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which covers June 1 of each year to May 31 of the next year. The proposed ESP extends to May 31, 2021, and has nine periods, covering nine years and five months. However, in some cases, I report results annually.

EXHIBIT D
Schedule of Proposed ESP

Period	Definition
1	January 2012, to May 31, 2013
2	June 1, 2013, to May 31, 2014
3	June 1, 2014, to May 31, 2015
4	June 1, 2015, to May 31, 2016
5	June 1, 2016, to May 31, 2017
6	June 1, 2017, to May 31, 2018
7	June 1, 2018, to May 31, 2019
8	June 1, 2019, to May 31, 2020
9	June 1, 2020, to May 31, 2021

Q. WHAT ARE THE IMPLICATIONS OF THIS SCHEDULE, IN TERMS OF FORECASTING PRICES?

A. One implication is that the period extends beyond the period for which forward prices from ICE and PJM are available. Hence, as discussed later, I present a computer model-based forecast to supplement ICE forward prices. This projection is based on a detailed analysis of supply and demand fundamentals.

Q. HOW DOES THE AUCTION PROCESS WORK?

A. As discussed by witness Lee in his testimony, Duke Energy Ohio will conduct a series of wholesale auctions that are designed to obtain the SSO energy and ancillary service requirements. Hence, the market component of the SSO price would be the auction price.

Q. WHAT IS AUCTIONED OFF?

A. Duke Energy Ohio would auction off a "slice of system" energy and ancillary needs generally for one, two, or three years of SSO service.[14] The goal is to have competitive procurement for energy, which is the largest portion of market prices for power, and to have frequent price updating of a significant portion of the load. The auctions generally would be staggered so that, each year, a third of the load was being sourced from auction winners from 3, 2, and 1 years prior.

Q. HOW WILL THE AUCTIONS BE CONDUCTED?

A. As described in the Direct Testimony of Robert J. Lee and James S. Northrup, the auction process will involve an Auction Manager who is independent of the company.

Q. WHAT PRODUCTS AND SERVICES WILL THE AUCTION WINNER BE RESPONSIBLE FOR?

A. The auction winner will be bidding for a slice or "tranche" of the Company's total retail energy load and will be responsible for assuring that the cost of serving up to 100% of that tranche is at the winner's bid price in \$/MWh of load served in a given period. The costs of serving this load include primarily energy purchases from the PJM energy market or, to the extent suppliers are relying on owned generation, the supplier's cost of serving the load will be dependent on the cost of goods sold (*e.g.*, fuel, emission allowances, etc.) for supplier's generation. The suppliers' costs of serving this load will not include capacity purchases from PJM's forward capacity market. Duke Energy Ohio is responsible for meeting the PJM capacity requirement for entire retail load. The winner must also cover 3

[14] See Attachment B to the Application for the Proposed Bid Timeline and Schedule.

smaller cost items, such as ancillary services needed to supply the load, and other items shown in Exhibit E.

EXHIBIT E
Components of the Auction Winner's Responsibility

	SSO Auction
Energy	Yes
Capacity	No
Ancillary Services	Yes
NITS, RTEP, MTEP[(1)]	No
PJM Market-Based Charges[(2)]	Yes
Losses	Yes

Note: (1) Generally,, those costs that will be recovered in the Company's approved Base Transmission Rider (Rider BTR).
(2) Generally, those costs billed from PJM not recovered in Rider BTR.

IV.2 FORECAST OF PROPOSED ESP PRICES

Q. WHAT IS THE FORECAST OF PRICES UNDER THE PROPOSED ESP?

A. Duke Energy Ohio forecasts that proposed ESP prices will start at 7.98 ¢/kWh in 2012. By 2021, prices will be [redacted] ¢/kWh. Thus, proposed ESP prices will increase [redacted] percent per year (Exhibit F-1). On average the price is [redacted] ¢/kWh.

EXHIBIT F-1
Proposed ESP Price (¢/kWh)

Year	Capacity Charge[1]	76 Percent of Energy Margin[1]	Net Capacity Charge	Retail Energy Price[2]	Proposed ESP Price
2012	2.77	0.70	2.06	5.91	7.98
2013	2.60	1.25	1.36	6.38	7.74
2014	2.92	1.47	1.46	6.94	8.40
2015	3.17	1.82	1.34	7.59	8.93
2016	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average 2012-2016	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average 2012-2021	3.25	1.63	1.63	[redacted]	[redacted]

[1] Source: Duke Energy Ohio
[2] Uses AD Hub forwards from 2012 to 2015. Post-2015 is ICF forecast. The retail electrical energy price does not include the capacity component. See later discussion. Source: ICE and ICF International

Q. WHAT ARE THE COMPONENTS OF PROPOSED ESP PRICES?

A. The components of the proposed ESP prices are: (1) the capacity charge; (2) 76 percent of net energy sales margins, which are deducted from the capacity charge to obtain the net capacity charge; (3) the net capacity charge; and (4) the auction results for retail electrical energy. On average, the 2012 – 2021 capacity charge is 30.6 percent of the total price under the proposed ESP, but the net capacity charge is 15 percent of the total proposed ESP price. During the 2012 to 2021 period, the energy price is [redacted] percent of the total price under the proposed ESP. The net capacity charge is only 15 percent of total proposed price, *i.e.*, half the capacity charge because 76 percent of the energy margin is 15 percent of the total proposed ESP price, *i.e.*, 30-15 = 15 percent. In other words, 76 percent of the energy margin decreases the capacity charge by half.

Q. WHAT ARE THE TRENDS IN THE COMPONENTS?

A. Between 2012 and 2021, the capacity charge is growing at an average rate of 3.7 percent per year, but the net capacity charge is increasing only modestly. This is because the energy margin increases between 2012 and 2021 at an average of 13 percent per year. Even though the net capacity charge is increasing only at 1.0 percent per year, on net, the total proposed SSO price grows because the electrical energy price is larger and growing [redacted] percent per year on average. The energy margin stops growing between 2017 and 2021, in part due to an assumed federal CO_2 program. Were this program not to be implemented, electrical prices would be lower, but net margins would be higher.

Q. HOW WAS THIS FORECAST DEVELOPED?

A. The retail energy price is converted from the forward and forecast wholesale electrical energy prices based on a set of formulas. This is discussed in a later section. The margin is based on analysis by Duke Energy Ohio, using forward and forecast wholesale prices. This forecast was prepared by Duke Energy Ohio with input from ICF on market prices in the post-2015 years, *i.e.*, largely post-2015.

Q. WHAT HAPPENS IF THE 5 PERCENT OF NET MARGINS DEVOTED TO BENEFIT ECONOMIC DEVELOPMENT IS TREATED THE SAME

AS THE 76 PERCENT USED TO BENEFIT CUSTOMERS VIA LOWER RATES?

A. Exhibits F-1 and F-2 show that the proposed ESP price falls from [redacted] ¢/kWh to [redacted] ¢/kWh over the 2012 to 2021 period. In the first five years, the proposed ESP price decreases by 0.09 ¢/kWh.

EXHIBIT F-2
Proposed ESP Price (¢/kWh)

Year	Capacity Charge[1]	76 percent of Energy Margin[1]	5 Percent of Energy Margin[1,2]	Net Capacity Charge[3]	Retail Energy Price	Proposed ESP Price
2012	2.77	0.70	0.05	2.01	5.91	7.93
2013	2.60	1.25	0.08	1.27	6.38	7.66
2014	2.92	1.47	0.10	1.36	6.94	8.30
2015	3.17	1.82	0.12	1.22	7.59	8.81
2016	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average 2012-2016	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average 2012-2021	3.25	1.63	0.11	1.52	[redacted]	[redacted]

[1] Source: Duke Energy Ohio
[2] The additional 5 percent accounts for economic development; 4 percent for customers and 1 percent for the Company.
[3] Uses AD Hub forwards from 2012 to 2015. Post-2015 is ICF forecast. The retail electrical energy price does not include the capacity component. Source: ICE and ICF International.

V. WHOLESALE POWER PRICE PROJECTION

V.1 INTRODUCTION

Q. HOW IS THIS SECTION ORGANIZED?

A. This section has five subsections. The first describes the organization of this section. The second subsection briefly discusses recent wholesale power prices, and the history of wholesale prices in the Duke Energy Ohio marketplace. The third presents recent forward prices for wholesale delivery, covering 2012 to 2015. These prices are observable forward prices available from ICE and/or PJM. The fourth subsection presents ICF's forecast of wholesale power prices, which is based on computer modeling of the North American power grid supply and demand fundamentals. This forecast is used for the 2016-2021 period (see Exhibit G). The fifth subsection discusses the forecasting approach.

EXHIBIT G
Power Price Forecast Bases

Period	Energy	Capacity
January 1, 2012 – May 31, 2013	ICE	PJM RPM Auction[1]
June 1, 2013 – May 31, 2014	ICE	PJM RPM Auction[1]
June 1, 2014 – May 31, 2015	ICE	PJM RPM Auction[1]
June 1, 2015 – May 31, 2016	ICE, ICF Forecast	PJM RPM Auction[1], ICF Forecast
June 1, 2016 – May 31, 2017	ICF Forecast	ICF Forecast
June 1, 2017 – May 31, 2018	ICF Forecast	ICF Forecast
June 1, 2018 – May 31, 2019	ICF Forecast	ICF Forecast
June 1, 2019 – May 31, 2020	ICF Forecast	ICF Forecast
June 1, 2020 – May 31, 2021	ICF Forecast	ICF Forecast

[1] Base Residual Auction

V.2 CURRENT WHOLESALE POWER MARKET CONDITIONS

Q. WHAT ARE CURRENT WHOLESALE SPOT POWER PRICES IN THE DUKE ENERGY OHIO ZONE?

A. In 2010, wholesale spot power prices were $34.8/MWh in nominal dollars for all-hours supply. This particular measure is for all-hours Cinergy Hub spot market (day ahead Midwest ISO LMP) electrical energy purchases. Over a recent 12 month[15] period, prices were $35.3/MWh in nominal dollars. Note, Cinergy Hub prices have been very similar historically to Midwest ISO CG&E zonal prices.

Q. HOW DO THE WHOLESALE ELECTRICAL SPOT ENERGY PRICES COMPARE TO HISTORICAL NOMINAL PRICES?

A. Historical nominal all-hours prices are shown in Exhibit H (left column). Current all-hours prices of $35.7/MWh (2011 YTD through April) are approximately $15/MWh below the record of approximately $51/MWh in 2008.

Q. HOW DO THESE PRICES COMPARE TO HISTORICAL REAL (*i.e.*, INFLATION ADJUSTED) PRICES?

A. May 2010 to April 2011 average prices are below the 1997-2011 YTD average, expressed in real 2010 dollars, by 9 percent; $35.0/MWh versus the long term average of $38.6/MWh (see Exhibits H and I). In 2009, prices were $29.8/MWh in real 2010 dollars. In only two years since 1998 were prices lower than 2009 prices. The 2009 price was 46 percent lower than in 1998 when the market price was at a record level (in real dollars).

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[15] Source: Midwest ISO. The 12 months are May 2010 to April 2011.

EXHIBIT H
Historical Wholesale Power Spot Prices – Cinergy Hub Delivery

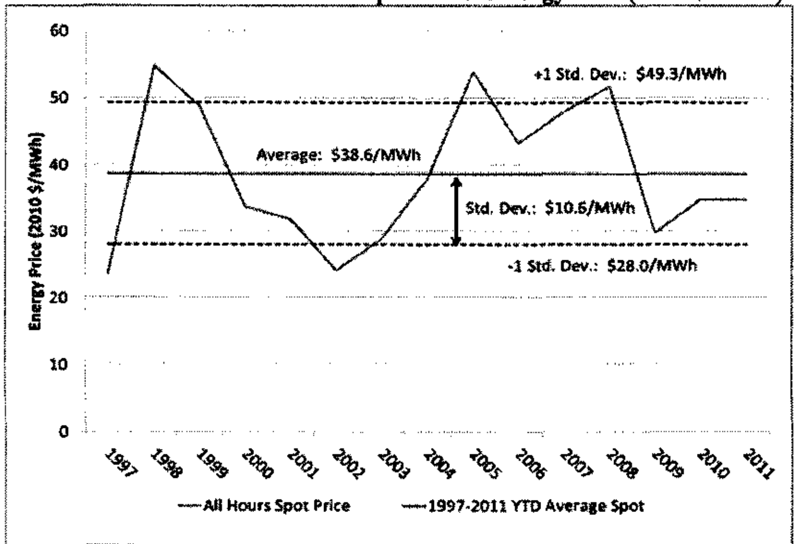
Scenario	All-Hours Wholesale Spot Price[1]	
	Nominal $/MWh	2010 $/MWh[3]
1997	18.0	23.6
1998	42.3	54.7
1999	38.2	48.7
2000	27.0	33.7
2001	26.1	31.9
2002	20.1	24.1
2003	24.5	28.8
2004	33.1	37.9
2005	48.7	53.9
2006	40.4	43.3
2007	46.1	48.0
2008	50.7	51.7
2009	29.5	29.8
2010	34.8	34.8
2011 YTD[2]	35.7	34.9
1997-2011 YTD Average	34.4	38.6

[1] Source: Spot prices shown for 1997 – 2011 YTD.
[2] 2011 YTD is through April 2011. 1997-2003 (Power Market Week), 2004-2005 (Platts' Megawatt Daily), 2006-2011 price data are from Midwest ISO for Cinergy Hub.
[3] Post-2010 inflation is assumed to be 2.5%.
Notes: 1997-2001, spot off-peak power prices were not available; the prices for these years were estimated based on the 2002 monthly off-peak price shape. In turn, the all-hours prices were derived based on peak- and off-peak prices.

Q. **HOW WOULD YOU CHARACTERIZE THE WHOLESALE ELECTRICAL ENERGY MARKET?**

A. The wholesale electrical energy market is liquid and well developed. However, prices can be extremely volatile compared to other commodity markets. Between 2008 and 2009, prices decreased 42 percent in nominal terms. Between 2003 and 2005, prices increased 99 percent in nominal terms. In real dollars, the standard deviation of annual prices is 28 percent of the average.

EXHIBIT I
Historical All-Hours Wholesale Spot Price Cinergy Hub (2010 $/MWh)



Sources: Spot prices shown for 1997-2011 YTD through April 2011. 1997-2011 spot prices are based on a 5x16 peak definition.

Q. **WHY ARE CURRENT WHOLESALE ELECTRICAL ENERGY PRICES LOWER THAN THE AVERAGE IN REAL TERMS?**

A. There are four very important factors.

- **Demand** – The recent recession lowered electricity demand. Electrical energy sales in 2009 in the U.S. were approximately 5 percent lower than sales in 2007. This is one of the largest decreases on record since World War II. While Midwest U.S. demand recovered in 2010 from 2009 lows, it was still below 2007 levels, and even still below the expectation for 2010 held in 2007 before the recession.
- **Natural Gas Prices** – Second, natural gas prices are low. Henry Hub natural gas prices in 2009 were $3.96/MMBtu in 2010 dollars, which was

the lowest price of any year in real dollars since 2000. In 2010, Henry Hub prices were \$4.37/MMBtu and \$4.08 for 2011 YTD through April. These low natural gas prices are in part due to the recession and in part reflect improved supply. Lower natural gas prices also tend to correlate with lower coal prices and vice versa.

- **Demand and Electrical Energy Prices** – Third, lower demand also lowers the price of electrical energy. Specifically, lower demand decreases the number of hours that natural gas power plants are needed to operate. This lowers the number of hours in which the marginal price setting unit is higher priced natural gas fired units rather than lower cost coal fired units.
- **Environmental Regulations** – Fourth, changes in environmental regulations have lowered the variable cost of generating electrical energy using existing coal plants, all else equal. Notably, SO_2 allowance prices are now close to zero.

Q. DO THESE PRICES INCLUDE THE PRICE OF A CAPACITY PRODUCT?

A. No.

Q. WHAT HAS BEEN THE RECENT HISTORY OF PJM CAPACITY PRICES?

A. Over the recent historical period, the PJM capacity price has been volatile. The RTO PJM capacity price for delivery in June 1, 2010, to May 31, 2011, was \$63.6/kW-yr. In the May 2010 auction conducted by PJM for 2013/2014 delivery, the RTO PJM capacity price was $10/kW-yr. Duke Energy Ohio is transferring from Midwest ISO to PJM. The capacity price in Midwest ISO has also been low. However, the Midwest ISO capacity market has a monthly short-term market structure that has not involved large volumes and that is in the process of being changed.

Q. WHAT ARE THE LATEST DEVELOPMENTS IN THE PJM CAPACITY MARKET?

A. On May 13, 2011, PJM announced that the RTO capacity prices increased from $10/kW-year for June 1, 2013, to May 31, 2014, delivery to $46/kW-year for June 1, 2014, to May 31, 2015, delivery.[16] This was a 360 percent increase.

Q. WHY DID THE PJM CAPACITY PRICE INCREASE?

A. The increase in capacity prices reflects several factors. They include rising demand, which is decreasing excess capacity; the high costs of new power plants; changes in transmission; and the high costs of maintaining existing unscrubbed coal plants due to tightening environmental regulations. Note, with one exception, all Duke Energy Ohio coal capacity is already scrubbed, mitigating the cost impacts of many new environmental regulations.

V.3 2012 TO 2015 PRICE FORECAST BASED ON OBSERVABLE FORWARDS

Q. WHY ARE YOU REPORTING 2012 TO 2015 PRICES SEPARATELY?

A. This is the period for which observable forwards exist and it is useful to distinguish the two sources of my forecast: forwards and computer projections. However, both show a trend of increasing wholesale power prices.

[16] UCAP. The price is for UCAP or unforced capacity. In PJM, UCAP capacity is less than installed capacity on average by approximately 6.25 percent.

Q. WHAT FORWARD PRICES ARE YOU USING?

A. I am using the forward price for the PJM AD Hub. Duke Energy Ohio received approval to join PJM in May 2011. The PJM AD Hub price covers American Electric Power (AEP) and Dayton Power and Light nodes in Ohio and Michigan. Duke Energy Ohio power plants are generally co-owned with Dayton Power and Light and AEP and, therefore, are generally in the PJM AD Hub. Note, the PJM AD Hub prices are only available since October 2004. Also, Duke Energy Ohio only joins PJM starting January 1, 2012. Therefore, as shown above, I use Cinergy Hub for historical data.

Q. WHAT IS THE FORECAST FOR FUTURE WHOLESALE ELECTRICAL ENERGY PRICES FOR 2012 TO 2015?

A. The forecast for all-hours wholesale electrical energy prices is $38.5/MWh, $41.2/MWh, $44.5/MWh, and $48.8/MWh (nominal dollars) for 2012, 2013, 2014, and 2015, respectively. The forecast is shown in Exhibits J and K. The price increases 7 percent in 2013, 8 percent in 2014, and 10 percent in 2015. 2015 prices are cumulatively 27 percent above 2012 prices. Exhibit K shows the same prices by time of day. Exhibits L and M compare the forecast to historical prices.

EXHIBIT J
Wholesale Power Prices – All-Hours (Nominal$/MWh)

Wholesale Power Price	Type	Prices
2009	Historical	29.5
2010	Historical	34.8
Last 12 Months[1]	Historical	35.3
2012	Forwards	38.5
2013	Forwards	41.2
2014	Forwards	44.5
2015	Forwards	48.8
Average 2012 to 2015	N/A	43.2

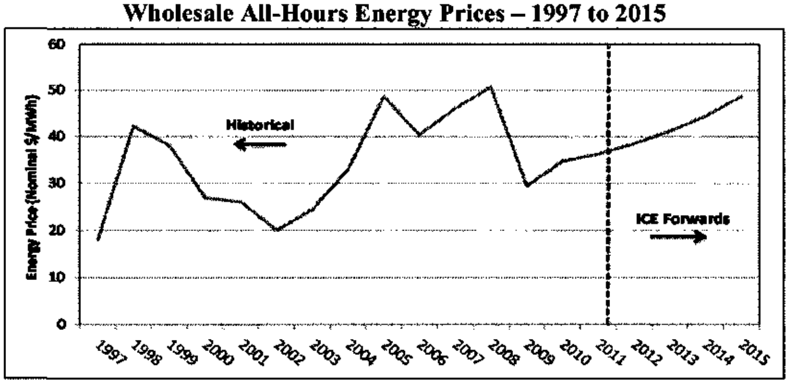
Source: Midwest-ISO LMP for 2009-2010 and last 12 months. AD Hub ICE forwards for 2012-2015 traded from November 2010 to April 2011.
[1] May 2010 to April 2011 average.

EXHIBIT K
AD Hub Wholesale All-Hours Energy Prices – 2011 to 2015 (Nominal $/MWh)

Year	Source	All Hours	On-Peak[1]	Off-Peak
2011[2]	ICE Forward	36.3	42.1	31.1
2012[2]	ICE Forward	38.5	44.7	33.0
2013[2]	ICE Forward	41.2	47.4	35.6
2014[2]	ICE Forward	44.5	50.6	38.9
2015[2]	ICE Forward	48.8	53.7	44.3
2012-2015 Average	ICE Forward	43.2	49.1	37.9

[1] 5X16
[2] Forwards for 2011-2015 traded from November 2010 to April 2011.

EXHIBIT L
Wholesale All-Hours Energy Prices – 1997 to 2015



[1] Historical Cinergy Hub. Forecast AD Hub.

EXHIBIT M
Duke Energy Ohio Zonal Energy Price Historical and Projections - 2007 to 2015[1]

Source	Year	ICF Base Case		
		All-Hours Energy Price (2010$/MWh)	**On-Peak Energy Price (2010$/MWh)**	**Off-Peak Energy Price (2010$/MWh)**
Historical	2007	48.0	62.4	34.8
Historical	2008	51.7	67.0	37.7
Historical	2009	29.8	35.3	24.7
Historical	2010	34.8	41.9	28.3
Historical	**2007-2010 Average**	**41.1**	**51.7**	**31.4**
ICE Forward	2011	35.5	41.1	30.3
ICE Forward	2012	36.7	42.5	31.4
ICE Forward	2013	38.3	44.0	33.1
ICE Forward	2014	40.3	45.8	35.2
ICE Forward	2015	43.1	47.4	39.2
Average	**2012 – 2015**	**39.6**	**44.9**	**34.7**

[1] Historical Cinergy Hub. Forecast AD Hub.

Q. WHAT IS THE BASIS FOR THE 2012 TO 2015 PROJECTION OF WHOLESALE POWER PRICES?

A. The 2012 to 2015 prices reflect the recent prices for forward delivery to the AD Hub in this period. For example, the 2012 price is the average price of transactions over the six months of November 2010 to April 2011 from ICE, the Inter-Continental Exchange, at the AD Hub for delivery in 2012 of wholesale power. Thus, this is an observable set of prices.[17]

Q. DOES THE WHOLESALE PRICE FORECAST INCLUDE ANCILLARY SERVICES?

A. Yes. All forecasts include 2.5 percent premium on energy prices to account for PJM ancillary services.

Q. WHAT DO THE FORWARDS INDICATE?

A. The forward market signals market expectations of rising wholesale power prices starting in 2012. As noted, 2015 prices are 27 percent higher than 2012 prices in nominal terms.

Q. WERE FORWARDS AVAILABLE AFTER 2015?

A. No.

Q. WHAT IS THE BASIS FOR THE 2012 TO 2015 CAPACITY PRICE PROJECTION?

A. The January 2012 to May 31, 2015, price for capacity is based on the PJM forward capacity price. This is also an observable price. As discussed below, the capacity price forecast for 2015 is composed of observable prices for January through May 31, 2015, and ICF's forecast for this price for the last seven months of 2015. The 2015 forward price for capacity is based on ICF's forecast because

[17] These prices are available for monthly delivery, but traded daily.

the PJM forward market price for capacity is not available for the last 7 months of 2015 and will not be available until Spring 2012.

Q. WHAT ARE THE PROJECTED CAPACITY PRICES?

A. The PJM capacity market is a required forward market and is referred to as the Reliability Pricing Model (RPM) capacity market. The next RPM Auction is for summer 2015 through May 31, 2016, supply and will be held in May 2012.

Q. WHAT ARE YOUR CAPACITY PRICE PROJECTIONS?

A. As noted, PJM capacity prices for January 1, 2010, to May 31, 2015, reflect actual auction results, while 2015 reflects blending auction results and forecasts into calendar year results for the PJM RTO sub-region (see Exhibit N).

EXHIBIT N
PJM RPM RTO Capacity Prices ($/UCAP)

Delivery Period	Source	Price (Nominal $/kW-yr)
2009-2010	RPM	37.2
2010-2011	RPM	63.6
2011-2012	RPM	40.2
2012-2013	RPM	6.0
2013-2014	RPM	10.1
2014-2015[1]	RPM	46.0
Average 2009 – 2015		33.9

Source: PJM. The delivery period is from June 1 to May 31 of the following year.
[1]The next RPM auction is June 1, 2015, to May 31, 2016, and will be held in May 2012.

Q. WHY ARE WHOLESALE POWER PRICES, BOTH ENERGY AND CAPACITY INCREASING BETWEEN 2009 AND 2015?

A. The increase in wholesale power prices reflects:

- **Environmental Regulations** – New environmental regulations including HAPs, CO_2, ash disposal, cooling water, and other environmental regulations are expected to cause coal plant retirements, and to raise the costs of existing coal power plants. This potential loss of capacity results in an increase in the value of existing capacity since buyers' next best alternative for securing capacity is new highly expensive new units. Energy prices can also rise due to added costs of operating existing coal plants.

- **Economic Recovery in the U.S. and PJM** – The economic recovery in the U.S. supports electricity demand growth and natural gas prices.
- **Rising Electricity Demand** – The growing demand for electricity contributes to the need for new capacity and hence a pronounced firming of capacity prices. In 2010, U.S. electricity sales in MWh increased 4.9 percent relative to 2009. Rising electricity demand also raises electrical energy prices by increasing reliance on higher cost coal and natural gas power plants.
- **Rising Natural Gas Prices** – Rising natural gas prices increase electric energy prices (see Exhibit O).

EXHIBIT O
Henry Hub Natural Gas Prices ($/MMBtu)

Year	Source	Real 2010$	Nominal $
2005	Historical	9.81	8.87
2006	Historical	7.20	6.72
2007	Historical	7.22	6.94
2008	Historical	9.00	8.84
2009	Historical	3.96	3.92
2010	Historical	4.37	4.37
2011 YTD[1]	Historical	4.08	4.19
2011	2011 YTD and NYMEX Futures[2]	4.28	4.38
2012	NYMEX Futures[2]	4.72	4.96
2013	NYMEX Futures[2]	4.91	5.28
2014	NYMEX Futures[2]	5.01	5.54
2015	NYMEX Futures[2]	5.11	5.78
Average 2012 – 2015		4.94	5.39

[1] 2011 YTD is through April, 2011.
[2] Traded over the period November 2010 to April 2011.
Source: Bloomberg

Q. ARE THERE OTHER STUDIES INDICATING POTENTIAL FOR PRICE INCREASES DUE TO ENVIRONMENTAL REGULATIONS?

A. Yes. A recent NERC study of environmental regulations concluded:

> Based on the assessment's assumptions, the greatest risk to Planning Reserve Margins occurs in 2015 for the Combined EPA Regulation Scenario. The overall total impact could make 46-76 GW of existing capacity "economically vulnerable" for retirement or derating by 2015. Additionally, the scenario cases assessed in this report indicate capacity reductions evident as early as 2013, resulting from the retirements of coal-fired plants and derate effects associated with plant retrofits. Impacts to Planning Reserve Margins can occur during the next four to eight years that could reduce bulk power system reliability, unless additional resources are constructed or acquired. It is essential that projected Conceptual supply resources be developed as one source of capacity replacement.
>
> The results of this assessment show a significant impact to reliability should the four potential EPA rules be implemented as assumed in this assessment. Impacts to both bulk power system planning and operations may cause serious concerns unless prompt

> industry action is taken. Planning Reserve Margins appear to be significantly impacted, deteriorating resource adequacy in a majority of the NERC Regions/sub-regions. Additionally, considerable operational challenges will exist in managing, coordinating, and scheduling an industry-wide environmental control retrofit effort.[18]

V.4 POST-2015 PRICE FORECASTS

Q. WHY IS A MODELING-BASED PRICE FORECAST NEEDED?

A. A forecast is needed because ICE and PJM forwards are not available after 2015.

Q. WHAT ZONE ARE YOU MODELING?

A. I am modeling the Duke Energy Ohio hub prices in Ohio (*i.e.*, the former CG&E territory). I also provide to Duke Energy Ohio an AD hub price for use in determining energy margins for Duke Energy Ohio power plants. Unless otherwise noted, I am referring to the Duke Energy Ohio hub prices.

Q. WHAT IS YOUR FORECAST OF WHOLESALE ELECTRICAL ENERGY PRICES FOR YEARS AFTER 2015?

A. My forecast indicates that wholesale electrical energy prices will continue to rise after 2015. Between 2015 and 2021, all-hours electrical energy prices increase from $48.8/MWh to $[redacted]/MWh in nominal dollars (see Exhibits P and Q). Between 2015 and 2021, the wholesale electrical energy prices rise by an additional [redacted] percent on top of the increases to 2015 discussed earlier. The cumulative all-hours 2012 to 2021 electrical energy price increase is [redacted] percent in nominal dollars.

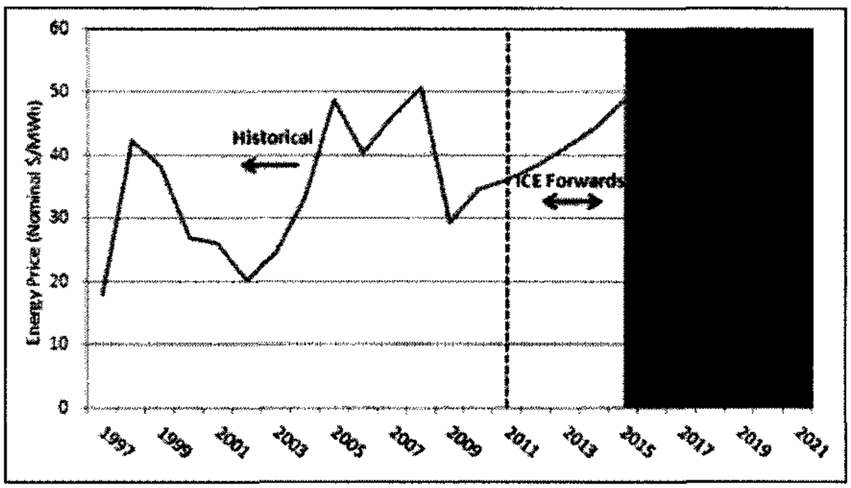
[18] NERC North American Electric Reliability Corporation, 2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations, pages 41-42, October 2010.

