Exhibit No.:	
Issues:	*Interim Energy Charge, Fuel Expense, Off-System Sales, KCPL Transmission Expense and Income Taxes*
Witness:	*John P. Cassidy*
Sponsoring Party:	*MoPSC Staff*
Type of Exhibit:	*Direct Testimony*
Case No.:	*ER-2004-0570*
Date Testimony Prepared:	*September 20, 2004*

MISSOURI PUBLIC SERVICE COMMISSION

UTILITY SERVICES DIVISION

FILED[3]

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Missouri Public Service Commission

DIRECT TESTIMONY

OF

JOHN P. CASSIDY

THE EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2004-0570

Jefferson City, Missouri
September 2004

Exhibit No. 34
Case No(s). ER-2004-0570
Date 12-06-04 Rptr KF

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In The Matter of the Tariff Filing of The Empire District Electric Company to Implement a General Rate Increase for Retail Electric Service Provided to Customers in its Missouri Service Area.	)))))	Case No. ER-2004-0570

AFFIDAVIT OF JOHN P. CASSIDY

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

John P. Cassidy, being of lawful age, on his oath states: that he has participated in the preparation of the following direct testimony in question and answer form, consisting of 30 pages to be presented in the above case; that the answers in the following direct testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true and correct to the best of his knowledge and belief.

John P. Cassidy

John P. Cassidy

Subscribed and sworn to before me this 16th day of September 2004.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
County of Cole
My Commission Exp. 07/01/2008

D Suzie Mankin

Notary

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DIRECT TESTIMONY

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JOHN P. CASSIDY

THE EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER–2004–0570

Q. Please state your name and business address.

A. John P. Cassidy, 1845 Borman Court, Suite 101, St. Louis, Missouri 63146.

Q. By whom are you employed and in what capacity?

A. I am employed by the Missouri Public Service Commission (Commission) as a Regulatory Auditor.

Q. Please describe your educational background.

A. I graduated from Southeast Missouri State University, receiving a Bachelor of Science degree in Business Administration, with a double major in Marketing and Accounting in 1989 and 1990, respectively.

Q. What has been the nature of your duties while in the employ of this Commission?

A. Since joining the Commission Staff in 1990, I have assisted with and directed audits and examinations of the books and records of utility companies operating within the state of Missouri. I have also conducted numerous audits of small water and sewer companies in conjunction with the Commission's informal rate proceedings.

Q. Have you previously filed testimony before this Commission?

A. Yes, I have. Please refer to Schedule 1, which is attached to my direct testimony, for a list of cases in which I have previously filed testimony. Please refer to Schedule 2, which is attached to my direct testimony, for a list of all other Commission case related activity in which I have been involved.

Q. Did you make an examination and analysis of the books and records of The Empire District Electric Company (Empire or Company) in regard to matters raised in this case?

A. Yes, in conjunction with other members of the Commission's Staff (Staff). I reviewed Company responses to Staff Data Requests, various fuel contracts and related reports, Empire's most recent 10K filing with the Securities and Exchange Commission, outside auditor workpapers, information posted on the Empire website, shareholder reports, company workpapers and testimony, Stipulation and Agreements and Commission Report and Orders from recent rate cases involving Empire and Aquila, Inc. (Aquila).

Q. With reference to Case No. ER–2004–0570, what matters will this direct testimony address?

A. This direct testimony outlines the Staff's recommendation with regard to the implementation of an Interim Energy Charge (IEC) to address the issue of volatility in the price of natural gas and its effect on Empire's overall fuel and purchased power expense. In addition, this testimony provides a discussion of the Staff's methodology for determining fuel and purchased power expense under an IEC. In addition, this testimony discusses fuel inventory levels and addresses the Staff's removal of non-recurring transmission service expenses from the test year. This direct testimony also explains the Staff's position with regard to the appropriate level of off-system sales to be included in revenues. Finally, this direct testimony provides a discussion of the Staff's position with regard to income taxes.

Q. What knowledge, skill, experience, training or education do you have in these matters?

A. I have analyzed fuel costs at Union Electric Company d/b/a AmerenUE as part of Case No. EC-2002-1. I have also reviewed testimony previously filed before this Commission, and Report and Orders from past cases regarding IEC's and fuel costs as well as other topics discussed in this testimony. In addition to my work experience at the Commission, I have attended numerous regulatory conferences and in house training sessions, reviewed various journals and trade articles and had many interactions with members of the utility regulatory profession.

Q. With reference to Case No. ER-2004-0570, what is the purpose of this direct testimony?

A. The purpose of this direct testimony is to explain and sponsor the following adjustments which appear on Accounting Schedule 10, Adjustments to the Income Statement:

Variable Production – Fuel Annualization	S-7.3
Purchased Power Energy Annualization	S-7.4
Purchased Power Demand Charge Annualization	S-6.4
Off-System Sales	S-3.1
KCPL Transmission Service	S-8.5

Current Income Tax	S-22.1
Deferred Income Tax	S-23.1

This testimony will also explain the following line items contained on Accounting Schedule 2, Rate Base:

Fuel Inventory

Deferred Income Taxes

Q. What Accounting Schedule are you sponsoring in this proceeding?

A. I am sponsoring Accounting Schedule 11 – Income Tax.

Q. What test year has the Staff utilized in this case?

A. The Staff has used the Commission authorized test year ending December 31, 2003, updated through June 30, 2004.

OVERVIEW OF ELECTRIC GENERATION FACILITIES

Q. What generating facilities does Empire own and use for the production of electric power?

A. Empire owns or co-owns the following generating facilities:

Iatan Plant Unit 1

Asbury Plant Units 1 and 2

Riverton Plant Units 7, 8, 9, 10 and 11

Empire Energy Center Units 1, 2, 3 and 4

State Line Unit 1

State Line Combined Cycle Unit

Ozark Beach Hydro Plant

Q. Please describe each generating facility owned or co-owned by Empire, including the type of units and the primary and secondary fuel sources for each unit.

