COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

PRE-FILED TESTIMONY
OF
DIANE W. JENKINS

KENTUCKY UTILITIES COMPANY

D/B/A OLD DOMINION POWER COMPANY

CASE NO. PUE-2016-00017

April 19, 2016

Summary of the Testimony of Diane W. Jenkins

My testimony addresses the application filed by Kentucky Utilities Company d/b/a Old Dominion Power Company ("KU" or "Company") and includes the following findings and recommendations:

1. KU's fuel factor application requests to decrease its levelized fuel factor by 0.577¢ per kWh from 2.863¢ per kWh to 2.286¢ per kWh effective for service rendered on or after April 1, 2016.

2. The proposed fuel factor was placed into effect on an interim basis effective April 1, 2016, and decreases the monthly bill of a residential customer using 1,000 kWh per month by $5.77.

3. KU reports an over-recovery position of $2,340,053 as of March 31, 2016. This projection was based on actual data through December 2015 plus estimated fuel recoveries in the months of January, February, and March 2016. The over-recovery position is the result of lower energy expense than was forecasted.

4. The Company's application includes historical and forecasted data for its cost of generation, purchases, and off-system sales. As part of this data, the Company has provided historical and projected data for individual unit performance.

5. The methodologies and models used to forecast energy sales and delivered fuel prices are reasonable.

6. KU's forecasts for energy sales and delivered fuel prices are reasonable given current economic conditions in the regional economy and fuel markets.

7. The Company's forecast for unit performance is reasonable and compares favorably with historical performance.

8. The fuel factor proposed by the Company appears reasonable.

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KENTUCKY UTILITIES COMPANY
D/B/A OLD DOMINION POWER COMPANY
CASE NO. PUE-2016-00017

Q1. PLEASE STATE YOUR NAME AND POSITION WITH THE COMMISSION.

A1. My name is Diane W. Jenkins. I am a Principal Utilities Analyst in the Commission's Division of Energy Regulation.

Q2. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A2. On February 16, 2016, Kentucky Utilities Company, doing business in Virginia as Old Dominion Power Company (hereinafter, "KU" or the "Company"), filed with the State Corporation Commission ("Commission") an application, written testimony, and exhibits in support of its request to decrease its levelized fuel factor by 0.577 cents per kilowatt-hour ("¢ per kWh") from 2.863¢ per kWh to 2.286¢ per kWh, effective for service rendered on and after April 1, 2016, pursuant to § 56-249.6 of the Code of Virginia ("Application").

On March 3, 2016, the Commission issued its Order Establishing 2016-2017 Fuel Factor Proceeding that established the instant case, directed the Company to issue public notice, set a schedule for hearing and for the filing of testimonies, and placed the proposed fuel factor into effect on an interim basis for service on and after April 1, 2016. The Commission also directed the Staff of the Commission ("Staff") to investigate KU's Application and file testimony.

The Commission did not receive any notice of participation or written public comments in this case.

In response to the Commission's directive, my testimony presents the Staff's conclusions and recommendations relative to the reasonableness of KU's: (i) projected fuel recovery position as of March 31, 2016, and the resulting correction factor; (ii) forecast of energy sales and delivered fuel prices, and the consistency of such forecast with the Commission's standards described in 20 VAC 5-300-100, "Standards for Fuel Cost Projections of Electric Utilities"; (iii) projected generating unit performance, purchase and interchange transactions, and net energy fuel mix and cost during the forecast period; and (iv) proposed total fuel factor reflecting projected Virginia jurisdictional fuel expense and sales for the period April 1, 2016-March 31, 2017.

Q3. PLEASE DETAIL THE COMPANY'S PROPOSED FUEL FACTOR AS FILED IN ITS APPLICATION.

A3. In its Application, the Company proposed a fuel factor of 2.286¢ per kWh which represents a decrease of 0.577¢ per kWh, or approximately 20 percent, from the previous fuel factor of 2.863¢ per kWh (See Attachment 1). The proposed fuel factor was placed into effect on an interim basis effective April 1, 2016, and decreases the monthly bill of a residential customer using 1,000 kWh from $109.48 to $103.71 or by $5.77, which is approximately 5.3 percent.[1] The Company's proposed fuel factor includes an in-period factor of 2.616¢ per kWh and a correction factor credit of 0.330¢ per kWh.

