Exhibit No.:	
Issues:	*Fuel and Purchase Power; Fuel Inventory*
Witness:	*Graham A. Vesely*
Sponsoring Party:	*MoPSC Staff*
Type of Exhibit:	*Direct Testimony*
Case No.:	*ER-2002-424*
Date Testimony Prepared:	*August 16, 2002*

MISSOURI PUBLIC SERVICE COMMISSION

UTILITY SERVICES DIVISION

DIRECT TESTIMONY

OF

GRAHAM A. VESELY

THE EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2002-424

Jefferson City, Missouri
August 2002

****Denotes Highly Confidential Information****

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BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In The Matter of The Empire District Electric Company of Joplin, Missouri, for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company.	)))))	Case No. ER-2002-424

AFFIDAVIT OF GRAHAM A. VESELY

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

Graham A. Vesely, 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 18 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.

G A Vesely

Graham A. Vesely

Subscribed and sworn to before me this 16th day of August 2002.

Toni M Charlton

TONI M. CHARLTON
NOTARY SEAL
NOTARY PUBLIC
STATE OF MISSOURI

TONI M. CHARLTON
NOTARY PUBLIC STATE OF MISSOURI
COUNTY OF COLE
My Commission Expires December 28, 2004

TABLE OF CONTENTS

DIRECT TESTIMONY OF

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DIRECT TESTIMONY

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GRAHAM A. VESELY

THE EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2002-424

Q. Please state your name and business address.

A. Graham A. Vesely, Noland Plaza Office Building, Suite 110, 3675 Noland Road, Independence, Missouri 64055.

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

A. I am a Regulatory Auditor with the Missouri Public Service Commission (Commission or PSC).

Q. Please describe your educational background.

A. In May of 1985, I received a Bachelor's degree in Civil Engineering from Saint Martins College, Olympia, Washington. In May of 1998, I completed an MBA degree with a focus in Accounting from Central Missouri State University, Warrensburg, Missouri. I have received a Certified Public Accountant certificate and am licensed as a CPA in Missouri.

Q. Please describe your employment history.

A. In May of 1985, I was employed as a civil engineer by the United States Air Force. From March 1988 until May 1995, I was employed by the Army Corps of Engineers as a member of a construction management group. At that time, I began working with the engineering firm of Malsy & Associates, Lincoln, Missouri, as a civil engineer. On February 26, 1999, I began my current employment with the Commission.

Q. What are your responsibilities with the Commission?

A. I am responsible for directing or assisting in the audits and examinations of the books and records of regulated utility companies operating within the state of Missouri.

Q. Have you previously filed testimony before this Commission?

A. Yes. Attached as Schedule 1 to this direct testimony, is a list of the cases in which I previously filed testimony before this Commission.

Q. With reference to Case No. ER-2002-424, have you examined and studied the books and records of The Empire District Electric Company (Empire, EDE or Company)?

A. Yes, with the assistance of other members of the Commission Staff (Staff).

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

A. The purpose of my direct testimony in this proceeding is to present the Staff's recommendations concerning the Company's:

1) Fuel expense;
2) Purchased power demand cost; and
3) Fuel inventory levels.

Q. What adjustments are you sponsoring in Case No. ER-2002-424?

A. I am sponsoring the following Adjustments to the Income Statement in Accounting Schedule 10:

Steam Power Production - Fuel Annualization	S-7.2
Combustion Turbine Production - Fuel Annualization	S-28.2
Purchased Power Energy Annualization	S-36.1
Purchased Power Demand Charge Annualization	S-36.2
Off-System Sales	S-3.1

Q. What test year is being used in this case?

A. The Commission authorized a test year ending December 31, 2001, be used in this case, with a known and measurable period updated through June 30, 2002. For a further discussion on the test year and update period used in this case, see the direct testimony of Staff Accounting witness Phillip K. Williams.

Q. Please describe adjustments S-7.2, S-28.2, S-36.1, S-36.2 and S-3.1A.

A. These items reflect the Staff's fuel and purchased power expense adjustments to the test year, as well as the revenue impact of off-system sales. I will provide a more detailed discussion of these adjustments later in my direct testimony.