A. The Iatan power plant is jointly owned by Kansas City Power & Light Company (KCPL), Aquila and Empire, with ownership percentages of 70%, 18% and 12%, respectively. KCPL began running the plant, as operating partner, in May 1980. The Iatan plant is a 670 megawatt (MW) base-load power plant, which utilizes low sulfur western coal as the main boiler fuel. No. 2 fuel oil is required for boiler start-ups and flame stabilization. Empire's ownership percentage entitles it to approximately 80 MW of Iatan's generation.

The Asbury generating station consists of two steam units that burn coal as the primary fuel and No. 2 fuel oil for flame stabilization and boiler start-ups. The Asbury plant received permission from the Missouri Department of Natural Resources (MoDNR) to burn tire derived fuels (TDF) at a maximum rate of 2% of total fuel input. In 2002, Empire began burning TDF. By doing so, Empire received an exemption from meeting more stringent emission limits, which would have required construction of a $24 million Selective Catalytic Reduction system to meet MoDNR Nitrogen Oxides (Nox) regulations at Asbury.

Asbury Unit 1 operates at 193 MW and Asbury Unit 2 has a 17 MW capacity. However, Unit 1 must be running in order to operate Unit 2. This requirement, combined with the costs of operating Unit 2, results in Empire generally operating Unit 2 only as a peaking unit during the summer months. The Asbury plant was completed in 1970.

The Riverton plant consists of five units. Riverton Units 7 (38 MW) and 8 (54 MW) are baseload/intermediate steam units that burn coal as the primary fuel and natural gas for boiler start-ups, flame stabilization and as a topping fuel to reach maximum generating capacity. Riverton Units 9 (12 MW), 10 (16MW) and 11 (16MW) are combustion turbine (CT) peaking units that burn natural gas as the primary fuel and are capable of using No. 2 oil as a secondary fuel and for testing.

The Empire Energy Center Units 1 (86 MW) and 2 (85 MW) are CT peaking units that burn natural gas as the primary fuel and Jet A oil as a secondary fuel. These units were installed in 1978 and 1982. In April 2003, Empire added Units 3 and 4, which are CT peaking units powered by jet engine technology that allows for prompt response to demand changes. These units are capable of burning either natural gas or Jet A oil and each unit has a capacity of 50 MW.

The Ozark Beach Plant consists of four hydro generators (16 combined MW) and is located between Lake Taneycomo and Tablerock Lake. Empire's use of the hydro units depends upon the lake levels and the operation of surrounding dams that are under the direction of the Army Corps of Engineers.

State Line Unit 1 is an 89 MW CT peaking unit that uses natural gas as the primary fuel and Jet A oil as a secondary fuel and was completed for service in June 1995.

The State Line Combined Cycle unit consists of two gas fired CTs that, when operated together in a heat recovery steam generation mode with a 200 MW steam generator, has a capacity of 500 MW. Empire owns 60% (300 MW) of this capacity, with Westar Inc., a subsidiary of Western Resources, owning the rest. One of these CTs was the former State Line Unit 2, completed in June 1997, and originally operated as a 150 MW CT. It was converted, along with a new 150 MW CT to operate as a combined cycle unit in June 2001.

INTERIM ENERGY CHARGE

Q. Please provide a general explanation of an interim energy charge (IEC) mechanism.

A. The IEC is a mechanism that allows a range of fuel and purchased power prices to be used in determining interim rates in a rate case, that are subject to refund with interest after a true-up. The IEC represents the amount of variable fuel and purchased power, included in the cost of service, above the permanent rate level. A base amount of variable fuel and purchased power costs establishes the IEC "floor" and is included in permanent rates. An additional estimated amount of variable fuel and purchased power costs establishes the IEC "ceiling." The difference between the "floor" and the "ceiling" is the IEC charge, and is set as an interim rate subject to refund. The fixed cost portion of fuel and purchased power expense is a component of the permanent rates and is not subject to true-up or refund.

Q. How does an IEC work?

A. The interim charge is in effect for a period of time (24 months in previous cases) beginning with the effective date of the rates as determined by the Commission in a case. At the conclusion of this time period, a true-up audit would be performed to identify the actual variable costs incurred for fuel and purchased power to determine if a company over or under-collected amounts during this period. If a company over-collected its actual variable cost for fuel and purchase power, then it would refund some portion, up to the entire interim amount collected from its customers with interest. Conversely, if a company under-collected prudently incurred costs associated with fuel and purchased power, that company would not have to refund any amounts to customers; rather, that company would be required to absorb the under-collected amount.

