the amounts credited to the Customers in the zone under Schedule 12 do not include any such incentives.

Details		Project A				Project B				Project C						
Life																
CIAC		No				No				Yes						
ROE Incentive (Basis Points)																
FCR W/O Incentive		0.15362565				0.15362565				#REF!						
FCR for This Project		#REF!				#REF!				#REF!						
Investment		-				-				-						
Annual Depreciation Exp																
In Service Month (1-12)																
	Invest Yr	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Total	Incentive Charged	Revenue Credit
W/O Incentive	2005	-	-	-	-									$ -		$ -
W Incentive	2005	-	-	-	#REF!									#REF!	#REF!	
W/O Incentive	2006	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2006	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2007	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2007	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2008	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2008	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2009	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2009	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2010	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2010	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2011	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2011	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2012	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2012	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2013	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2013	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2014	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2014	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2015	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2015	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2016	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2016	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2017	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2017	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2018	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2018	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2019	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2019	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2020	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2020	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2021	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2021	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2022	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2022	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2023	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2023	-	-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
W/O Incentive	2024	-	-	-	-	-	-	-	-	-	-	-	#REF!	#REF!		#REF!
W Incentive	2024		-	-	#REF!	-	-	-	#REF!	-	-	-	#REF!	#REF!	#REF!	
....	....		....	.....	....	....	....	Page 1 of 1	....	....	.....	.....	....			$ -
....	....	....	.....	.....	....	....	.....	.....	....	....	.....	.....	....		$ -	
															#REF!	#REF!

ANNEX 2 TO SCHEDULE TSCA
FORMULA RATE IMPLEMENTATION PROTOCOLS

Section 1 Annual Updates

A. The Annual Transmission Revenue Requirements applicable under Appendix A shall be applicable to services on and after June 1 of a given calendar year through May 31 of the subsequent calendar year (the "Rate Year").

B. On or before April 30 of each year, Midwest Energy shall recalculate its Annual Transmission Revenue Requirements, producing the "Annual Update" for the upcoming Rate Year, and post such Annual Update on SPP's Internet website via link to the Transmission Services page or a similar successor page.

C. If the date for making the Annual Update posting/filing should fall on a weekend or a holiday recognized by the FERC, then the posting/filing shall be due on the next business day.

D. The date on which the last of the events listed in Section 1.b or 1.c occurs shall be that year's "Publication Date."

E. Upon written request for a particular year's Annual Update by any load serving entity whose customers are allocated costs of the Midwest Energy facilities, any state utility commission in which customers that are allocated costs of the Midwest Energy facilities are located, or any of the state utility commissioners or consumer advocates who represent customers that are allocated costs of the Midwest Energy facilities (collectively "Interested Parties"), Midwest Energy will promptly make available to such entity and/or a consultant designated by it, a "workable" Excel file containing that year's Annual Update data.

F. The Annual Update for the Rate Year:

(i) shall, to the extent specified in the Formula Rate, be based upon Midwest Energy's FERC Form No. 1 data for the most recent calendar year, and to the extent specified in the Formula Rate, be based upon the books and records of Midwest Energy consistent with FERC accounting policies;

(ii) shall, as and to the extent specified in the Formula Rate, provide supporting documentation for data not otherwise available in the FERC Form No. 1 that are used in the Formula Rate;[1]

(iii) shall provide notice of material changes in Midwest Energy's accounting policies and practices from those in effect for the calendar year upon which the immediately preceding

[1] It is the intent of the Formula Rate, including the supporting explanations and allocations described therein. that each input to the Formula Rate will be either taken directly from the FERC Form No. I or reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information. Where the reconciliation is provided through a worksheet included in the filed Formula Rate template, the inputs to the worksheet must meet this transparency standard, and doing so will satisfy this transparency requirement for the amounts that are output from the worksheet and input to the main body of the Formula Rate.

Annual Update was based ("Material Accounting Changes")[2];

(iv) shall be subject to challenge and review only in accordance with the procedures set forth in this Annex and only as to the appropriateness of the application of the Formula Rate according to its terms and the procedures in this Annex (including terms and procedures related to challenges concerning Material Accounting Changes); and

(v) shall not seek to modify the Formula Rate and shall not be subject to challenge by any party seeking to modify the Formula Rate *(i.e.,* all such modifications to the Formula Rate - including return on equity – will require, as applicable, a Kansas Corporation Commission (KCC) filing).

G. Formula Rate inputs (i) rate of return on common equity, (ii) depreciation rates, and (iii) "Post-Employment Benefits other than Pension" pursuant to Statement of Financial Accounting Standards No. 106, Employers" Accounting for Postretirement Benefits Other Than Pensions ("PBOP") charges shall be stated values to be used in the rate formula until changed pursuant to a KCC filing; provided, however, that notwithstanding the foregoing limitation, any changes in PBOP charges that do not exceed an impact on the formula output Net Zonal Revenue Requirement for Midwest Energy of 2.5% as compared to the immediately preceding Annual Update may be included in an Annual Update without such a filing.

Section 2 Annual Review Procedures

Each Annual Update shall be subject to the following review procedures ("Annual Review Procedures"):

A. Interested Parties shall have up to one hundred fifty (150) days after the Publication Date (unless such period is extended with the written consent of Midwest Energy) to review the calculations ("Review Period") and to notify Midwest Energy in writing of any specific challenges, including challenges related to Material Accounting Changes, to the application of the Formula Rate ("Preliminary Challenge").