EXHIBIT P
Base Case – Wholesale All-Hours Electrical Energy Prices – 2012 to 2021[3]
(Nominal $/MWh)

Year[2]	Source	All Hours	On-Peak[1]	Off-Peak
2012	ICE Forward	38.5	44.7	33.0
2013	ICE Forward	41.2	47.4	35.6
2014	ICE Forward	44.5	50.6	38.9
2015	ICE Forward	48.8	53.7	44.3
2016	ICF Forecast	[redacted]	[redacted]	[redacted]
2017	ICF Forecast	[redacted]	[redacted]	[redacted]
2018	ICF Forecast	[redacted]	[redacted]	[redacted]
2019	ICF Forecast	[redacted]	[redacted]	[redacted]
2020	ICF Forecast	[redacted]	[redacted]	[redacted]
2021	ICF Forecast	[redacted]	[redacted]	[redacted]
Average 2012 - 2015	NA	**43.2**	**49.1**	**37.9**
Average 2016 - 2021	NA	[redacted]	[redacted]	[redacted]
Average 2012 - 2021	NA	[redacted]	[redacted]	[redacted]

[1] On peak defined as 5 x 16
[2] Simple averages of all transactions from November 2010 through April 2011 for delivery in 2012 to 2015.
[3] ICE forwards for AD Hub. ICF forecast for the Duke Energy Ohio zone.

EXHIBIT Q
Wholesale All-Hours Energy Prices – 1997 to 2021[1]



[1] Historical Cinergy Hub. ICE forwards for AD Hub.

Q. **WHAT ARE YOUR ELECTRICAL ENERGY PRICE FORECASTS IN REAL 2010$?**

A. Electrical energy prices for all hours supply to Duke Energy Ohio increase from forward levels reaching $43.1/MWh in 2015 (in real 2010$), which is an increase of approximately $8/MWh over 2012. By 2021, prices are approximately $[redacted]/MWh in real 2010 dollars (see Exhibit R). Thus, the cumulative increase in real dollars from 2012 to 2021 is nearly [redacted] percent.

EXHIBIT R
Real Electrical Energy Prices – 2010$/MWh

Period	Source	Year	All-Hours Energy Price (2010$/MWh)	On-Peak Energy Price (2010$/MWh)	Off-Peak Energy Price (2010$/MWh)
Historical	Historical	2007	48.0	62.4	34.8
	Historical	2008	51.7	67.0	37.7
	Historical	2009	29.8	35.3	24.7
	Historical	2010	34.8	41.9	28.3
	Historical	**2007-2010 Average**	**41.1**	**51.7**	**31.4**
Forecast	ICE Forward	2011	35.5	41.1	30.3
	ICE Forward	2012	36.7	42.5	31.4
	ICE Forward	2013	38.3	44.0	33.1
	ICE Forward	2014	40.3	45.8	35.2
	ICF Forward	2015	43.1	47.4	39.2
	ICF Forecast	2016	[redacted]	[redacted]	[redacted]
	ICF Forecast	2017	[redacted]	[redacted]	[redacted]
	ICF Forecast	2018	[redacted]	[redacted]	[redacted]
	ICF Forecast	2019	[redacted]	[redacted]	[redacted]
	ICF Forecast	2020	[redacted]	[redacted]	[redacted]
	ICF Forecast	2021	[redacted]	[redacted]	[redacted]
	Average	**2012 – 2021**	[redacted]	[redacted]	[redacted]
	Average	**2012 – 2015**	**39.6**	**44.9**	**34.7**
	Average	**2016 – 2021**	[redacted]	[redacted]	[redacted]

Peak Definition: 5x16 Peak Hours, 5x8 + 2x24 Off-Peak Hours
Historical Power Price: Cinergy Hub. Forward AD Hub

Q. WHY ARE ELECTRICAL ENERGY PRICES RISING?

A. There are several reasons for the increase in electrical energy after 2015. First, prices continue to increase after 2015 due to HAPS and other non-CO_2 environmental regulations, which start in 2015. Environmental controls result in significant coal retirements in this period and higher operating costs for existing coal units (*e.g.*, high variable costs for using Dry Sorbent Injection). A large amount of coal capacity is projected to retire across the U.S. by 2020. The coal retirements and higher operating costs result in an increase in electrical energy prices relative to 2010 prices. Second, the coal retirements increase the use of natural gas and natural gas power plants, raising electrical energy prices after 2015. Third, growing electricity demand increases reliance on natural gas plants as the marginal price setting units. Fourth, there is a large price increase starting in 2018 because, in 2018 and thereafter, there is a \$/ton CO_2 adder that, for existing fossil power plants, further increases the costs of generating power. In the case of coal power plants, costs are increased by approximately \$[redacted]/MWh in real dollars.

Q. WHAT IS THE SYSTEM IMPLIED HEAT RATE?

A. The "system implied heat rate" is the ratio of power prices to natural gas prices. It is a convenient rule of thumb for describing power prices in relation to natural gas prices, and is not used in the modeling.

Q. WHAT DO YOU PROJECT FOR THIS METRIC?

A. We project a surge in all-hours electrical energy prices separate from the impact of natural gas price increases and, hence, rising system implied heat rates (see Exhibit S). Between 2015 and 2018, prices rise due to environmental regulations, including CO_2 control and federal HAPs and their associated costs. Note, 2016 could be the first year with HAPs regulations fully in effect.[19] The assumed national CO_2 price in 2018, in real 2010 dollars, is \$[redacted]/ton, which translates to roughly [redacted]/MWh and [redacted]/MWh impact on power prices when coal and natural gas combined cycle units are on the margin, respectively. This calculation assumes heat rates of 10,000 Btu/kWh and 7,000 Btu/kWh for coal and combined

[19] HAPs regulations are expected to be finalized in November 2011. Compliance would be required by November 2014 unless a one year extension is given, which would delay the effect to November 2015. If this happens, the impact of HAPs is really only felt beginning in 2016.

cycle, respectively. Equivalently, at the [redacted]/MMBtu natural gas price impact, this translates to a market implied heat rate increase of approximately [redacted] Btu/kWh and [redacted] Btu/kWh for hours in which coal and natural gas combined cycles are on the margin, respectively.

EXHIBIT S
Duke Energy Ohio Zonal Implied Heat Rate Projections

Period		Year	ICF Base Case All-Hours IHR (Btu/kWh)	ICF Base Case On-Peak IHR (Btu/kWh)	ICF Base Case Off-Peak IHR (Btu/kWh)
Historical[1]		2007	6,498	8,446	4,713
Historical[1]		2008	5,609	7,271	4,090
Historical[1]		2009	7,096	8,428	5,879
Historical[1]		2010	7,504	9,035	6,111
Historical[1]		**2007-2010 Average**	**6,677**	**8,295**	**5,198**
Forecast	ICE[2]	2011	7,832	9,079	6,699
Forecast	ICE[2]	2012	7,378	8,552	6,311
Forecast	ICE[2]	2013	7,411	8,521	6,401
Forecast	ICE[2]	2014	7,623	8,675	6,666
Forecast	ICE[2]	2015	7,996	8,800	7,265
Forecast	ICF[3]	2016	[redacted]	[redacted]	[redacted]
Forecast	ICF[3]	2017	[redacted]	[redacted]	[redacted]
Forecast	ICF[3]	2018	[redacted]	[redacted]	[redacted]
Forecast	ICF[3]	2019	[redacted]	[redacted]	[redacted]
Forecast	ICF[3]	2020	[redacted]	[redacted]	[redacted]
Forecast	ICF[3]	2021	[redacted]	[redacted]	[redacted]
Forecast	ICF[3]	**2012 – 2015 Average**	**7,602**	**8,637**	**6,661**
Forecast	ICF[3]	**2016 – 2021 Average**	[redacted]	[redacted]	[redacted]
Forecast	ICF[3]	**2012-2021 Average**	[redacted]	[redacted]	[redacted]

[1] Historical IHRs are calculating using Cinergy Hub power prices and DEO delivered gas prices. Source: Midwest ISO and Bloomberg.
[2] ICE Forecast IHRs are calculated using ICE AD Hub forward prices for 2011-2015 traded from November 2010 to April 2011. Gas prices are DEO delivered prices. Source: ICE and Bloomberg.
[3] ICF Forecast IHRs are calculated using DEO Zonal projected power prices and DEO delivered gas prices. Source: ICF International.

Q. WHAT ARE YOUR CAPACITY PRICE FORECASTS?

A. As noted, PJM capacity prices for January 1, 2010, to May 31, 2015, reflect actual auction results (blending auction year results into calendar year results) for the

PJM RTO sub-region. The capacity price variation across PJM sub-regions reflects the auction cleared prices for their respective Local Delivery Areas (LDAs). Projected PJM capacity price for 2015 to 2021 reflect a transition from auction pricing to our fundamentals-based projection on June 1, 2015. Demand growth and significant retirements of smaller, older, coal units, resulting from environment regulations offset, increases in demand-side management and energy efficiency. Starting on June 1, 2015, prices reflect ICF's projection of equilibrium in parts of PJM and the need for new capacity. It should be noted that the 2015 annual price is similar to the level of prices in the most recent PJM auction for June 1, 2014, to May 31, 2015, PJM zones because the forecast is very similar to the auction announced May 13, 2011.

Q. WHY ARE CAPACITY PRICES INCREASING?

A. They are increasing primarily due to the need to add new capacity, combined with the high capital costs of new capacity. This is, in turn, due to growing electricity demand and retirement of coal power plants. Prices are also rising due to general inflation (see Exhibit T).

EXHIBIT T
PJM RPM RTO Capacity Prices – 2009 to 2021

Delivery Period[1]	Source	Price (Nominal $/kW-yr)
2009-2010	RPM	37.2
2010-2011	RPM	63.6
2011-2012	RPM	40.2
2012-2013	RPM	6.0
2013-2014	RPM	10.1
2014 – 2015	RPM	46.0
2015[1]	ICF Forecast	[redacted]
2016	ICF Forecast	[redacted]
2017	ICF Forecast	[redacted]
2018	ICF Forecast	[redacted]
2019	ICF Forecast	[redacted]
2020	ICF Forecast	[redacted]
2021	ICF Forecast	[redacted]
Average 2012 – 2015		**25.6**
Average 2016 – 2021		[redacted]

[1] Based on summer delivery. UCAP price based on EFORd of 6.25 percent.
Source: PJM and ICF

Q. WHAT IS YOUR FORECAST FOR AD PJM HUB PRICES?

A. In 2016 – 2021, all-hours AD PJM Hub prices are $0.2/MWh (in 2010$) above the average Duke Energy Ohio price.

V.5 FORECASTING APPROACH

Q. HOW WAS YOUR POST-2015 FORECAST DEVELOPED?

A. I used the ICF proprietary IPM® Model to develop wholesale power market prices. This model is a widely used and accepted forecasting model based on supply and demand fundamentals. The model is used by the U.S. Environmental Protection Agency and is used extensively in private sector assignments. IPM® captures a detailed representation of all electric boilers and generators in the North America power markets. The model uses a linear optimization to simultaneously solve for all years power plant dispatch and fuel use, capacity expansion, environmental retrofitting, modernization/re-powering, inter-regional transmission, electric energy and capacity prices, fuel prices, and emissions costs. The model captures the performance characteristics and limitations of conventional and unconventional generation technologies, including gas and steam turbines, combined cycle, co-generation, nuclear, hydro, wind, solar, and other renewables. Energy efficiency and demand side management programs are evaluated in an integrated framework with other resource options. IPM® is also a dynamic model that optimizes capacity decisions over the entire planning period simultaneously.

Q. WHAT ARE THE BASIC ASSUMPTIONS UNDERLYING THE POST 2015 FORECAST OF WHOLESALE POWER PRICES?

A. The forecast reflects the following assumptions:

- The wholesale power market is competitive and efficient;
- Wholesale power prices reflect the marginal costs of supply;
- Supply decisions including entry and exit and dispatch will reflect the set of decisions that minimizes the discounted costs of meeting demand subject to need to meet demand over the 2016 to 2021 planning horizon; and
- There is no shortage of supply once excess supply is eliminated by demand growth and retirements.

Q. WHAT ARE THE KEY INPUT PARAMETERS IN YOUR MARKET PRICE FORECAST?

A. The key assumptions[20] include:

- **Natural Gas Prices** – Natural gas prices are an important determinant of on-peak wholesale power prices in the Duke Energy Ohio market and will be increasingly important over time as a large portion of new capacity is natural gas-fired. However, in other hours, coal generation sets prices, particularly off-peak in Duke Energy Ohio zone. Exhibit U presents ICF's natural gas price forecast in real and nominal dollar terms. Natural gas prices over the last 12 months were $4.1/MMBtu (May 2010 through April 2011). Natural gas prices will rise in real terms by [redacted] percent per year in the 2015 to 2021 period, as measured at Henry Hub, or from $4.1/MMBtu over the last 12 months to $[redacted]/MMBtu in the 2015 to 2021 period. Our approach to natural gas pricing reflects our view of the fundamentals of the market; specifically, natural gas prices are projected using ICF's Gas Market Model (GMM). GMM is a full supply/demand equilibrium model of the North American natural gas market. Our forecast is that the recent trend of low natural gas prices will continue. Our forecast for Henry Hub natural gas prices never exceeds [redacted]/MMBtu in 2010 dollars over the 2015 to 2021 period. In contrast, historically between 2000 and 2009 Henry Hub natural gas price had in one year exceeded $9/MMBtu in 2010 dollars (in 2005 in real 2010 dollars). Indeed, the lowest Henry Hub price in the 2005 to 2008 period in real 2010 dollars was $7.20/MMBtu. Our view is that abundant natural gas supplies, particularly from the development of shale gas, will continue to

[20] Based on ICF assumptions as of May 2011.

depress natural gas prices in the long term relative to average prices over the 2000 to 2010 period. If natural gas prices are higher than the ICF forecast, our power price forecast will be higher.

EXHIBIT U
Henry Hub Natural Gas Prices ($/MMBtu)

Year	Source	Real 2010$	Nominal $
2005	Historical	9.81	8.87
2006	Historical	7.20	6.72
2007	Historical	7.22	6.94
2008	Historical	9.00	8.84
2009	Historical	3.96	3.92
2010	Historical	4.37	4.37
2011 YTD[1]	Historical	4.08	4.19
2011	Average of Historical and NYMEX Futures[1,2]	4.28	4.38
2012	NYMEX Futures[2]	4.72	4.96
2013	NYMEX Futures[2]	4.91	5.28
2014	NYMEX Futures[2]	5.01	5.54
2015	NYMEX Futures[2]	5.11	5.78
2016	Average of NYMEX Futures[1] and ICF Forecast	[redacted]	[redacted]
2017	ICF Forecast	[redacted]	[redacted]
2018	ICF Forecast	[redacted]	[redacted]
2019	ICF Forecast	[redacted]	[redacted]
2020	ICF Forecast	[redacted]	[redacted]
2021	ICF Forecast	[redacted]	[redacted]
Average 2012 – 2021	ICF Forecast	[redacted]	[redacted]

[1] 2011 YTD is through April, 2011.
[2] Traded over the period November 2010 to April 2011.
Source: Bloomberg

- **Peak and Energy Demand** – Projected peak and energy demand for PJM and Duke Energy Ohio for the 2011 - 2021 period are based on PJM's 2011 forecast. Of the two, the PJM growth rate is more important for determining prices. PJM peak and energy are forecasted to grow at 1.9

percent per year in the near-term from 2011-2015. Electricity demand at peak will reflect average weather conditions and, in PJM for 2012 through 2021, will grow 0.9 percent per year from 2011 levels on a weather normalized basis. This compares with the average growth rate between 2000 and 2007 (the last year before the last recession) at a 1.4 percent per year rate. Duke Energy Ohio's growth is similar to PJM in the short-term, growing at about 1.9 percent from 2011-2015. Growth rates are before accounting for DSM levels.

- **Demand Resource** – In PJM, Demand Resource is forecast to reach but not exceed 11.4 percent of the planning reserves of PJM. The PJM planning reserve margin is assumed to be 15.5 percent.
- **Environmental Regulations** – The forecast assumes that there will be federal CO_2 controls starting on January 1, 2018. The assumed program is a \$/ton CO_2 program implemented via regulations or other method. No such program currently exists and, if one is not implemented, wholesale power prices will be lower than forecast. The forecast also assumes that there will be command and control HAPS regulations by 2015 such that all U.S. coal-fired power plants are required to have SO_2 scrubbers, activated carbon injection, and/or fabric filters with Dry Sorbent Injection (DSI). As will be discussed, the assumption of CO_2 and HAPS regulations has important implications for natural gas prices and for the costs of fossil-fuel generation in general. Future regulations governing SO_2, NO_x, coal ash and water cooling also become more stringent.

- **Capital Costs for New Builds** – New combined cycle plants are assumed to be available in 2015, approximately at [redacted]/kW (2010$) in the Duke Energy Ohio region. In the forecast, the construction of new power plants does not have to be in the Duke Energy Ohio region, but in locations that allow PJM to meet its reliability targets. New simple-cycle units are assumed to have capital investment costs that are [redacted] percent lower relative to combined cycles, depending upon the region and year of build. New power plant costs vary by region as a function of variation in underlying labor and material costs, ambient conditions, local environmental regulations (to the extent applicable), etc.
- **Delivered Coal Prices** – Delivered coal prices are projected to decrease [redacted] percent per year in real terms between 2014 and 2017; this metric is measured at the Duke Energy Ohio plants.

VI. RETAIL MARKET PRICE PROJECTION

VI.1 INTRODUCTION

Q. HOW IS THIS SECTION ORGANIZED?

A. The first subsection introduces the retail pricing discussion. The second subsection summarizes the retail price forecasts. The third subsection describes the forecasts by customer class. The fourth subsection discusses the price forecasting approach. The fifth subsection discusses the components of the retail price.

Q. HOW ARE RETAIL PRICES RELEVANT TO YOUR TESTIMONY?

A. They are relevant in two respects. First, retail market prices are used in determining the SSO prices under the MRO. In the first five MRO periods, the MRO price is a blend of the retail market price and the price under a continuation of the legacy ESP. By the end of the fifth period, the prices under the MRO equal the retail market prices. Second, the retail market price for electrical energy is a component of the price under the proposed ESP. Under the proposed ESP, the retail market price for electrical energy requirements is added to the non-bypassable net capacity charge to obtain the total SSO generation service price.

VI.2 <u>SUMMARY OF RETAIL PRICE FORECASTS</u>

Q. ARE RETAIL PRICES READILY OBSERVABLE IN A MANNER SIMILAR TO FORWARD WHOLESALE PRICES?

A. No. ICE does not provide retail prices. There is no multi-year time series of historical retail prices that is available. Hence, I do not compare my retail price forecasts to historical retail prices.

Q. WHAT ARE THE RETAIL MARKET PRICES ESTIMATED FOR USE IN DETERMINING PRICES UNDER THE MRO?

A. The estimated nominal retail market prices are shown below for 2012 – 2021, and average [redacted] ¢/kWh (see Exhibit V). In 2012, the average retail market price is 6.14 ¢/kWh. By 2015, retail prices are 47 percent higher than 2012 at 9.04 ¢/kWh. The retail market prices increase primarily because of increasing wholesale electrical energy and capacity prices. In comparison, wholesale electrical energy and capacity prices in nominal dollars are 27 and 535 percent higher in 2015 versus 2012, respectively. In 2021, retail prices are higher than

2015 levels by [redacted] percent because the forward wholesale electrical energy and capacity prices are again higher than the 2015 level. 2012 to 2021 retail prices increase [redacted] percent. In comparison, the 2012 to 2021 increase in wholesale all-hours nominal electrical energy and the capacity component of retail prices are [redacted] and [redacted] percent, respectively.

EXHIBIT V
Retail Market Price – Weighted Average of All Consumer Classes Based on AD Hub Price Curve (Nominal¢/kWh)[1]

Year	Price	Cumulative Change From 2012 (%)
2012	6.14	N/A
2013	6.63	8%
2014	7.87	28%
2015	9.04	47%
2016	[redacted]	[redacted]
2017	[redacted]	[redacted]
2018	[redacted]	[redacted]
2019	[redacted]	[redacted]
2020	[redacted]	[redacted]
2021	[redacted]	[redacted]
Average 2012-2016	[redacted]	N/A
Average[2] 2012-2021	[redacted]	N/A

[1] Assumes no switching.
[2] Simple average.

Q. WHAT ARE THE RETAIL ELECTRIC ENERGY PRICES USED TO ESTIMATE PRICES UNDER THE PROPOSED ESP?

A. The prices for retail electric requirements service are shown in Exhibit V-1. On average, these prices are [redacted] percent lower than retail market prices. This is because the product is energy only; capacity is not required to be offered at this price. Rather, capacity is the responsibility of Duke Energy Ohio. Note, unless otherwise noted, retail prices shown in the rest of this section are for both energy and capacity, and are referred to as retail market prices.

EXHIBIT V-1
Retail Electric Prices to Estimate SSO Prices Under Proposed ESP (nominal ¢/kWh)

Year	Retail Electric Energy Service
2012	5.91
2013	6.38
2014	6.94
2015	7.59
2016	[redacted]
2017	[redacted]
2018	[redacted]
2019	[redacted]
2020	[redacted]
2021	[redacted]
Average 2012 – 2016	[redacted]
Average 2012 – 2021	[redacted]

VI.3 RETAIL MARKET PRICES BY CLASS

Q. DOES THE FORECAST OF RETAIL PRICES VARY BY CUSTOMER CLASS?

A. Yes. Prices shown above were kWh weighted averages of the various customer classes. Exhibit W shows retail prices for the following customer classes: RS, which is residential, TS, which is industrial load at high voltage, and DM, DP, and DS, which are various commercial and larger customer rate classes (see Exhibit W).

EXHIBIT W

Retail Market Prices by Customer Class – 2012 – 2021 (Nominal ¢/kWh)

Customer Class	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Average 2012 - 2016	Average 2012 - 2021
RS	6.35	6.87	8.30	9.64	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DM	6.36	6.87	8.21	9.46	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DP	5.83	6.29	7.35	8.38	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DS	6.25	6.75	7.96	9.10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TS	5.63	6.09	7.05	8.02	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
kWh Weighted Average	**6.14**	**6.63**	**7.87**	**9.04**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Q. WHAT IS THE FORECAST FOR RESIDENTIAL CUSTOMERS?

A. The forecast for residential customers of retail prices for generation service is approximately 6.35 ¢/kWh or $63.5/MWh in 2012. The residential price is modestly (+3%) above the weighted average and close to all the other classes except TS customers, which are 8 percent lower than the average; RS is 13 percent above TS.

Q. WHAT ARE THE IMPLICATIONS OF THE DIFFERENCES BETWEEN CLASSES?

A. There is some potential for auction prices for non-switching SSO load to be closer to the RS level than the average. While the difference is small, classes with a significantly below average cost might be more likely to switch.

Q. ARE THERE PUBLIC RETAIL PRICES IN THE DUKE ENERGY OHIO SERVICE TERRITORY THAT ARE AVAILABLE TO COMPARE?

A. Currently, both Dominion Energy and FirstEnergy Solutions offer Duke Energy residential customers a fixed retail price of 5.99 ¢/kWh through December 2011 and December 2012, respectively. But the Dominion offer is only available to the first 15,000 residential customers who enroll. AEP Retail Energy offers Duke Energy customers a retail price of 5.89¢/kWh through the December 2011 billing cycle. In addition, Direct Energy also offers Duke Energy residential customers a fixed price of 7.8¢/kWh for 12 billing cycles from enrollment. This information is available from the Commission's website. The average of these three offers is 6.6¢/kWh. In comparison, the 2012 forecast for Duke Energy Ohio residential customers is 6.35¢/kWh. I conclude that the forecast prices contained herein appear roughly comparable.

VI.4 RETAIL PRICE FORECASTING APPROACH

Q. HOW IS THE RETAIL PRICE FORECAST DEVELOPED?

A. Generally, the retail price forecast reflects costs of retail service; most notably the costs of wholesale power purchases. Thus, the retail forecast assumes that the primary driver of retail prices is the cost of that service.

Q. MORE SPECIFICALLY, HOW IS THE RETAIL FORECAST DEVELOPED?

A. As noted, the forecast of retail market prices is based on assessing the costs of retail service for each consumer. Specifically, this cost-based assessment is based principally on three inputs:

- **Wholesale Prices** – The starting point is forward or forecast wholesale power prices for the wholesale products that would need to be purchased in the marketplace at the time the service provider is arranging for a service offering. The most important product that would be purchased is on-peak and off-peak power supply by month, which can be thought of as resulting in the need for 24 wholesale product prices per year (12x2). For example, 50 MW or 100 MW blocks for January 2009 on-peak would be expected to be purchased. This is because these products are the most observable and liquidly traded forward products in the wholesale power markets. Also, capacity will need to be procured in the PJM RPM market. The forward power purchases allow providers to manage the risks of meeting the requirements of customers. At the time of contracting to supply power, retail CRES providers offset the forward power sale to customers (the short) with a forward power purchase (the long), and hence, limit the risks of providing retail service to a manageable level.

- **Consumer Load Shapes** – The second key input is the consumer's load shape, which is an estimate of the expected consumer demands in kWh or MWh over time. The "flatter" the load shape, the lower the average cost and vice versa. This is because the share of lower priced off-peak power is higher. This explains in large part why industrial customers have lower costs of supply: their load shapes are the flattest. While this is a critical parameter, the retail provider is also responsible for unexpected variances in load, *i.e.*, the provider is providing full firm requirements service. Thus, other customer data is also used as discussed below.
- **Formulas/Model for Tailoring Price to Consumer** – A third set of inputs are formulas/models used to create a retail price based on wholesale market prices and customer load shapes. These formulas account for load uncertainty, including the potential for unexpected customer demand to occur when wholesale prices are high, and the other costs of serving retail load.

Q. HAS A SIMILAR RETAIL PRICE FORECASTING APPROACH BEEN PREVIOUSLY PRESENTED TO THE COMMISSION?

A. Yes, the approach has been presented to the Commission several times. It has been used to forecast retail prices based on wholesale forward prices and as an alternative to Duke Energy Ohio's Rate Stabilization Plan (RSP).

Q. PLEASE PROVIDE ADDITIONAL DETAIL ON THE COMPONENTS OF THE RETAIL PRICE PROJECTION.

A. The components of the retail price projection include:

- **Market Index of Energy Prices** – The first and largest component of the retail price is the Energy Price also referred to as the Market Index. This is the weighted average purchase price of wholesale electrical energy for monthly on-peak and off-peak expected MWh sales volumes.
- **Covariance Adjustment** – This factor accounts for the covariance between customer load variation and electric energy price variation. Loads that move with the electric energy price – *i.e.*, are correlated with the price – have high covariances and vice versa. For example, a load that increases during summer peaks when prices are the highest has a high covariance and vice versa. This covariance increases costs of service above what would be indicated by expected average prices and demands. Put another way, covariance creates risks of costs exceeding revenues for a period, in spite of hedging. For example, if, during periods in which customer demand is higher than expected (*e.g.*, extreme weather), electric energy prices are also higher, there are additional costs for the supply that must be procured. Therefore, procurement needs to be designed to reliably provide sufficient coverage for the potential of unexpectedly high

prices during the summer peak coinciding with unexpectedly high customer demand. In the highly simplified example shown in Exhibit X, the retail supplier purchases power in advance of the summer, based on an assumption of a normal summer, at costs equal to $100. During the half the summers when it is hotter than average, the retail suppliers incur an extra $20 in cost as demand is 2 MWh higher and prices have doubled. In the other half of the summers, when it is cooler than average, they earn $10 from sales of extra supply; they sell 2 MWh less at depressed prices. On average, costs are $15/MWh above the level based on expected sales and prices.

EXHIBIT X
Simplified Example of How Covariance Affects the Costs of Managing Load Variation

Procurement Situation	Quantity (MWh)	Electric Energy Price ($/MWh)	Net Cost of Purchases ($)
Hot Summer Supplemental Purchases	+2	20	140 (+40)
Expected Summer – Forward Purchase in Advance Based on Expected Conditions	10	10	100
Cool Summer – Sale of Excess Supply	-2	5	90 (-10)

- **Capacity Price** – The supplier must obtain capacity equal to the load's expected peak times one plus the reserve margin.
- **Ask-Adder** – The ask-adder can be thought of as a broker's fee. This is based on Duke Energy Ohio's experience that it pays more than the index

price of electric energy when it is a purchaser, and receives less when it is a seller. This factor increases electric energy costs.

- **Energy Losses and Adjustments** – This factor captures energy and demand losses in the transmission and distribution system. This is similar to traditional existing tariffs.
- **Supply Management Fee** – This fee includes the cost of scheduling, balancing, procurement and risk management, hourly adjustment, load following, natural consumer migration (in and out), managing odd lots and floats between billing cycles, and is initially proposed at 6 percent of electric energy cost.
- **Operating Risk Adjustment** – This adjustment creates margin to, in part, cover potential commodity-related risks, including: (1) booking and settlement; (2) modeling/forecasting methods; (3) contracts and delivery; (4) security and personnel; (5) programming, faulty data, meter reading; (6) information systems and telecommunications; (7) legal, regulatory and political issues; (8) economic downturns; and (9) natural disasters. This does not include sales or general and administrative costs. This estimate was based on Value Line estimates of operating margin for 2002-2009 for all industries, which equaled 18.6%.