Q. Does the Staff propose that an IEC be implemented for Empire in this case?

A. Yes. The Staff recommends in this case, that an IEC be adopted, for a period of 24 months, due to the extreme volatility currently exhibited by natural gas prices. The IEC eliminates the need to pinpoint fuel prices used in the development of fuel and purchased power costs in rates. The Staff believes that given the current volatile state of natural gas prices no one can predict, with a reasonable degree of certainty, the natural gas prices that Empire will pay in the future to fuel their generating facilities. Therefore, an IEC represents the most reasonable approach to address this situation. The uncertainty surrounding natural gas prices also impacts the cost of purchased power obtained on the market. Natural gas is currently the primary fuel source for 704 MW of Empire's system capacity of 1264 MW and a significant portion of Empire's energy is either generated from natural gas fired units or purchased on the spot market. The uncertainty surrounding rising natural gas prices, combined with the Company's heavy reliance on natural gas and purchased power, led the Staff to conclude that an IEC represents the best way to proceed in determining fuel costs for Empire in this proceeding.

Q. Are there any additional benefits associated with the use of an IEC for Empire?

A. Yes. Because any amounts over-collected through the IEC are subject to refund with interest, the pressure to precisely estimate price increases for the fuel components at Empire is significantly reduced. Staff believes that it is a significant advantage to be able to use a mechanism that allows the Company to recover costs, while permitting a refund of cost over-collections back to Empire's customers. Essentially, this approach provides a "safety-net" for both Empire and its customers if the natural gas cost estimates are missed. Staff does not believe this mechanism is appropriate in normal economic circumstances and still supports the use of actual historical information during such times. However, with the existence of price volatility, such as that seen recently in the natural gas industry, and the significant potential impact on Empire and its customers, the Staff views the IEC as an effective approach to address the situation.

Q. Explain how natural gas prices have been volatile in recent years.

A. The following chart shows how NYMEX monthly closing prices have tracked for each calendar year ending 1996-2003. For 2004, the chart reflects a nine-month average of January – September.

YEAR	**NYMEX CLOSE PRICE**
1996	$2.59
1997	$2.59
1998	$2.11
1999	$2.27
2000	$3.89
2001	$4.27
2002	$3.22
2003	$5.39
2004	$5.81

Q. Does the Staff's proposed IEC give consideration to other fuel costs besides natural gas prices?

A. Yes. The Staff's IEC proposes to include all variable fuel and purchase power costs. The Staff does this to address changes in purchase power and other fuel prices and to avoid potential manipulation of the process by the Company. It is important to note that the IEC process is not intended to allow utilities to reap windfall profits, nor is the process designed to allow customers to unduly benefit from being totally insulated from the rising fuel and purchased power costs.

Q. Does Empire have a hedging program in place to help address volatile natural gas prices?

A. Yes. Beginning in November 2001, Empire began a hedging program designed to mitigate energy price volatility. As part of this program the Company is currently required to hedge a minimum of 60% of year one expected gas burn, 40% of year two expected gas burn, 20% of year three expected gas burn and 10% of year four expected gas burn. The Company also has the flexibility of being able to hedge up to 80% of any year's expected requirements. This process was implemented to protect both the customers and the shareholders from volatility in the marketplace and provide some degree of certainty for expected fuel costs.

Q. Has this program been successful for Empire?

A. Yes. Through the use of effective hedging strategies, Empire experienced overall natural gas costs of $2.70 / MMBTU during 2002 and $3.02 / MMBTU during 2003 compared to an average NYMEX close price of $3.22 during 2002 and $5.39 during 2003. Despite the effectiveness of this natural gas procurement program, Empire's hedged natural gas costs are increasing throughout 2004. During the first seven months of 2004 hedged natural gas costs prices have increased to $4.24 / MMBTU. As of

September 16, 2004, Empire has approximately 40% of its 2005 gas needs already hedged at \$4.15 / MMBTU. However, Empire must still acquire 60% of its 2005 gas needs at currently estimated higher gas price levels.

Q. How did the Staff establish the floor or base amounts to be included in permanent rates as part of its IEC proposal?

A. The Company's hedging program has been in effect since November 2001. The Staff examined a thirty-two month history of Empire's overall hedged natural gas costs from November 2001 through June 2004. An average of this thirty two month history resulted in an overall natural gas price of \$3.20 / MMBTU. The Staff used this natural gas cost to establish its floor or base amount to be included in permanent rates.

Q. How did the Staff establish the ceiling to be included in interim rates as part of its IEC proposal?

A. The Staff used the Energy Information Administration's (EIA) forecasted natural gas price for 2005. The EIA was created by Congress in 1977 and is an independent statistical agency of the US Department of Energy. In its report dated August 10, 2004 the EIA expected average natural gas prices for 2005 to be \$6.60 / MMBTU. This price when combined with Empires 40% hedged position for 2005, results in an overall natural gas price of \$5.62 / MMBTU for Empire for 2005. This price has been incorporated in Staff's production cost model, which will be discussed later in this direct testimony.

Q. Has the Commission approved an IEC in past rate cases where similar circumstances existed?

A. Yes. The Commission approved the use of an IEC for Empire in its Report and Order in Case No. ER-2001-299, dated September 20, 2001. The Commission's Report and Order stated:

> The parties emphasized that Empire is different from other electric utilities in the state with regard to its dependence upon natural gas-fired generation and purchased power, especially with the addition of the natural gas-fired SLCC [State Line Combined Cycle]. The parties also noted that while some fuel costs are relatively stable, there has been recent volatility in the price of natural gas and purchased power, and there is great difficulty for anyone to attempt to predict with reasonable certainty what the market price of natural gas or purchased power will be at any given time in the future. The parties assured the Commission that the suggested resolution of this issue, for this particular company in this particular circumstance, is appropriate and reasonable, in that it incorporates a forecasted fuel method which the Commission has utilized in other forms in previous cases, and it includes a "true-up" to actual cost method which the Commission finds appropriate in this situation for the protection of customers. Utilizing the "traditional" approach of attempting to ascertain a fixed cost for natural gas and purchased power prices carries with it the prospect of the ratepayers either paying significantly more or less than the actual costs. The Commission does not wish to subject either Empire or its customers to such potential extremes. The compromise approach fashioned by the parties in this proceeding ensures rate stability and seeks to prevent either "windfall" profits or dramatic losses by ensuring that actual fuel and purchased power costs are the basis for the process to be used. [Report and Order in Case No. ER-2001-299, pages 23 and 24]

The Commission recently approved a two-year IEC for Aquila, as part of Case No. ER-2004-0034. In that case the IEC was limited to the variable cost for fuel and purchased power.