The in-period component of KU's proposed fuel factor of 2.616¢ per kWh is based on projected fuel expenses of $18,526,043 and projected energy sales of 708,288,805 kWh in its Virginia jurisdiction during the twelve month forecast period from April 1, 2016, through March 31, 2017. This in-period component of the proposed fuel factor represents a decrease of 0.307¢ per kWh, approximately 10.5 percent, from the previous in-period factor of 2.923¢ per kWh.

Additionally, KU is proposing a decrease in the correction factor component of the proposed fuel factor, from a credit of 0.060¢ per kWh to a credit of 0.330¢ per kWh. In its Application, the Company projected an over-recovery balance of $2,340,053 as of March 31, 2016. This projection was based on actual data through December 2015 plus estimated fuel recoveries in the months of January, February, and March 2016.

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[1] The residential bill impact percentage was calculated excluding local utility taxes.

The Company explains that the over-recovery position is the result of lower energy expense than was forecasted, namely lower gas volumes, lower per kWh coal costs, and lower purchased power expense.

Q4. HOW DOES THE COMPANY FORECAST ENERGY SALES?

A4. KU's energy sales forecast is based on the Company's July 2015 forecast. In general, the Company uses econometric modeling to establish historical energy consumption relationships and to project future energy sales based on multiple independent explanatory variables such as: 1) national, regional, and state economic conditions; 2) demographic and consumption characteristics including end use modeling data considering appliance saturation and efficiencies; and 3) weather data. The Virginia and Kentucky service territories are modeled separately with distinct modeling for each customer class, using similar methodologies. The Virginia service area represents less than 5 percent of KU's total energy sales.

IHS Global Insight of Boston, MA, provides the national U.S. macroeconomic and state level input data, as well as economic assumptions, demographic forecasts, and other regional data, that are needed to prepare the sales forecast. Weather data comes from the National Oceanic and Atmospheric Administration. In addition, the Company obtains information about growth prospects directly from its largest customers.

Q5. HOW DOES THE COMPANY FORECAST FUEL PRICES?

A5. Coal is the primary fuel used by KU. The Company anticipates that approximately 99 percent of its estimated total coal purchases will be acquired pursuant to existing contract commitments and spot (short-term) market purchases. Forecasted prices for existing coal contracts are developed by escalating current coal prices, based on the price escalator clauses of the contracts. The remaining 1 percent of purchases are uncommitted purchases. Uncommitted coal prices are forecasted based on a combination of coal prices obtained from suppliers' bids received during KU's procurement period and a commercially available coal market forecast prepared by Wood Mackenzie, Ltd.

Current transportation, barge fleeting, and rail car maintenance costs are added to the forecast price for the total forecast delivered price. Similar to last year, transportation costs account for approximately 15 percent of the total forecast delivered coal purchases for the 2016-2017 fuel year.

KU has no contracts to purchase oil or natural gas as both fuels are purchased on the spot market on an "as-needed" basis. Fuel oil is not a significant production fuel, and prices are forecasted based on the New York Mercantile Exchange ("NYMEX") futures pricing for #2 fuel oil, which is available for New York harbor delivery. Natural gas prices are similarly forecasted based on the market price of Henry Hub NYMEX natural gas futures and market-priced pipeline transportation rates.

Historically, KU's baseload electric demand was primarily supplied using coal-fired generating units. However, recent changes to the generation fleet, including the retirement of several coal-fired units and the addition of the first combined cycle unit, Cane Run 7 ("CR7"), has created the need for KU to update its business strategy for fuel procurement. CR7 is required to operate a minimum amount in order to meet the projected baseload electric demand. Further, CR7's high efficiency and low natural gas prices make this unit competitive with the coal-fired base load units. Because of uncertainty regarding the volume of natural gas required, KU will continue to purchase physical natural gas on an "as-needed" basis, typically in the day-ahead or intra-day spot market. However, in 2016, the Company expects to begin purchasing a portion of the projected minimum natural gas requirement for CR7 on a longer-term basis.