Q. WHAT ARE THE PARAMETERS FOR THESE COMPONENTS?

A. The parameters for estimating these components are summarized in Exhibit Y. The largest cost factor, as noted, is the energy price index. The second largest is for operating risks. The third largest adjustment for most customers is the covariance adjustment, although, for some customers, this is small.

EXHIBIT Y
Selected Auction ESP Retail Rate Components

Components	Current
Market Index of Electricity Prices Energy Cost Adjustments – Ask Adder	2011 – 1% 2012 – 2% 2013 – 3% 2014 and Thereafter – 4%
Energy Cost Adjustments – Covariance Adjustment	Varies[1]
Supply Management Fee	6%
Margin/Operating Risk Adjustment[2]	18.6%
Energy Losses	6.8%

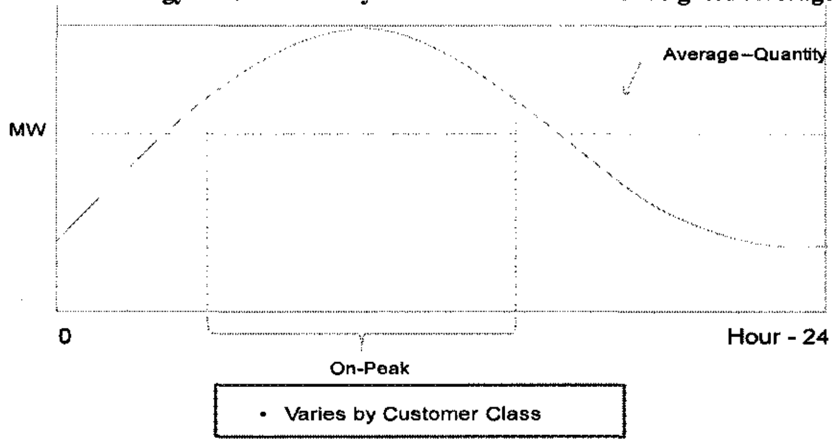
[1] Covariance adjustments are 9.8 percent for RS, 9.1 percent for DM, 8 percent to DS, 3.2 percent for DP, and 1.2 percent for TS based on the 50 percentile rate
[2] Operating Risk Adjustment is the 2002-2009 average of annual Average Operating Income over Sales/Revenue for all industries.
Source: Value Line Datafile

VI.5 RETAIL PRICE COMPONENTS

Q. WHAT IS THE ENERGY MARKET INDEX?

A. The energy market index is the customer electric energy price, weighted by its monthly usage of MWh of on-peak and off-peak power (see Exhibit Z). As noted, this is used to calculate the first cost component of retail market price. Because the load shape varies by customer, the relative quantities of monthly off- and on-peak varies. Thus, the energy market index varies across customers, even if all prices are the same.

EXHIBIT Z
Market Energy Index – Monthly On-Peak and Off-Peak Weighted Average



Q. HOW DO ENERGY INDEX AND RETAIL MARKET PRICE COMPARE TO THE ALL-HOURS WHOLESALE MARKET PRICE?

A. The index price is about 5 percent higher than the all-hours energy price for different classes and rises on average from approximately 4.04 ¢/kWh to [redacted] ¢/kWh between 2012 and 2021 (see Exhibit AA).

EXHIBIT AA
Index Price (¢/kWh)

Customer Class	2012		2013		2014		2015		2016		2017		2018		2019		2020		2021	
	Ratio of Index to The All-Hours Wholesale Price	Energy Index	Ratio of Index to The All-Hours Wholesale Price	Energy Index	Ratio of Index to The All-Hours Wholesale Price	Energy Index	Ratio of Index to The All-Hours Wholesale Price	Energy Index	Ratio of Index to The All-Hours Wholesale Price	Energy Index	Ratio of Index to The All-Hours Wholesale Price	Energy Index	Ratio of Index to The All-Hours Wholesale Price	Energy Index	Ratio of Index to The All-Hours Wholesale Price	Energy Index	Ratio of Index to The All-Hours Wholesale Price	Energy Index	Ratio of Index to The All-Hours Wholesale Price	Energy Index
RS	1.05	4.04	1.05	4.32	1.05	4.65	1.04	5.09	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DM	1.06	4.09	1.06	4.37	1.06	4.70	1.05	5.13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DP	1.04	4.00	1.04	4.28	1.04	4.61	1.03	5.05	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DS	1.06	4.08	1.06	4.36	1.06	4.69	1.05	5.12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TS	1.03	3.96	1.03	4.24	1.03	4.57	1.03	5.01	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Simple Average	1.05	4.03	1.05	4.31	1.04	4.64	1.04	5.08	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Weighted Average	1.05	4.04	1.05	4.31	1.05	4.65	1.04	5.08	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Q. WHAT ARE THE LARGEST COMPONENTS OF THE RETAIL MARKET PRICE?

A. In 2012, in all cases, the largest component of the retail market price is by far the market index of electric energy prices. The second largest is the operating risk adjustment, which is still much smaller than the electric energy index. The third and the fourth largest are the energy loss and covariance adjustments (Exhibit BB). Over time, the capacity charge component grows from 0.16 ¢/kWh in 2012 to 1.04 ¢/kWh in 2015. By 2021, the capacity component is even higher at [redacted] ¢/kWh. This is a [redacted] percent increase.

EXHIBIT BB
Summary of Retail Price by Component Before Retail Capacity Rider – Weighted Average of all Consumer Classes – 2012-2021 (¢/kWh)

Component	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Average 2012 - 2021
Market Index of Electrical Energy Prices[1]	4.04	4.31	4.65	5.08	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Covariance Adjustment	0.28	0.30	0.33	0.36	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity	0.16	0.18	0.66	1.04	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ask Adder (2 to 4%)	0.09	0.14	0.23	0.26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Energy Losses and Adjustments (6.8%)	0.31	0.34	0.40	0.46	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Supply Management Fee (6%)	0.29	0.32	0.38	0.43	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Operating Risk Adjustment (18.6%)	0.96	1.04	1.23	1.42	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Energy Charge, excluding Retail Capacity Rider	**6.14**	**6.63**	**7.87**	**9.04**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[1] Includes 2.5 percent for ancillary services.

Q. WHAT IS THE PREMIUM BETWEEN THE RETAIL MARKET PRICE AND THE ELECTRIC ENERGY PRICE INDEX?

A. In the above example where prices are weighted by the volume of sales to five rate classes examined before switching, the retail price has, on average, a [redacted] percent premium above the electric energy price (see Exhibit CC). The premium increases over time primarily due to the increase in capacity prices.

EXHIBIT CC
Ratio of Retail Market Price to Wholesale Price Index

Customer Class	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Average 2012-2021
RS	1.65	1.67	1.87	1.98	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DM	1.65	1.67	1.85	1.94	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DP	1.51	1.53	1.65	1.72	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DS	1.62	1.64	1.79	1.87	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TS	1.46	1.48	1.59	1.64	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Simple Average	1.58	1.60	1.75	1.83	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Weighted Average	1.59	1.61	1.77	1.85	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Q. WHAT WAS THE RANGE OF THE COMPONENTS OF THE RETAIL PRICES ACROSS RATE CLASSES?

A. The components and the total retail prices can vary significantly across rate classes, reflecting different costs of service. The 2012 retail average price is 6.14 ¢/kWh. However, the price for TS customers, which take power at high voltages and have a relatively flat load profile, is 5.63 ¢/kWh in 2012, while a residential customer has a price of 6.35 ¢/kWh. This is because of the large variation among the customers with respect to demand characteristics such as load shape, especially the ratio of peak in MW to sales in MWh, and covariance (see Exhibit DD).

EXHIBIT DD
Structure of the Retail Market Across Customer Classes Price – 2012

Component	RS	DM	DP	DS	TS	Weighted Average
Market Index of Electrical Energy Prices[1]	4.04	4.09	4.00	4.08	3.96	4.04
Covariance Adjustment	0.40	0.37	0.13	0.33	0.05	0.28
Capacity	0.21	0.19	0.12	0.16	0.11	0.16
Ask Adder – (2%)	0.09	0.09	0.09	0.09	0.08	0.09
Energy Losses and Adjustments (6.8%)	0.32	0.32	0.30	0.32	0.29	0.31
Supply Management Fee (6%)	0.30	0.30	0.28	0.30	0.27	0.29
Margin/Operating Risk Adjustment (18.6%)	0.99	1.00	0.91	0.98	0.88	0.96
Average Energy Charge – Weighted Average of all Consumer Classes	6.35	6.36	5.83	6.25	5.63	6.14

[1] Energy price is calculated based on average price of forwards for AD Hub between 11/2010 and 4/2011 for delivery in 2012.
Source: Forward wholesale power prices are from ICE.

Q. WHAT HAPPENS TO THE RETAIL MARKET PRICE WHEN THE WHOLESALE ELECTRIC ENERGY PRICE INDEX CHANGES?

A. The retail market price moves approximately proportionally to the wholesale price index. Thus, a ten percent increase in weighted average wholesale power prices increases the retail market price by approximately ten percent. This is important because wholesale power prices are volatile and, hence, the costs of CRES providers and, ultimately, of consumers will also be volatile.

VII. MRO PRICE PROJECTION

Q. HOW DO YOU CALCULATE MRO PRICES?

A. The first step in calculating prices under an MRO is to establish the transition period blending mechanism. The assumed blending percentages are shown in Exhibit EE.

EXHIBIT EE
MRO Blending Mechanism

Period	Market Share (%)	Legacy ESP Share (%)	Total (%)
2012	10	90	100
2013	20	80	100
2014	30	70	100
2015	40	60	100
2016	50	50	100
2017	100	0	100
2018	100	0	100
2019	100	0	100
2020	100	0	100
2021	100	0	100

The second step is to calculate the blended MRO price, which equals a weighted average of the prices under an extension of the legacy ESP and the retail market price.

Q. WHAT IS YOUR MRO PRICE PROJECTION FOR 2012 TO 2015?

A. In 2012, the MRO price is projected to be 7.74 ¢/kWh (see Exhibit FF). Thus, it is 2 percent lower than the legacy ESP price because the market price is low at 6.14 ¢/kWh, lowering the weighted average price. The effect is muted because the retail market price only has a ten percent weight in 2012. By 2015, the MRO price increases to 8.14 ¢/kWh, which is five percent above the 2012 MRO price. This increase is modest because the legacy ESP price is projected to decrease 5 percent from 2012 to 2015, and the legacy ESP price determines 60 percent of the

MRO price. Without the effect of the blending of the legacy ESP, the MRO increase would be much larger. This is because the retail market price is forecast to increase 47 percent from 2012 to 2015.

Q. WHAT IS YOUR MRO PRICE PROJECTION PAST 2015?

A. In 2016, the MRO price increases [redacted] percent versus 2015. This occurs because the legacy ESP price share continues to drop and retail prices continue to rise. After 2016, the MRO price equals the market price, and the market price increases without the moderating effect of the legacy or proposed ESP's capacity price treatment (see Exhibit FF). By 2021, the MRO price is [redacted] ¢/kWh or [redacted] percent higher than in 2015 and [redacted] percent higher than the 2012 MRO price.

EXHIBIT FF
MRO Option Pricing

Period	Legacy ESP PTC[1] (¢/kWh)	ESP Weight (%)	Retail Market Price[2] (¢/kWh)	Retail Market Price Weight (%)	MRO[3] (¢/kWh)
2012	7.92	90	6.14	10	7.74
2013	7.44	80	6.63	20	7.28
2014	7.62	70	7.87	30	7.70
2015	7.54	60	9.04	40	8.14
2016	7.49	50	[redacted]	50	[redacted]
2017	N/A	0	[redacted]	100	[redacted]
2018	N/A	0	[redacted]	100	[redacted]
2019	N/A	0	[redacted]	100	[redacted]
2010	N/A	0	[redacted]	100	[redacted]
2021	N/A	0	[redacted]	100	[redacted]
Average 2012-2016	**7.60**	N/A	[redacted]	N/A	[redacted]
Average 2012-2021	N/A	N/A	[redacted]	N/A	[redacted]

[1] Source: Duke Energy Ohio.
[2]Based on current forwards. ICE forwards transaction date from November 2010 through April 2011 for delivery in 2012, 2013, 2014 and 2015. AD PJM Hub price.
[3]MRO is the weighted average of legacy ESP and retail market price based on ESP and retail market weights shown in the table.
N/A = Not Applicable

VIII. COMPARISON OF MRO AND PROPOSED ESP

Q. WHAT DOES THE COMPARISON OF THE PROPOSED ESP AND THE MRO SHOW ON AVERAGE?

A. As shown in Exhibit GG-1, the price under the proposed ESP is lower on average by 8 percent than the price under the MRO over the 2012 to 2021 period or by 0.92 ¢/kWh.

EXHIBIT GG-1
Proposed ESP vs. MRO – Based on AD Hub Price Curve

Year	MRO (¢/kWh)	Proposed ESP[1] (¢/kWh)	Difference (¢/kWh) Proposed ESP – MRO
2012	7.74	7.98	+0.23
2013	7.28	7.74	+0.46
2014	7.70	8.40	+0.70
2015	8.14	8.93	+0.79
2016	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]
Average 2012 – 2016	[redacted]	[redacted]	[redacted]
Average 2012 – 2021	[redacted]	[redacted]	-0.92

[1]Based on 76% of energy profit from energy sales being credited back to Duke Energy Ohio customers.

Q. IS THE PROPOSED ESP ALWAYS LOWER THAN THE MRO?

A. No, the proposed ESP is lower in 5 of the ten years than the MRO. However, in the other five years the proposed ESP is slightly higher – *i.e.*, the ESP price in 2012 to 2016 is slightly higher. For example, the proposed ESP is 3 percent or 0.23 ¢/kWh higher than the MRO in 2012. In these five years, on average, the proposed ESP is [redacted] ¢/kWh or [redacted] percent higher than the MRO. In the 2017 to 2021 period, the proposed ESP is [redacted] percent or [redacted] ¢/kWh lower than the MRO, more than offsetting the effects of the earlier years on the overall average.

Q. WHAT HAPPENS IF THE 5 PERCENT OF NET MARGINS DEVOTED TO ECONOMIC DEVELOPMENT WERE TREATED THE SAME AS THE 76 PERCENT USED TO BENEFIT CUSTOMERS?

A. The proposed ESP price is lower by 1 percent on average for the 2012 to 2021 period. On average, the 2012 to 2021 proposed ESP price is [redacted] ¢/kWh, or 8.9 percent lower than the MRO. Also, the difference between the proposed ESP and the MRO in the first five years decreases on average from [redacted] ¢/kWh to [redacted] ¢/kWh (see Exhibit GG-2), and the difference is [redacted] percent, not [redacted] percent.

EXHIBIT GG-2
Proposed ESP vs. MRO – Based on AD Hub Price Curve

Year	MRO (¢/kWh)	Proposed ESP[1] (¢/kWh)	Difference (¢/kWh) Proposed ESP – MRO
2012	7.74	7.93	+0.19
2013	7.28	7.66	+0.38
2014	7.70	8.30	+0.61
2015	8.14	8.81	+0.67
2016	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]
Average 2012 – 2016	[redacted]	[redacted]	[redacted]
Average 2012 – 2021	[redacted]	[redacted]	-1.03

[1] The additional 5 percent accounts for economic development; 4 percent for customers and 1 percent from the Company.

IX. SIGNIFICANTLY EXCESSIVE EARNINGS TEST (SEET)

Q. WHY IS THERE A SIGNIFICANTLY EXCESSIVE EARNINGS TEST (SEET)?

A. Per R.C. 4928.143(E), a prospective SEET is required because the proposed ESP extends beyond three years.

Q. HOW WILL IT BE CONDUCTED?

A. It is proposed to be conducted with the following provisions: Duke Energy Ohio's return on common equity will be computed using its prior-year publicly reported FERC Form 1 financial statements, including off-system sales, subject only to the specific adjustments described by Duke Energy Ohio witness Wathen.

Q. IS THERE A SUBSTANTIAL LIKELIHOOD THAT DUKE ENERGY OHIO'S EARNINGS WOULD BE SIGNIFICANTLY EXCESSIVE UNDER THE PROPOSED ESP?

A. No.

Q. WHY DO YOU HAVE THIS OPINION?

A. The Company's proposed ESP is based on revenue requirements for the Company's power plants, less 76 percent of the margins derived from those plants. Thus, the rate will be limited to the net revenue requirements plus 19 percent of margins.[21] The revenue requirements are a regulated construct with limited returns on invested capital. Therefore, the earnings from these do not create a substantial likelihood that Duke Energy Ohio will have significantly excessive earnings.

X. CONCLUSIONS

[21] The remaining 5 percent is being devoted to economic development.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. The Duke Energy Ohio's proposed ESP would replace the current Duke Energy Ohio ESP starting in January 1, 2012. Under the proposal, the electrical energy portion of SSO service would be auctioned off. The price for electrical energy will account for the large majority of the total SSO power price and the proposed ESP will ensure a long-term and vibrant competitive market for this commodity. The capacity responsibility would be undertaken for all customers by Duke Energy Ohio. Duke Energy Ohio will charge customers for this capacity less 76 percent of margins earned by the plants. This proposed ESP will have the benefit of increasing the stability of SSO rates but will do so in a balanced manner that provides Duke Energy Ohio a reasonable expectation of revenues in exchange for the hedge being provided against volatile electrical energy and capacity prices.

The price under the proposed ESP is expected to be below the price under an MRO on average between 2012 and 2021. This conclusion is based on observable forwards and model forecasts. Over this period, the proposed ESP will be eight percent below the MRO price: [redacted] ¢/kWh for the proposed ESP price versus [redacted] ¢/kWh for the MRO price. In half the years, the MRO is above the proposed ESP; in the five years where the proposed ESP is higher, it is only modestly higher at [redacted] ¢/kWh or [redacted] percent higher than the MRO price. In comparison, in the second five years, the proposed ESP price is [redacted] ¢/kWh or [redacted] percent lower than the MRO price.

There is an added benefit to the proposed ESP: economic development funding equal to five percent of the net margins. Thus, for example, if natural gas prices increase raising power prices, there will be more economic development funding. If this benefit is treated the same as the 76 percent of net margins used to decrease rates, the price advantage of the proposed ESP over the MRO price between 2012 and 2021 increases by 1 percent. Also, the difference between the proposed ESP and MRO prices in the first five years is lower at [redacted] ¢/kWh, or [redacted] percent versus [redacted] ¢/kWh or [redacted] percent without addressing economic development. The legacy ESP was approved under similar circumstances; namely, the proposed ESP price was, on average, below the MRO price, but not in all years. In addition, the proposed ESP will have less volatility than the MRO. Therefore, I conclude that the proposed ESP pricing is superior in the aggregate to the MRO pricing.

I do not expect there to be significantly excessive earnings under the proposed ESP. Nevertheless, there is provision for applying such a test that is outlined in the testimony of Duke Energy Ohio witness Wathen. The expectation that earnings will not be significantly in excess is because the only significant factor that can add earnings to the return underlying the Company's Retail Capacity Rider is limited by the fact that the Company is proposing to retain only 19 percent of the net margins on sales from its Legacy Generation assets. Also, the revenue requirements charge for generation is a regulated concept, albeit with some built in lag, which necessarily limits earnings. Thus, the structure also greatly decreases the potential for significantly excessive earnings.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

II. JUDAH L. ROSE

III. EDUCATION

1982 M.P.P., John F. Kennedy School of Government, **Harvard University**

1979 S.B., Economics, **Massachusetts Institute of Technology**

IV. EXPERIENCE

Judah L. Rose joined ICF in 1982 and currently serves as a Managing Director of ICF International. Mr. Rose has 30 years of experience in the energy industry. Mr. Rose's clients include electric utilities, financial institutions, law firms, government agencies, fuel companies, and IPPs. Mr. Rose is one of ICF's Distinguished Consultants, an honorary title given to three of ICF's 3,500 employees, and has served on the Board of Directors of ICF International as the Management Shareholder Representative.

Mr. Rose has supported the financing of tens of billion dollars of new and existing power plants and is a frequent counselor to the financial community.

Mr. Rose frequently provides expert testimony and litigation support. Mr. Rose has provided testimony in over 100 instances in scores of state, federal, international, and other legal proceedings.

Mr. Rose has also addressed approximately 100 major energy conferences, authored numerous articles published in Public Utilities Fortnightly, the Electricity Journal, Project Finance International, and written numerous company studies. Mr. Rose has also appeared in TV interviews.

Mr. Rose received a M.P.P. from the John F. Kennedy School of Government, Harvard University, and an S.B. in Economics from the Massachusetts Institute of Technology.

A. PRESS INTERVIEWS

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LA Times
Arkansas Democratic Gazette
Galveston Daily News
The Times-Picayune
Pittsburgh Post-Gazette
Power Markets Week

Wires: Bridge News
V. Associated Press
VI. Dow Jones Newswires

VII.

VIII. TESTIMONY

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108. Surrebuttal Testimony – Revenue Requirement of Judah Rose on Behalf of Dogwood Energy, LLC, In the Matter of the Application of KCP&L Greater Missouri Operations Company for Approval to Make Certain Changes to its Charges for Electric Service, Case No. ER-2010-0356, January 12, 2011.

107. Rebuttal Report Concerning Coal Price Forecast for the Harrison Generation Facility, Meyer, Unkovic and Scott, LLP, filed December 6, 2010.

106. Direct Testimony of Judah Rose on behalf of Duke Energy Ohio In the Matter of the Application of Duke Energy Ohio for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications, and Tariffs for Generation Service, Case No. 10-2586-EL-SSO, filed November 15, 2010.

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104. Declaration of Judah Rose in re: Boston Generating LLC, et al., Chapter 11, Case No. 10-14419 (SCC) Jointly Administered, September 29, 2010.

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101. Direct Testimony of Judah Rose on behalf of Plains and Eastern Clean Line LLC, in the Matter of the Application of Plains and Eastern Clean Line LLC for a Certificate of Public Convenience and Necessity to Operate as an Electric Transmission Public Utility in the State of Arkansas, Docket No. 10-041-U, June 4, 2010.

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99. Rebuttal Testimony on Behalf of TransEnergie, Canada, Province of Quebec, District of Montreal, No.: R-3669-2008-Phase 2, FERC Order 890 and Transmission Planning, July 3, 2009.

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97. Hawaii Structural Ironworkers Pension Trust Fund v. Calpine Corporation, Case No. 1-04-CV-021465, Assessment of Calpine's April 2002 Earnings Projections, March 25, 2009.

96. Coal Price Report for Harrison Coal Plant, Allegheny Energy Supply Company, LLS and Monongahela Power Company versus Wolf Run Mining Company, Anker Coal Group, etc., Civil Action. No. GD-06-30514, In the Court of Common Pleas, Allegheny County, Pennsylvania, February 6, 2009.

95. Supplemental Direct Testimony of Judah Rose, on behalf of Southwestern Electric Power Company, In the Matter of the Application of Southwestern Electric Power Company for Authority to Construct a Natural-Gas Fired Combined Cycle Intermediate Generating Facility in the State of Louisiana, Docket No. 06-120-U, December 9, 2008.

94. Rebuttal Testimony of Judah Rose on behalf of Kelson Transmission Company, LLC re: Application of Kelson Transmission Company, LLC For A Certificate of

Convenience and Necessity For the Amended Proposed Canal To Deweyville 345 kV Transmission Line Within Chambers, Hardin, Jasper, Jefferson, Liberty, Newton, And Orange Counties, SOAH Docket No. 473-08-3341, PUCT Docket No. 34611, October 27, 2008.

93. Testimony of Judah Rose, on behalf of Redbud Energy, LP, in Support of Joint Stipulation and Settlement Agreement, In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Granting Pre-Approval of the Purchase of the Redbud Generating Facility and Authorizing a Recovery Rider, Cause No. PUD 200800086, September 3, 2008.

92. Direct Testimony of Judah L. Rose on behalf of Duke Energy Carolinas, In the Matter of Advance Notice by Duke Energy Carolinas, LLC, of its Intent to Grant Native Load Priority to the City of Orangeburg, South Carolina, and Petition of Duke Energy Carolinas, LLC and City of Orangeburg, South Carolina for Declaratory Ruling With Respect to Rate Treatment of Wholesale Sales of Electric Power at Native Load Priority, Docket No. E-7, SUB 858, August 15, 2008.

91. Affidavit filed on behalf of Public Service of New Mexico pertaining to the Fuel Costs of Southwest Public Service for Cost-of-Service and Market-Based Customers, August 11, 2008.

90. Direct Testimony of Judah L. Rose on behalf of Duke Energy Ohio, Inc., Before the Public Utilities Commission of Ohio, In the Matter of the Application of Duke Energy Ohio, Inc. for Approval of an Electric Security Plan, July 31, 2008.

89. Rebuttal Testimony, Judah L. Rose on Behalf of Duke Energy Carolinas, in re: Application of Duke Energy Carolinas, LLC for Approval of Save-A-Watt Approach, Energy Efficiency Rider and Portfolio of Energy Efficiency Programs, Docket No. E-7, Sub 831, July 21, 2008.

88. Updated Analysis of SWEPCO Capacity Expansion Options as Requested by Public Utility Commission of Texas, on behalf of SWEPCO, June 27, 2008.

87. Direct Testimony of Judah L. Rose on Behalf of Nevada Power/Sierra Pacific Electric Power Company, Docket No. 1, Public Utilities Commission of Nevada, Application of Nevada Power/Sierra Pacific for Certificate of Convenience and Necessity Authorization for a Gas-Fired Power Plant in Nevada, May 16, 2008.

86. Rebuttal Testimony of Judah L. Rose on Behalf of the Advanced Power, Commonwealth of Massachusetts, Before the Energy Facilities Siting Board, Petition of Brockton Power Company, LLC, EFSB 07-7, D.P.U. 07-58 & 07-59, May 16, 2008.

85. Supplemental Rebuttal Testimony on Commissioner's Issues of Judah L. Rose for Southwestern Electric Power Company, on behalf of Southwestern Electric Power Company, PUC Docket No. 33891, Public Utilities Commission of Texas, May 2008.

84. Supplemental Direct Testimony on Commissioners' Issues of Judah Rose for Southwestern Electric Power Company, for the Application of Southwestern Electric Power Company for Certificate of Convenience and Necessity Authorization for a Coal-Fired Power Plant in Arkansas, SOAH Docket No. 473-07-1929, PUC Docket No. 33891, Public Utility Commission of Texas, April 22, 2008.

83. Rebuttal Testimony of Judah Rose, In the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize A Reasonable Rate of Return on the Fair Value of Its Operations Throughout the State of Arizona, Estimation of Market Value of Fleet of Utility Coal Plants, April 1, 2008.

82. Rebuttal Report of Judah Rose, Ohio Power Company and AEP Power Marketing Inc. vs. Tractebel Energy Marketing, Inc. and Tractebel S.A. Case No. 03 CIV 6770, 03 CIV 6731 (S.D.N.Y.), January 28, 2008

81. Proposed New Gas-Fired Plant, on behalf of AEP SWEPCO, 2007

80. Rebuttal Report, Calpine Cash Flows, on behalf of Unsecured Creditor's Committee, November 21, 2007.

79. Expert Report. Calpine Cash Flows, on behalf of Unsecured Creditor's Committee, November 19, 2007.

78. Application of Duke Energy Carolina, LLC for Approval of Energy Efficiency Plan Including an Energy Efficiency Rider and Portfolio of Energy, Docket No. 2007-358-E, Public Service Commission of South Carolina, December 10, 2007.

77. Independent Transmission Cause No. PUD200700298, Application of ITC, Public Service of Oklahoma, December 7, 2007.

76. Verified Petition of Duke Energy Indiana, Inc. Requesting the Indiana Utility Regulatory Commission to Approve an Alternative Regulatory Plan Pursuant to Ind. Code š8-1-2.5-1, et. Seq. for the Offering of Energy Efficiency Conservation, Demand Response, and Demand-Side Management Programs and Associated Rate Treatment Including Incentives Pursuant to a Revised Standard Contract Rider No. 66 in Accordance With Ind. Code šš8-1-2.5-1 et seq. and 8-1-2-42(a); Authority to Defer Program Costs Associated with its Energy Efficiency Portfolio of Programs; Authority to Implement New and Enhanced Energy Efficiency Programs, Including the PowerShare® Program in its Energy Efficiency Portfolio

of Programs; and Approval of a Modification of the Fuel Adjustment Cause Earnings and Expense Tests, Indiana Utility Regulatory Commission, Cause No. 43374, October 19, 2007.

75. Rebuttal Testimony, Docket No. U-30192, Application of Entergy Louisiana, LLC For Approval to Repower the Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery, October 4, 2007

74. Direct Testimony of Judah Rose on Behalf of Tucson Electric Power Company, In the matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of Its Operations Throughout the State of Arizona, Estimation of Market Value of Fleet of Utility Coal Plants, July 2, 2007.

73. Portfolio of New Plants, Testimony on behalf of AEP: SWEPCo, before the Arkansas Public Service Commission, In the Matter of Application of SWEPCO for a Certificate of Environmental Compatibility and Public Need for the Construction, Ownership, Operation, and Maintenance of a Coal-Fired Base Load Generating Facility in the Hempstead County, Arkansas, dated June 2007.

72. Rebuttal Testimony, Causes No. PUD 200500516, 200600030, and 20070001 Consolidated, on behalf of Redbud Energy, before the Corporation Commission of the State of Oklahoma, June 2007.

71. IGCC Coal Plant, CPCN Rebuttal Testimony on behalf of Duke Energy Indiana, Cause No. 43114 before the Indiana Utility Regulatory Commission, May 2007.

70. Responsive Testimony, Causes No. PUD 200500516, 200600030, and 200700012 Consolidated, on behalf of Redbud Energy, before the Corporation Commission of the State of Oklahoma, May 2007.

69. Rebuttal Testimony, FPL – CO_2 Emissions and the Everglades Coal-Fired Power Plant, Docket No. 070098-EL, March 2007

68. Rebuttal Testimony, Electric Utility Power Hedging, on behalf of Duke Energy Indiana, Cause No. 38707-FAC6851, May 2007.