Q. What IEC mechanism is the Staff proposing in the current case?

A. The Staff proposes the same mechanism and 24-month period that was agreed to by all of the parties and approved by the Commission for Aquila in Case No. ER-2004-0034, but based on the price and operational parameters specific to this case.

FUEL EXPENSE

Q. What was your responsibility in this case with regard to the determination of fuel expense?

A. I determined representative levels for the following: a) unit costs for coal, TDF (tire derived fuel), natural gas and fuel oil used to produce electricity, and b) annualized demand charge costs for a purchased power contract. As was previously explained in this direct testimony, I determined natural gas prices to be used to establish base costs as well as for interim costs to be included as part of the Staff's IEC proposal. Staff witness Leon Bender, of the Commission's Energy Department, input this data into the RealTime TM production cost model (fuel model) to prepare the fuel and purchased power cost calculations used in the Staff's direct filing. The Staff's fuel model calculates the majority of overall fuel and purchased power costs.

Q. Please explain how the Staff examined fuel prices in this case.

A. The Staff reviewed the coal, rail freight and trucking transportation contracts. The Staff also reviewed natural gas contracts and purchased power capacity agreements. In addition, the Staff examined historical information regarding the operations of individual generating units and the prices paid for fuel and transportation charges by each unit and fuel type. The Staff examined the monthly operating reports to determine TDF prices. As stated earlier, the Staff used an average of a thirty-two month history of Empire's hedged natural gas prices to establish its floor or base amount to be included in permanent rates. The Staff used the EIA's forecasted natural gas price for 2005 combined with Empire's 2005 hedged gas position to establish the ceiling and to calculate the amount of fuel and purchased power costs included in determining the refundable interim rate in its IEC proposal.

Q. How did the Staff use fuel prices in determining the total annualized fuel expense?

A. Staff witness Bender used these various fuel prices to develop two fuel model calculations. One of these calculations established the base or permanent fuel cost. The other calculation determined the ceiling for fuel costs, which is included in the interim rate. Each of these calculations computed the level of normalized net system fuel and purchased power expense, exclusive of purchased power demand charges, cost of off-system sales (sales to other electric utilities) and cost of energy exchanged. I subsequently added the same cost levels associated with purchased power demand charges, off-system sales and energy exchanged to the fuel model calculations for both the base and ceiling results. I also added the following costs to each of the fuel model's results:

1) maintenance and leasing costs for unit trains;

2) property taxes on unit trains;

3) railroad spur maintenance costs;

4) non-labor fuel handling costs

The fuel model is fully explained in the direct testimony of Staff witness Bender.

Q. Were there any fuel related costs that occurred during the test year that will no longer exist in the future?

A. Yes. During the test year the Company paid amounts related to the Atlantic Richfield Companies for a coal contract relating to the Iatan generating unit.

However, this contract expired on December 31, 2003. The Staff has excluded this cost from fuel expense and has instead included the coal costs related to the appropriate replacement coal contracts as inputs to the fuel model.

Q. Were any other fuel related costs that occurred during the test year non- recurring?

A. Yes. Empire entered into a gas purchase agreement with Enron North America Corp. (Enron) in June 2001. Empire terminated this agreement and all related transactions effective December 2001, primarily due to the drop in Enron's credit ratings and concern over its viability as a company. Throughout 2002 and 2003, Enron demanded that Empire pay approximately $6.1 million that Enron claimed it was owed as a result of Empire's early termination of the agreement. During October 2003, an agreement was reached to settle the dispute for a $1.0 million payment. Empire charged this amount to fuel expense during the third quarter of 2003. The Staff has excluded this cost from fuel expense, as part of income statement adjustment S-7.3, because it is a non-recurring item.

Q. How did the Staff determine the cost of coal used at Empire's plants?

A. The Staff examined the specific contract prices of the coal burned at each plant. The Staff also examined all coal rail freight and trucking contracts in effect as of June 30, 2004. Total coal costs include the commodity costs, rail freight and trucking costs, where applicable. For each generating unit, the Staff examined historical information for each individual component of the total coal cost and then added the individual cost components to derive the total coal cost for each plant.

At the Asbury plant, Empire burns a mix or blend of Wyoming low sulfur coal and Kansas high sulfur coal in order to achieve acceptable environmental results. At Riverton 7, Empire burns a mix of Wyoming coal and Oklahoma high sulfur coal. At Riverton 8, Empire burns only Wyoming coal. Through data requests and discussions with Company employees the Staff determined that the reasonable mix proportions are 91% Wyoming coal to 9% Kansas coal for the Asbury units, 75% Wyoming coal to 25% Oklahoma coal for Riverton 7 and 100% Wyoming coal for Riverton 8. I provided the computed coal costs and mix information to Staff witness Bender for input into the production cost model.