Q6. WHAT IS YOUR EVALUATION OF THE METHODOLOGY USED TO FORECAST ENERGY SALES AND DELIVERED FUEL PRICES?

A6. The Company's methodologies and models used to forecast energy sales and delivered fuel prices have evolved over a period of several years, generally conform to current modeling and forecasting practices, and have been reviewed by the Staff in this and previous proceedings. The Staff believes that these methodologies and models are reasonable.

Q7. WHAT IS YOUR EVALUATION OF THE REASONABLENESS OF FORECASTED ENERGY SALES AND DELIVERED FUEL PRICES?

A7. With respect to energy sales, the Company's forecast of Virginia jurisdictional energy sales for the 2016-2017 fuel year is about 2.5 percent lower than actual 2015-2016 fuel year sales. KU's energy sales forecast for calendar year 2016 is less than 1 percent lower than the Company's previous forecast for calendar year 2016, in large part because of continued weakness in the mine power sector. Mine power loads historically constitute a significant portion of the Large Power Sales Class in this service territory. Mining closures also negatively impact residential and commercial sales. The Company's energy forecast is based on a normal weather distribution using twenty years of data. KU's 2016-2017 energy sales forecast assumes normal weather.

With respect to delivered fuel prices, the Company's forecast of delivered coal prices reflects existing contract commitments and the conditions prevailing in the coal markets when the forecast was completed in January 2016. The forecast results in a total average delivered coal price of approximately 219 cents per million BTU for the 2016-2017 fuel year, which is approximately 4.5 percent lower than the 2015 actual average delivered coal price. KU is purchasing almost entirely high-sulfur coal. The Company forecasts that high-sulfur coal (mostly from the Illinois Basin) will account for 93 percent of the Company's anticipated coal supply requirements in the 2016-2017 fuel year.

As noted above, KU continues to purchase large volumes of high-sulfur coal from the Illinois Basin. According to the Company, mining in this region is typically performed by large mines. The Company states that due to the investment and operating cost required for these large mines, suppliers require longer term contracts with price indices, rather than shorter term contracts with fixed annual price adjustments.

KU projects coal prices to increase for E.W. Brown and decrease for Ghent and Trimble County with an overall decrease of 5.8 percent. The changes in coal prices at these stations are the result of new contracts, the renegotiation of current contracts, and/or changes to transportation costs.

Natural gas prices were forecasted based on the Henry Hub natural gas futures price strip traded at the NYMEX on June 18, 2015. NYMEX Henry Hub futures prices as of January 7, 2016, are lower than the forecasted natural gas prices – by an average of $0.57 per MMBtu for the 2016-2017 fuel year. Given the potential volatility in natural gas prices, the Staff believes that the Company's forecast is reasonable for purposes of establishing the 2016-2017 fuel factor.

KU purchases firm natural gas pipeline capacity to ensure fuel availability for its combustion turbine units and, KU's new combined cycle unit, CR7. The new unit began commercial operation in mid-June of 2015. The Company's pipeline capacity costs are projected to be about 15 percent higher than actual costs for calendar year 2015.

Overall, the Staff believes that the Company's forecasts of energy sales and delivered fuel prices are reasonable given current economic conditions in the regional economy and fuel markets.

Q8. HAS THE COMPANY MET THE STANDARDS SET BY THE COMMISSION FOR EVALUATING FUEL COSTS PROJECTIONS OF ELECTRIC UTILITIES?

A8. In its 1989 Session, the Virginia General Assembly adopted Senate Resolution No. 156, which directed that the Commission establish standards for evaluating fuel costs projections of electric utilities. On November 27, 1990, the Commission issued its Final Order in Case No. PUE-1990-00004 adopting "Standards for Fuel Cost Projections of Electric Utilities". These standards are provided as Attachment 2 to this report. The Staff believes the Company has complied with the above standards.