67. Direct Testimony for Southwestern Electric Power Company, Before the Louisiana Public Service Commission, Docket No. U-29702, in re: Application of Southwestern Electric Power Company for the Certification of Contracts for the Purchase of Capacity for 2007, 2008, and 2009 and to Purchase, Operate, Own, and Install Peaking, Intermediate and Base Load Coal-Fired Generating Facilities in Accordance with the Commission's General Order Dated September 20, 1983. Consolidated with Docket No. U-28766 Sub Docket B in re: Application of

Southwestern Electric Power Company for Certification of Contracts for the Purchase of Capacity in Accordance with the Commission's 'General Order of September 20, 1983, February 2007.

66. Second Supplemental Testimony on Behalf of Duke Energy Ohio Before the Public Utility Commission of Ohio, Case No. 03-93-EL-ATA, 03-2079, EL-AAM, 03-2081, EL-AAM, 03-2080, EL-ATA, February 28, 2007.

65. Electric Utility Power Hedging, on behalf of Duke Energy Indiana, Cause No. 38707-FAC6851, February 2007.

64. CPCN for Cliffside Coal-Fired Plant, on behalf of Duke Carolinas, Docket No. E7, SUB790, December 2006.

63. Expert Report, Chapter 11, Case No. 01-16034 (AJG) and Adv. Proc. No. 04-2933 (AJG), November 6, 2006.

62. IGCC Coal Plant, Testimony on behalf of Duke Energy Indiana, Cause No. 43114, October 2006.

61. Market Power and the PSEG Exelon Merger on Behalf of the NJBPU Staff, NJBPU, BPU Docket No. EM05020106, OAL Docket No. PUC-1874-05, Supplemental Testimony March 20, 2006.

60. Market Power and the PSEG Exelon Merger on Behalf of the NJBPU Staff, NJBPU, BPU Docket No. EM05020106, OAL Docket No. PUC-1874-05, Surrebuttal Testimony December 27, 2005.

59. Market Power and the PSEG Exelon Merger on Behalf of the NJBPU Staff, NJBPU, BPU Docket No. EM05020106, OAL Docket No. PUC-1874-05, November 14, 2005.

58. Brazilian Power Purchase Agreement, confidential international arbitration, October 2005.

57. Cost of Service and Fuel Clause Issues, Rebuttal Testimony on behalf of Public Service of New Mexico, Docket No. EL05-151, November 2005.

56. Cost of Service and Peak Demand, FERC, Testimony on behalf of Public Service of New Mexico, September 19, 2005, Docket No. EL05-19.

55. Cost of Service and Fuel Clause Issues, Testimony on behalf of Public Service of New Mexico, FERC Docket No. EL05-151-000, September 15, 2005.

54. Cost of Service and Peak Demand, FERC, Responsive Testimony on behalf of Public Service of New Mexico, August 23, 2005, Docket No. EL05-19.

53. Prudence of Acquisition of Power Plant, Testimony on behalf of Redbud, September 12, 2005, No. PUD 200500151.

52. Proposed Fuel Cost Adjustment Clause, FERC, Docket Nos. EL05-19-002 and ER05-168-001 (Consolidated), August 22, 2005.

51. Market Power and the PSEG Exelon Merger on Behalf of the NJBPU, FERC, Docket EC05-43-000, May 27, 2005.

50. New Air Emission Regulations and Investment in Coal Power Plants, rebuttal testimony on behalf of PSI, April 18, 2005, Causes 42622 and 42718.

49. Rebuttal Report: Damages due to Rejection of Tolling Agreement Including Discounting, February 9, 2005, CONFIDENTIAL.

48. New Air Emission Regulations and Investment in Coal Power Plants, supplemental testimony on behalf of PSI, January 21, 2005, Causes 42622 and 42718.

47. Damages Due to Rejection of Tolling Agreement Including Discounting, January 10, 2005, CONFIDENTIAL.

46. Discount rates that should be used in estimating the damages to GTN of Mirant's bankruptcy and subsequent abrogation of the gas transportation agreements Mirant had entered into with GTN, December 15, 2004. CONFIDENTIAL

45. New Air Emission Regulations and Investment in Coal Power Plants, testimony on behalf of PSI, November 2004, Causes 42622 and 42718.

44. Rebuttal Testimony of Judah Rose on behalf of PSI, "Certificate of Purchase as of yet Undetermined Generation Facility" Cause No. 42469, August 23, 2004.

43. Rebuttal Testimony of Judah Rose on behalf of the Hopi Tribe, Case No. A.02-05-046, Mohave Coal Plant Economics, June 4, 2004.

42. Supplemental Testimony "Retail Generation Rates, Cost Recovery Associated with the Midwest Independent Transmission System Operator, Accounting Procedures for Transmission and Distribution System, Case No. 03-93-EL-ATA, 03-2079, EL-AAM, 03-2081, EL-AAM, 03-2080, EL-ATA for Cincinnati Gas & Electric, May 20, 2004.

41. "Application of Southern California Edison Company (U338-E) Regarding the Future Disposition of the Mohave Coal-Fired Generating Station," May 14, 2004.

40. "Appropriate Rate of Return on Equity (ROE) TransAlta Should be Authorized For its Capital Investment Related to VAR Support From the Centralia Coal-Fired Power Plant", for TransAlta, April 30, 2004, FERC Docket No. ER04-810-000.

39. "Retail Generation Rates, Cost Recovery Associated with the Midwest Independent Transmission System Operator, Accounting Procedures for Transmission and Distribution System, Case No. 03-93-EL-ATA, 03-2079, EL-AAM, 03-2081, EL-AAM, 03-2080, EL-ATA for Cincinnati Gas & Electric, April 15, 2004.

38. "Valuation of Selected MIRMA Coal Plants, Acceptance and Rejection of Leases and Potential Prejudice to Leasors" Federal Bankruptcy Court, Dallas, TX, March 24, 2004 CONFIDENTIAL.

37. "Certificate of Purchase as of yet Undetermined Generation Facility", Cause No. 42469 for PSI, March 23, 2004.

36. "Ohio Edison's Sammis Power Plant BACT Remedy Case", In the United States District Court of Ohio, Southern Division, March 8, 2004.

35. "Valuation of Power Contract," January 2004, confidential arbitration.

34. "In the matter of the Application of the Union Light Heat & Power Company for a Certificate of Public Convenience and Necessity to Acquire Certain Generation Resources, etc.", before the Kentucky Public Service Commission, Coal-Fired and Gas-Fired Market Values, July 21, 2003.

33. "In the Supreme Court of British Columbia", July 8, 2003. CONFIDENTIAL

32. "The Future of the Mohave Coal-Fired Power Plant – Rebuttal Testimony", California P.U.C., May 20, 2003.

31. "Affidavit in Support of the Debtors' Motion", NRG Bankruptcy, Revenues of a Fleet of Plants, May 14, 2003. CONFIDENTIAL

30. "IPP Power Purchase Agreement," confidential arbitration, April 2003.

29. "The Future of the Mohave Coal-Fired Power Plant", California P.U.C., March 2003.

28. "Power Supply in the Pacific Northwest," contract arbitration, December 5, 2002. CONFIDENTIAL

27. "Power Purchase Agreement Valuation", Confidential Arbitration, October 2002.

26. "Cause No. 42145 - In support of PSI's petition for authority to acquire the Madison and Henry County plants, rebuttal testimony on behalf of PSI. Filed on 8/23/02."

25. "Cause No. 42200 - in support of PSI's petition for authority to recover through retail rates on a timely basis. Filed on 7/30/02."

24. "Cause No. 42196 - in support of PSI's petition for interim purchased power contract. Filed on 4/26/02."

23. "Cause No. 42145 - In support of PSI's petition for authority to acquire the Madison and Henry County plants. Filed on 3/1/2002."

22. "Analysis of an IGCC Coal Power Plant", Minnesota state senate committees, January 22, 2002

21. "Analysis of an IGCC Coal Power Plant", Minnesota state house of representative committees, January 15, 2002

20. "Interim Pricing Report on New York State's Independent System Operator", New York State Public Service Commission (NYSPSC), January 5, 2001

19. "The need for new capacity in Indiana and the IRP process", Indiana Utility Regulatory Commission, October 26, 2000

18. "Damage estimates for power curtailment for a Cogen power plant in Nevada", August 2000. CONFIDENTIAL

B. 17. "Valuation of a power plant in Arizona", arbitration, July 2000. CONFIDENTIAL

16. Application of FirstEnergy Corporation for approval of an electric Transition Plan and for authorization to recover transition revenues, Stranded Cost and Market Value of a Fleet of Coal, Nuclear, and Other Plants, Before PUCO, Case No. 99-1212-EL-ETP, October 4, 1999 and April 2000.

15. "Issues Related to Acquisition of an Oil/Gas Steam Power plant in New York", September 1999 Affidavit to Hennepin County District Court, Minnesota

14. "Wholesale Power Prices, A Cost Plus All Requirements Contract and Damages", Cajun Bankruptcy, July 1999. Testimony to U.S. Bankruptcy Court.

13. "Power Prices." Testimony in confidential contract arbitration, July 1998.

12. "Horizontal Market Power in Generation." Testimony to New Jersey Board of Public Utilities, May 22, 1998.

11. "Basic Generation Services and Determining Market Prices." Testimony to the New Jersey Board of Public Utilities, May 12, 1998.

10. "Generation Reliability." Testimony to New Jersey Board of Public Utilities, May 4, 1998.

9. "Future Rate Paths and Financial Feasibility of Project Financing." Cajun Bankruptcy, Testimony to U.S. Bankruptcy Court, April 1998.

8. "Stranded Costs of PSE&G." Market Valuation of a Fleet of Coal, Nuclear, Gas, and Oil-Fired Power Plants, Testimony to New Jersey Board of Public Utilities, February 1998.

7. "Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code." Market Value of Fleet of Nuclear, Coal, Gas, and Oil Power Plants, Rebuttal Testimony filed July 1997.

6. "Future Wholesale Electricity Prices, Fuel Markets, Coal Transportation and the Cajun Bankruptcy." Testimony to Louisiana Public Service Commission, December 1996.

5. "Curtailment of the Saguaro QF, Power Contracting and Southwest Power Markets." Testimony on a contract arbitration, Las Vegas, Nevada, June 1996.

4. "Future Rate Paths and the Cajun Bankruptcy." Testimony to the U.S. Bankruptcy Court, June 1997.

3. "Fuel Prices and Coal Transportation." Testimony to the U.S. Bankruptcy Court, June 1997.

2. "Demand for Gas Pipeline Capacity in Florida from Electric Utilities." Testimony to Florida Public Service Commission, May 1993.

1. "The Case for Fuel Flexibility in the Florida Electric Generation Industry." Testimony to the Florida Department of Environmental Regulation (DER), Hearings on Fuel Diversity and Environmental Protection, December 1992.

IX. SELECTED SPEAKING ENGAGEMENTS

99. Rose, J.L., Vinson & Elkins Conference, Houston, TX, November 11, 2010.

98. Rose, J.L., Fundamentals of Electricity Transmission, EUCI, Crystal City, Arlington, VA, June 29-30, 2010.

97. Rose, J.L., Economics of PC Refurbishment, Improving the Efficiency of Coal-Fired Power Generation in the U.S., DOE-NETL, February 24, 2010.

96. Rose, J.L., Fundamentals of Electricity Transmission, EUCI, Orlando, FL, January 25-26, 2010.

95. Rose, J.L., CO_2 Control, "Cap & Trade", & Selected Energy Issues, Multi-Housing Laundry Association, October 26, 2009.

94. Rose, J.L., Financing for the Future – Can We Afford It?, 2009 Bonbright Conference, October 9, 2009.

93. Rose, J.L., EEI's Transmission and Market Design School, Washington, D.C., June 2009.

92. Rose, J.L., ICF's New York City Energy Forum - Market Recovery in Merchant Generation Assets, June 10, 2008.

91. Rose, J.L., Southeastern Electric Exchange – Integrated Resource Planning Task Force Meeting, Carbon Tax Outlook Discussion, February 21-22, 2008.

90. Rose, J.L., AESP, NEEC Conference, Rising Prices and Failing Infrastructure: A Bleak or Optimistic Future, Marlborough, MA, October 23, 2006.

89. Rose, J.L., Infocast Gas Storage Conference, "Estimating the Growth Potential for Gas-Fired Electric Generation," Houston, TX, March 22, 2006.

88. Rose, J.L., "Power Market Trends Impacting the Value of Power Assets," Infocast Conference, Powering Up for a New Era of Power Generation M&A, February 23, 2006.

87. Rose, J.L., "The Challenge Posed by Rising Fuel and Power Costs", Lehman Brothers, November 2, 2005.

86. Rose, J.L., "Modeling the Vulnerability of the Power Sector", EUCI – Securing the Nation's Energy Infrastructure, September 19, 2005

85. Rose, J.L., "Fuel Diversity in the Northeast, Energy Bar Association, Northeast Chapter Meeting, New York, NY, June 9, 2005.

84. Rose, J.L., "2005 Macquarie Utility Sector Conference", Macquarie Utility Sector Conference, Vail, CO, February 28, 2005.

83. Rose, J.L., "The Outlook for North American Natural Gas and Power Markets", The Institute for Energy Law, Program on Oil and Gas Law, Houston, TX, February 18, 2005.

82. Rose, J.L. "Assessing the Salability of Merchant Assets – What's on the Horizon?" Infocast – The Market for Power Assets, Phoenix, AZ, February 10, 2005.

81. Rose, J.L. "Market Based Approaches to Transmission – Longer-Term Role", National Group of Municipal Bond Investors, New York, NY, December 10, 2004.

80. Rose, J.L. "Supply & Demand Fundamentals – What is Short-Term Outlook and the Long-Term Demand? Platt's Power Marketing Conference, Houston, TX, October 11, 2004.

79. Rose, J.L. "Assessing the Salability of Merchant Assets – When Will We Hit Bottom?, Infocast's Buying, Selling, and Investing in Energy Assets Conference, Houston, TX, June 24, 2004.

78. Rose, J. L. "After the Blackout – Questions That Every Regulator Should be Asking," NARUC Webinar Conference, Fairfax, VA, November 6, 2003.

77. Rose, J. L., "Supply and Demand in U.S. Wholesale Power Markets," Lehman Brothers Global Credit Conference, New York, NY, November 5, 2003.

76. Rose, J.L., "Assessing the Salability of Merchant Assets – When Will We Hit Bottom?", Infocast's Opportunities in Energy Asset Acquisition, San Francisco, CA, October 9, 2003.

75. Rose, J.L., "Asset Valuation in Today's Market", Infocast's Project Finance Tutorial, New York, NY, October 8, 2003.

74. Rose, J.L., "Forensic Evaluation of Problem Projects", Infocast's Project Finance Workouts: Dealing With Distressed Energy Projects, September 17, 2003.

73. Rose, J.L., National Management Emergency Association, Seattle, WA, September 8, 2003.

72. Rose, J.L., "Assessing the Salability of Merchant Assets – When Will We Hit Bottom?", Infocast's Buying, Selling & Investing in Energy Assets, Chicago, IL, July 24, 2003.

71. Rose, J.L., CSFB Leveraged Finance Independent Power Producers and Utilities Conference, New York, NY, "Spark Spread Outlook", July 17, 2003.

70. Rose, J.L., Multi-Housing Laundry Association, Washington, D. C., "Trends in U.S. Energy and Economy", June 24, 2003.

69. Rose, J.L., "Power Markets: Prices, SMD, Transmission Access, and Trading", Bechtel Management Seminar, Frederick, MD, June 10, 2003.

68. Rose, J.L., Platt's Global Power Market Conference, New Orleans, LA, "The Outlook for Recovery," March 31, 2003.

67. Rose, J.L., "Electricity Transmission and Grid Security", Energy Security Conference, Crystal City, VA, March 25, 2003.

66. Rose, J.L., "Assessing the Salability of Merchant Assets – When Will We Hit Bottom?, Infocast's Buying, Selling & Investing in Energy Assets, New York City, February 27, 2003.

65. Rose, J.L., Panel Discussion, "Forensic Evaluation of Problem Projects", Infocast Conference, NY, February 24, 2003.

64. Rose, J.L., PSEG Off-Site Meeting Panel Discussion, February 6, 2003 (April 13, 2003).

63. Rose, J.L., "The Merchant Power Market—Where Do We Go From Here?" Center for Business Intelligence's Financing U.S. Power Projects, November 18-19, 2002.

62. Rose, J.L., "Assessing U.S. Regional And The Potential for Additional Coal-Fired Generation in Each Region," Infocast's Building New Coal-Fired Generation Conference, October 8, 2002.

61. Rose, J.L., "Predicting the Price of Power for Asset Valuation in the Merchant Power Financings, "Infocast's Product Structuring in the Real World Conference, September 25, 2002.

60. Rose, J.L., "PJM Price Outlook," Platt's Annual PJM Regional Conference, September 24, 2002.

59. Rose, J.L., "Why Investors Are Zeroing in on Upgrading Our Antiquated Power Grid Rather Than Exotic & Complicated Technologies," New York Venture Group's Investing in the Power Industry—Targeting The Newest Trends Conference, July 31, 2002.

58. Rose, J.L., Panel Participant in the Salomon Smith Barney Power and Energy Merchant Conference 2002, May 15, 2002.

57. Rose, J.L., "Locational Market Price (LMP) Forecasting in Plant Financing Decisions," Structured Finance Institute, April 8-9, 2002.

56. Rose, J.L., "PJM Transmission and Generation Forecast", Financial Times Energy Conference, November 6, 2001.

55. Rose, J.L., "U.S. Power Sector Trends", Credit Suisse First Boston's Power Generation Supply Chain Conference, Web Presented Conference, September 12, 2002.

54. Rose, J.L., "Dealing with Inter-Regional Power Transmission Issues", Infocast's Ohio Power Game Conference, September 6, 2001

53. Rose, J.L., "Where's the Next California", Credit Suisse First Boston's Global Project Finance Capital Markets Conference, New York NY, June 27 2001

52. Rose, J.L, "U.S. Energy Issues: What MLA Members Need to Know," Multi-housing Laundry Association, Boca Raton Florida, June 25, 2001

51. Rose, J.L., "How the California Meltdown Affects Power Development", Infocast's Power Development and Finance Conference 2001, Washington D.C., June 12, 2001

50. Rose, J.L., "Forecasting 2001 Electricity Prices" presentation and workshop, What to Expect in western Power Markets this Summer 2001 Conference, Denver, Colorado, May 2, 2001

49. Rose, J.L., "Power Crisis in the West" Generation Panel Presentation, San Diego, California, February 12, 2001

48. Rose, J.L., "An Analysis of the Causes leading to the Summer Price Spikes of 1999 & 2000" Conference Chair, Infocast Managing Summer Price Volatility, Houston, Texas, January 30, 2001.

47. Rose, J. L., "An Analysis of the Power Markets, summer 2000" Generation Panel Presentation, Financial Times Power Mart 2000 conference, Houston, Texas, October 18, 2000

46. Rose, J.L., "An Analysis of the Merchant Power Market, Summer 2000" presentation, Conference Chair, Merchant Power Finance Conference, Atlanta, Georgia, September 11 to 15, 2000

45. Rose, J.L., "Understanding Capacity Value and Pricing Firmness" presentation, Conference Chair, Merchant Plant Development and Finance Conference, Houston, Texas, March 30, 2000.

44. Rose, J.L., "Implementing NYPP's Congestion Pricing and Transmission Congestion Contract (TCC)", Infocast Congestion Pricing and Forecasting Conference, Washington D.C., November 19, 1999.

43. Rose, J.L., "Understanding Generation" Pre-Conference Workshop, Powermart, Houston, Texas, October 26-28, 1999.

42. Rose, J.L., "Understanding Capacity Value and Pricing Firmness" presentation, Conference Chair Merchant Plant Development and Finance Conference, Houston, Texas, September 29, 1999.

41. Rose, J.L., "Comparative Market Outlook for Merchant Assets" presentation, Merchant Power Conference, New York, New York, September 24, 1999.

40. Rose, J.L., "Transmission, Congestion, and Capacity Pricing" presentation, Transmission The Future of Electric Transmission Conference, Washington, DC, September 13, 1999.

39. Rose, J.L., "Effects of Market Power on Power Prices in Competitive Energy Markets" Keynote Address, The Impact of Market Power in Competitive Energy Markets Conference, Washington, DC, July 14, 1999.

38. Rose, J.L., "Peak Price Volatility in ECAR and the Midwest, Futures Contracts: Liquidity, Arbitrage Opportunity" presentation at ECAR Power Markets Conference, Columbus, Ohio, June 9, 1999.

37. Rose, J.L., "Transmission Solutions to Market Power" presentation, Do Companies in the Energy Industry Have Too Much Market Power? Conference, Washington, DC, May 24, 1999.

36. Rose, J.L., "Repowering Existing Power Plants and Its Impact on Market Prices" presentation, Exploiting the Full Energy Value-Chain Conference, Chicago, Illinois, May 17, 1999.

35. Rose, J.L., "Transmission and Retail Issues in the Electric Industry" Session Speaker, Gas Mart/Power 99 Conference, Dallas, Texas, May 10, 1999.

34. Rose, J.L., "Peak Price Volatility in the Rockies and Southwest" presentation at Repowering the Rockies and the Southwest Conference, Denver, Colorado, May 5, 1999.

33. Rose, J.L., "Understanding Generation" presentation and Program Chairman at Buying & Selling Power Assets: The Great Generation Sell-Off Conference, Houston, Texas, April 20, 1999.

32. Rose, J.L., "Buying Generation Assets in PJM" presentation at Mid-Atlantic Power Summit, Philadelphia, Pennsylvania, April 12, 1999.

31. Rose, J.L., "Evaluating Your Generation Options in Situations With Insufficient Transmission," presentation at Congestion Management conference, Washington, D.C., March 25, 1999.

30. Rose, J.L., "Will Capacity Prices Drive Future Power Prices?" presentation at Merchant Plant Development conference, Chicago, Illinois, March 23, 1999.

29. Rose, J.L., "Capacity Value – Pricing Firmness," presentation at Market Price Forecasting conference, Atlanta, Georgia, February 25, 1999

28. Rose, J.L., "Developing Reasonable Expectations About Financing New Merchant Plants That Have Less Competitive Advantage Than Current Projects," presentation at Project Finance International's Financing Power Projects in the USA conference, New York, New York, February 11, 1999.

27. Rose, J.L., "Transmission and Capacity Pricing and Constraints," presentation at Power Fair 99, Houston, Texas, February 4, 1999.

26. Rose, J.L., "Peak Price Volatility: Comparing ERCOT With Other Regions," presentation at Megawatt Daily's Trading Power in ERCOT conference, Houston, Texas, January 13, 1999.

25. Rose, J.L., "The Outlook for Midwest Power Markets," presentation to The Institute for Regulatory Policy Studies at Illinois State University, Springfield, Illinois, November 19, 1998.

24. Rose, J.L., "Developing Pricing Strategies for Generation Assets," presentation at Wholesale Power in the West conference, Las Vegas, Nevada, November 12, 1998.

23. Rose, J.L., "Understanding Electricity Generation and Deregulated Wholesale Power Prices," a full-day pre-conference workshop at Power Mart 98, Houston, Texas, October 26, 1998.

22. Rose, J.L., "The Impact of Power Generation Upgrades, Merchant Plant Developments, New Transmission Projects and Upgrades on Power Prices," presentation at Profiting in the New York Power Market conference, New York, NY, October 22, 1998.

21. Rose, J.L., "Capacity Value – Pricing Firmness," presentation to Edison Electric Institute Economics Committee, Charlotte, NC, October 8, 1998.

20. Rose, J.L., "Locational Marginal Pricing and Futures Trading," presentation at Megawatt Daily's Electricity Regulation conference, Washington, D.C., October 7, 1998.

19. Rose, J.L., Chairman's opening speech and "The Move Toward a Decentralized Approach: How Will Nodal Pricing Impact Power Markets?" at Congestion Pricing and Tariffs conference, Washington, D.C., September 25, 1998.

18. Rose, J.L., "The Generation Market in MAPP/MAIN: An Overview," presentation at Megawatt Daily's MAIN/MAPP – The New Dynamics conference, Minneapolis, Minnesota, September 16, 1998.

17. Rose, J.L., "Capacity Value – Pricing Firmness," presentation at Market Price Forecasting conference, Baltimore, Maryland, August 24, 1998.

16. Rose, J.L., "ICF Kaiser's Wholesale Power Market Model," presentation at Market Price Forecasting conference, New York, New York, August 6, 1998.

15. Rose, J.L., Campbell, R., Kathan, David, "Valuing Assets and Companies in M&A Transactions," full-day workshop at Utility Mergers & Acquisitions conference, Washington, D.C., July 15, 1998.

14. Rose, J.L., "Must-Run Nuclear Generation's Impact on Price Forecasting and Operations," presentation at The Energy Institute's conference entitled "Buying and Selling Electricity in the Wholesale Power Market," Las Vegas, Nevada, June 25, 1998.

13. Rose, J.L., "The Generation Market in PJM," presentation at Megawatt Daily's PJM Power Markets conference, Philadelphia, Pennsylvania, June 17, 1998.

12. Rose, J.L., "Market Evaluation of Electric Generating Assets in the Northeast," presentation at McGraw-Hill's conference: Electric Asset Sales in the Northeast, Boston, Massachusetts, June 15, 1998.

11. Rose, J.L., "Overview of SERC Power," opening speech presented at Megawatt Daily's SERC Power Markets conference, Atlanta, Georgia, May 20, 1998.

10. Rose, J.L., "Future Price Forecasting," presentation at The Southeast Energy Buyers Summit, Atlanta, Georgia, May 7, 1998.

9. Rose, J.L., "Practical Risk Management in the Power Industry," presentation at Power Fair, Toronto, Canada, April 16, 1998.

8. Rose, J.L., "The Wholesale Power Market in ERCOT: Transmission Issues," presentation at Megawatt Daily's ERCOT Power Markets conference, Houston, Texas, April 1, 1998.

7. Rose, J.L., "New Generation Projects and Merchant Capacity Coming On-Line," presentation at Northeast Wholesale Power Market conference, New York, New York, March 18, 1998.

6. Rose, J.L., "Projecting Market Prices in a Deregulated Electricity Market," presentation at conference: Market Price Forecasting, San Francisco, California, March 9, 1998.

5. Rose, J.L., "Handling of Transmission Rights," presentation at conference: Congestion Pricing & Tariffs, Washington, D.C., January 23, 1998.

4. Rose, J.L., "Understanding Wholesale Markets and Power Marketing," presentation at The Power Marketing Association Annual Meeting, Washington, D.C., November 11, 1997.

2. Rose, J.L., "Determining the Electricity Forward Curve," presentation at seminar: Pricing, Hedging, Trading, and Risk Management of Electricity Derivatives, New York, New York, October 23, 1997.

3. Rose, J.L., "Market Price Forecasting In A Deregulated Market," presentation at conference: Market Price Forecasting, Washington, D.C., October 23, 1997,

1. Rose, J.L., "Credit Risk Versus Commodity Risk," presentation at conference: Developing & Financing Merchant Power Plants in the New U.S. Market, New York, New York, September 16, 1997.

X. SELECTED PUBLICATIONS

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Rose, J.L. and Surana, S. "Forecasting Recessions and Investment Strategies." World-Generation, June/July 2010, V.22, #3.

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Rose, J.L., "Missed Opportunity: What's Right and Wrong in the FERC Staff Report on the Midwest Price Spikes," *Public Utilities Fortnightly,* November 15, 1998.

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Rose, J.L., D. Kathan, and J. Spencer "Electricity Deregulation in the New England States," *Energy Buyer*, Volume 1, Issue 10, June-July 1997.

Rose, J.L., S. Muthiah, and M. Fusco, "Financial Engineering in the Power Sector," *The Electricity Journal,* Jan/Feb 1997.

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Rose, J.L. and C. Mann, "Unbundling the Electric Capacity Price in a Deregulated Commodity Market," *Public Utilities Fortnightly,* December 1995.

Booth, William and J.L. Rose, "FERC's Hourly System Lambda Data as Interim Bulk Power Price Information," *Public Utilities Fortnightly,* May 1, 1995.

Rose, J.L. and M. Frevert, "Natural Gas: The Power Generation Fuel for the 1990s." Published by Enron.

XI.

XII.EMPLOYMENT HISTORY

ICF Resources Incorporated	Managing Director	1999-Present
	Vice President	1996-1999
	Project Manager	1993-1996
	Senior Associate	1986-1993
	Associate	1982-1986

1

DUKE ENERGY OHIO EXHIBIT ____

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service.	)	Case No. 11-3549-EL-SSO
In the Matter of the Application of Duke Energy Ohio for Authority to Amend its Certified Supplier Tariff, P.U.C.O. No. 20.	)	Case No. 11-3550-EL-ATA
In the Matter of the Application of Duke Energy Ohio for Authority to Amend its Corporate Separation Plan.	)	Case No. 11-3551-EL-UNC

REDACTED VERSION

DIRECT TESTIMONY OF

WILLIAM DON WATHEN JR.

ON BEHALF OF

DUKE ENERGY OHIO, INC.

June 20, 2011

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Attachments:

WDW-1: Revenue Requirement Calculation for Rider RC
WDW-2: Projected Rider RC Calculations and the Better in the Aggregate Test

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William Don Wathen Jr., and my business address is 139 East Fourth Street, Cincinnati, Ohio 45202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services LLC (DEBS) as General Manager and Vice President of Rates, Ohio and Kentucky. DEBS provides various administrative and other services to Duke Energy Ohio, Inc., (Duke Energy Ohio or the Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received Bachelor Degrees in Business and Chemical Engineering, and a Master of Business Administration Degree, all from the University of Kentucky. After completing graduate studies, I was employed by Kentucky Utilities Company as a planning analyst. In 1989, I began employment with the Indiana Utility Regulatory Commission as a senior engineer. From 1992 until mid-1998, I was employed by SVBK Consulting Group, where I held several positions as a consultant focusing principally on utility rate matters. I was hired by Cinergy Services, Inc., in 1998, as an Economic and Financial Specialist in the Budgets and Forecasts Department. In 1999, I was promoted to the position of Manager, Financial Forecasts. In August 2003, I was named to the position of Director -

Rates. On December 1, 2009, I took the position of General Manager and Vice President of Rates, Ohio and Kentucky.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO?