Q. Please explain the tier one and tier two pricing of the coal contract Empire has in place with the Rochelle Coal Company.

A. The contract for the Wyoming coal used at Asbury and Riverton 7 and 8 provides for a higher tier one price for a specified initial level of tons purchased by Empire. After that, each ton is purchased at a lower tier two price. The structure of the coal tier pricing agreement was reflected in the production cost model by Staff witness Bender.

Q. What price did the Staff include in its fuel model for No. 2 and Jet A fuel oil?

A. The Staff used the most recent prices for No. 2 and Jet A fuel oil purchased at each of Empire's plants. Empire burns fuel oil mainly as a secondary fuel or in some instances for flame stabilization. As a result, fuel oil is purchased infrequently. The limited number of purchases of fuel oil makes it difficult to employ any meaningful type of averaging method. An accurate historical analysis of fuel oil prices is also not possible because Empire does not make purchases during the majority of the year. Thus, any trend in costs could be misleading because of the limited amount of available data. The Staff believes the most recent purchase prices are the best available reflection of ongoing costs based on Empire's purchasing practice regarding fuel oil.

Q. Please describe how the Staff determined the coal cost for the Iatan plant that was used as an input to the fuel model.

A. The coal at the Iatan plant is now supplied from various mines as part of six different coal contracts. The Staff examined the coal and freight contracts in conjunction with Company supplied reports and used delivered cost for coal for the 12 month period ending June 30, 2004.

Q. How does Empire take delivery of coal supplies at its generating facilities?

A. Empire leases a unit train for coal deliveries to its Asbury plant. This same coal is then trucked to its Riverton generating facilities. Empire also has a Company owned unit train that it leases to the Union Pacific Railroad. The Staff reflected the net lease amounts in the unit train annualized expense. Empire is also responsible for its 12% ownership share of the unit trains leased by KCPL for the Iatan generating station.

Q. How did the Staff treat unit train costs?

A. The Staff added the property taxes, leased train charges and miscellaneous operations and maintenance (O&M) charges for the test year to the output results from the fuel model, as a separate component, since the unit train costs were not included as an input to the fuel model. The Staff added railroad "spur" line costs and non-labor fuel handling costs to the fuel model output. The Staff included the O&M costs for unit trains and the railroad spur line based on the 12 months ending December 31, 2003. The Staff totaled the annualized dollars for each cost component of the unit train and included this amount in arriving at total fuel expense.

Q. How did the Staff calculate the fuel costs for the State Line Combined Cycle plant, State Line Unit 1, Energy Center Units 1, 2, 3 and 4 as well as Riverton Units 9, 10 and 11?

A. As natural gas fired units, the fuel costs associated with operating these units is determined by the Staff's fuel model, using the gas costs I provided as an input to Staff witness Bender.

Q. Please summarize the Staff's calculation of the fuel costs in this proceeding.

A. The Staff's base and ceiling fuel costs represent the cost of generating and purchasing power to meet the level of megawatt hour (MWH) sales in the Staff's revenue annualization in this case. As previously stated, I provided Staff witness Bender the fuel prices as inputs for the fuel models. Staff witness Janice Pyatte of the Energy Department and Doyle L. Gibbs of the Auditing Department developed normalized and annualized sales through June 30, 2004. Staff witness Rick Campbell of the Energy Department, developed the Staff's annualized net system load with input from Staff witness Alan Bax who developed a line loss percentage and a Company use level. Staff witness Bender used this system load as an input for the fuel models. Please refer to the respective direct testimonies of Staff witnesses Bender, Campbell, Bax, Pyatte and Gibbs for a complete discussion of each of these areas.

After reviewing the results of the fuel model at base and interim levels, I added the other fuel related cost components that were not inputs to the model, previously discussed in this direct testimony, to calculate the Staff's normalized and annualized fuel and purchased power expense. Staff adjustment S-7.3 reflects normalized and annualized fuel and fuel related expenses in its cost of service calculation.

DEMAND CHARGES - CAPACITY CONTRACTS

Q. Please describe the capacity contract that Empire has with Western Resources' Jeffrey Energy Center (Jeffrey).

A. This contract allows Empire to purchase capacity on an annual basis through May 31, 2010. The Staff added the annual fixed demand charge amount associated with the Jeffrey contract to the results of the Staff's production cost model because the model only computes the variable purchased power energy charges.

Q. Were any other fuel costs added that were not calculated in the Staff's production cost models?

A. Yes. The fuel costs for both energy and demand costs associated with off-system sales and energy exchanged were added to the results of the Staff's base and ceiling production cost model results since the model does not determine the level of these types of sales.

Q. Did the Company have any other capacity contracts that were in effect during the test year?

A. Yes. During the first six months of the test year, the Company had a short-term capacity contract in place with American Electric Power (AEP). However, this contract expired in June 2003 and was not renewed. Staff Adjustment S-6.4 adjusts purchased power capacity charges to eliminate the test year amounts that related to the expired AEP contract that existed during the test year.

PURCHASED POWER - ENERGY CHARGES

Q. Please explain adjustment S-7.4.

A. Staff adjustment S-7.4 annualized purchased power energy charges based on the Staff's fuel model results. These purchased power energy charges represent the purchased power the Company obtains on the spot market to meet the load requirements of its wholesale and retail electric customers.

OFF-SYSTEM SALES

Q. What are off-system sales?

A. Off-system sales relate to sales of electricity made at times when utilities have met all obligations to serve their customers and have excess energy to sell to other utilities. The off-system sale transactions occurring between utilities results in profits (net margin) to the selling entity, in this case, Empire. Net margin refers to the total proceeds from the sale less the associated generation costs.