OVERVIEW OF ELECTRIC GENERATION

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 and 2

State Line Unit 1

State Line Combined Cycle Unit

Ozark Beach Hydro Plant (4 units)

Q. Please describe each facility 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), St. Joseph Light & Power Company, a division of Aquila, Inc. and Empire, with ownership percentages of 70%, 18% and 12%, respectively. KCPL began running the plant, as operating partner, in May of 1980. The Iatan plant is a 670-megaWatt (MW) base-load power plant, which utilizes low cost, 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 base-load steam units that burn coal as the primary fuel and No. 2 fuel oil for flame stabilization. Asbury Unit 1 operates at 193 MW and Asbury Unit 2 has a 20 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. This plant was completed in 1970.

The Riverton plant consists of five units. Riverton Units 7 (38 MW) and 8 (53 MW) are base load/intermediate steam units that burn coal as the primary fuel and natural gas for flame stabilization. Riverton Units 9, 10 and 11 (45 combined MW) are combustion turbine (CT) peaking units that burn natural gas as the primary fuel and No. 2 oil as a secondary fuel.

The Empire Energy Center consists of two (90 MW each) 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 1981.

The Ozark Beach plant is a hydro plant consisting 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 a 90 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 heat-recovery steam generation mode with a 200 MW steam generator, can produce a total of 500MW of power. 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 was 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.

Q. How are quantities expressed for the various types of fuels?

A. Coal is purchased in tons; natural gas is purchased in decatherms (Dth); fuel oil is purchased in either gallons or barrels (42 gallons per barrel). The actual quantities purchased for coal and natural gas are converted into a Btu energy content for purposes of calculating the cost of the purchase. Fuel oil is generally priced on a per gallon or per barrel basis rather than on the basis of Btu content.

Q. What is the meaning of Btu content?

A. Btu stands for British thermal unit. MMBtu stands for one million Btus. One decatherm is equal to one MMBtu. The Btu content of fuel is a measure of its energy content available for electrical generation when the fuel is combusted.

<u>FUEL AND PURCHASED POWER EXPENSE</u>

Q. What was your responsibility in this case with regard to the determination of the cost of fuel and purchased power?

A. I determined a representative level for Empire's: a) unit costs for coal, natural gas and fuel oil used to produce electricity, and b) annualized demand charge costs from purchased power contracts. Additionally, I was responsible for providing a five-year average of the scheduled outage rates, forced outage rates, and equivalent forced outage rates to Staff witness David Elliott of the Energy Department for input to the RealTime™ production cost model (production cost model or fuel model). The Staff used the fuel model to calculate a portion of its annualized fuel and purchased power expense.

Q. How did you examine the fuel prices in this case?

A. I reviewed the coal and rail freight and trucking transportation contracts. I reviewed natural gas contracts, including natural gas pipeline transportation agreements. I also reviewed purchased power capacity agreements. The Staff performed numerous analyses of actual historical information regarding the operations of the individual generating units and the prices paid for fuel and transportation charges by each unit and fuel type. The analyses included fuel burns by unit, MMBtus consumed, the actual megaWatt-hour generation by unit and the number, length and type of outages. The Staff also reviewed the purchases of power from other utilities over several years.

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

A. Staff witness Elliott used these prices in the Staff's RealTime? production cost model to compute 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 costs associated with purchased power demand charges, off-system sales and energy exchanged to the production cost model results. I also added the following costs to the production cost model's results to arrive at an overall total annualized level of fuel and purchased power expense:

1) maintenance and leasing costs for unit trains;
2) property taxes on unit trains;
3) maintenance cost for railroad spur;
4) non-labor fuel handling costs; and
5) Atlantic Richfield Company (ARCO) advance payment amortization relating to the Iatan Generating Unit's fuel coal contract.

The RealTime™ production cost model will be discussed in greater detail by Staff witness Elliott in his direct testimony. Labor costs related to fuel handling are covered in Staff Accounting witness Leslie L. Lucus's payroll annualization.

Q. Please explain the ARCO advance payment amortization.

A. Coal used at the Iatan plant (12% owned by Empire) previously came from the Black Thunder Mines in Wyoming, under a contract with the Atlantic Richfield Company (ARCO). The contract was effective January 1, 1984 through December 31, 2003. The Arch Coal Company (Arch) acquired ARCO and subsequently agreed to re-negotiate a new lower per-ton contract price with KCPL, Iatan's managing partner. The new contract became effective April 1, 1999. Terms of the new contract include:

1) ** HC **
2) ** HC **
3) ** HC
HC **

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The coal supplier benefited by receiving the cash prepayment, and Empire benefited through overall reduced coal costs over the remainder of the contract. Empire accounted for its share of the transaction (in the same manner that KCPL did) by recording a prepayment, and is amortizing this prepayment on the basis of tons of coal purchased, over the remaining years of the revised contract. This correctly matches the savings in coal costs with the related expenses incurred to realize those savings. Therefore, the Staff is reflecting the ARCO prepayment amortization in its expense recommendation in this case.