A. Yes. I have presented testimony on numerous occasions before the Public Utilities Commission of Ohio (Commission) and various other state, local, and federal regulators.

Q. PLEASE SUMMARIZE YOUR DUTIES AS GENERAL MANAGER AND VICE PRESIDENT OF RATES, OHIO AND KENTUCKY.

A. As General Manager and Vice President of Rates, Ohio and Kentucky, I am responsible for all state and federal rate matters involving Duke Energy Ohio and Duke Energy Kentucky, Inc.

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

A. The purpose of my testimony is to support various aspects of Duke Energy Ohio's proposed electric security plan (ESP). I provide testimony regarding the primary components of the Company's proposed ESP, provisions for testing the plan in years four and eight pursuant to R.C. 4928.143(E), transitional conditions should the plan be terminated, and the association with governmental aggregators. Finally, I address the comparison between the proposed ESP and the expected results under R.C. 4928.142 in respect of pricing.

II. PRIMARY COMPONENTS OF THE ESP

Q. PLEASE DESCRIBE THE PRIMARY COMPONENTS OF DUKE ENERGY OHIO'S PROPOSED ESP.

A. The Company's proposed ESP is comprised of both cost-based and market-based pricing elements, the intent of which is to provide customers with rate stability and price certainty while retaining their ability to select competitive providers of the energy commodity. The table below summarizes the riders that are incorporated into and a part of the proposed ESP.

Table 1 – New Riders		
Rider Name	**Description**	**Avoidable?**
Rider RC	Retail Capacity	No
Rider PSM	Profit Sharing Mechanism	No
Rider RE	Retail Energy	Yes
Rider AER-R	Alternative Energy Recovery Rider	Yes
Rider RECON	Reconciliation Rider for over-/under-recovery of eliminated ESP-era riders	Yes
Rider UE-GEN	Uncollectible Expense Rider for Generation	No
Rider DR	Distribution Reliability	No

Further, certain riders that were approved in Duke Energy Ohio's current ESP under Case No. 08-920-EL-SSO, *et al.*, will be unaffected by this filing. Those riders are Rider SAW, Rider SAW-R, and Rider ECF. As these three riders are unchanged by this Application, I do not discuss them in detail in my testimony.

Finally, upon implementation of the proposed ESP, a number of existing riders will be terminated. Table 2 is a summary of the riders that will be no longer exist under the new ESP.

Table 2 – Riders Being Eliminated	
Rider Name	**Description**
Rider PTC-BG	Price-to-Compare: Base Generation
Rider PTC-FPP	Price-to-Compare: Fuel and Purchased Power
Rider PTC-AAC	Price-to-Compare: Annually Adjusted Component
Rider SRA-CD	System Reliability Adjustment: Capacity Dedication
Rider SRA-SRT	System Reliability Adjustment: System Reliability Tracker
Rider DR-IM	Distribution Reliability: Infrastructure Modernization

A. Rider RC (Retail Capacity)

Q. PLEASE DESCRIBE RIDER RC.

A. Rider RC is predicated upon a formula rate for developing the fixed costs associated with the Company's legacy generating assets that, under the Company's proposal, will effectively be dedicated to Ohio customers, as well as a reasonable rate of return for those assets. Through Rider RC, Duke Energy Ohio will recover the costs that are incurred in serving its customers with a reliable and adequate supply of capacity over the full term of the ESP. Additionally, to the extent the Company incurs costs to secure sufficient capacity to meet its reliability requirements, such costs would be incorporated into Rider RC. However, any third-party purchases necessary to meet the reliability requirement would be treated as an expense for determining the revenue requirement for Rider RC; so, there would be no return component for such market or third-party purchases. The Rider RC rate will be adjusted each year to reflect actual costs incurred, or changes in rate base as a result of environmental expenditures or other changes to the generating assets on which the rate is predicated.

The formula used to develop Rider RC has its roots in traditional ratemaking inasmuch as the Company incorporated many elements of the calculations it would make for determining the revenue requirement for its regulated gas and electric operations. The formula also incorporates a number of ratemaking concepts used by the Federal Energy Regulatory Commission (FERC) for its formula ratemaking for network integrated transmission service (NITS).[1]

Much like the formula used for setting the Company's NITS revenue requirement, the revenue requirement for Rider RC is based on actual, historic costs. All of the starting information used for the calculation begins with data from the FERC Form 1 Annual Report, a document which is publicly available. The formula includes a calculation of rate base, which in this case will be the rate base attributable to Duke Energy Ohio's Legacy Generating Assets.[2] In exchange for dedicating the assets to customers, the Company would seek a reasonable return on the rate base. The return would be based on an appropriate return on equity (ROE), as supported by Duke Energy Ohio witness Dr. Roger A. Morin, the average cost of debt for the most recent actual period, and the relative proportion of equity and debt making up the Company's capital structure.

The next step of the formula is to determine the expenses to be recovered. Eligible expenses include book depreciation expense, operating and maintenance

[1] As a current member of the Midwest Independent System Operator, Inc. (Midwest ISO), Duke Energy Ohio annually updates its revenue requirement pursuant to a Midwest ISO formula rate, Attachment O, approved by the Federal Energy Regulatory Commission.
[2] See Direct Testimony of Salil Pradhan for a description of the Legacy Generating Assets.

(O&M) expense, property and other taxes, and income taxes on the equity portion of the return on rate base.

Q. **ARE ANY ADJUSTMENTS NECESSARY TO THE 'PER BOOKS' INFORMATION?**

A. Yes. A number of adjustments to the information contained in the Form 1 are necessary to determine the appropriate revenue requirement for Duke Energy Ohio's Legacy Generating Assets.

Rate Base Adjustments:

a. The values represented in the Form 1 for production plant include purchase accounting adjustments associated with the merger of Duke Energy and Cinergy Corp. in 2006. Purchase accounting is typically not allowed for recovery in conventional ratemaking; consequently, the impact of purchase accounting was removed from all plant and O&M accounts, and was also removed from the capital structure.

b. In April 2011, Duke Energy Ohio transferred its ownership stake in a number of gas-fired generation assets (often referred to as the DENA plants) that have never been used and useful for its retail customers. Because those assets are now owned by an affiliate and are not being dedicated to customers as part of the proposed ESP, the value of these assets indicated in the Form 1 for 2010 is removed from the Rider RC revenue requirement calculation along with all related expenses.

c. Duke Energy Ohio has common and general plant that supports its generation business and its other lines of business (*e.g.*, electric distribution, electric transmission, and gas distribution); consequently, some common and general plant is being allocated to Legacy Generation rate base in proportion to its relative net plant.

d. Applying conventional ratemaking principles commonly used before this Commission, the Rider RC formula deducts from rate base Legacy Generation's share of Accumulated Deferred Income Taxes (ADITs) and Accumulated Deferred Income Tax Credits (ADITCs). Some ADITs and ADITCs are clearly attributable to one line of business or another, while some are related to assets/expenses that cross more than one line of business. Because of the magnitude of ADITs, the schedules sponsored in Attachment WDW-1 include a detailed summary of each accounting record for this item and the allocation of those ADITs among the Company's lines of business.

e. To recognize the need for cash working capital, the FERC allows companies to estimate cash working capital needs by dividing non-fuel O&M expense by 8 (often referred to as the 45-day method). This methodology is often used in FERC rate cases and is a component of the formula rate for establishing the NITS revenue requirement.

O&M Adjustments:

a. Because the retail capacity rider is only intended to recover fixed costs, costs that are directly proportional to the number of MWh being generated (*i.e.*, variable costs) are excluded from the calculation. Consequently, expenses such as fuel expense, emission allowance (EA) expense, and environmental reagent expenses are eliminated.

b. All historic purchased power expense is eliminated; however, [redacted]

c. Certain O&M costs, particularly administrative and general (A&G) costs, support lines of business in addition to Legacy Generation. The bulk of these A&G costs are labor related; therefore, it is appropriate to allocate to Legacy Generation an amount of these costs in proportion to that line of business' share of overall salaries and wages. This is another common application of ratemaking principles and is consistent with the allocation methods used in our retail distribution rate cases in Ohio.

Taxes

a. Income taxes are included at the statutory effective rate and the calculation includes an adjustment to reflect the statutory level of Gross Domestic Production Tax Deduction under Section 199 of the Internal Revenue Code (Section 199 Deduction). Although the Section 199 Deduction can only be used if there is a positive taxable income for current taxes (as opposed to book income), ratemaking typically uses statutory rates for taxes and, because the

ESP, if approved, will ensure that Duke Energy Ohio will have positive book income, it is appropriate to include this benefit for customers.

b. Ohio no longer has a state income tax but, instead, has a commercial activities tax (CAT tax). The effect of this tax is included in the revenue requirement calculation.

c. Property and other taxes are included at the levels allocable to Legacy Generation for 2010.

Q. PLEASE DESCRIBE HOW RIDER RC WILL BE UPDATED.

A. As described above, the FERC-approved formula for establishing the revenue requirement for NITS allows for an annual update to the revenue requirement calculation shortly after the source of the data is available. Specifically, because the FERC formula uses the FERC Form 1 and this document is not publicly available until mid-April every year, the formula for calculating new transmission rates is updated in May each year, with rates becoming effective the next month.

In order to allow the Commission sufficient time to review the filing each year, the Company proposes that a filing be made each year on or before June 1 to update the revenue requirement and the rates for Rider RC. The Commission would have the opportunity to establish a formal review process and new rates would be updated upon a Commission order approving the rates for implementation by January 1 of the following year.

Q. IS RIDER RC PROPOSED AS A NON-BYPASSABLE RIDER?

A. Yes. In exchange for providing retail customers with virtually all of the value of the Legacy Generating Assets owned by Duke Energy Ohio and a fixed capacity charge that will not be subject to the market volatility that is discussed in the Direct Testimony of Duke Energy Ohio witnesses B. Keith Trent and Judah L. Rose, Rider RC will be unavoidable and thus applicable to all retail customers in Duke Energy Ohio's service territory. The Company's proposal to share most of the benefits of owning the generation (*e.g.*, profits on off-system sales, ancillary service revenue, etc.) is a major element of this proposal and it will also serve to mitigate any volatility that customers may experience in their price for electricity.

B. Rider PSM (Profit Sharing Mechanism)

Q. WHAT IS RIDER PSM?

A. Rider PSM is a mechanism that will enable Duke Energy Ohio to credit back to customers most of the net profits derived from the Legacy Generating Assets. Most of this profit is derived from the sale of economic generation into the market. For example, when the market price of power exceeds the cost to the Company of generating that power, there will be a resulting margin (or profit) on the sale of this generation. Under the Company's ESP proposal, all of Duke Energy Ohio's economic generation will be available for dispatch into the market and all of the net profit derived from that market will be available for sharing between customers and the Company.

Q. HOW WILL DUKE ENERGY OHIO MANAGE ITS PORTFOLIO OF ASSETS TO OPTIMIZE THE VALUE OF THIS GENERATION FOR CUSTOMERS?

A. In many ways, the Company's management of Rider PSM will resemble its management of the current Rider PTC-FPP (fuel and purchased power rider). In both cases, the Company will have a portfolio of assets including coal, EAs, etc., that will be the basis for the costs of the products being sold in the market. There is a direct correlation between managing the portfolio of these assets and the value being created from these assets. Duke Energy Ohio witness Salil Pradhan discusses how the Company plans to manage the commodity positions (*e.g.*, fuel, emission allowances, etc.) and hedging strategy for Legacy Generating Assets, thereby creating the value for Rider PSM.

Q. PLEASE DESCRIBE HOW RIDER PSM WILL BE UPDATED.

A. For the initial rates being established in this ESP for 2012, Duke Energy Ohio will forecast the profits projected for sharing in Rider PSM for the entire year. That calculation will establish a baseline amount to be credited against Rider RC. Beginning with a March 1, 2012, filing, the Company will update Rider PSM based on updated forecasts for the upcoming full quarter (*i.e.*, April-June 2012 in the March 1 filing) and will reconcile the most recently completed prior quarter for actual data (*i.e.*, comparing the amount of profits to be shared for the quarter vs. how much was actually shared). In many ways, this process will mirror the current, quarterly filings for the existing Rider PTC-FPP.

The projected and reconciliation component of quarterly filings will include the revenue derived from ownership of the Legacy Generating Assets (*e.g.*, day-ahead and real-time sales in PJM, ancillary service revenue, etc.) and all variable costs (*e.g.*, fuel, EAs, reagent costs, etc.) incurred to generate the associated revenue.

Q. DOES THE COMPANY PROPOSE A REVIEW PROCESS FOR RIDER PSM?

A. Yes. On both a quarterly and annual basis, the Company proposes a review process that mirrors the current Rider PTC-FPP. The Company will file its quarterly update at least thirty days prior to the effective date of the new Rider PSM rates and, unless there is some intervention or Commission-ordered review, the new rates will become effective without the need for explicit Commission approval.

In the first quarter after each year the Rider PSM is in effect, the Commission will conduct an audit of the prior year's operation of Rider PSM. Much like the current annual audit for Rider PTC-FPP, the Commission may review the Company's management, policies, and practices for managing the asset portfolio and may review the financial data underlying the rate setting process for Rider PSM. The auditor would submit a report of its findings to the Commission and a formal review may be conducted. If the Commission engages an independent third-party auditor, those costs would be included, and netted against the customer share of amounts to be credited, in Rider PSM.

Q. YOU MENTIONED EARLIER THAT THE EFFECT OF RIDER PSM WILL BE TO MITIGATE THE VOLATILITY RETAIL CUSTOMERS MAY EXPERIENCE IN THEIR OVERALL PRICE OF ELECTRICITY. PLEASE EXPLAIN WHAT YOU MEAN BY THAT.

A. First of all, although distribution and transmission service would be part of an overall bill, the prices for these components are relatively stable. Principally, what

I am describing is the interaction between (1) the cost of service based price of capacity; (2) the availability of a market-based standard service offer exclusively for energy secured via an open auction process; and (3) the assignment of most of the value derived from the Legacy Generating Assets to all retail customers.

All involved in the retail and wholesale power markets are aware of how volatile the price of both capacity and energy has been. The Company's witnesses Trent and Rose discuss the volatility that has existed and will continue to exist in the markets for these products. The ESP being proposed by the Company is fundamentally designed to limit the volatility customers will see in electricity prices over an extended period of time. First, the cost-based capacity of the Legacy Generating Assets offers pricing stability to retail customers, which means customers will be exposed to little, if any, volatility in the market price for capacity. One has only to look at the outcome of the recent auction for capacity in PJM for evidence of how volatile the price for capacity can be. From planning year 2013/2014 to planning year 2014/2015, the market price set in PJM's auctions went from about $28 per MW-day to over $125 per MW-day. For planning year 2011/2012, the price was $110 per MW-day and, for planning year 2012/2013, the price was $16 per MW-day. This kind of volatility and instability in a major component of electric prices cannot be in the best interests of the Company, its customers, or the long-term economic growth of our region. Under the proposed ESP, most of the capacity needed to serve retail load will be from identified assets and priced to customers at an embedded cost, ensuring that Duke

Energy Ohio's retail customers will not see this type of volatility or instability in the price their capacity.

The market price of energy can also be quite volatile. The proposed ESP provides that all customers will pay a market price for energy, whether via a Standard Service Offer or when purchasing from competitive retail electric service (CRES) providers. However, the proposal to share virtually all of the net profits from Duke Energy Ohio's energy sales from its own Legacy Generation serves to mitigate the volatility in the overall price of generation. For example, without such a sharing mechanism, if retail energy prices were to escalate rapidly, customers would have to pay the rapidly escalating energy price as this type of market force would impact both the market-based SSO price and CRES providers' offers. However, with the sharing proposal and a properly managed portfolio of generation components (*e.g.*, fuel, EAs, etc.), higher energy prices should translate into higher profits for the Legacy Generating Assets. The net effect is that, while customers may pay higher energy prices in the market, these higher energy prices should translate into greater profits for Duke Energy Ohio's Legacy Generating Assets that will offset retail customers' overall generation price. Ultimately, the Company's proposal limits customers' exposure almost exclusively to the volatility in the underlying input prices for Duke Energy Ohio's Legacy Generating Assets, which, as discussed in the testimony of Duke Energy Ohio witness Salil Pradhan, can be effectively managed through portfolio optimization (or active management).

Q. **IS RIDER PSM PROPOSED AS A NON-BYPASSABLE RIDER?**

A. Yes. Because this rider is inexorably linked to Rider RC, it will be non-bypassable credit. Duke Energy Ohio's plan centers upon all customers in the footprint paying the non-bypassable charge for the stability offered by the Company's capacity. It is therefore reasonable that all customers also receive the proportional benefit those assets provide through Rider PSM.

C. Rider RE (Retail Energy)

Q. **PLEASE DESCRIBE RIDER RE.**

A. The Company's proposed ESP decouples capacity from energy. The Company will be the single source of capacity for all retail customers and the market will be the exclusive provider of energy for retail customers. Toward that end, the Company will procure 100 percent of its retail energy requirement via a competitive bid process, as detailed in the Direct Testimony of Duke Energy Ohio witness Robert J. Lee. As proposed by Mr. Lee, such wholesale auctions generally will be conducted two times per year[3] for the duration of the ESP and, after the approval process is complete, the results of the auctions will be converted into retail rates for Duke Energy Ohio's SSO customers. The Company's proposed Rider RE (Retail Energy) will be the vehicle for transforming the results of the auction into retail rates. Duke Energy Ohio witness Jeffrey R. Bailey discusses the process for converting the wholesale rates to retail rates, for recovery through Rider RE.

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[3] During 2011, there will be only one auction, as there would be insufficient time for two auctions.

The Company also proposes to recover through Rider RE prudently incurred costs associated with conducting the auctions pursuant to its CBP plan. And, in the event a supplier defaults, Duke Energy Ohio proposes to recover, through Rider RE, the net costs incurred by it to provide SSO service. The net costs would be those unrecovered costs remaining after the Company reasonably pursues contractual remedies against the defaulting supplier.

Q. PLEASE EXPLAIN THE COMPANY'S CONTIGENCY PLAN TO PROCURE WHOLESALE ENERGY FOR DELIVERY BEGINNING JANUARY 1, 2012, IF IT IS UNABLE TO CONDUCT AN AUCTION IN 2011 AND THE COST RECOVERY MECHANISM FOR THIS PLAN.

A. As described by Duke Energy Ohio witnesses Robert J. Lee and James S. Northrup, the Company proposes to conduct wholesale energy auctions for its SSO load, with delivery beginning on January 1, 2012. In the event a Commission order approving the proposed ESP is not issued in sufficient time to enable the first auction to be conducted in time to meet that goal, Duke Energy Ohio proposes to procure the energy necessary to serve its load via the PJM Spot Energy Market, for whatever period is necessary as a result of the delay. Costs for the acquisition of this energy will be recovered through Rider RE.

Q. PLEASE EXPLAIN HOW RIDER RE WILL BE UPDATED.

A. Within thirty days of the conclusion of each auction for SSO load, the Company will make a filing with the Commission detailing the process of converting the results of the auction into retail rates. In addition to recovering the cost of supplier-provided energy, the Company will seek to recover the costs of conducting the auction including, but not limited to, the cost of consultants hired by the Commission to review the auction process and the direct costs of conducting the auction. Further, Rider RE will be used to reconcile the rates charged to customers with the amounts paid to wholesale suppliers.

Q. IS RIDER RE PROPOSED AS A NON-BYPASSABLE RIDER?

A. No. Rider RE reflects the Company's SSO energy price and, as such, is unconditionally avoidable by shopping customers.

D. <u>Rider AER-R (Alternative Energy Resource Requirement)</u>

Q. PLEASE DESCRIBE RIDER AER-R.

A. Rider AER-R is being proposed to recover the Company's costs for complying with the Ohio's renewable energy requirements. The responsibility for procuring renewable energy certificates (RECs) generally follows the load obligation, although the nexus is slightly convoluted insofar as the REC obligation is based on the average of the prior three years' of load rather than the current load obligation.[4] Taken to its extreme, this requirement could mean a supplier of retail energy, whether it is the electric distribution utility or a CRES provider, could have an obligation to supply RECs if it served <u>any</u> load in the prior three years, even if it has no load to serve in the current year.

Q. PLEASE EXPLAIN HOW RIDER AER-R WILL BE UPDATED.

A. The rider will be filed quarterly and will include true-up provisions.

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[4] O.A.C. 4901:1-40-03(B)(1).

Q. IS RIDER AER-R PROPOSED AS A NON-BYPASSABLE RIDER?

A. No. Pursuant to R.C. 4928.64(E) costs to comply with the alternative energy resource requirements must be bypassable. Consequently, Rider AER-R is an unconditionally avoidable charge.

E. Rider RECON (Reconciliation)

Q. PLEASE DESCRIBE RIDER RECON.

A. Rider RECON is intended to true up Duke Energy Ohio's current Rider PTC-FPP (fuel and purchased power) and Rider SRA-SRT (system reliability tracker), both of which will expire upon the effective date of the ESP proposed in the Company's Application. It is a near certainty that both of those riders will have a balance of over- or under-recovery as of December 31, 2011. The purpose of Rider RECON, therefore, is to true up the collective balance of any over- or under-recovery for these two existing riders. To the extent the sum of the balances of over-/under-recovery for the two riders is an over-recovery, Rider RECON will be a credit to non-shopping customers. If the cumulative balance is an under-recovery, Rider RECON will be a charge to non-shopping customers. Because the balance of over-/under-recovery for Rider RECON is expected to be relatively small, the anticipated duration of Rider RECON is short – Duke Energy Ohio will be able to resolve any over- or under-recoveries within six months of the new ESP. And once that resolution occurs, Rider RECON will expire. It should also be noted that, because the magnitude of Rider RECON is expected to be relatively small and the duration of recovery is expected to be relatively short, the Company is proposing that no carrying costs be included in the rider. This is reasonable particularly in light of the fact that there are no carrying charges associated with either Rider PTC-FPP or Rider SRA-SRT that are being reconciled in the proposed Rider RECON.

Q. WHEN WILL RIDER RECON BE IMPLEMENTED?

A. As discussed above, the riders being trued up via Rider RECON are proposed to end on December 31, 2011. Because it will take some time to determine the actual results (*i.e.*, revenue and costs) for the period in question, the Company anticipates making a filing on or before March 1, 2012, to establish Rider RECON. Absent any objection from the Commission or intervenors, the rider will go into effect on April 1, 2012. Depending on the magnitude of the amount to be reconciled, the duration of Rider RECON could be up to six months.

Q. RIDERS PTC-FPP AND SRA-SRT ARE SUBJECT TO ANNUAL AUDITS. WILL THAT AFFECT YOUR PROPOSAL REGARDING RIDER RECON?

A. In prior Commission audits of these two riders, the Commission has ordered Duke Energy Ohio to exclude a cost that had previously been recovered. Because the twelve-month period ending December 31, 2011, is also subject to an annual audit, which will not be conducted until early in 2012, the Company proposes to use Rider RECON to address any Commission-ordered refunds or charges stemming from the audit review process.

Q. IS RIDER RECON PROPOSED AS A NON-BYPASSABLE RIDER?

A. Rider RECON is being proposed as an unconditionally bypassable rider.

F. Rider UE-GEN (Uncollectible Generation Expense)

Q. PLEASE EXPLAIN RIDER UE-GEN.

A. Duke Energy Ohio is proposing to recover the cost of bad debt associated with its SSO service, via Rider UE-GEN. The Company currently has an approved rider to recover costs of bad debt associated with distribution service (Rider UE-ED[5]) and bad debt related to retail transmission is a component of the FERC-approved formula rates for calculating the NITS revenue requirement that is recoverable through Rider BTR.[6] However, there is no existing rider mechanism to recover the bad debt expense associated with serving SSO load, therefore, the Company, proposes to implement Rider UE-GEN for that purpose.

Additionally, Duke Energy Ohio proposes to modify its existing Purchase of Accounts Receivable (PAR) program, with such modifications enabling the recovery of the bad debt associated with CRES providers' accounts receivable.

As I understand, Duke Energy Ohio is the only electric distribution utility (EDU) in Ohio that purchases accounts receivable on any terms from CRES providers. Under the current structure and pursuant to prior Commission approval, CRES providers must be enrolled in the Company's PAR program in order to have their accounts receivable purchased at a discounted rate. Although the current structure has aided CRES providers and, by extension, the competitive retail market, there are improvements that can be made to the scope of this

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[5] "UE-ED" means "uncollectible expense – electric distribution."
[6] The Commission approved the Company's Application to implement Rider BTR on May 6, 2011, in Case No. 11-2641-EL-RDR.

purchase of accounts receivable program that, if properly implemented, will benefit both CRES providers and the Company.

Here, Duke Energy Ohio is proposing to align the purchase of electric generation accounts receivable from CRES providers with its purchase of natural gas accounts receivable. Under this proposal, the Company will purchase electric generation accounts receivable at no discount, remitting payment on the twentieth day of the month after which billing occurs. Duke Energy Ohio will recover the uncollectible generation expense associated with all generation accounts – its own and those purchased from CRES providers – via Rider UE-GEN.

Q. WILL RIDER UE-GEN BE A NON-BYPASSABLE RIDER?

A. Yes. Given that it extends to the uncollectible expense of all customers – shopping and non-shopping – the rider must be non-bypassable.

Q. HAS THE COMMISSION RECENTLY OFFERED AN OPINION REGARDING A RIDER LIKE UE-GEN?

A. Yes. A similar rider was discussed as part of Duke Energy Ohio's request for approval of a Market Rate Offer (MRO) in Case No 10-2586-EL-SSO.

Specifically, in its February 23, 2011, Order, the Commission held:

> In considering the proposed creation of Rider UE-GEN, the Commission is mindful that, as proposed by Dominion and RESA, as an unavoidable rider. Rider UE-GEN furthers state policy by promoting competition. Specifically, if Duke purchases accounts receivable at no discount, this will likely increase CRES providers' usage of Duke's billing service. Additionally, greater access to consolidated billing for CRES providers, without a purchase of accounts receivable discount, creates a level playing field and allows greater freedom for customer shopping without undergoing a second credit evaluation by a CRES provider, thus promoting shopping among low-income consumers. Therefore, the Commission would support the creation of Rider UE-GEN as an

> unavoidable rider, designed to recover bad debt associated with customers taking generation service through the SSO and from CRES providers. Moreover, the Commission recognizes that if Duke recovered Rider UE-GEN consistent with the process set forth by Duke in its reply brief, it would resolve any issues regarding Duke's PAR.

G. Rider DR (Distribution Reliability)

Q. PLEASE EXPLAIN RIDER DR.

A. Rider DR, as proposed in the Application, is intended to recover incremental capital investment for distribution-related reliability investment that is not otherwise recovered through base rates, and a rate of return. Rider DR would thus be used as a mechanism for all distribution upgrades, including the Company's current SmartGrid deployment program. The incremental revenue requirement applicable to Rider DR would be determined by subtracting from the current distribution cost of service the revenue that is recovered through base rates.

The proposed Rider DR incorporates a decoupling mechanism, thereby reducing any disincentive that an EDU may have to promote energy efficiency programs. In this regard, Rider DR will recover the difference between the actual base distribution revenue and adjusted based distribution revenue, where:

Actual Base Distribution Revenue = Actual Base Distribution Revenue for Each Rate Schedule

Adjusted Base Distribution Revenue = Annual Base Distribution Revenue for Each Rate Schedule Approved in the Most Recent Case, Adjusted for Changes in Billing Determinants

Q. WHAT IS THE RATE OF RETURN THAT WOULD BE APPLICABLE TO THE INCREMENTAL CAPITAL INVESTMENT RECOVERED VIA RIDER DR?

A. The rate of return would be equal to the rate of return approved in the Company's most recent electric distribution rate case, which is 10.63 percent.

Q. **WHY WOULD YOU USE AN ROE RATE FOR RIDER DR THAT IS DIFFERENT THAN WHAT DR. MORIN IS PROPOSING FOR CALCULATING RIDER RC?**

A. The purpose of Rider DR is limited to tracking the change in "distribution"-related investment and "distribution"-related O&M. Duke Energy Ohio and all investor-owned utilities in Ohio operate unbundled businesses. Rates for distribution, transmission, and generation are set at different times, potentially from different regulatory agencies (*i.e.*, the ROE for transmission investment is set by the FERC), and based on different assessments of risks. Because Rider DR is addressing only the distribution business, it is appropriate to use the most recent ROE established for that line of business. The ROE advocated in this proceeding by Dr. Morin is for the Company's generation business; so, it is not unexpected that the ROE for generation and distribution business would be different.

Q. **IF RIDER DR IS APPROVED, WILL THE COMPANY CONTINUE SEEKING RECOVERY OF ITS SMARTGRID INVESTMENT THROUGH RIDER DR-IM?**

A. No. If Rider DR is approved, the Company will make no future filings for recovery of SmartGrid investments via Rider DR-IM. Virtually all of the SmartGrid investment is related to the operation of an electric distribution system. In many ways, the SmartGrid program mirrors another very successful capital improvement program currently underway for the Company's gas operations. In that program, the accelerated main replacement program (AMRP), the Company invested a significant amount of capital in its gas distribution system. The Commission approved a rider (Rider AMRP) for the Company to recover the costs of the program and, since the program began in 2001, the Company has had two base rate cases for gas service. In both rate cases, the then existing AMRP investment was "rolled-in" to base rates. When the Company files its next general rate case for electric distribution, it will make the same proposal for its SmartGrid investment.

In the Company's view, SmartGrid investment should be included in Rider DR because it is designated as distribution investment and virtually all of the costs and savings are distribution-related. Also, because it is an investment that would be rolled into distribution base rates, it follows that it should be treated like all other distribution investment for purposes of establishing Rider DR. Duke Energy Ohio witness Mark Wyatt provides testimony regarding the Company's distribution infrastructure investment, including a discussion of the SmartGrid program.