Q. Why is it appropriate to include off-system sales in the current revenue requirement determination for the Company?

A. The same generating facilities, equipment and personnel that are necessary to provide service to Missouri retail electric customers are also used to make off-system sales. It is appropriate to include the off-system sales in this case because Empire customers are already paying for all costs associated with these facilities in the production of electricity to meet their load. To the extent that other sales can be made using these facilities, the customers should benefit from these sales. Off-system sales represent an efficient utilization of the electric system that has been put in place to meet the electricity needs of Empire's customers. Staff adjustment S-3.1 adjusts off-system sales revenue to a normalized level. This adjustment is consistent with the adjustment made by the Company and the Staff in previous rate cases.

KCPL TRANSMISSION SERVICE

Q. What does Staff Adjustment S-8-5 represent?

A. Staff Adjustment S-8-5 represents the removal of the test year costs associated with the payments made by Empire to KCPL for transmission service from the Iatan plant. Empire ceased taking transmission service from KCPL in September 2002, and at that time began taking Network Integration Service, under the Southwest Power Pool's Open Access Transmission Tariff. Empire believed it had the right to terminate the service under the older Iatan transmission agreement, whereas KCPL contended that Empire did not. The dispute was resolved when Empire agreed to pay the monthly contractual payments through March 2004, at which time the service arrangement and related payments were permanently discontinued.

FUEL INVENTORY

Q. What coal inventory level have you included in this case for Empire's Iatan, Asbury and Riverton plants?

A. The Company's current policy is to maintain a 60 day supply of coal at its Asbury and Riverton plants and it is KCPL's current policy to maintain a 45 day supply of coal at the Iatan plant. Therefore, Staff has included a 60 day supply of coal for the Asbury and Riverton plants and a 45 day supply for the Iatan plant based on the Staff's average daily burn for these facilities, as calculated by the fuel model. The Staff's coal inventory levels reflect the same prices used as inputs to the fuel model.

Q. What fuel oil inventory levels have you included in this case for Empire's Iatan, Asbury, Riverton and Energy Center plants?

A. The Staff examined fuel oil inventory levels on a monthly basis from June 1, 2003 through June 30, 2004. The Staff believes that a 13-month average is representative of ongoing levels.

Q. What fuel oil inventory level did the Staff compute for the State Line generating station?

A. Empire did not purchase any Jet A fuel oil at its State Line plant during the test year or in the previous year. The Staff used a 13-month average of investment level of fuel inventory at State Line.

Q. What TDF inventory level did the Staff compute for inclusion in rate base?

A. The Staff examined TDF on a monthly basis from June 1, 2003 through June 30, 2004 and used a 13-month average.

INCOME TAXES

Q. Please explain adjustment S-22.1.

A. Adjustment S-22.1 adjusts current income taxes to a level consistent with the Staff's calculation of Net Operating Income Before Taxes (NOIBT).

Q. Please explain each component of the Company's total income tax liability.

A. There are four components to the total income tax liability. These four components include: 1) current income tax, 2) amortization of deferred ITC, 3) deferred income tax, and 4) the amortization of deferred income tax. These components are summarized in the income tax calculation on Accounting Schedule 11.

Q. Please describe the current income tax component.

A. Staff calculated the current income tax component shown on Accounting Schedule 11 by taking the NOIBT amount from Accounting Schedule 9, Income Statement and adjusting it by the additions to and deductions from NOIBT that appear on Accounting Schedule 11. Staff then multiplied this result by the appropriate federal and state income tax rates to arrive at the adjusted expense level. This calculation is based upon the fact that federal income taxes are 50% deductible for state income tax purposes and that state income taxes are fully deductible for federal income tax purposes. The calculation in this case is based on the use of a 35% federal income tax rate and a 6.25% state income tax rate. This results in an effective overall tax rate of 38.39%.

Q. How was adjustment S-22.1 calculated?

A. Adjustment S-22-1 reflects the difference between the annualized current income tax expense, described above, and the Company's test year level of current income taxes. The annualized level of current income tax expense is shown on Accounting Schedule 11, line 39.

Q. Please describe the amortization of deferred ITC component.

A. The amortization of deferred ITC component represents the recovery by the ratepayer of a portion of previously deferred ITC. The amount is based on the level of deferred ITC amortization reflected on the Company's books during the 12 months ended December 31, 2003, which represents the test year.

Q. Please describe the deferred income tax component.

A. The deferred income tax component reflects the tax expense associated with specific timing differences recognized in the determination of current income tax according to the Internal Revenue Service Code (Code), but deferred (normalized) to a future period for ratemaking purposes. The largest timing difference included in deferred income tax is the difference between the tax deduction for depreciation, under accelerated methods prescribed by the Code, used in calculating current income tax, and the corresponding tax deduction for depreciation under the straight line method, used in the ratemaking process. This timing difference must be deferred (normalized) according to the Code. The deferred income tax amount is calculated by multiplying those tax timing differences that the Staff has normalized by the overall effective tax rate of 38.39% as previously discussed. A description of the tax timing differences, including those to be normalized will be provided later in my testimony.