Q9. PLEASE DESCRIBE THE SYSTEM POWER SUPPLY RELATIONSHIP BETWEEN KU AND LG&E.

A9. KU's power supply and fuel expense forecast is based on the projected joint economic dispatch of KU and LG&E generating units necessary to serve the combined native load of both utilities pursuant to the provisions of the Power Supply System Agreement ("PSSA"). For purposes of allocating fuel expenses, each company's generation is first dedicated to its own load. After meeting its own load, the next lowest variable cost generation is available to the other company at an amount equal to the incremental fuel cost of the selling company plus one half of the difference between the incremental fuel cost of the selling company and the avoided fuel cost of the purchasing company. After the energy requirements for both companies are met, any remaining generation is available for off-system sales.

Q10. PLEASE DISCUSS KU'S PROJECTED NET ENERGY SUPPLY MIX.

A10. As shown in Attachment 3, the Company projects that approximately 72 percent of its net energy supply will be provided from its coal-fired generation fleet, 24 percent from gas-fired combustion turbines, and 4 percent from net purchases.[2] Additionally, the Company continues to receive a small amount (less than 1 percent) of its net energy supply from hydro generation and forecasts a small percentage of energy from solar generation beginning in 2016. Approximately 88 percent of KU's projected power purchases are economy purchases from its affiliate, LG&E, which has mostly coal-fired generating facilities. As compared to actual results for calendar year 2015, the projected energy supply mix reflects a decrease in the level of coal-fired generation and an increase in natural gas-fired combustion turbine. The increase in natural gas generation is driven by the commercial operation of the combined cycle unit, Cane Run 7.

[2] Actual results for calendar year 2015 were 80 percent from its coal fired generation fleet, 16 percent from gas fired combustion turbines, and 4 percent from net purchases.

Q11. PLEASE DISCUSS THE PROJECTED AVERAGE NET ENERGY SUPPLY COST.

A11. The projected total average net energy supply cost for the fuel year is 2.434¢ per kWh. This is an approximately 4 percent decrease from the actual 2.538¢ per kWh average fuel cost for calendar year 2015. The Company projects a decrease in the average fuel cost of its coal-fired generation (2.353¢ per kWh for the forecast period versus 2.470¢ per kWh in 2015). The Company forecasts a decrease in the average fuel cost for its gas-fired combustion turbines (2.997¢ per kWh in 2015 versus 2.647¢ per kWh for the forecast period). Cane Run Unit 7 is expected to be a baseload unit and will have a considerable impact on the Company's gas burn. Primarily driven by the CR7 addition, KU expects to generate 24 percent of the energy from natural gas in 2016 compared to 16 percent in 2015.

Q12. PLEASE SUMMARIZE THE PROJECTED PERFORMANCE OF THE KU GENERATING UNITS DURING THE FORECAST PERIOD.

A12. Attachment 4 shows the Company's forecast performance data for each KU generating unit for the period April 2016 through March 2017. The Company is forecasting that its coal-fired and combined cycle generation facilities will achieve a weighted average aggregate Equivalent Availability Factor ("EAF") of 83 percent, which is the same as actual 2015 performance and slightly higher than the actual five-year average EAF of 82.6 percent. The lengthy planned outages of three steam units impacted the EAF for 2015. Excluding these three planned outages, EAF would have been 87.0 percent.

Three coal fired units (E.W. Brown 3, Ghent 1, and Ghent 2) have scheduled maintenance during the 2016-2017 fuel year and are forecasted to have an EAF for the twelve months ending March 2017 that is less that the five year average EAF. These units are forecasted to have EAFs of 80.4 percent, 78.3 percent, and 72.2 percent, respectively.

Trimble 2 performed well throughout the 2015-2016 fuel year and had an EAF of 85.4 percent. The Company forecasts Trimble 2 will have an EAF of 85.2 during the 2016-2017 fuel year.