Fuel Costs

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

A. I examined the specific contract prices of the coal burned at each plant. Total coal cost includes the commodity cost, rail freight and trucking cost, where applicable. For each generating unit, I 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. I then converted the total cost on a dollar-per-ton basis to dollars-per-MMBtu based upon the contract Btu energy content of the coal.

I reviewed coal/freight/trucking contracts in force as of June 30, 2002. At the Asbury plant, Empire burns a mix or blend of Wyoming coal (Peabody) and Utah coal (Genwal) in order to achieve acceptable results. It was necessary to figure per-MMBtu costs for both coals. Through data requests, I determined that the reasonable mix proportions are 90% Wyoming coal to 10% Utah coal. I provided this information to Staff witness Elliott for input to the production cost model. At Riverton 8 Empire burns 100% Wyoming (Peabody) coal, whereas at the Riverton 7 plant Empire uses a mix of 75% Wyoming (Peabody) coal to

25% Oklahoma coal. I provided the computed coal costs and mix information to Staff witness Elliott.

Q. Please explain the tier 1 and tier 2 pricing of the Peabody coal.

A. The contract for the Peabody coal used at Asbury and Riverton 7 and 8 provides for a tier 1 price for the first ** HC ** purchased by Empire. After that, each ton purchased is priced at a lower tier 2 price.

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

A. The Staff used the most recent prices for No. 2/Jet A oil purchased at each of Empire's plants. I converted the average dollar per gallon to a dollar per MMBtu based upon the Btus per gallon of oil.

Empire burns No. 2/Jet A fuel oil only as a secondary fuel or for flame stabilization. As a result, No. 2/Jet A fuel oil is purchased infrequently. The limited number of purchases of No. 2 fuel oil makes it difficult to perform any meaningful type of averaging method. An accurate historical analysis of No. 2 fuel oil prices is 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 data available to analyze. The Staff believes the most recent fuel prices are the best available reflection of ongoing costs based on Empire's purchasing practice regarding No. 2/Jet A fuel oil.

Q. What natural gas costs did the Staff use in developing its total fuel cost for each plant?

A. Staff examined gas invoices, Company monthly fuel reports and other Company data. From this analysis it was determined that the 12-month period ended June 30, 2002, average cost of $3.29 per MMBtu (excluding transportation costs) is the reasonable level on a going-forward basis. The delivered cost of natural gas must also include transportation charges required to move the natural gas from the supply and production side to the delivery point of each power plant. Staff has added all fixed and variable transportation costs to the results of Staff witness Elliott's production cost model.

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

A. I analyzed and developed a cost per ton for each component of the total coal cost. As discussed previously, the total coal cost includes the commodity cost of the coal itself and all freight costs. I combined the individual cost components to derive the total coal cost. I converted the total cost on a dollar per ton basis to dollars per MMBtu based upon contractual Btu content of the coal.

Q. Please describe how you calculated the cost for each of the above detailed components for Iatan.

A. The coal at the Iatan plant is supplied from mines in Wyoming and freighted by Burlington Northern/Santa Fe and Kansas City Southern railroads. I examined the coal and freight contracts to determine the June 30, 2002, delivered per-ton contract cost for coal.

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

A. Empire leases an aluminum unit train for coal deliveries to its Asbury plant. This same coal is then trucked to its Riverton generating units. Empire also has a Company-owned steel unit train that it leases to Union Pacific Railroad. I have 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 you treat unit train costs?

A. I 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. I also 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 railroad spur line based on the 12 months ending December 31, 2001. The Staff totaled the annualized dollars for each cost component of the unit train and included this amount in arriving at total energy costs.

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

A. As natural gas fired units, the annualized fuel cost of operating these units is determined by the Staff's production cost model, based in part on input of the normalized cost of gas I provided to Staff witness Elliott.

Demand Charges – Capacity Contracts

Q. Please describe the various capacity contracts that Empire has entered into.

A. During the test year as updated through June 30, 2002, Empire bought electric power through the following two capacity contracts:

1) ** HC ** of capacity from American Electric Power Service Corporation (AEPC), originally due to expire May 31, 2002;

2) ** HC ** of capacity from Western Resources' Jeffrey Energy Center, through May 31, 2010.