Q. Please explain the tax concept of "normalization."

A. Under the Code, the Company recognizes certain items in the calculation of current income tax at different times than when the items are recognized for book purposes. Items for which this tax treatment applies are called "tax timing" differences. Normalization treatment eliminates these differences for ratemaking purposes so that income tax expense is based solely on the book income impact of these timing differences. As an example, the excess of tax depreciation over straight-line tax depreciation is deducted from operating income and results in lower current taxable income and current income tax expense. However, the reduction in current income tax for this timing difference is offset by a corresponding increase in deferred income tax. The net result on total income tax expense is zero.

For excess tax depreciation and Contributions in Aid of Construction (CIAC), the tax timing differences have been normalized and reflected in the Staff's deferred income tax calculation in this case.

Q. Please explain the tax concept of "flow-through."

A. The term flow-through refers to the tax treatment that equates the amount provided by the ratepayer for income tax expense with the amount paid to the taxing authority. Under flow-through, no deferred tax is created to offset the impact of the timing difference on current income tax expense.

Q. Please describe the amortization of the deferred income tax component.

A. The amortization of the deferred income tax component represents the amount of excess deferred income taxes flowed back to the ratepayers. These excess deferred income taxes result from the Tax Reform Act of 1986. Prior to 1986, income taxes were deferred at a rate of 46%. After 1986, they were deferred at a 35% rate. The excess deferrals, resulting from the 11% higher rate, must be amortized and flowed back to the ratepayers. The amortization of the deferred income tax component in this case was determined from data provided by the Company in various workpapers. The amount of the amortization is included in the Staff's calculation of deferred income tax, which appears on line 42 of Accounting Schedule 9, Income Statement.

Q. Please describe adjustment S-23.1.

A. Adjustment S-23.1 represents the amount needed to adjust total test year booked deferred income taxes to the adjusted level of deferred income taxes calculated by the Staff.

Q. How are tax timing differences presented in the Staff's case?

A. Tax timing differences are represented on Accounting Schedule 11, Income Tax, as additions to and as deductions from NOIBT.

Q. Please identify the additions used to arrive at net taxable income in this case.

A. Annualized book depreciation is added back to net income before taxes because the deduction for tax depreciation in determining income taxes is different than for book depreciation. It is necessary to add back this item to avoid deducting depreciation amounts twice for tax purposes. Operations and maintenance depreciation, non-deductible expense and CIAC are also added back to NOIBT.

Q. Please list the deductions used to arrive at net taxable income.

A. The deductions are: (1) interest expense, (2) tax straight-line depreciation (3) excess tax depreciation and (4) cost of removal.

Q. Please explain the deduction for interest expense and how it was calculated.

A. Interest expense is calculated by multiplying the jurisdictional rate base by the Staff's weighted cost of debt (3.77%), which is sponsored by Staff witness David F. Murray of the Financial Analysis Department.

This methodology assures that the amount of interest expense used in the calculation of income tax expense, for ratemaking purposes, equals the interest expense the ratepayer is required to provide the Company in rates. Since the revenue requirement recommended by the Staff is based on a rate of return computation, the interest synchronization method allows an interest deduction consistent with the rate of return computation that is applied to rate base. Interest synchronization has been consistently used by the Staff and adopted by the Commission in past orders.

Q. Please identify the source of the amount of the deduction for tax straight-line depreciation.

A. The amount of this item was determined by using historical information to develop a ratio of the tax basis of depreciable plant to Empire's book basis of depreciable property. This ratio was applied to the annualized book depreciation that was included in Staff's revenue requirement to determine the Missouri jurisdictional straight-line tax depreciation amount used in the calculation of income tax expense.

Q. Please describe the deduction for excess tax depreciation.

A. Staff determined the excess tax depreciation by subtracting the jurisdictional amount for straight-line tax depreciation, described above, from total tax depreciation. The amount of excess tax depreciation is subject to normalization restrictions under the Code that do not allow flow through treatment of this item for regulatory purposes. Utility companies like Empire benefit from this restriction because the associated deferred taxes provide enhanced cash flow to their operations. The deferred taxes are accumulated and used as an offset to rate base.

Q. Why does a depreciable basis difference exist between the depreciable book basis and tax basis?

A. A difference exists between the depreciable book basis and tax basis because the Code has allowed expenditures, which are capitalized for book purposes, to be deducted in the year incurred for tax purposes. As a result, the tax basis is typically lower than the basis used to calculate book depreciation.

Q. In reference to the items discussed above, please identify the items that Staff is proposing to normalize in the income tax calculation.

A. Staff is proposing to normalize excess tax depreciation and CIAC. Since the Staff has recognized these timing differences in its calculation of current income tax, it is necessary to provide corresponding deferred income tax treatment for these items. The Staff calculated the deferred income tax component by multiplying these timing differences by the effective tax rate of 38.39%.

Q. Which of the items is the Staff proposing to flow-through in its income tax calculation?

A. The Staff is proposing to flow-through straight-line tax depreciation, interest expense and cost of removal.

Q. Are there any specific tax-related items that you are sponsoring on Accounting Schedule 2, Rate Base?

A. Yes. I am sponsoring the line item, deferred income taxes that appears on Accounting Schedule 2, Rate Base, as a subtraction from net plant.

Q. Please explain the subtraction of deferred income tax from net plant.

A. The balance of deferred income taxes included on Accounting Schedule 2 is composed of the accumulated deferred income tax balances related to CIAC, software costs, accelerated depreciation, loss on required debt, pensions and interest capitalized.

The balances of deferred taxes reflect the Missouri jurisdictional balances as of December 31, 2003, updated through June 30, 2004, the cut-off date ordered by the Commission in this case.