In addition to forecast EAFs, Attachment 4 provides each generating unit's projected Capacity Factor ("CF"), Heat Rate, net output in megawatt-hours ("MWh"), and fuel expense as defined in the Commission's Definitional Framework of Fuel Expenses for Old Dominion Power Company (Attachment 5). With respect to Heat Rate, the Company projects that its coal-fired generation units will achieve an aggregate thermal efficiency of 10,704 Btu per kWh which compares favorably to historical data.

Q13. PLEASE DESCRIBE THE COMPANY'S PROJECTIONS OF POWER PURCHASES AND SALES FOR THE FORECAST PERIOD.

A13. Attachment 6 details KU's projections of wholesale power purchases and off-system sales for the forecast period. The Company forecasted that it will purchase approximately 1.66 million MWh at an average cost of 2.935¢ per kWh. Approximately 88 percent of the projected wholesale purchases are from LG&E pursuant to the PSSA at an average cost of 2.955¢ per kWh.

With respect to off-system sales, KU forecasted total deliveries of 669,328 MWh at an average price of 3.163¢ per kWh. Approximately 91 percent of these sales are projected to LG&E through the PSSA at a forecast average price of 3.066¢ per kWh. The remaining sales are to the wholesale market. The Company projects off-system sales margins of $922,140 for the forecast period, 75 percent of which are credited to projected fuel expenses.

Q14. WHAT ARE THE STAFF'S CONCLUSIONS AND RECOMMENDATIONS?

A14. The Staff believes that the Company's projected Virginia jurisdictional fuel expenses and sales for the forecast period are reasonable. The Staff recommends that the Commission accept KU's proposed forecast of energy sales and delivered fuel prices for the purpose of establishing a 2016-2017 fuel factor and approve the proposed fuel factor of 2.286¢ per kWh.

Q15. DOES THIS CONCLUDE YOUR TESTIMONY?

A15. Yes

Attachment 1

Kentucky Utilities Company
PROPOSED FUEL FACTOR
April 1, 2015 - March 31, 2016

	PREVIOUS FUEL FACTOR (¢/kWh)	COMPANY PROPOSED AND INTERIM FUEL FACTOR (¢/kWh)
In-period Factor	2.923	2.616
Correction Factor	(0.060)	(0.330)
Total Fuel Factor	2.863	2.286

Based on Projected:

Fuel Over-Recovery Balance	$2,340,053
Virginia Jurisdictional Fuel Expense	$18,526,043
Virginia Jurisdictional Sales (kWh)	708,288,805

Attachment 2

Standards for Fuel Cost Projections of Electric Utilities

- A sophisticated "state-of-the-art" production costing model should be utilized for projecting fuel expenses.

- Key input data and assumptions should reflect historic data. Any significant deviation from historic trends should be adequately explained and evaluated for reasonableness.

- Key input data such as load forecasts, generating unit characteristics, fuel data, and system parameters should be developed in the same relative time frame and reflect consistent assumptions.

- Demand forecasts should be current and reflect economic growth, normal weather, the price of electricity, elasticity assumptions, appliance saturations, income and population changes in the utility's service area. They should also reflect projections of energy, peak demand and the effects of demand-side options.

- Expected fuel prices should reflect historic fuel costs adjusted for any known dynamics of the projection: i.e., labor contracts, expected operation of the spot market, current fuel contracts, the world fuel market, inventory levels and fuel availabilities, purchasing volumes, coal severance taxes, etc.

- Unit operations should consider planned maintenance, forced outages, expected dispatch levels, historical performance levels, seasonal capabilities, as well as ongoing enhancements or unit deterioration.

- Dispatch orders should reflect such variables as system economics, unit availabilities, minimum operating levels, heat rates, and terms and conditions of purchased power contracts.

- Purchase power levels should consider need, system economics, power availability and transmission constraints.

- Projections supporting the development of cogeneration rates should include a comparison of key input data and assumptions from the last fuel projection filed with the Commission. Major changes should be adequately explained.