Q. **WILL RIDER DR RECOVER ONLY INCREMENTAL COSTS?**

A. No. To the extent there are benefits associated with a particular initiative or event, customers would more quickly realize those benefits under the proposed Rider DR. A conspicuous example of a cost reduction that would flow through Rider DR is any savings in distribution-related property taxes. Duke Energy Ohio is currently engaged in an appeal process to reduce its property taxes. If successful, a significant portion of any property tax reduction would be related to distribution investment. Rider DR would provide a vehicle to pass any realized savings on to customers in short order. Absent a vehicle such as Rider DR, customers would not see the benefit of a property tax reduction until the next distribution rate case.

Q. IS DUKE ENERGY OHIO PROPOSING TO RECOVER INCREMENTAL OPERATING AND MAINTENANCE EXPENSE THROUGH RIDER DR?

A. Yes. Again, to the extent the costs are distribution-related, the proposal is to compare the current year costs to comparable costs as approved in current rates. Duke Energy Ohio witness James E. Ziolkowski provides a detailed explanation of the rider and an estimate of the rider rates during the ESP.

Q. IS RIDER DR PROPOSED TO BE A NON-BYPASSABLE RIDER?

A. Yes. Rider DR addresses distribution issues and, hence, relates to all customers, whether they purchase energy from Duke Energy Ohio or from a competitive supplier.

H. Riders Unchanged by the ESP

Q. IS THE COMPANY PROPOSING ANY CHANGES TO ITS COST RECOVERY FOR MEETING ENERGY EFFICIENCY TARGETS IN THIS CASE?

A. Not at this time. Until further notice, the Company will continue to use its Rider SAW-R (save-a-watt Rider) to recover the cost of complying with the state's energy efficiency mandates.

Q. IS THE COMPANY PROPOSING ANY CHANGES TO ITS ECONOMIC COMPETITIVENESS FUND RIDER?

A. No. The Company is not intending to alter its current Rider ECF (economic competitiveness fund rider). However, as detailed in the Direct Testimony of Julia S. Janson, Duke Energy Ohio is proposing to create a new program focused on economic development in southwest Ohio.

Q. PLEASE EXPLAIN HOW THE COMPANY'S PROPOSED NEW ECONOMIC DEVELOPMENT PROGRAM WILL BE FUNDED.

A. As discussed above, a percentage of the net profits derived from ownership of the Legacy Generating Assets (*e.g.*, energy sales) will be credited back to customers through Rider PSM. Similarly, a percentage of the net profits will be allocated Duke Energy Ohio. The Company is proposing that a portion of these profits, otherwise allocated to customers and the Company, will fund the proposed new economic development program. Specifically, the Company's proposal is to share the net profits such that 80 percent of the net profits benefit customers and 20 percent benefit the Company. Of each share, 5 percent will support the new economic development program.

As described by Duke Energy Ohio witness Janson, Advance Southwest Ohio will be a program to provide financial support for economic development, retention, and expansion in targeted southwest Ohio regional clusters. This program will be funded with 5 percent of the customers' 80 percent portion of net profits from energy and ancillary services sales and 5 percent of the Company's 20 percent portion of such profits. These funds will be provided directly to Advance Southwest Ohio such that the amount credited to customers through Rider PSM is the remaining 76 percent of the net profits. The expenditure of these funds will be controlled, as discussed by witness Janson, by the Company, with the approval of the Chairman of the Commission as to expenditures of the monies supplied by the customers.

The funding for Advance Southwest Ohio will not be based on any tariff. Instead, the process of computing the Rider PSM credit will address the funding of the programs.

I. Summary of ESP Riders

Q. WOULD YOU SUMMARIZE THE VARIOUS RIDERS THAT CUSTOMERS WILL BE SUBJECT TO DURING THE ESP?

A. Under the Company's proposal, the only significant difference in the riders applicable to retail customers is whether the customer is a shopper or a non-shopper. The proposed ESP is a considerably simpler model in that regard.

Table 3 - Riders Applicable to Non-Shopper and Shopper

Non-Shopper		Shopper
Generation Riders		**Generation Riders**
Rider RC		Rider RC
Rider PSM		Rider PSM
Rider RE (bypassable)	→	CRES Offer (Energy + AER + Market-Based RTO costs)
Rider AER-R (bypassable)		
Rider UE-GEN		Rider UE-GEN
Rider RECON (bypassable)		
Transmission Riders [a]		**Transmission Riders** [a]
Rider BTR		Rider BTR
Rider RTO (bypassable)		
Distribution Riders		**Distribution Riders**
Rider SAW-R		Rider SAW-R
Rider DR		Rider DR
Rider ECF		Rider ECF

Note: [a] The Company is not seeking approval of transmission cost recovery in this proceeding. Transmission riders are shown here for purposes of comparing charges for shopping and non-shopping customers.

III. PROVISIONS FOR TESTING THE ESP AND TRANSITIONAL CONDITIONS SHOULD THE ESP BE TERMINATED

Q. IS DUKE ENERGY OHIO RECOMMENDING PROVISIONS FOR TESTING ITS PROPOSED ESP?

A. Yes. Pursuant to R.C. 4928.143(B)(1), an ESP having a term longer than three years may include provisions permitting the Commission to test the plan, as required under Section (E) of R.C. 4928.143. Additionally, the ESP may include transitional conditions should the Commission elect to terminate the ESP and migrate to the MRO as a result of the required testing under Section (E).

Q. WHAT ARE THE PROVISIONS THAT THE COMPANY IS PROPOSING FOR TESTING THE PLAN?

A. R.C. 4928.143(E) sets forth two prospective tests that must be conducted in respect of any ESP having an approved term longer than three years. Specifically, the law requires that, in year four and every fourth year thereafter, the Commission:

> [D]etermine whether the plan, including its then-existing pricing and all other terms and conditions, including any deferrals and any future recovery of deferrals, continues to be more favorable in the aggregate and during the remaining term of the plan as compared to the expected results that would otherwise apply under section 4928.142 of the Revised Code.

Additionally, the Commission is to determine whether the prospective effect of the ESP is "substantially likely" to provide the Company with significantly excessive earnings.

Thus, there are two aspects of the prospective testing of the ESP to be conducted by the Commission – an "in the aggregate" test and a significantly excessive earnings test. I identify the recommended provisions for both aspects of the testing below.

A. Prospective "In the Aggregate" Test

Q. PLEASE IDENTIFY THE PROVISIONS FOR CONDUCTING THE "IN THE AGGREGATE" TEST UNDER R.C. 4928.143(E).

A. The ESP must be compared against the expected results under R.C. 4928.142 and, as Duke Energy Ohio owned generating assets as of July 31, 2008, it is subject to a blending requirement under the MRO provisions. As the Commission has previously opined, R.C. 4928.142(D) contemplates a default blending period of 10 percent market bid in year, 20 percent in year two, 30 percent in year three, 40 percent in year four, 50 percent in year five, and 100 percent after year five.

As of the fourth year of the ESP, the Company will not have previously filed an MRO and, consequently, this blending criterion is applicable when comparing Duke Energy Ohio's ESP and the expected results under R.C. 4928.142. Accordingly, for purposes of establishing the expected results under R.C. 4928.142, Duke Energy Ohio proposes, with respect to the year-four test, that the MRO pricing be based upon the following percentages, for each relevant year of the comparison:

Table 4 - MRO Blending Percentages

Year of ESP	Market	Most Recent ESP
4	10%	90%
5	20%	80%
6	30%	70%
7	40%	60%
8	50%	50%
9+	100%	0%

The "most recent ESP" at the time of the first test, as referenced in the table above, is comprised of the retail rates for Rider RC, as offset by Rider PSM, and Rider RE as of May 31, 2015, and the "market" reflects the projected market prices for capacity and energy at the time of the comparison.

Duke Energy Ohio proposes that, at the time such a comparison is made, the forecasted prices resulting from the MRO blending percentages identified above be compared to Company's projected Rider RC rates at that time, as off-set by Rider PSM, and the projected Rider RE rates for the period between June 1, 2015, and May 31, 2021.

The "in the aggregate" test contemplates a comparison of all of the terms and conditions of the ESP against with the expected results under R.C. 4928.142. Accordingly, when determining whether the ESP remains more favorable than the expected results under the MRO provisions. Duke Energy Ohio witness Trent summarizes these other considerations. Notably, however, consideration must be given to the benefits derived from, among other things, creating and funding economic development via Advance Southwest Ohio contrasting with the absence of a similar program and dollars for economic development that would not exist under the MRO structure.

But a comparison of costs necessary to comply with Ohio's alternative energy resource (AER) requirements would be an unnecessary exercise as both Duke Energy Ohio and CRES providers have the same obligation. Furthermore, Rider AER-R or something similar would exist in either an ESP or an MRO and would recover the same costs inasmuch as the obligations for alternative energy are independent of the structure of Company's retail generation business (*i.e.*, MRO vs. ESP). Ultimately, the costs to comply with the AER requirements should be largely the same, whether incurred by Duke Energy Ohio or reflected in CRES providers' offers, or whether the Company is operating under an MRO or an ESP. Thus, projections related to Rider AER-R should be excluded from the review.

The same analysis should be conducted in year eight of the ESP, revised only to adjust the blending percentages. Again, as no MRO will have been filed by the eighth year of the Company's ESP, the blending percentages for that eighth year must be 10 percent market/90 percent most recent ESP. And the percentages applicable to the ninth year necessarily would be 20 percent market/80 percent most recent ESP. Here, the "most recent ESP" price would be comprised of the retail rates for Rider RC, as offset by Rider PSM, and Rider RE as of May 31, 2019.

Q. IS THE COMPANY PROPOSING TO ADJUST THE "MOST RECENT ESP" PRICE FOR PURPOSES OF TEST UNDER R.C. 4928.143(E)?

A. Yes. The comparison is of the proposed ESP to the "expected results that would otherwise apply under section 4928.142." Because R.C. 4928.142(D) (*i.e.*, the MRO statute) provides that the most recent ESP price can be adjusted for such things as fuel, purchased power, and environmental costs, the Legacy ESP price used in the blending is adjusted for projected changes in these costs for as long as the blending occurs.

B. Prospective Significantly Excessive Earnings Test

Q. PLEASE IDENTIFY THE PROVISIONS FOR CONDUCTING THE SIGNIFICANTLY EXCESSIVE EARNINGS TEST UNDER R.C. 4928.143(E).

A. R.C. 4928.143(E) also requires the Commission to determine, in year four and every fourth year thereafter, whether the prospective effect of the Company's proposed ESP is substantially likely to lead to significantly excessive earnings. Pursuant to this statutory requirement, therefore, the Commission must ascertain the substantial likelihood of Duke Energy Ohio significantly over-earning from June 1, 2015, through the termination of the ESP on May 31, 2021. Again, a similar test will be conducted for the period of June 1, 2019, through May 31, 2021. In administering this test, Duke Energy Ohio recommends the following methodology.

For purposes of this calculation, Duke Energy Ohio will use calendar year projections. At the time of the first test, the Company will provide a projection of earnings from its electric operations for each year through 2021 (only for purposes of applying this test, it is assumed that the proposed ESP at the end of 2021 rather than May 31, 2021). The financial statements supporting this calculation will include an income statement and balance sheet for Duke Energy Ohio's electric operations. To calculate the projected return on equity, the Company will start with Net Income and make the following adjustments, if necessary:

- Eliminate all depreciation and amortization expense and impairment charges related to the purchase accounting recorded pursuant to the Duke Energy/Cinergy Corp. merger and post-merger impacts to retained earnings;
- Eliminate all impacts of refunds to customers pursuant to R.C. 4928.143(E);
- Eliminate all impacts of mark-to-market accounting;
- Eliminate all impacts of material, non-recurring gains or losses, including but not limited to, the sale or disposition of assets;
- Eliminate all impacts of parent, affiliated, or subsidiary companies and, to the extent reasonably feasible and prudently justified in the opinion of Duke Energy Ohio, eliminate the impacts of its natural gas distribution business.

The adjusted net income will be divided by Common Equity to determine the resulting ROE. Certain adjustments will be made to Common Equity.

- Eliminate the acquisition premium recorded to equity pursuant to the Duke Energy/Cinergy Corp. merger.
- Eliminate the cumulative effect of the Net Income adjustments.

If the projected annual return on ending common equity for the relevant years, as adjusted pursuant to the above, is 50 percent higher[7] than the ROE used

[7] *See In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Administration of the Significantly Excessive Earnings Test under Section 4928.143(F), Revised Code, and Rule 4901:1-35-10, Ohio Administrative Code*, Case No. 10-1261-EL-UNC, Opinion and Order at pages 20, 24-25 (January 11, 2011).

for calculating Rider RC, there is a substantial likelihood that the Company will have "significantly" excessive earnings. However, the Commission's reviews in year four and year eight do not obligate the Company to refund any monies to customers as a result of a prospective earnings test. Rather, should the Commission determine that the Company's ESP is no longer better, in the aggregate, than the expected results under R.C. 4928.142 or that there is a substantial likelihood that Duke Energy Ohio will, prospectively, have significantly excessive earnings under the ESP, the Commission can only then decide whether to terminate the then-current ESP.

Q. ARE THERE ANY OTHER ASPECTS TO THE REVIEWS CONTEMPLATED FOR YEARS FOUR AND EIGHT OF THE ESP?

A. As Rider RC is largely predicated upon costs to serve and a rate of return, it would be reasonable, in the context of the year-four and year-eight reviews, to ascertain whether any adjustment (increase or decrease) to the ROE rate is appropriate. Because the required ROE may change for a variety of factors, including general economic conditions, changes in risk profiles, etc., the Commission, any intervenor, or the Company may, at the time of the review, offer testimony regarding changes to the ROE used for calculating Rider RC. If no party files testimony supporting a new ROE at that time, the then-current, approved ROE will persist until the next review. If a party does file testimony in support of a new ROE, all parties would have an opportunity to respond by filing rebuttal testimony and the Commission would determine, based on the filed evidence, an appropriate ROE for future calculations of Rider RC.

Q. IS DUKE ENERGY OHIO PROPOSING A PARTICULAR DATE BY WHICH THE REVIEWS IN YEAR FOUR AND YEAR EIGHT WOULD BE INSTITUTED?

A. On or before January 1, 2015, the Company will make a filing with the Commission with all relevant material upon which the Commission may rely in evaluating whether the ESP continues to be better, in the aggregate, than an MRO. The Company will make another filing on or before January 1, 2019, for the next review.

Q. IF THE COMMISSION SHOULD DECIDE TO TERMINATE THE ESP AS A RESULT OF THE REVIEW PURSUANT TO R.C. 4928.143(E), WHAT ARE THE TRANSITIONAL CONDITIONS THAT THE COMPANY PROPOSES?

A. Assuming the Commission would terminate the proposed ESP before it expired on May 31, 2021, it must have made a determination that the ESP was no longer "better in the aggregate" than the MRO or that continuation of the ESP will result in significantly excessive earnings. Thereafter, the Commission will have to determine whether to terminate the plan and migrate Duke Energy Ohio to the alternate MRO structure. It is not possible to predict at this time, what course the Commission may prescribe. Therefore, until the Commission approves an alternative SSO, the Company would operate under the terms of the ESP that exists at that time. Inasmuch as the transition of the proposed ESP to an MRO would affect the auction schedule and products included in the auctions, Duke Energy Ohio proposes some transitional conditions in its application. Company witness Lee speaks to these conditions. However, Duke Energy Ohio expressly reserves the right to recommend additional conditions for an orderly transition, should the Commission require the Company to provide a SSO in the form of an MRO.

IV. GOVERNMENTAL AGGREGATION

Q. WHAT IS GOVERNMENTAL AGGREGATION?

A. Governmental aggregation is a process by which municipalities, townships, or counties may negotiate for rates for the collective load of the non-mercantile customers in the area. Thus, the loads of the residents are aggregated for improved negotiating leverage. Governmental aggregation is provided for in R.C. 4928.20.

Q. WHAT IS REQUIRED BY DIVISION (I) OF REVISED CODE 4928.20?

A. The words of division (I) of that statute read as follows:

> Customers that are part of a governmental aggregation under this section shall be responsible only for such portion of a surcharge under section 4928.144 of the Revised Code that is proportionate to the benefits, as determined by the commission, that electric load centers within the jurisdiction of the governmental aggregation as a group receive. The proportionate surcharge so established shall apply to each customer of the governmental aggregation while the customer is part of that aggregation. If a customer ceases being such a customer, the otherwise applicable surcharge shall apply. Nothing in this section shall result in less than full recovery by an electric distribution utility of any surcharge authorized under section 4928.144 of the Revised Code.

The words of R.C. 4928.144, referenced in division (I), read as follows:

> The public utilities commission by order may authorize any just and reasonable phase-in of any electric distribution utility rate or price established under sections 4928.141 to 4928.143 of the Revised Code, and inclusive of carrying charges, as the commission considers necessary to ensure rate or price stability for

> consumers. If the commission's order includes such a phase-in, the order also shall provide for the creation of regulatory assets pursuant to generally accepted accounting principles, by authorizing the deferral of incurred costs equal to the amount not collected, plus carrying charges on that amount. Further, the order shall authorize the collection of those deferrals through a nonbypassable surcharge on any such rate or price so established for the electric distribution utility by the commission.

Q. WHAT IS REQUIRED BY DIVISION (J) OF REVISED CODE 4928.20?

A. The words of division (J) of that statute read as follows:

> On behalf of the customers that are part of a governmental aggregation under this section and by filing written notice with the public utilities commission, the legislative authority that formed or is forming that governmental aggregation may elect not to receive standby service within the meaning of division (B)(2)(d) of section 4928.143 of the Revised Code from an electric distribution utility in whose certified territory the governmental aggregation is located and that operates under an approved electric security plan under that section. Upon the filing of that notice, the electric distribution utility shall not charge any such customer to whom competitive retail electric generation service is provided by another supplier under the governmental aggregation for the standby service. Any such consumer that returns to the utility for competitive retail electric service shall pay the market price of power incurred by the utility to serve that consumer plus any amount attributable to the utility's cost of compliance with the alternative energy resource provisions of section 4928.64 of the Revised Code to serve the consumer. Such market price shall include, but not be limited to, capacity and energy charges; all charges associated with the provision of that power supply through the regional transmission organization, including, but not limited to, transmission, ancillary services, congestion, and settlement and administrative charges; and all other costs incurred by the utility that are associated with the procurement, provision, and administration of that power supply, as such costs may be approved by the commission. The period of time during which the market price and alternative energy resource amount shall be so assessed on the consumer shall be from the time the consumer so returns to the electric distribution utility until the expiration of the electric security plan. However, if that period of time is expected to be more than two years, the commission may reduce the time period to a period of not less than two years.

The words of division (B)(2)(d) of R.C. 4928.143, referenced in that section, read as follows, with the lead-in information of division (B)(2):

> The plan may provide for or include, without limitation, any of the following:
>
> (d) Terms, conditions, or charges relating to limitations on customer shopping for retail electric generation service, bypassability, standby, back-up, or supplemental power service, default service, carrying costs, amortization periods, and accounting or deferrals, including future recovery of such deferrals, as would have the effect of stabilizing or providing certainty regarding retail electric service;

R.C. 4928.64, referenced in division (J), addresses the provision, by an electric distribution utility, of electricity from alternative energy resources.

Q. WHAT IS REQUIRED BY DIVISION (K) OF REVISED CODE 4928.20?

A. The words of Division (K) read as follows:

> The commission shall adopt rules to encourage and promote large-scale governmental aggregation in this state. For that purpose, the commission shall conduct a immediate review of any rules it has adopted for the purpose of this section that are in effect on the effective date of the amendment of this section by S.B. 221 of the 127th general assembly, July 31, 2008. Further, within the context of an electric security plan under section 4928.143 of the Revised Code, the commission shall consider the effect on large-scale governmental aggregation of any nonbypassable generation charges, however collected, that would be established under that plan, except any nonbypassable generation charges that relate to any cost incurred by the electric distribution utility, the deferral of which has been authorized by the commission prior to the effective date of the amendment of this section by S. B. 221 of the 127th general assembly, July 31, 2008.

Q. HOW DOES DUKE ENERGY OHIO INTEND TO ADDRESS GOVERNMENTAL AGGREGATION PROGRAMS AND IMPLEMENTATION OF DIVISION (I) OF REVISED CODE 4928.20?

A. As I understand based upon advice of counsel, Duke Energy Ohio is not, in this Application, seeking any deferral or phasing in of deferrals, as authorized under R.C. 4928.144. Thus, the provisions of R.C. 4928.20(I) are not applicable to the Company's proposed ESP. And to the extent R.C. 4928.20(I) is intended to assist governmental aggregators, the Company's ESP will not impede that intent.

Q. **HOW DOES DUKE ENERGY OHIO INTEND TO ADDRESS GOVERNMENTAL AGGREGATION PROGRAMS AND IMPLEMENTATION OF DIVISION (J) OF REVISED CODE 4928.20?**

A. As I understand, based upon advice of counsel, the provisions of R.C. 4928.20(J) that concern a charge for standby service are also not applicable to the Company's ESP Application. Duke Energy Ohio is not proposing any charge for providing standby service. Accordingly, the implementation of R.C. 4928.20(J) is not complicated by the Company's proposed ESP.

Q. **HOW DOES DUKE ENERGY OHIO INTEND TO ADDRESS GOVERNMENTAL AGGREGATION PROGRAMS AND IMPLEMENTATION OF DIVISION (K) OF REVISED CODE 4928.20?**

As I understand, based upon advice of counsel, R.C. 4928.20(K) provides instruction to the Commission in promulgating rules to "encourage and promote large-scale governmental aggregation" in Ohio. As this instruction is directed to the Commission, Duke Energy Ohio's ESP is necessarily irrelevant to implementation of certain parts of R.C. 4928.20(K). That is, the Company's filing is not one that will result in rules designed to encourage or promote aggregations.

R.C. 4928.28(K) also directs the Commission to consider the effect of any non-bypassable generation charge on large-scale aggregation, with the exception of non-bypassable charges for which a deferral was created prior to the effective date of SB 221. Again, compliance with this statutory provision requires conduct by the Commission. But to assist the Commission in its consideration, Duke Energy Ohio submits that its proposed ESP will not impede the formation of large-scale governmental aggregations. Rather, the competitive retail market should be more robust under the Company's proposal. All retail load will pay a market price for energy. The proposed ESP removes a perversion that exists in the current ESP where one provider, namely Duke Energy Ohio, must provide energy and capacity at a non-competitive rate while all other providers compete at market rates. The Company's proposed ESP is designed to remove that disconnect. No provider, including Duke Energy Ohio, has a competitive advantage or disadvantage in pricing its product, energy in this case, to retail load, whether it is an aggregated load or its is on an individual customer basis.

An additional benefit of the proposed ESP is the long-term nature of the plan. To date, no utility has offered any ESP that lasts longer than three years. In fact, the most recent application for an ESP filed by AEP-Ohio[8] is shorter still at only twenty-nine months. It is difficult for the utility, CRES providers, and customers – and for aggregations – to operate with any degree of long-term

[8] *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to 4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan,* Case No. 11-348-EL-SSO, *et al.*

certainty under a regulatory model that gets reset every three years. The nine-year, five-month duration of the Company's proposed ESP will provide a level of certainty about the future that none of these stakeholders have enjoyed since deregulation began more than ten years ago.

Duke Energy Ohio's proposal is a straightforward structure. Rider RE and Rider AER-R are the only generation riders relevant to competitive offers. One transmission rider, Rider RTO, would be included in the price-to-compare as well. Although it is not a generation rider, it is a charge that is avoidable for switching customers. Thus, customers need only consider these riders for purposes of determining whether a CRES provider's offer is beneficial.

Finally, all retail customers, including those who are aggregated, benefit from the energy credit and participation in Duke Energy Ohio's Rider PSM. Accordingly, customers need not weigh whether exercising their right to choose generation suppliers will deprive them of receiving a credit. Furthermore, because Duke Energy Ohio will be the capacity provider for its entire footprint, all customers, including any those whose load is aggregated, will pay the Company's price for capacity and will, therefore, share in the net profits from energy and ancillary sales from the Legacy Generation Assets. As the Company's proposed economic development program includes the dedication of a portion of those same net profits toward economic development, those municipalities whose residents have aggregated are also eligible to receive the benefits of qualifying economic development projects.

V. BETTER IN THE AGGREGATE TEST

Q. IS THE COMPANY'S PROPOSED ESP BETTER, IN THE AGGREGATE,THAN EXPECTED RESULTS THAT WOULD OTHERWISE APPLY UNDER R.C. 4928.142, IN RESPECT OF PRICING?

A. Yes. Attachment WDW-2 provides a summary of the projected generation rates customers can expect to pay under the Company's proposed ESP. I have also included the projected rates that "would otherwise apply under Section 4928.142 of the Revised Code." For ease of reference, the latter projected rates are referred to as the MRO rates. Duke Energy Ohio witness Rose includes a summary of the expected retail market prices for energy and for an 'all-in' product that would include energy and capacity. Using these price forecasts and the Company's forecasts for the net capacity rate (*i.e.*, Rider RC + Rider PSM), it is possible to estimate the overall generation price expected in the proposed ESP.

Multiplying the proposed ESP prices and the expected MRO prices by retail sales provides an estimate of the total value of either plan. As is shown on Attachment WDW-2, the net present value of the Company's proposed ESP is approximately $927 million greater than the total value of the alternative MRO using the same weighted-average cost of capital that was used in the calculation of the revenue requirement for Rider RC.

Q. WHAT MEANING SHOUD THE COMMISSION TAKE FROM THIS COMPARISON?

A. First, and foremost, the figures contribute significantly to the conclusion that the Company's proposed ESP is better in the aggregate than the results that could be expected under an MRO. Clearly, the Ohio General Assembly contemplated that the ESP versus MRO comparison was more than just economic but the fact that the Company's proposed ESP is almost $1 billion better than the MRO just on economic value is significant. As described by other Company witnesses, including Keith Trent and Julie Janson, Duke Energy Ohio believes the proposed ESP offers numerous other benefits that are less quantifiable. Combining the nearly $1 billion in economic value with the numerous other benefits of the ESP over the MRO absolutely satisfies the obligation under R.C. 4928.143(C)(1).

VI. CONCLUSION

Q. **WERE ATTACHMENTS WDW-1 AND WDW-2 PREPARED UNDER YOUR DIRECTION?**

A. Yes.

Q. **DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

A. Yes.

Duke Energy Ohio
Revenue Requirement for Capacity Dedication
12 Months Ending 12/31/2010 (actuals)

Line No.	Description	Reference	Amount
1	Production Rate Base	Schedule B-1	$1,710,924,208
2	Return on Rate Base	Schedule D	7.88%
3	Return on Rate Base	*Calculated*	$134,820,828
4	Operation & Maintenance Expense	Schedule C-2	$274,690,153
5	Depreciation Expense	Schedule C-3	$83,804,191
6	Taxes Other Than Income Taxes	Schedule C-3	$23,649,423
7	Income Tax & Commercial Activities Tax (@0.26% of revenue)	Schedule C-4	$49,374,541
8	Annual Fixed Cost for Production	*Calculated*	$566,339,136
9	Less: Credit for Customer Share of Generation Profits	Schedule E	($144,295,425)
10	Net Amount to be Recovered in Retail Capacity Rider	*Calculated*	$422,043,711

Duke Energy Ohio **Schedule B-1**

Rate Base Calculation (As of December 31, 2010)

Line No.	Rate Base Component	Supporting Schedule	Allocated to Legacy Generation
	Plant In Service		
1	Steam Production Plant	B-2	$3,051,344,587
2	Other Production Plant	B-2	21,943,247
3	Total Production Plant	*calculated*	3,073,287,834
4	Transmission	B-2	23,043,118
5	Distribution	B-2	-
6	Intangible Plant	B-2.1	-
7	General	B-2.1	32,447,023
8	Common	B-2.1	99,262,688
9	Total Plant In Service	*calculated*	$3,228,040,663
	Reserve for Accumulated Depreciation		
10	Steam Production Plant	B-2	($1,082,527,498)
11	Other Production Plant	B-2	(26,258,999)
12	Total Production Plant	B-2	(1,108,786,497)
13	Transmission	B-2	(9,517,588)
14	Distribution	B-2	-
15	Intangible Plant		-
16	General	B-2	(1,979,874)
17	Common	B-2	(43,661,678)
18	Total Reserve for Accumulated Depreciation	*calculated*	($1,163,945,637)
19	Net Plant In Service (Line 7 + Line 14)	*calculated*	$2,064,095,026
20	Construction Work In Progress (production plant)	B-2	$0
21	Cash Working Capital Allowance	B-3	$34,336,269
22	Other Working Capital Allowance	B-3	$158,871,180
23	Other Items:		
24	Deferred Income Taxes	B-4	($544,929,835)
25	Investment Tax Credits	B-4	($1,448,432)
26	Other Rate Base Adjustments		$0
27	Rate Base (Line 15 through Line 24)	*calculated*	$ 1,710,924,208

Duke Energy Ohio
Plant In Service

Schedule B-2

Line No.	Account Title	Form 1 Reference	Total Company	Adjustments: DENA	Adjustments: Purch Acctg	Adjusted Total Company	Percent Allocated to Production		Production Plant Allocated to SSO Service
	Gross Plant								
1	Electric Production - Steam	p. 205(g)(16)	$3,330,170,587	$0	($278,826,000)	$3,051,344,587	100.00%		$3,051,344,587
2	Electric Production - Other	p. 205(g)(45)	1,717,309,032	(1,695,365,785)	-	21,943,247	100.00%		21,943,247
3	Electric Transmission Plant	p. 207(g)(58)	671,111,058	(74,141,428)	-	596,969,630	3.86%	(d)	23,043,118
4	Electric Distribution Plant	p. 207(g)(75)	1,844,361,344	-	-	1,844,361,344	0.00%		-
5	Miscellaneous Intangible Plant	p. 205(g)(5)	76,063,040	-	-	76,063,040	0.00%		-
6	General Plant	p. 207(g)(99)	104,375,566	(21,581,426)	-	82,794,140	39.19%		32,447,023
7	Common Plant (Elec portion)	p. 256.2	253,285,756	-	-	253,285,756	39.19%		99,262,688
8	Total Gross Plant		$7,996,676,383	($1,791,088,639)	($278,826,000)	$5,926,761,744			$3,228,040,663
	Accumulated Depreciation								
9	Electric Production - Steam	p. 219(c)(20)	($1,188,561,498)	$0	$106,034,000	($1,082,527,498)	100.00%		($1,082,527,498)
10	Electric Production - Other	p. 219(c)(24)	(466,698,116)	440,439,117	-	(26,258,999)	100.00%		(26,258,999)
11	Electric Transmission Plant	p. 219(c)(25)	(233,399,352)	20,046,350	-	(213,353,002)	4.46%	(d)	(9,517,588)
12	Electric Distribution Plant	p. 219(c)(26)	(625,814,226)	-	-	(625,814,226)	0.00%		-
13	Miscellaneous Intangible Plant			-	-	-	0.00%		-
14	General Plant	p. 219(c)(28)	(10,627,310)	5,575,323	-	(5,051,987)	39.19%		(1,979,874)
15	Common Plant (Elec portion)	p. 256.2	(111,410,252)	-	-	(111,410,252)	39.19%		(43,661,678)
16	Total Accumulated Depreciation		($2,636,510,754)	$466,060,790	$106,034,000	($2,064,415,964)			($1,163,945,637)
	Construction Work In Progress	(a)							
17	Electric Production - Steam	(b)	58,745,649	$0	$0	$58,745,649	100.00%		$58,745,649
18	Electric Production - Other	(b)	629,201	(629,201)	-	-	100.00%		-
19	Electric Transmission Plant	(b)	-	-	-	-	0.00%		-
20	Electric Distribution Plant	(b)	48,671,842	-	-	48,671,842	0.00%		-
21	Miscellaneous Intangible Plant	(b)	-	-	-	-	0.00%		-
22	General Plant	(b)	13,334,528	-	-	13,334,528	39.19%		5,225,802
23	Common Plant	(c)	-	-	-	-	39.19%		-
24	Total Construction Work In Progress	p. 200(c)(11)	$121,381,220	($629,201)	$0	$120,752,019			$63,971,451

Note: [a] Excludes AFUDC and capitalized interest.
[b] Internal Accounting Records.
[c] Common Plant CWIP included in line 7.
[d] Step up transformers.