Q. With reference to the tax timing differences that were reflected (excess tax depreciation and CIAC), what justification exists for the inclusion in the rate base of deferred income tax balances related to items that were not specifically normalized in the past?

A. As long as it is intended that a tax timing difference be normalized, one should be indifferent to its inclusion for total tax expense. This is because a tax timing difference can be normalized in one of two ways: 1) the item can be used to determine current taxable income and a deferred income tax expense explicitly calculated on that tax timing difference, or 2) the item can be excluded from the tax calculation. Either way, total income tax is unaffected. Normalization represents a shift between the level of the current and deferred components of total income tax expense.

It is the Staff's opinion that these deferred tax balances are legitimate inclusions for the determination of rate base, since the related tax timing differences have been effectively normalized through exclusion from the tax calculation in the past.

Q. How were the amounts of the deferred tax balances determined?

A. The deferred tax balance associated with accelerated depreciation, losses on reacquired debt, tax interest capitalized, CIAC and software costs reflect the Missouri jurisdictional balances accumulated through June 30, 2004. The prepaid pension asset balance, included in rate base, was multiplied by the effective tax rate to determine the deferred tax balance associated with pensions. This balance reflects the deferred income tax associated with the normalization of the tax timing difference that is represented by the prepaid pension asset recognized by the Staff.

Q. Does this conclude your direct testimony?

A. Yes, it does.

SCHEDULE OF TESTIMONY FILINGS

JOHN P. CASSIDY

COMPANY	CASE NO.
Missouri Cities Water Company	WR-91-172 & SR-91-174
St. Louis County Water Company	WR-91-361
Southwestern Bell Telephone Company	TC-93-224
Laclede Gas Company	GR-94-220
Empire District Electric Company	ER-95-279
Imperial Utility Corporation	SC-96-247
St. Louis County Water Company	WR-97-382
Laclede Gas Company	GR-98-374
United Water Missouri, Inc.	WR-99-326
Union Electric Company	EC-2000-795
Union Electric Company	GR-2000-512
Laclede Gas Company	GR-2001-629
Union Electric Company, d/b/a AmerenUE	EC-2002-01
Union Electric Company, d/b/a AmerenUE	EC-2002-1025
Laclede Gas Company	GR-2002-356
Laclede Gas Company	GT-2003-0117
Missouri-American Water Company	WR-2003-0500 & WC-2004-0168
Missouri-American Water Company	SM-2004-0275

Other Case Activity

JOHN P. CASSIDY

Utility Name	Description	Year
Continental Telephone Company	Earnings Investigation	1990
Taney County Utilities Corporation	Informal Rate Case	1991
Union Electric Company	ACA, GR-91-131	1991
Imperial Utility Corporation	Informal Rate Case	1991-92
Cat-Pac Waterworks, Inc.	Informal Rate Case	1992
Port Perry Service Company	Informal Rate Case	1993
KMB Utility Corporation	Informal Rate Case	1993
Central Jefferson County Utilities	Informal Rate Case	1993
West Elm Place Corporation	Informal Rate Case	1993
Alltel Missouri Service Corporation	Earnings Investigation	1994
Cedar Hill Utility Company	Informal Rate Case	1994
M.P.B. Inc.	Informal Rate Case	1994
P.C.B. Inc.	Informal Rate Case	1994
Mill Creek Sewer Company	Informal Rate Case	1994
KMB Utility Corporation	Informal Rate Case	1995
Herculaneum Sewer Company	Informal Rate Case	1995
Central Jefferson County Utilities	Informal Rate Case	1995
KMB Utility Corporation	Informal Rate Case	1996-97
KMB Utility Corporation	Davis Receivership	1996-97
West Elm Place Corporation	Informal Rate Case	1997
Gladlo Water and Sewer Company	Informal Rate Case	1997
Central Jefferson County Utilities	Informal Rate Case	1997-98
West Elm Place Corporation	Property Tax Issue	1997-98
Eastern Missouri Utility Company	Informal Rate Case	1998
West Elm Place Corporation	Asset Sale	1998
Imperial Utility Corporation	Asset Sale	1998
Gladlo Water and Sewer Company	Informal Rate Case	1998
Hunter's Ridge Subdivision	WA-2000-142	1999

Utility Name	Description	Year
Missouri-American Water Company	Certificate Cases	1999
AcquaSource Utilities	SM-2000-214	1999-2000
Missouri-American Water Company	WR-2000-281	1999-2000
House Springs Sewer Company	SC-99-135	1999-2003
KMB Utility Corporation	EIERA Loan Audit	2000
L.W. Sewer Corporation	EIERA Loan Audit	2000
Missouri-American Water Company	WA-2000-58	2000
Missouri-American Water Company	WA-2000-59	2000
Missouri-American Water Company	WA-2000-461	2000
Gladlo Water and Sewer Company	Informal Rate Case	2001
Union Electric Company	EC-2001-431,2nd Earp	2001
Argyle Estates Water System	Informal Rate Case	2001
South Jefferson County Utility Company	Informal Rate Case	2001
KMB Utilities / Davis Water	WM-2001-463, Sale Case	2001
Laclede Gas Company	AX-2002-203	2002
TBJ Sewer Systems	Informal Rate Case	2002
Mill Creek Sewer Company	Informal Rate Case	2002-03
KMB Utility Corporation	Informal Rate Case	2002-03
Cedar Hill Estates Water Company	Informal Rate Case	2002-03
KMB / Cedar Hill Estates Water	WM-2003-0194	2002-03
North Oak Sewer District	Informal Rate Case	2002-03