The Company indicated that the contract with AEPC, which had been extended through the end of 2002, would not be continued after 2002.

Q. How did the Staff reflect the contract demand charges in this case?

A. Adjustment S-36.2 annualizes the Company's costs for fixed demand charges under the Western Resources contract only.

I added the annualized fixed demand charges to the results of the Staff's production cost model because the model only computes variable purchased power energy charges.

Q. Were there any other fuel and/or purchased power costs that were not calculated in the Staff's production cost model?

A. Yes. The fuel costs and purchased power costs (energy and demand) associated with off-system sales and energy exchanged were added to the results of the Staff's production cost model since the model is based upon net system input only and does not reflect these types of 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 native load customers and have excess energy to sell to other utilities. The off-system sale transactions occur between utilities resulting in profits (net margin) to the selling entity, in this case, Empire.

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 employee/personnel that are necessary to provide service to Missouri retail electric customers are also needed to make off-system sales. It is appropriate to include the off-system sales in this case because Empire customers are paying for all costs associated with the facilities to produce electricity for the firm retail customers, i.e., native load customers. To the extent that other sales can be made using those facilities, the customers should benefit from these sales. The off-system sales are made at a time when the generating facilities of power and purchases are not needed to serve the native load customers. Off-system sales represent an efficient utilization of the electric system that has been put in place to meet the native load customers' electricity needs.

Q. Does Empire benefit from these off-system sales?

A. Yes. To the extent that there are increases in off-system sales that occur after rates are determined in any given proceeding, the Company will benefit from the growth and increase in net margins (off-system sales less fuel costs) throughout the period until rates are changed by the Commission in a general rate proceeding.

Q. Has the Commission recognized the benefits of including off-system sales in the determination of revenue requirements in other cases?

A. Yes. Staff has consistently included off-system sales in all of the electric cases that I am aware of dating back to the early 1980s and the Commission has agreed with this recommendation. More recently, for instance, in Aquila, Inc. (formerly UtiliCorp) Case No. ER-97-394, the Commission included off-system sales in the calculation of the rate level ordered in that case. The Commission stated, in part, as follows:

> The Commission finds the Staff provided competent and substantial evidence that all of the off-system sales revenue should be reflected in the test year revenue for the purposes of setting rates. The Staff is correct in stating that, since all of the costs of producing the off-system sales revenue were borne by the ratepayers, and since UtiliCorp has benefited from regulatory lag, the total amount of this revenue should be included in rates.
>
> The Commission adopts the adjustment proposed by the Staff.

Q. Please explain adjustment S-3.1 to annualize the revenues for off-system sales.

A. The Staff determined that the off-system sales level the Company made during the 12-month period ended June 30, 2002, represent a normal annual level of sales. Adjustment S-3.1 provides for a normal annual level of these revenues. The fuel expense for the portion of electricity sold off-system that Empire generated with its own plants, as well as purchases made for resale to other utilities as off-system sales have been included in the overall fuel and purchased power expense adjustments.

The total fuel and purchased power adjustments reflect a normal level of energy and demand charges, respectively, for the portion of electricity Empire sold off-system that it purchased from other utilities.

<u>Generating Unit Availability</u>

Q. What historical analysis did the Staff perform relating to the generating units' availability?

A. Staff updated the historical unit availability analysis from Empire's last five rate cases, Case Nos. ER-90-138, ER-94-174, ER-95-279, ER-97-81 and ER-2001-299 to include the most current information. This analysis, when taken together from the prior rate cases, covers a period of 15 years from 1987 through June 30, 2002, on a monthly as well as an annual basis.

Staff witness Elliott took this information into account when programming the production cost model. The production cost model requires a level of scheduled and forced outages rates be included to reflect the simulation of "actual" generating unit operations.

Q. Why is it necessary to reflect outages in the production cost model?

A. Generating units will require planned (scheduled) maintenance and/or experience forced (unscheduled) outages due to equipment failure on an ongoing basis. A scheduled outage occurs when a generating unit is taken out of service for general maintenance and equipment repair on a planned basis. Scheduled outages generally occur during periods of off-peak production, such as the spring and fall months of the year.

Forced outages occur when generating units experience equipment failure on an unplanned or unexpected basis. These outages occur randomly and infrequently.