Attachment 3

Kentucky Utilities Company
NET ENERGY SUPPLY and FUEL COST

ACTUAL

April 2013 - March 2014	MWh	% of Total	¢/kWh
Company Generation			
COAL	19,505,317	88%	2.558
OIL	-		0.000
GAS CT	326,938	1%	9.048
HYDRO	106,623		
Purchases	2,694,800		2.598
Sales	360,146		3.164
NET PURCHASES	2,334,654	10%	
TOTAL NET OUTPUT	22,273,532	100%	2.637

April 2014 - March 2015	MWh	% of Total	¢/kWh
Company Generation			
COAL	18,548,042	82%	2.599
OIL	-		0.000
GAS CT	982,748	4%	8.005
HYDRO	72,287		
Purchases	3,486,423		2.874
Sales	376,669		3.832
NET PURCHASES	3,109,754	14%	
TOTAL NET OUTPUT	22,712,831	100%	2.847

12 months ending December 2015

Company Generation	MWh	% of Total	¢/kWh
COAL	17,325,294	80%	2.470
OIL	-		0.000
GAS CT	3,533,296	16%	2.997
HYDRO	97,943		
Purchases	1,731,455		2.539
Sales	908,374		2.794
NET PURCHASES	823,081	4%	
TOTAL NET OUTPUT	21,779,614	100%	2.538

FORECAST

April 2013 - March 2014	MWh	% of Total	¢/kWh
Company Generation			
COAL	18,545,524	81%	2.602
OIL	0		
GAS CT	583,723	3%	6.061
HYDRO	73,120		
Purchases	3,829,142		2.922
Sales	181,607		3.042
NET PURCHASES	3,647,535	16%	
TOTAL NET OUTPUT	22,849,902	100.0%	2.732

April 2014- March 2015	MWh	% of Total	¢/kWh
Company Generation			
COAL	17,663,922	78%	2.687
OIL	0		
GAS CT	891,885	4%	5.949
HYDRO	77,931		
Purchases	4,172,345		3.047
Sales	163,059		3.212
NET PURCHASES	4,009,286	18%	
TOTAL NET OUTPUT	22,643,024	100.0%	2.869

FORECAST- CURRENT FUEL FACTOR

April 2015 - March 2016	MWh	% of Total	¢/kWh
Company Generation			
COAL	15,945,447	70%	2.623
OIL	0		
GAS CT	5,159,236	23%	2.990
HYDRO	74,347		
Purchases	1,969,641		3.068
Sales	504,779		3.177
NET PURCHASES	1,464,862	6%	
TOTAL NET OUTPUT	22,643,892	100.0%	2.725

FORECAST - PROPOSED FUEL FACTOR

April 2016- March 2017	MWh	% of Total	¢/kWh
Company Generation			
COAL	16,348,046	72%	2.353
OIL	0		
GAS CT	5,380,205	24%	2.647
HYDRO	71,207		
SOLAR	8,365		
Purchases	1,658,873		2.935
Sales	669,328		3.163
NET PURCHASES	989,545	4%	
TOTAL NET OUTPUT	22,797,368	100.0%	2.434