B. Interested Parties shall have up to one hundred twenty (120) days after each annual Publication Date (unless such period is extended with the written consent of Midwest Energy) to serve reasonable information requests on Midwest Energy; provided, however, that the potentially Interested Parties shall make a good faith effort to submit consolidated sets of information requests that limit the number and overlap of questions to the maximum extent practicable. Such information requests shall be limited to what is necessary to determine if Midwest Energy has properly applied the Formula Rate and the procedures in this Annex, and be directed to ascertaining whether the Formula Rate is just and reasonable. In addition, such information requests shall not solicit information concerning costs or allocations where the costs or allocation method have been determined by the KCC or in the context of other Annual Updates, except that such information requests shall be permitted if they seek to determine if there has been a material change in circumstances.

[2] Such notice may incorporate by reference applicable disclosure statements filed with the Securities and Exchange Commission ("SEC").

C. Midwest Energy shall make a good faith effort to respond to information requests pertaining to the Annual Update within fifteen (15) business days of receipt of such requests. Midwest Energy may give reasonable priority to responding to requests that satisfy the practicable coordination and consolidation provision of Section 2.B above.

D. Preliminary or Formal Challenges related to Material Accounting Changes are not intended to serve as a means of pursuing other objections to the Formula Rate. Failure to make a Preliminary Challenge with respect to a Material Accounting Change in an Annual Update shall act as a bar with respect to that Annual Update but shall not bar a subsequent Preliminary Challenge related to a subsequent Annual Update to the extent such Material Accounting Change affects the subsequent Annual Update.

E. Preliminary or Formal Challenges related to Material Accounting Changes shall be subject to the resolution procedures and limitations in Section 3, except that Section 3.c. shall not apply. In any proceeding initiated to address a Preliminary or Formal Challenge or sua sponte by the KCC, a party or parties (other than Midwest Energy) seeking to modify the Formula Rate in any respect shall bear the burden of proving that the Formula Rate is no longer just and reasonable without such modification and that the proposed modification is just, reasonable and consistent with the original intent of the Formula Rate and the procedures in this Annex; provided, however, that in any such proceeding, in determining whether the Formula Rate is no longer just and reasonable without modification to reflect a Material Accounting Change and whether the proposed modification is just and reasonable, no offsets unrelated to the applicable Material Accounting Changes may be considered.

Section 3 Resolution of Challenges

A. If Midwest Energy and any interested party(ies) have not resolved any Preliminary Challenge to the Annual Update within twenty-one (21) days after the Review Period, an interested party shall have an additional twenty-one (21) days (unless such period is extended with the written consent of Midwest Energy to continue efforts to resolve the Preliminary Challenge) to make a Formal Challenge with the KCC, which shall be served on Midwest Energy by electronic service on the date of such filing. However, there shall be no need to make a Formal Challenge or to await conclusion of the time periods in Section 2 if the KCC already has initiated a proceeding to consider the Annual Update. A party's Formal Challenge may not raise any issue that was not the subject of that party's Preliminary Challenge during the applicable Review Period.

B. Any response by Midwest Energy to a Formal Challenge must be submitted to the KCC within thirty (30) days of the date of the filing of the Formal Challenge, and shall be served on the filing party(ies) by electronic service on the date of such filing.

C. Except as provided in Section 2.E, in any proceeding initiated by the KCC concerning the Annual Update or in response to a Formal Challenge, Midwest Energy shall bear the burden of proving that it has reasonably applied the terms of the Formula Rate, and the applicable procedures in these formula Rate Implementation Protocols, in that year's Annual Update.

D. Subject to judicial review of KCC orders, each Annual Update shall become final and no longer subject to challenge pursuant to these Annual Review Protocols or by any other means by the KCC or any other entity on the later to occur of (i) passage of the twenty-one (21) day period (or extended period, if applicable) for making a Formal Challenge if no such challenge

has been made and the FERC has not initiated a proceeding to consider the Annual Update, or (ii) a final FERC order issued in response to a Formal Challenge or a proceeding initiated by the FERC to consider the Annual Update.

E. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of Midwest Energy to file unilaterally with the KCC changes to the Formula Rate or any of its inputs (including, but not limited to, rate of return and Transmission Incentive Mechanisms) or the right of any other party to request such changes before the KCC.

F. Subject to Section 2.C above, it is recognized that resolution of Formal Challengers concerning Material Accounting Changes may necessitate adjustments to the Formula Rate input data for the applicable Annual Update or changes to the rate formula to achieve a just and reasonable end result consistent with the intent of the Formula Rate.

Section 4 Changes to Annual Informational Filings

Any changes to the data inputs, including but not limited to revisions to Midwest Energy's FERC Form No. 1, or as the result of any KCC proceeding to consider the Annual Update, or as a result of the procedures set forth herein, shall be incorporated into the Formula Rate and the charges produced by the Formula Rate (with interest determined in accordance with 18 C.F.R. § 38.19a) in the Annual Update for the next effective Rate Period. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments and any refunds or surcharges, however, actual refunds or surcharges (with interest determined in accordance with 18 C.F.R. §38.19a) for the then current rate year shall be made in the event that the Formula Rate is replaced by a stated rate for Midwest Energy.