Duke Energy Ohio
Working Capital

Schedule B-3

Line No.	Account Title		Source	Amount
1	Cash Element of Working Capital	Based on 1/8 Oper. & Maint. Expense less purchased gas costs or fuel and purchased power expenses.	Sch C-2.1 ÷ 8	$34,336,269
	Other Working Capital:			
2	Fuel Stock		Sch B-3.1	$82,733,128
	Emission Allowance Inventory			
3	SO_2 Emission Allowances		Sch B-3.1	$23,545,397
4	NO_x Emission Allowances		Sch B-3.1	$1,101,380
5	Materials and Supplies		Sch B-3.1	$36,873,430
6	Prepayments		Sch B-3.1	$14,617,846
7	Total Other Working Capital		*Sum*	$158,871,180
8	Total Working Capital		*Sum*	$193,207,449

Duke Energy Ohio
Other Working Capital

Schedule B-3.1

Line No.	FERC Acct	Account Title	Source	Total Company [a]	Adjustments: DENA/Non-Native	Adjustments: Purch Acctg	Adjusted Total Company	Percent Allocated to Production	Production Plant Allocated to SSO Service
1	151	Fuel Stock	p. 227.1.b & 227.1.c	$84,365,447	(11,219)	(1,621,100)	$82,733,128	100.00%	$82,733,128
2	154	Materials and Supplies (Production)	p. 227.7.b & 227.7.c	46,584,305	(9,710,875)	-	36,873,430	100.00%	$36,873,430
3	165	Prepayments	p. 111.57.c	15,120,900	(503,054)	-	14,617,846	100.00%	$14,617,846
4	158	SO_2 Emission Allowances	p. 228(a).m.1. & 228(a).m29	148,146,419	(124,601,022)	-	23,545,397	100.00%	$23,545,397
5	158	NO_x Emission Allowances	p. 228(b).m.1. & 228(b).m29	3,553,093	($2,451,713)	$0	$1,101,380	100.00%	$1,101,380

Notes: [a] Average of beginning and ending balance for 2010.

Duke Energy Ohio
Accumulated Deferred Income Taxes and Investment Tax Credits

Schedule B-4

Line No.	Account Title	Form 1 Source	Total Company	Legacy Generation	Other Electric	Gas
1	Account 190	p. 234	$150,680,487	$57,180,700	$44,281,910	$49,217,877
2	Account 281	p. 273	(15,661,825)	(15,661,825)	-	-
3	Account 282	p. 275	($1,277,200,957)	($463,794,104)	($633,529,618)	($179,877,235)
4	Account 283	p. 277	(244,845,319)	(122,654,606)	(80,051,376)	(47,033,917)
5	Total Deferred Tax Adjustment	Sum	($1,387,027,614)	($544,929,835)	($669,299,084)	($177,693,275)
6	Investment Tax Credit (Account 255)	p. 267	$3,695,922	$1,448,432	$2,247,490	3,125,491

Note: The data above was taken from Duke Energy Ohio's internal accounting records. The information does not tie to the FERC Form 1 due to differences in the manner in which ADITs are aggregate internally and reported for FERC Form 1. All detail for the ADITs are provided in Schedule B-4.1.

Duke Energy Ohio
Accumulated Deferred Income Taxes and Investment Tax Credits

Schedule B-4.1

Line No.	Account Title	Total Company	Legacy Generation	Other Electric	Gas
	Account 190 (Detailed Accounts)				
1	FERC - FIT Adj Offset to Regulatory Asset (254100)	($2,117,500)	$0	($1,481,756)	($635,744)
2	KY 190002 Adjustment to Deferreds	(34,714)	-	(34,714)	-
3	Bad Debts - Tax over Book	866,053	-	443,094	422,959
4	Uncollectible Provision PIP ADJ	(260,737)	-	-	(260,737)
5	Offsite Gas Storage Costs	2,943,146	-	-	2,943,146
6	Asset Retirement Obligation	7,313,626	1,554,043	290,087	5,469,496
7	Property Tax - Propane Inventory	471,021	-	-	471,021
8	Leased Meters - Elec & Gas	(6,379,598)	-	(7,019,553)	639,955
9	Meters & Transformers	(832,743)	-	(832,743)	-
10	Lease Meters-Current	73,306	-	45,354	27,952
11	Mark to Market - ST	(9,792,640)	(12,692,999)	2,900,359	-
12	Mark to Market - LT	27,839,152	542,255	27,296,897	-
13	Unamortized Debt Premium	781,097	1,123,308	(249,940)	(92,271)
14	Unamortized Debt Discount	(2,309,335)	(2,511,472)	1,555,552	(1,353,415)
15	Cash Flow Hedge - Reg Asset/Liab	(957,706)	-	(957,706)	-
16	Save-A-Watt Regulated Deferred Liability	4,018,321	-	4,018,321	-
17	Accrued Vacation	4,565,627	1,681,646	1,888,026	995,955
18	Property Tax Reserves	5,391,011	13,394,664	(17,072,530)	9,068,877
19	Severance Accrual ST	11,950	9,660	1,596	694
20	MGP Sites	17,349,158	-	(217,783)	17,566,941
21	Employee Benefits	(2,513,947)	(987,002)	(991,327)	(535,618)
22	Gas Supplier Refunds	96,611	-	-	96,611
23	Natural Gas in Transit	111,449	-	-	111,449
24	Unbilled Revenue - Ruel	6,961,868	-	-	6,961,868
25	Demand Side Management (DSM) Defer	746,055	-	746,055	-
26	Emission Allowance Expense	31,598,644	31,598,644	-	-
27	Retirement Plan Expense - Underfunded	113,402,304	49,677,533	44,329,338	19,395,433
28	Non-qualified Pension - Accrual	2,158,967	846,842	906,013	406,112
29	Retirement Plan Funding - Underfunded	(66,875,504)	(25,927,633)	(27,546,020)	(13,401,851)
30	Non-qualifed Pension - Payment	(254,008)	(92,524)	(161,484)	-
31	Environmental Reserve	(256)	-	(256)	-
32	Joint Owner Pension Receivable	(3,456,410)	(3,453,421)	(2,989)	-
33	FAS 87 Qual Plan OCI	(16,348,299)	(16,348,299)	-	-
34	Accrued Pension Admin Fees	1,033,837	1,033,767	70	-
35	Accrual NQ Pension ST	260,615	74,797	130,258	55,560
36	FAS 87 Non Qual Plan OCI	(73,616)	(73,616)	-	-
37	FAS 106 OPEB OCI	4,539,776	4,539,776	-	-
38	Annual Incentive Plan Comp	670,473	284,019	282,378	104,076
39	Payable 401 (K) Match	59,482	19,956	27,707	11,819
40	SIT - Known Reserves - Cur Asset	61,541	76,502	(14,961)	-
41	Tax Interest Accrual - Cur Liab	(139,054)	-	(139,054)	-
42	Tax Int Accrual - Non-cur Liab	2,448,850	-	2,448,850	-
43	OPEB Expense Accrual	19,780,082	4,386,154	14,657,890	736,038
44	OPEB Funding Payment	(2,575,966)	(618,361)	(1,591,381)	(366,224)
45	FAS 112 Medical Expenses Accrual	1,941,272	741,241	795,693	404,338
46	FAS 112 Medical Funding Payment	(314,470)	(50,319)	(234,349)	(29,802)
47	OPEB Admin Fees	(3,415,297)	(3,414,332)	(965)	-
48	Accrual OPEB ST	32,034	(60,805)	77,121	15,718
49	Accrual Post Retirement ST	(77,183)	(55,463)	(9,496)	(12,224)

Duke Energy Ohio
Accumulated Deferred Income Taxes and Investment Tax Credits

Line No.	Account Title	Total Company	Legacy Generation	Other Electric	Gas
50	OCI - FAS 106 Actuarial Gain/Loss	(4,539,776)	(4,539,776)	-	-
51	OCI - Actuarial GL Qual	16,348,299	16,348,299	-	-
52	OCI - Actuarial GL NQ	73,616	73,616	-	-
53	Federal Benefit of State for 190 CY	58,050	-	58,050	-
54	Federal Benefit of State for 190 PY	620,111	-	620,111	-
55	Federal Benefit of State on 190 Gain Contingency PY	1,036,888	-	1,036,888	-
56	Miscellaneous	(1,715,046)	-	(1,714,791)	(255)
57	**Total Account 190**	$150,680,487	$57,180,700	$44,281,910	$49,217,877
	Account 281 (Detailed Accounts)				
58	Pollution Control	($15,661,825)	($15,661,825)	$0	$0
	Account 282 (Detailed Accounts)				
59	Other Non-Current After-Tax DTL for PP&E	($6,913,547)	$0	($6,913,547)	$0
60	Other Non-Current AT ST DTL for PP&E	(5,348)	-	(5,348)	-
61	FERC - FIT Plant Adj (Util - 411)	9,420,173	-	9,420,173	-
62	FERC - FIT Plant Adj (Util - 410)	(1,198,171,621)	(389,773,184)	(675,425,443)	(132,972,994)
63	FERC - FIT Plant Adj (Util - 411)	(3,152,122)	(3,424,067)	271,945	-
64	FERC - SIT Plant Adj (Util - 410)	(12,864,043)	(17,062,585)	9,570,270	(5,371,728)
65	FERC - SIT Plant Adj (Util 411)	4,250,249	(1,181,782)	341,545	5,090,486
66	FERC - FIT Adj Offset to Regulatory Liability (182320)	13,348,634	(3,012,041)	16,728,483	(367,808)
67	KY 282101 Adjustment to Deferreds	(1,683,642)	-	(1,683,642)	-
68	AFUDC Interest	(449,897)	-	(472,216)	22,319
69	Repairs Allowed on Post ADR Prop	(746,844)	(270,620)	(252,561)	(223,663)
70	Book Depreciation/Amortization	278,666,136	114,084,544	129,438,931	35,142,661
71	Book Gain/Loss on Property	(89,829)	-	(89,829)	-
72	Contributions in Aid (CIACs)	3,149,116	486,708	812,158	1,850,250
73	Cost of Removal	(2,229,679)	63,107	(1,283,042)	(1,009,744)
74	Tax Interest Capitalized	7,706,653	5,764,518	1,204,412	737,723
75	Tax Depreciation/Amortization	(383,337,124)	(196,672,243)	(121,070,233)	(65,594,648)
76	Tax Gains/Losses	(11,078,329)	6,564	153,505	(11,238,398)
77	Casualty Loss	(3,525,213)	(3,525,213)	-	-
78	Section 174 R&E Deduction	(956,942)	(590,008)	(366,934)	-
79	Repairs 481(a) (Pursuant to 3115)	(27,352,656)	(27,352,656)	-	-
80	FAS 34	(4,864,002)	(4,802,252)	(65,112)	3,362
81	Book Depr On Trans Equip to ADR	221,484	(305)	190,683	31,106
82	Excess Salvage	777,530	-	38,692	738,838
83	263A ADJUSTMENT	(5,107,145)	(571,906)	(4,535,239)	-
84	Loss on ACRS	(11,141,280)	(307,491)	(6,799,681)	(4,034,108)
85	Non-Cash Overhead Basis Adj	36,455,019	2,789,838	34,198,830	(533,649)
86	Equipment Repairs - Annual Adj	(57,479,136)	(55,100,136)	(2,379,000)	-
87	481(a) Fixed Asset Retirement	265,265	265,265	-	-
88	Impairment of Plant Assets	57,497,207	57,497,207	-	-
89	T & D Repairs 481(a) (pursuant to 3115)	(12,340,414)	-	(12,340,414)	-
90	T & D Repairs - Annual Adj.	716,599	-	716,599	-
91	Self Developed Software	(7,212,407)	(2,504,984)	(3,137,914)	(1,569,509)
92	Asset Retirement Costs - ARO	(628,200)	17,231	93,024	(738,455)
93	KY - Bonus Depreciation Adj	475,392	172,964	140,399	162,029

Duke Energy Ohio
Accumulated Deferred Income Taxes and Investment Tax Credits

Schedule B-4.1

Line No.	Account Title	Total Company	Legacy Generation	Other Electric	Gas
94	OH - Bonus Depreciation Adj	38,622	19,737	3,901	14,984
95	OH - Franchise Tax Adj	(64,166)	(14,864)	(33,013)	(16,289)
96	Purchase Accounting Adjustment	61,204,550	61,204,550		
97	Total Account 282	($1,277,200,957)	($463,794,104)	($633,529,618)	($179,877,235)
	Account 283 (Detailed Accounts)				
98	Other Non-Current After-Tax DTL	(6,740,341)	$0	($6,740,341)	$0
99	KY 283101 Adjustment to Deferreds	(17,357)	-	(17,357)	-
100	Noncurrent Bad Debt Provision	1,275,319	-	(1,074,113)	2,349,432
101	Reverse Book Partnership Earnings	347,959	-	347,959	-
102	POST IN SERVICE - CARRYING COSTS	(4,962,909)	-	-	(4,962,909)
103	Loss on Reacquired Debt-Amort	(2,174,199)	-	(1,390,719)	(783,480)
104	Merger Costs	195,247	72,211	57,718	65,318
105	RTC Amortization	(1,039,005)	-	(1,039,005)	-
106	RSP Costs Capitalization	(42,443,388)	(41,890,132)	(553,256)	-
107	Inventory & Contract Write-up	(1,928,259)	(1,928,259)	-	-
108	Reg Asset/Liab Def Revenue	(7,076,041)	(7,076,041)	-	-
109	Reg Asset - Accr Pension FAS158 - FAS87Qual	(27,923,666)	-	(21,711,853)	(6,211,813)
110	Reg Asset Smart Grid Gas Furnace	(2,255,870)	-	(2,255,870)	-
111	Reg Asset Smart Grid Dfd Other O&M	(4,314,445)	-	(3,164,681)	(1,149,764)
112	Reg Asset Smart Grid PISCC	(1,932,480)	-	(1,613,510)	(318,970)
113	Reg Asset Smart Grid Deferred Depr.	(1,474,058)	-	(1,269,442)	(204,616)
114	Reg Liab RSU & Other Misc Dfd Costs	33,404	-	33,404	-
115	Reg Asset Hurricane Ike Storm Damage	(5,667,325)	-	(5,667,325)	-
116	Reg Asset - MGP Costs	(21,216,275)	-	-	(21,216,275)
117	Reg Asset - Elec Rate Case Expense	(159,326)	-	(230,160)	70,834
118	Reg Asset-Pension Post Retirement PAA-FAS87Qual and (	(29,857,547)	-	(18,829,475)	(11,028,072)
119	Reg Asset - DEO Econ Dev	(354,209)	-	(354,209)	-
120	Vacation Carryover - Reg Asset	(1,977,629)	-	(1,386,275)	(591,354)
121	Rate Case - Deferred Costs	(183,455)	-	(183,455)	-
122	Deferred Fuel Cost Purch Gas Adjustment	1,680,031	-	-	1,680,031
123	Deferred Pipeline Installation Costs	(425,568)	-	(425,568)	-
124	Emission Allowance Trading	(71,827,955)	(71,827,955)	-	-
125	Retirement Plan Expense - Overfunded	6,196,136	-	6,196,136	-
126	Retirement Plan Funding - Overfunded	(13,950,396)	-	(13,950,396)	-
127	Miscellaneous Current Taxable Inc. Adj - DTL	(2,959,479)	-	(2,959,479)	-
128	Sec 481 Adj - State Inc Tax	(886)	(886)	-	-
129	Tax Interest Accrual - Cur Asset	(1,210,526)	-	(1,210,526)	-
130	Tax Int Accrual - Non-cur Asset	(497,277)	-	(497,277)	-
131	ARO Regulatory Asset	(3,544)	(3,544)	(162,301)	(4,732,279)
132	Total Account 283	($244,845,319)	($122,654,606)	($80,051,376)	($47,033,917)

CONFIDENTIAL PROPRIETARY TRADE SECRET

Duke Energy Ohio
Summary of Legacy Generation-Related O&M expenses

Schedule C-2

Line No	FERC Account	Account Description (Form 1, pages 320-323)	Total Per Books	Adjustments DENA	Adjustments Purch Acctg	Adjustments Other	Adjusted Total	% Allocable To Prod Demand	Net Allocated To Prod Demand	Note
		Steam Power Generation								
		Operation								
1	500	Operation Supervision and Engineering	$7,979,442	[redacted]						Eliminate DENA exp
2	501	Fuel	500,732,647	[redacted]						Eliminate Fuel
3	502	Steam Expenses	35,278,673	[redacted]						Eliminate Reagents
4	503	Steam from Other Sources		[redacted]						
5	504	(Less) Steam Transferred-Cr.		[redacted]						
6	505	Electric Expenses	1,918,599	[redacted]						
7	506	Miscellaneous Steam Power Expenses	21,716,204	[redacted]						Eliminate DENA exp
8	507	Rents	(122,466)	[redacted]						
9	509	Allowances	18,450,412	[redacted]						Eliminate EA expense
10		Total Operation	$585,953,511	[redacted]						
		Maintenance		[redacted]						
11	510	Maintenance Supervision and Engineering	$6,329,523	[redacted]						
12	511	Maintenance of Structures	6,964,295	[redacted]						
13	512	Maintenance of Boiler Plant	67,792,108	[redacted]						Eliminate Beckjord Deferral
14	513	Maintenance of Electric Plant	11,705,184	[redacted]						
15	514	Maintenance of Miscellaneous Steam Plant	19,259,150	[redacted]						
		Total Maintenance Expense	$112,050,260	[redacted]						
		Total Steam Production expenses	$698,003,771	[redacted]						
		Other Power Generation		[redacted]						
		Operation		[redacted]						
16	546	Operation Supervision and Engineering	$7,338,549	[redacted]						Eliminate DENA exp
17	547	Fuel	237,772,264	[redacted]						Eliminate Fuel
18	548	Generation Expenses	1,644,827	[redacted]						Eliminate DENA exp
19	549	Miscellaneous Other Power Generation Expenses	2,985,941	[redacted]						Eliminate DENA exp
		Total Operation Expenses (Other Power)	$249,741,581	[redacted]						
		Maintenance		[redacted]						
20	551	Maintenance Supervision and Engineering	$1,326,109	[redacted]						
21	552	Maintenance of Structures	2,187,547	[redacted]						
22	553	Maintenance of Generating and Electric Plant	13,757,108	[redacted]						
23	554	Maintenance of Misc Other Power Gen Plant	2,417,741	[redacted]						
		Total Maintenance Expenses (Other Power)	$19,688,505	[redacted]						
		Other Power Supply Expenses		[redacted]						
24	555	Purchased Power	128,536,142	[redacted]						Eliminate historical
25	555.xxx	Capacity Purch Needed for PJM Min Reserve	-	[redacted]						[redacted]
26	556	System Control and Load Dispatching	-	[redacted]						
27	557	Other Expenses	27,351,656	[redacted]						Demand
28		Total Other Power Supply expenses	$175,576,303	[redacted]						
29		Total Direct Generation expenses	$1,123,321,655	[redacted]						

CONFIDENTIAL PROPRIETARY TRADE SECRET

Duke Energy Ohio
Summary of Legacy Generation-Related O&M expenses

Schedule C-2

Line No	FERC Account	Account Description (Form 1, pages 320-323)	Total Per Books	Adjustments DENA	Adjustments Purch Acctg	Adjustments Other	Adjusted Total	% Allocable To Prod Demand	Net Allocated To Prod Demand	Note
		Administrative and General expenses								
		Operation								
1	920	Administrative & General Salaries	64,806,339	[redacted]						Allocate w/ S&W
2	921	Office Supplies & Expenses	30,636,069							Allocate w/ S&W
3	922	Administrative Expenses Transferred - Credit	443							Allocate w/ S&W
4	923	Outside Services Employed	27,609,883							Allocate w/ S&W
5	924	Property Insurance	12,606,913							Allocate on plant
6	925	Injuries & Damages	6,404,639							Allocate w/ S&W
7	926	Employee Pension & Benefits	45,659,273							Allocate w/ S&W
8	928000	State Regulatory Commission expense	3,413,434							Direct (recovered in D)
9	928020	Federal Regulatory Commission expense	670,790							All but Trans & DENA
10	929	Duplicate Charges-Credit	(2,972,326)							Allocate w/ S&W
11	930000	General Advertising expenses	87,626							Allocate w/ S&W
12	930202	Miscellaneous General expenses	1,754,264							Allocate w/ S&W
13	931	Rents	8,009,348							Allocate w/ S&W
14		Total Operation	198,686,695							
		Maintenance								
15	935	Maintenance of equipment	2,970,214							Allocate w/ S&W
		Total Administrative and General expense	201,656,909							
		Total expenses	$1,324,978,564							

Duke Energy Ohio
Depreciation Expense & Property Taxes

Schedule C-3

Line No.	Account Title	Source	Total Company	Adjustments DENA	Adjustments Purch Acctg	Adjusted Total	Percent Allocated to Production	Amount for Legacy Gen
	Depreciation Expense							
1	Intangible Plant	p. 336.1.f	$17,504,993	$0	($7,755,000)	$9,749,993	39.2%	$3,821,022
2	Steam Production Plant	p. 336.2.f	73,725,960	-	-	73,725,960	100.0%	73,725,960
3	Other Production Plant	p. 336.6.f	58,360,702	(58,166,842)	-	193,860	100.0%	193,860
4	Transmission Plant	p. 336.7.f	11,107,812	-	-	11,107,812	0.0%	-
5	Distribution Plant	p. 336.8.f	42,678,072	-	-	42,678,072	0.0%	-
6	General Plant	p. 336.10.f	2,923,288	-	-	2,923,288	39.2%	1,145,637
7	Common Plant - Electric	p. 336.11.f	14,812,386	-	-	14,812,386	33.2%	4,917,712
8	Total Depreciation Expense		$221,113,213	($58,166,842)	($7,755,000)	$155,191,371		$83,804,191
	Property Tax							
9	Intangible Plant		$0	$0	$0	$0	39.2%	$0
10	Steam Production Plant		15,029,700	-	-	15,029,700	100.0%	15,029,700
11	Other Production		3,714,939	(3,714,939)	-	-	100.0%	-
12	Transmission Plant	Notes to p. 263.20.I	17,322,248	-	-	17,322,248	0.0%	-
13	Distribution Plant	Total FERC elec less T & Gen	55,210,089	-	-	55,210,089	0.0%	-
14	General & Common (Electric)	Common alloc to Elec	6,307,819	-	-	6,307,819	39.2%	2,472,034
15	Total Property Taxes		$97,584,795	($3,714,939)	$0	$93,869,856		$17,501,734
16	**Payroll Taxes**	p. 263.4.5.12I	12,810,088	(678,604)	-	12,131,484	44.5%	5,400,771
17	**Franchise Tax**		1,642,804	-	-	1,642,804	44.5%	731,354
18	**Commercial Activities Tax** [a]		4,568,022	-	-	4,568,022	0.0%	-
19	**Highway Use Tax**		34,961	-	-	34,961	44.5%	15,564
20	Total Taxes Other Than Income		$116,640,670	($4,393,543)	$0	$112,247,127		$23,649,423

Note: [a] Commercial Activities Tax of 0.26% included in Schedule A revenue requirement calculation.

Duke Energy Ohio **Schedule C-4**
Calculation of Income Tax Factors

Line No	Description	Amount
1	Income before Federal Income Tax	100.00%
2	Gross Domestic Production Tax Credit	9.00%
3	Income After Gross Domestic Tax Credit	91.00%
4	Federal Income Tax 35.00%	31.85%
5	Gross Revenue Conversion Factor (1/(1-0.3442))	1.4674

Duke Energy Ohio
Capitalization and Cost of Capital as of December 31, 2010

Schedule D

Line No.	Account Title	Total Company	Adjustments: DENA	Adjustments: Purch Acctg	Adjusted Total Company	Ratio	Cost Rate [a]	After-Tax WACC	GRCF [h]	Pre-Tax WACC
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Common Equity	$5,463,938,777	($1,077,160,243)	($1,180,779,435)	$3,205,999,099	55.8%	10.75%	6.00%	1.4674	8.80%
2	Preferred Equity	-	-	-	-	-	-	-	-	-
3	Long-Term Debt	2,534,482,320	-	2,330,168	2,536,812,488	44.2%	4.26%	1.88%	1.0026	1.88%
4	Total Capitalization	$7,998,421,097	($1,077,160,243)	($1,178,449,267)	$5,742,811,587	100.0%		7.88%		10.68%

Notes: [a] Per Books Capital for DE-Ohio Consolidated. (As reported in the Company's Compliance Filing for Significantly Excessive Earnings Test, Case No. 11-2954-EL-UNC.)
[b] Based on internal account information.
[c] Based on internal account information.
[d] Sum of Columns (a), (b), and (c).
[e] As percent of total capitalization.
[f] Return on Equity rate as proposed by Company. Interest on long-term debt is actual interest expense from Form 1, page 257.33.l, divided by LTD balance above.
[g] Column (e) * (Column (f).
[h] Gross Revenue Conversion Factor (GRCF) calculated on Schedule C-4.
[i] Column (g) * (Column (h).

Duke Energy Ohio
Allocation of Capacity Costs for Rate Design

Schedule F

Line No	Description	12 CP	Percent of Total 12 CP Demand	Allocation of Fixed Gen Rev Req	Allocation of PSM Credit	Net Capacity Rev Req	
		(a)	(b)	(c)	(d)	(e)	
	Average of 12 CP Demand by Rate Schedule:						
1	Residential (RS, TD, ORH)	1,582,951	46.76%	$264,821,457	($67,472,866)	$197,348,591	To Rate Design
2	Electric Space Heating (EH)	13,736	0.41%	2,297,979	(585,493)	1,712,486	
3	Secondary Distribution - Small (DM)	87,168	2.57%	14,582,862	(3,715,513)	10,867,349	
4	Unmetered Small Fixed Load (GSFL, ADPL)	4,746	0.14%	793,987	(202,297)	591,690	
5	Secondary Distribution (DS)	978,791	28.91%	163,747,872	(41,720,706)	122,027,166	
6	Primary Distribution (DP)	311,768	9.21%	52,157,556	(13,289,028)	38,868,528	
7	Transmission Voltage (TS)	390,191	11.53%	65,277,415	(16,631,788)	48,645,627	
8	Lighting	15,900	0.47%	2,660,007	(677,733)	1,982,274	
9	Total	3,385,251	100.00%	$566,339,136	($144,295,425)	$422,043,710	

Notes: [a] Average of 12 Coincident Monthly Peaks based on load research data for 2010.

Duke Energy Ohio Late Filed Exhibit 10.1
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Attachment WDW-1
Page 17 of 17

Duke Energy Ohio
Allocation Factors

Line No.	Category	Form 1 Reference	Per Books	Adjustments DENA	Adjustments Purch Acctg	Adjusted Total Company	Ratio	
	W&S Allocator for Electric							
1	Production	354.20.b	$57,676,930	10,780,226		$46,896,704	44.5%	[redacted]
2	Transmission	354.21.b	3,321,634					
3	Distribution	354.23.b	23,830,724					
4	Other [a]	354.24,25,26.b	20,512,455					
5	Total		$105,341,743					
					% Electric	**W&S Allocator**	**W&S for Common**	
	W&S Allocator for Common							
6	Electric	200.8.c	$7,996,676,383		84.7%	44.5%	37.7%	
7	Gas	201.8.d	1,442,435,032					
8	Total		$9,439,111,415					
9	Electric G, T, D Gross Plant		$7,841,778,021					
10	Legacy Generation (Gross Plant)		$3,073,287,834					
11	Legacy Gen GP as % if G, T, D Plant		39.19%					
12	Legacy Gen GP as % of G&E Plant		33.20%					

Notes: [a] "Other" includes labor for Customer Accounts, Customer Service & Information, Customer Service & Informational, and Sales, all of which are allocated to distribution expenses.