Kentucky Utilities Company
GENERATING UNIT PERFORMANCE FORECAST

April 2016 - March 2017

Unit	MDC MW	EAF %	CF %	Heat Rate Btu/kWh	Net Output MWh	Fuel Expense $	Fuel Expense ¢/kWh
Brown 1	106	88	17	11,836	158,369	5,696,636	3.597
Brown 2	166	91	26	10,869	380,395	12,315,759	3.238
Brown 3	410	80	22	12,346	796,711	29,373,191	3.687
Ghent 1	474	78	72	10,803	3,045,787	69,054,087	2.267
Ghent 2	495	72	64	10,670	2,777,824	62,360,307	2.245
Ghent 3	485	85	75	11,107	3,241,349	75,762,631	2.337
Ghent 4	485	91	72	11,071	3,078,415	71,747,501	2.331
Trimble 2	445	85	71	9,243	2,869,196	58,328,670	2.033
Total/Avg Coal	3066	83	61	10,704	16,348,046	384,638,782	2.353
Haefling 1-2	24	90	0	23,541	48	9,659	20.123
Brown 5	130	82	2	13,211	20,732	681,472	3.287
Brown 6	146	88	0	11,226	4,814	138,890	2.885
Brown 7	146	90	1	11,207	8,281	241,853	2.921
Brown 8	121	86	3	14,340	33,521	1,214,056	3.622
Brown 9	121	90	3	14,137	29,201	1,037,821	3.554
Brown 10	121	78	2	14,361	20,157	762,505	3.783
Brown 11	121	90	3	14,288	27,143	976,523	3.598
Paddy's Run	147	88	4	10,775	62,866	1,906,992	3.033
Trimble 5	159	90	20	10,861	300,896	8,973,048	2.982
Trimble 6	159	90	14	10,896	212,846	6,404,878	3.009
Trimble 7	159	90	13	10,878	194,483	5,819,585	2.992
Trimble 8	159	90	4	10,853	62,708	1,847,852	2.947
Trimble 9	159	90	10	10,880	146,510	4,361,522	2.977
Trimble 10	159	90	3	10,869	37,538	1,108,645	2.953
Cane Run	521	90	88	6,820	4,218,462	80,776,794	1.915
Total/Avg CTs	2552	90	80	2,426	5,380,206	116,262,095	2.161
					Capacity Charges	26,172,934	
					Total Gas	142,435,029	2.647
Dix Dam 1-3 Hydro	24				71,207		
Brown Solar	6				8,365		
TOTAL/AVG SYSTEM	5,642				21,807,824	527,073,811	2.417

NOTES:
1. MDC = Maximum Dependable Capacity (summer net)
2. EAF = Equivalent Availability Factor
3. CF = Capacity Factor

Attachment 5

VIRGINIA STATE CORPORATION COMMISSION'S
DEFINITIONAL FRAMEWORK OF FUEL EXPENSES
FOR OLD DOMINION POWER COMPANY

a. The cost of fossil fuels shall be those items initially charged to account 151 and cleared to accounts 501, 518 and 547 on the basis of fuel used. In those instances where a fuel stock account (151) is not maintained, e.g., gas for combustion turbines, the amount shall be based on the cost of fuel consumed and entered in account 547.

b. The cost of nuclear fuel shall be the amount contained in account 518, excluding lease finance charges, except that if account 518 also contains any expense for fossil fuel which has already been included in the cost of fossil fuel, it shall be deducted from this account.

c. Total energy costs associated with purchased power and charged to account 555 shall be recoverable as fuel costs. The demand component of such power purchases shall be recoverable as fuel costs except when such purchases are made for reliability reasons or the maintenance of reserve margin requirements.

d. All refunds of fuel costs resulting from overcharges, late delivery, or any other reason and all recoveries and adjustments of whatever nature affecting the price of fuel shall be passed on through these proceedings.

e. Company shall be permitted to adjust for system losses through development of a fuel factor based upon fuel costs divided by sales or through the application of a separately derived loss factor applied to a fuel factor based on net energy requirements.

f. Energy revenues associated with off-system sales of power shall be credited against fuel factor expenses in an amount equal to the total incremental fuel factor costs incurred in the production and delivery of such sales. In addition, 75 percent of the total annual margins from off-system sales shall be credited against fuel factor expenses.

Attachment 6

Kentucky Utilities Company
PURCHASE AND INTERCHANGE TRANSACTIONS FORECAST
April 2016- March 2017

PURCHASES	MWh	Energy $	¢/kWh
Long Term Firm - Ohio Valley Electric Corp. (OVEC)	200,153	5,579,913	2.788
Economy from LG&E (under the PSSA)	1,458,085	43,080,743	2.955
Non-Firm Market Economy to supply native load	635	34,554	5.442
Total	1,658,873	48,695,210	2.935

OFF-SYSTEM SALES	MWh	Energy $	¢/kWh
Economy to LG&E (under the PSSA)	609,228	18,679,904	3.066
Short-Term Economy to Market	60,101	2,489,136	4.142
	669,329	21,169,040	3.163

	MWh	Energy $
NET PURCHASES	989,544	27,526,170

Note: Capacity charges do not flow through the Virginia fuel factor and are not shown.