There is also another outage type, referred to as partial outages (or equivalent forced outages), which result in the generating unit's production of electricity being reduced or "derated." The generating unit is able to stay on-line and generate electricity but is unable to produce at its rated capacity.

Information on each of the three types of outages was compiled by outage duration and any related deratings for each generating unit by month from 1987 to present. Scheduled outage rates were determined for input to the fuel model to reflect the expected outages for planned maintenance that occur for each generating unit, such as turbine and boiler overhauls. Each of Empire's generating units is on a five-year overhaul cycle for both turbines and boilers.

Forced outages are determined for the production cost model to reflect the unexpected outages for unplanned maintenance to repair equipment failures. I provided Staff witness Elliott with this information for both forced and equivalent forced outages for input to the production cost model.

Calculation of Fuel and Purchased Power Adjustments

Q. Please summarize the Staff's calculation of the fuel and purchased power energy costs in this proceeding.

A. The Staff's annualized fuel and purchased power energy costs represent the cost of producing 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 Elliott the fuel prices, including related freight costs, as inputs into the production cost model. The Staff's annualized net system load (sales adjusted for weather, adjusted line losses and Company use) was provided by Staff witnesses Lena Mantle and Richard Campbell. Staff witnesses Janice Pyatte and Charles R. Hyneman provided normalized and annualized growth sales to reflect annualized loads through June 30, 2002. Staff witness Elliott input these and other components, including capacity and availability of the generating units, purchased power energy costs from demand contracts and purchased power energy costs from non-contract spot purchases, into the production cost model. Please refer to the respective direct testimonies of Staff witnesses Campbell, Elliott, Hyneman, Mantle and Pyatte.

After reviewing the results of the production cost model, I added other fuel cost-related components that were not inputs into the model. These included non-labor related fuel handling costs, unit train lease and property tax expenses, O&M costs for the unit trains, maintenance costs for Empire's railroad spur, the ARCO advance payment amortization (renegotiated Iatan coal contract) and the demand costs of Empire's purchased power capacity contracts in effect as of June 30, 2002. The result represents Staff's annualized fuel expense reflected in adjustments S-7.2 and S-28.2 and Staff's purchased power energy and demand costs reflected in Staff adjustments S-36.1 and S-36.2. Lastly, adjustment S-3.1 provides for the revenue impact of a normalized level of off-system sales.

FUEL STOCK INVENTORY LEVELS

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

A. My responsibility was to determine reasonable inventory levels and costs for Empire's coal inventories maintained at its Iatan, Asbury and Riverton plants and for the No. 2/Jet A oil inventories maintained at its Iatan, Asbury, Riverton, Energy Center and State Line plants.

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

A. I have included a 60-day supply of coal for the Asbury and Riverton plants and a 45-day supply for the Iatan plant based upon the Company's average daily burn over the test year. I priced the coal inventory levels at current prices to determine the dollar amount to include in rate base for coal inventory.

Q. What is the basis for your 60- and 45-day supply recommendations?

A. As stated in response to Staff Data Request No. 52, the Company's current policy is to maintain a 60-day supply of coal at its Asbury and Riverton plants. It has been KCPL's policy to maintain a 45-day supply at the Iatan plant. The 45-day policy at Iatan is also consistent with the Company's response to Staff Data Request No. 52. Accordingly, I computed the 45- and 60-day supplies of coal based upon the Company's average daily burn at each plant over the test year.

Q. What No. 2/Jet A oil inventory levels have you included in this case for Empire's Iatan, Asbury, Riverton and Energy Center plants?

A. I examined No. 2/Jet A oil inventory levels on a monthly basis through June 30, 2002, for these plants, and used a 13-month average.

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

A. Empire did not burn or purchase any Jet A fuel oil at its State Line plant during the test year.

Q. Does this conclude your direct testimony?

A. Yes, it does.

GRAHAM A. VESELY

LISTING OF CASE PARTICIPATION

Company Name	Case Number	Disposition
St. Joseph Light & Power Company	ER-99-247	Direct Stipulated
Atmos Energy Corporation	GM-200-312	Rebuttal Stipulated
Missouri Gas Energy	GR-2002-292	Direct Stipulated
Missouri Public Service	ER-2001-672	Direct, Surrebuttal Stipulated

INFORMAL CASES

Raytown Water Company

Timbercreek Sewer Company

Silverleaf Resorts