CONFIDENTIAL PROPRIETARY TRADE SECRET

Duke Energy Ohio
Revenue Requirement for Capacity Dedication
12 Months Ending 12/31

Line No.	Description	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	Production Rate Base	$1,710,924,208	$1,812,539,468	$1,867,177,215	$1,992,868,930	$2,172,178,886	$2,273,779,857	$2,281,811,416	$2,332,618,257	$2,329,273,786	$2,292,406,444
2	Return on Rate Base	7.88%	7.88%	7.88%	7.88%	7.88%	7.88%	7.88%	7.88%	7.88%	7.88%
3	Return on Rate Base	$134,820,828	$142,828,110	$147,133,565	$157,038,072	$171,167,698	$179,173,380	$179,806,740	$183,810,319	$183,073,974	$180,641,628
4	Operation & Maintenance Expense	$274,690,153	$244,424,905	$318,800,370	$361,793,087	$325,331,493	$352,509,226	$380,342,054	$412,675,462	$433,589,912	$442,546,474
5	Depreciation Expense	$83,804,191	$83,327,859	$80,746,617	$80,714,064	$84,967,171	$88,305,785	$90,661,942	$95,625,170	$99,087,192	$101,424,883
6	Taxes Other Than Income Taxes	$23,649,423	$20,184,187	$19,967,682	$20,133,048	$17,262,884	$17,817,018	$18,084,273	$18,356,537	$18,630,870	$18,910,333
7	Income Tax	$49,374,541	$50,751,105	$52,280,962	$55,800,330	$60,821,009	$63,665,668	$63,890,720	$65,313,311	$65,051,666	$64,187,380
8	Annual Fixed Cost for Production	$566,339,138	$541,516,267	$618,929,196	$675,478,601	$659,550,254	$701,471,077	$732,785,729	$775,779,799	$799,433,616	$807,710,699
9	Total Retail Sales (MWh)	20,473,777	20,810,354	21,177,162	21,344,607	21,306,958	21,288,315	21,261,578	21,246,265	21,240,063	21,241,344
10	Average cost of capacity before credits ($/MWh)	$27.66	$26.02	$29.23	$31.65	$30.95	$32.95	$34.47	$36.51	$37.64	$38.03
11	Estimated Credit for Customer Share of Generation Profits	[redacted]									
12	Net Production Fixed Cost for Native Load										
13	Projected Retail Energy Price (Rose Testimony, Exhibit F-1)	$59.14	$63.84	$69.48	$75.91	[redacted]					
14	Total Generation Price for Retail (Proposed ESP)	[redacted]									
15	Projected Generation Price under MRO (Rose Testimony, Exhibit -FF)	$77.40	$72.80	$77.00	$81.40	[redacted]					
16	Revenue at Proposed ESP Rates ($ million)	[redacted]									
17	Revenue at MRO Rates ($ million)										
18	NPV of Revenue at Proposed Rates (discounted at WACC) ($million)	$14,413									
19	NPV of Revenue at MRO Rates (discounted at WACC) ($million)	$15,339									
20	Difference ($million)	($927)									

Duke Energy Ohio
Projected Rate Base for Legacy Generation
12 Months Ending 12/31

Rate Base Components	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Plant In Service										
Steam Production Plant	$3,051,344,587	$3,399,300,913	$3,522,369,904	$3,719,062,304	$3,975,909,288	$4,158,749,817	$4,256,292,063	$4,395,610,627	$4,480,380,419	$4,545,977,169
Other Production Plant	$21,943,247									
Total Production Plant	$3,073,287,834	$3,399,300,913	$3,522,369,904	$3,719,062,304	$3,975,909,288	$4,158,749,817	$4,256,292,063	$4,395,610,627	$4,480,380,419	$4,545,977,169
Transmission	$23,043,118									
Distribution	$0									
Intangible Plant	$0									
General	$32,447,028									
Common	$99,262,688									
Total Plant In Service	$3,228,040,669	$3,399,300,913	$3,522,369,904	$3,719,062,304	$3,975,909,286	$4,158,749,817	$4,256,292,063	$4,395,610,627	$4,480,380,419	$4,545,977,169
Reserve for Accumulated Depreciation										
Steam Production Plant	($1,082,527,498)	(1,227,831,337)	(1,298,024,022)	(1,369,835,111)	(1,447,289,979)	(1,530,176,524)	(1,616,406,081)	(1,707,598,866)	(1,802,253,674)	(1,899,246,172)
Other Production Plant	($26,258,999)									
Total Production Plant	($1,108,786,497)	($1,227,831,337)	($1,298,024,022)	($1,369,835,111)	($1,447,289,979)	($1,530,176,524)	($1,616,406,081)	($1,707,598,866)	($1,802,253,674)	($1,899,246,172)
Transmission	($9,517,588)									
Distribution	$0									
Intangible Plant	$0									
General	($1,979,874)									
Common	($43,661,678)									
Total Reserve for Accumulated Depreciation	($1,163,945,637)	($1,227,831,337)	($1,298,024,022)	($1,369,835,111)	($1,447,289,979)	($1,530,176,524)	($1,616,406,081)	($1,707,598,866)	($1,802,253,674)	($1,899,246,172)
Net Plant In Service	$2,064,095,026	$2,171,469,576	$2,224,345,882	$2,349,227,194	$2,528,619,307	$2,628,567,293	$2,639,885,982	$2,688,011,761	$2,678,126,746	$2,646,730,997
Construction Work In Progress (production plant)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cash Working Capital Allowance	$34,336,269	$28,576,980	$30,338,419	$31,148,823	$31,066,666	$32,713,651	$29,432,521	$32,113,584	$32,654,127	$33,182,534
Other Working Capital Allowance	$158,871,180	$158,871,180	$158,871,180	$158,871,180	$158,871,180	$158,871,180	$158,871,180	$158,871,180	$158,871,180	$158,871,180
Other Items:										
Deferred Income Taxes	($544,929,835)	($544,929,835)	($544,929,835)	($544,929,835)	($544,929,835)	($544,929,835)	($544,929,835)	($544,929,835)	($544,929,835)	($544,929,835)
Investment Tax Credits	($1,448,432)	($1,448,432)	($1,448,432)	($1,448,432)	($1,448,432)	($1,448,432)	($1,448,432)	($1,448,432)	($1,448,432)	($1,448,432)
Other Rate Base Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Other Items	($546,378,267)	($546,378,267)	($546,378,267)	($546,378,267)	($546,378,267)	($546,378,267)	($546,378,267)	($546,378,267)	($546,378,267)	($546,378,267)
Rate Base	$1,710,924,208	$1,812,539,468	$1,867,177,215	$1,992,863,930	$2,172,178,886	$2,275,775,857	$2,281,811,416	$2,332,618,257	$2,323,273,786	$2,252,406,444

Duke Energy Ohio
Projected Sales from Legacy Generation
12 Months Ending 12/31

CONFIDENTIAL PROPRIETARY TRADE SECRET

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Revenues	[redacted]									
Generation Revenue										
PJM Capacity Revenue										
Total Revenue										
Cost of Goods Sold										
Fuel Cost										
SO2 Cost										
NOx Cost										
CO2 Cost										
Total Non-Native COGS										
Generation Energy Margins										
Other Variable Costs										
Reagent Costs										
MISO Marketing Fees										
Brokering										
Total Energy Margins										
Energy Margin to Rate Payer										
Energy Margin to Shareholder										
Energy Margin to Economic Development										
Total Energy Margin										
Retail Sales (MWhs)										
Rate Payer Energy Credit ($/MWh)										
Generation Volumes										

VOM Escalation Rate	1.50%
Rate Payer Share of Energy Margin	80.00%
ShareHolder Share of Energy Margin	20.00%
Energy margin Allocated to Economic Development	5.00%

CONFIDENTIAL PROPRIETARY TRADE SECRET

Duke Energy Ohio
Projected Operating and Maintenance Expenses
12 Months Ending 12/31

O&M Forecast	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Ohio Gen Total OU View	[redacted]										
Exclusions for ESP											
Reagents											
MISO Marketing Fees											
Transmission											
Beckjord Deferral											
PJM Transfer Cost											
Cincinnati Economic Development											
AR Fees											
Total Exclusions											
Adjusted O&M											
Adjusted O&M w/o Beckjord for 2015											
Projected O&M											
New Environmental Fixed O&M											
Total O&M Revenue Requirement	$228,615,837	$242,707,354	$249,100,507	$248,593,326	$261,709,310	$255,460,171	$255,908,670	$261,293,019	$265,460,276	$269,593,837	$273,419,520
O&M for ESP EBIT	[redacted]										
Ash Pond O&M											
Payroll Taxes											
Beckjord Station RC View											
Beckjord Station Reagents											
Beckjord Station Payroll Taxes											
Inflation Rate for O&M and Payroll Taxes											

[illegible]
[illegible]
[illegible]

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	$0	$0	$0	$0	$0	$0					
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]					
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]					
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]					
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]					
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]					
[illegible] CT	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]					
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]					
[illegible] CT	$0	$0	$0	$0	$0	$0					
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]							[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	$0	$0	$0	$0	$0	$0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

CONFIDENTIAL PROPRIETARY TRADE SECRET

Duke Energy Ohio
Projected Other Taxes
12 Months Ending 12/31

Property Taxes	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Beckjord	[redacted]										
Miami Fort											
Zimmer											
Conesville											
Killen											
Stuart											
Beckjord CT											
Dick's Creek											
Miami Fort CT											
Total Property Taxes	$13,397,958	$14,330,292	$14,410,044	$14,657,292	$15,113,664	$13,074,367	$13,270,483	$13,469,540	$13,671,583	$13,876,657	$14,084,807
Payroll Taxes	$6,786,229	$5,637,390	$5,723,004	$4,861,772	$4,935,868	$5,009,906	$5,085,055	$5,161,330	$5,238,750	$5,317,332	$5,397,092
Total Other Taxes	$20,184,187	$19,967,682	$20,133,048	$19,519,064	$20,049,532	$18,084,273	$18,355,537	$18,630,870	$18,910,333	$19,193,988	$19,481,898

Inflation Rate for Property and Payroll Taxes 1.50%

CONFIDENTIAL PROPRIETARY TRADE SECRET

Duke Energy Ohio
Projected Cost of Purchased Capacity
12 Months Ending 12/31

Capacity Short Position Forecast	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Projected Capacity Short Position (MWs)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
January - May Capacity Price ($/MW-Day)	$110.00	$16.50	$27.73	$125.00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
June - December Capacity Price ($/MW-Day)	$16.50	$27.73	$125.00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
January - May Capacity Cost ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
June - December Capacity Cost ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Projected Capacity Cost ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
January - May Capacity Price ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
June - December Capacity Price ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

CONFIDENTIAL PROPRIETARY TRADE SECRET

Duke Energy Ohio
Projected Retail Sales
12 Months Ending 12/31

BAU Forecast (MWhs)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Residential	[redacted]									
Commercial										
Industrial										
Street Light										
OPA										
Interdepartmental										
Total BAU										

CONFIDENTIAL PROPRIETARY TRADE SECRET

Duke Energy Ohio
Projected Net Book Value (Legacy Generation)
12 Months Ending 12/31

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Net Book Value Original Plant											
Historical Cost											
Accumulated Depreciation											
Beginning Net Book Value											
CWIP											
Forecasted Capex											
Forecasted Depreciation											
Ending Net Book Value											
Net Book Value Future Environmental											
Historical Cost											
Accumulated Depreciation											
Beginning Net Book Value											
CWIP											
Forecasted Capex											
Forecasted Depreciation											
Ending Net Book Value											
Net Book Value Ash Pond											
Historical Cost											
Accumulated Depreciation											
Beginning Net Book Value											
CWIP											
Forecasted Capex											
Forecasted Depreciation											
Ending Net Book Value											
NBV Original Plant + Future Environmental											
Historical Cost											
Accumulated Depreciation											
Beginning Net Book Value											
CWIP											
Forecasted Capex											
Forecasted Depreciation											
Ending Net Book Value											
NBV Original Plant + Future Environmental + Ash Pond											
Historical Cost											
Accumulated Depreciation											
Beginning Net Book Value											
CWIP											
Forecasted Capex											
Forecasted Depreciation											
Ending Net Book Value											
NBV Original Plant + Ash Pond											
Historical Cost											
Accumulated Depreciation											
Beginning Net Book Value											
CWIP											
Forecasted Capex											
Forecasted Depreciation											
Ending Net Book Value											

[redacted]

CONFIDENTIAL PROPRIETARYY TRADE SECRET

Duke Energy Ohio
Projected Capital Expenditures (Legacy Generation)
12 Months Ending 12/31

Capital Expenditures Forecast	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Beckjord	[redacted]										
Miami Fort											
Zimmer											
Conesville											
Killen											
Stuart											
Beckjord CT											
Dick's Creek											
Miami Fort CT											
Total Capex											
IDC											
Beckjord											
Miami Fort											
Zimmer											
Conesville											
Killen											
Stuart											
Beckjord CT											
Dick's Creek											
Miami Fort CT											
Total IDC											
IDC % of Capex spend											
Total Capex and IDC Current Plant											
Future Environmental Capex											
Air											
Waste											
Water											
Totals											
Future Env Capex Ash Pond Closures											
Air											
Waste											
Water											
Totals											

Duke Energy Ohio
Projected Depreciation Expense
12 Months Ending 12/31

Depreciation Forecast	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Beckjord	$0	$0	$0	$0	$0	$0					
Miami Fort	$17,327,921	$17,388,372	$17,300,916	$17,263,401	$17,562,224	$17,518,870					
Zimmer	$25,940,434	$23,807,484	$23,247,528	$23,321,624	$23,294,867	$23,769,292					
Conesville	$3,844,166	$3,918,061	$4,129,188	$4,474,836	$4,638,787	$5,022,972					
Killen	$4,102,177	$4,140,740	$4,092,125	$4,070,805	$4,066,329	$4,094,804					
Stuart	$19,981,915	$20,239,048	$19,924,167	$20,460,505	$21,439,074	$22,494,224					
Beckjord CT	$1	$320	$645	$974	$1,308	$1,649					
Dick's Creek	$193,407	$193,525	$193,897	$193,885	$193,873	$193,860					
Miami Fort CT	$0	$0	$0	$0	$0	$0					
Total Existing Depreciation	$71,390,021	$69,687,551	$68,888,465	$69,786,030	$71,195,463	$73,085,671	$73,085,671	$73,085,671	$73,085,671	$73,085,671	$73,085,671
Incremental Depreciation on 2017 - 2020 Capex							$4,503,433	$7,518,781	$9,105,476	$10,223,775	$10,223,775
Total Depreciation Current Plant	$71,390,021	$69,687,551	$68,888,465	$69,786,030	$71,195,483	$73,085,671	$77,589,104	$80,604,452	$82,191,147	$83,309,446	$83,309,446
Estimated Depreciation on Future Environmental Capex	$15,316	$505,134	$2,922,624	$7,668,838	$11,691,082	$13,143,886	$13,609,881	$14,050,355	$14,801,351	$15,351,662	$15,419,656
Estimated Depreciation on Future Env Capex Ash Pond Closure	$0	$0	$0	$0	$0	$0	$625,291	$3,182,735	$8,834,348	$13,061,693	$13,863,489
Other Depreciation (Software, Shared Services, Common Plant)	$11,922,622	$10,553,933	$8,902,975	$7,512,304	$5,419,246	$4,432,385	$4,432,385	$4,432,385	$4,432,385	$4,432,385	$4,432,385

Duke Energy Ohio Late Filed Exhibit 10.2
Page 1 of 1

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service.	)))))))	Case No. 11-3549-EL-SSO
In the Matter of the Application of Duke Energy Ohio for Authority to Amend its Certified Supplier Tariff, P.U.C.O. No. 20.	)))	Case No. 11-3550-EL-ATA
In the Matter of the Application of Duke Energy Ohio for Authority to Amend its Corporate Separation Plan.	)))	Case No. 11-3551-EL-UNC

REDACTED VERSION

DIRECT TESTIMONY OF

BRIAN D. SAVOY

ON BEHALF OF

DUKE ENERGY OHIO, INC.

June 20, 2011

TABLE OF CONTENTS

PAGE

Attachments:

Workpapers:

See Attachment WDW-2

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Brian D. Savoy, and my business address is 526 South Church Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services LLC (DEBS) as Managing Director of Corporate Financial Planning and Analysis. DEBS provides various administrative and other services to Duke Energy Ohio, Inc., (Duke Energy Ohio or the Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I earned a bachelor of business administration degree in accounting from Lamar University in Beaumont, Texas. I am a certified public accountant in both Texas and Ohio.

Prior to joining Duke Energy, I was a Manager with the international accounting firm, Deloitte & Touche, based in Houston, Texas. During my tenure at Deloitte & Touche, I served various energy clients through audit and consulting services.

I joined Duke Energy in July 2001 as Manager of Technical Accounting in Houston, Texas and, in December of that year, I was named Director of Risk Management Accounting. In April 2004, I was promoted to Senior Director of Risk Management Accounting and Analysis at Duke Energy North America in

Houston, Texas. In this role, I led the derivative accounting and trading control functions for the energy trading and marketing activities of Duke Energy.

In April 2006, I was promoted to Vice President and Controller of the Commercial Power unit of Duke Energy in Cincinnati, Ohio. In this role, I was responsible for the financial accounting, reporting and internal controls of Duke Energy's non-regulated generation and Duke Energy Generation Services businesses.

In March 2009, I was appointed to General Manager of Corporate Financial Planning & Analysis in Duke Energy's headquarters in Charlotte, North Carolina. In this role, I am responsible for leading the financial forecasting and planning for the corporation. In January 2011, my title was changed to Managing Director of Corporate Financial Planning & Analysis, but there was no change to my responsibilities.

Q. PLEASE DESCRIBE YOUR DUTIES AS MANAGING DIRECTOR OF CORPORATE FINANCIAL PLANNING AND ANALYSIS.

A. I lead and direct a team of approximately thirty professionals in the preparation of the short- and long-term financial forecasts of earnings and cash flow of Duke Energy, including each operating unit. This role also includes financial modeling of sensitivities and strategic scenarios and evaluating the projected financial impact of those alternatives. The primary deliverables from this group are financial presentations to senior management and the board of directors as well as financial targets for employee incentive compensation.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO?

A. Yes. Earlier this year, I testified before the Public Utilities Commission of Ohio (Commission) in Duke Energy Ohio's application for approval of a market rate offer, filed under Case No. 10-2586-EL-SSO.

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

A. The purpose of my testimony is to sponsor pro forma financial projections in respect of the implementation of the Company's proposed electric security plan (ESP or Plan). My testimony addresses the effect of the ESP upon the Company for the duration of the Plan, as required by O.A.C. 4901:1-35-03(C)(2).

II. DISCUSSION

Q. WHAT ARE THE ATTACHMENTS FOR WHICH YOU ARE RESPONSIBLE?

A. I am sponsoring all or part of the following items:

- BDS-1: Projected Statements of Income
- BDS-2: Projected Balance Sheets
- BDS-3: Projected Sources and Uses of Funds

Q. PLEASE IDENTIFY AND DESCRIBE ATTACHMENT BDS-1.

A. Attachment BDS-1 is the Projected Statements of Income that incorporate the proposed ESP structure for the legacy coal generation assets of Duke Energy Ohio for the period between January 1, 2012, and May 31, 2021.

Q. PLEASE IDENTIFY AND DESCRIBE ATTACHMENT BDS-2

A. Attachment BDS-2 contains the Projected Balance Sheets for the legacy coal generation assets of Duke Energy Ohio for the nine years and five months ending December 31, 2012; December 31, 2013; December 31, 2014; December 31, 2015; December 31, 2016; December 21, 2017; December 31, 2018; December 31, 2018; December 31, 2019; December 31, 2020; and May 31, 2021.

Q. PLEASE IDENTIFY AND DESCRIBE ATTACHMENT BDS-3.

A. Attachment BDS-3 is the Projected Sources and Uses of Funds for the legacy coal generation assets of Duke Energy Ohio for the period between January 1, 2012, and May 31, 2021.

Q. HOW ARE THESE ATTACHMENTS AND SCHEDULES RELEVANT TO THE COMPANY'S REQUEST FOR AN ELECTRIC SECURITY PLAN?

A. As I have been informed, Ohio law allows for an electric utility company such as Duke Energy Ohio to extend to its customers a standard service offer in the form of an ESP. In seeking approval of such an offer, the Company must satisfy certain criteria. Relevant to my testimony is the requirement that the Company provide pro forma financial projections.

Specifically, I understand that Duke Energy Ohio must provide pro forma financial projections of the effect of that Plan's implementation upon the Company, for the duration of the ESP. Additionally, the information provided by the Company must include the assumptions made and methodologies used in preparing the pro forma financial projections.

Q. WHAT IS THE DURATION OF THE ESP THAT YOU USED FOR PURPOSES OF DEVELOPING THE PRO FORMA FINANCIAL PROJECTIONS ATTACHED TO AND A PART OF YOUR TESTIMONY?

A. The pro forma financial projections attached to and incorporated into my testimony reflect the nine-year, five-month term of the ESP, as proposed by the Company.

Q. WHAT ASSUMPTIONS DID YOU MAKE FOR PURPOSES OF DEVELOPING THESE PRO FORMA FINANCIAL PROJECTIONS?

A. I made the following assumptions:

- The capacity charge has been prepared under the assumption of being updated annually.
- The capacity charge for the first year of the ESP was determined using the cost of service for the legacy coal generation assets based on the FERC Form 1 data for 2010.
- Financial forecasts and resulting capacity charges for years after 2010 are derived via forecasted capital plans with historical test year convention (*e.g.*, 2012 forecast was used to determine the capacity charge for 2014, etc.).
- For purposes of calculating the capacity charge, return on equity as well as the overall weighted average cost of capital was held constant for the duration of the ESP term. The return on equity is based on the recommendation of Duke Energy Ohio witness Dr. Roger A. Morin and the weighted average cost of capital is based on the Company's capital

structure, adjusted to remove the impacts of purchase accounting and the equity associated with the Company's investment in generation assets acquired in the 2006 merger. Additionally, the capital structure is held constant, as well, during the term of the ESP at 55.8 percent equity and 44.2 percent debt for capacity charge calculation purposes.

- In the projected Balance Sheets, equity changes from year to year based on the amount of projected net income closed to retained earnings. No distributions to Duke Energy have been assumed. Distributions will be evaluated on an annual basis based on the cash position and future needs.
- Cash on hand at the start of the projection period is sufficient to cover net uses of cash in any particular year of the projection. As a result, no additional capital from debt or equity is assumed.
- Forecasted net profits from the energy and ancillary services sales are derived from utilizing forecasted commodity prices obtained from ICF International (ICF) and Duke Energy Ohio's commercial business model.
- Duke Energy Ohio does not participate in the energy auctions under its proposed ESP.
- [redacted] Beyond the current known base residual auction clearing price, capacity prices have been forecasted by ICF.

Q. PLEASE EXPLAIN WHY THE CAPITAL STRUCTURE OF 45.3 PERCENT EQUITY AND 54.7 PERCENT DEBT FOR 2012, AS WELL AS SUBSEQUENT YEARS, IS LOWER THAN THE CAPITAL STRUCTURE ASSUMED TO DETERMINE THE EQUITY COMPONENT OF RATE BASE IN ORDER TO DERIVE THE PROPOSED ESP CAPACITY CHARGE.

A. The Projected Balance Sheets presented begin with the historical Duke Energy Ohio values applicable to the legacy coal generation assets. The historical retained earnings include the writeoff of goodwill associated with the legacy coal generation assets of Duke Energy Ohio. Adjusting the retained earnings for the goodwill write-off results in a capital structure of approximately 53% equity and 47% debt. In each year of the projection, the relative proportion of debt and equity will vary slightly depending on (1) earnings that increase equity, (2) dividends that lower equity, and (3) issuances/redemption of debt which raise or lower debt balances. On the other hand, the projected revenue requirement for the ESP capacity charge assumes a constant capital structure; consequently, there will be a variance between the projected capital structure in the financial statements and the capital structure used in the ratemaking formula.

Q. WHAT IS THE METHODOLOGY THAT YOU EMPLOYED IN PREPARING THE PRO FORMA FINANCIAL PROJECTIONS?

A. The pro forma financial statements were developed consistent with the methodology utilized by the Company for preparing its normal operating forecast. This process involves input from various groups within the Company. The key forecasting inputs from these groups relate to the forecasting of load, generation, O&M, capital expenditures and financing.

III. CONCLUSION

Q. WERE ATTACHMENTS BDS-1 THROUGH BDS-3 PREPARED BY YOU OR PERSONS UNDER YOUR DIRECTION AND CONTROL?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

CONFIDENTIAL PROPRIETARY TRADE SECRET

Duke Energy Ohio
Legacy Generation Assets
Projected Income Statements

Exhibit BDS -1
Page 1 of 1

Line	Description	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	Operating Revenues	[redacted]									
2	Capacity Revenue										
3	Energy Sales										
5	Total Electric Operating Revenues										
6	Cost of Generation and Purchased Capacity										
7	Fuel Cost										
8	Emission Cost										
9	Capacity Purchase Cost										
10	Total Cost of Generation and Purchased Power										
11	Energy Credit										
12	Gross Margin										
13	Operating Expenses										
14	Operation and Maintenance										
15	Depreciation and Amortization										
16	Taxes Other Than Income Taxes										
17	Total Operating Expenses										
18	Operating Income										
19	Interest Expense										
20	Earnings Before Income Tax										
21	Income Taxes										
22	Current Income Taxes										
23	Deferred Income Taxes										
24	Total Income Taxes										
25	Net Income										

Duke Energy Ohio
Legacy Generation Assets
Projected Balance Sheets

Line	Description	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	ASSETS										
2	Gross Plant In Service	2,795,753,991	2,982,793,391	3,233,511,373	3,396,453,904	3,578,647,150	3,757,292,220	3,963,581,038	4,263,106,085.	4,336,751,243	4,398,702,186
3	CWIP	48,971,000	58,624,000	64,753,000	84,645,000	-	-	-	-	-	-
4	TOTAL UTILITY PLANT	2,844,724,991	3,041,417,391	3,298,264,373	3,481,098,904	3,578,647,150	3,757,292,220	3,963,581,038	4,263,106,085	4,336,751,243	4,398,702,186
5	Accumulated Depreciation	318,507,103	419,086,865	519,634,073	624,434,388	732,573,317	843,068,404	958,526,717	1,071,740,758	1,173,165,641	1,216,121,263
6	NET UTILITY PLANT	2,526,217,887	2,622,330,527	2,778,630,300	2,856,664,516	2,846,073,833	2,914,223,817	3,005,054,321	3,191,365,327	3,163,585,602	3,182,580,923
7	CURRENT ASSTS										
8	Cash and Cash Equivalents	301,323,942	285,296,761	252,153,772	346,650,429	492,489,501	565,840,470	602,905,985	581,937,177	778,503,774	771,445,077
9	Receivables	-	-	-	-	-	-	-	-	-	-
10	Inventory	120,576,000	120,576,000	120,576,000	120,576,000	120,576,000	120,576,000	120,576,000	120,576,000	120,576,000	120,576,000
11	Other	16,413,000	16,413,000	16,413,000	16,413,000	16,413,000	16,413,000	16,413,000	16,413,000	16,413,000	16,413,000
12	TOTAL CURRENT ASSETS	438,312,942	422,285,761	389,142,772	483,639,429	629,478,501	702,829,470	739,894,985	718,926,177	915,492,774	908,434,077
13	Intangible Assets, Net	231,205,000	231,205,000	231,205,000	231,205,000	231,205,000	231,205,000	231,205,000	231,205,000	231,205,000	231,205,000
14	Other Non-current Assets	18,792,000	18,792,000	18,792,000	18,792,000	18,792,000	18,792,000	18,792,000	18,792,000	18,792,000	18,792,000
13	TOTAL ASSETS	3,214,527,829	3,294,613,288	3,417,770,072	3,590,300,945	3,725,549,333	3,867,050,287	3,994,946,305	4,160,288,504	4,329,075,376	4,341,012,000
14	EQUITY AND LIABILITIES										
15	Common Stock	379,315,000	379,315,000	379,315,000	379,315,000	379,315,000	379,315,000	379,315,000	379,315,000	379,315,000	379,315,000
16	Additional Paid-in Capital	2,090,232,000	2,090,232,000	2,090,232,000	2,090,232,000	2,090,232,000	2,090,232,000	2,090,232,000	2,090,232,000	2,090,232,000	2,090,232,000
17	Retained Earnings	(1,401,203,171)	(1,311,665,712)	(1,196,620,928)	(1,067,515,055)	(940,529,667)	(804,232,713)	(673,324,695)	(520,327,496)	(357,201,624)	(291,063,000)
18	Accumulated Other Comprehensive Income (loss)	(21,312,000)	(21,312,000)	(21,312,000)	(21,312,000)	(21,312,000)	(21,312,000)	(21,312,000)	(21,312,000)	(21,312,000)	(21,312,000)
19	TOTAL EQUITY	1,047,031,829	1,136,569,288	1,251,614,072	1,380,719,945	1,507,705,333	1,644,002,287	1,774,910,305	1,927,907,504	2,091,033,376	2,157,172,000
20	LONG TERM DEBT	1,263,387,000	1,263,387,000	1,263,387,000	1,263,387,000	1,263,387,000	1,263,387,000	1,263,387,000	1,263,387,000	1,263,387,000	1,263,387,000
21	TOTAL CAPITAL	2,310,418,829	2,399,956,288	2,515,001,072	2,644,106,945	2,771,092,333	2,907,389,287	3,038,297,305	3,191,294,504	3,354,420,376	3,420,559,000
22	CURRENT LIABILITIES										
23	Accounts Payable	148,350,000	142,501,000	131,869,000	159,276,000	159,276,000	159,276,000	159,276,000	159,276,000	159,276,000	159,276,000
24	Notes Payable and Commercial Paper	-	-	-	-	-	-	-	-	-	-
25	Taxes Accrued	56,324,000	45,548,000	56,132,000	62,702,000	70,965,000	76,169,000	73,157,000	85,502,000	91,163,000	36,961,000
26	Interest Accrued	6,142,000	6,142,000	6,142,000	6,142,000	6,142,000	6,142,000	6,142,000	6,142,000	6,142,000	6,142,000
27	Other	18,623,000	18,623,000	18,623,000	18,623,000	18,623,000	18,623,000	18,623,000	18,623,000	18,623,000	18,623,000
28	TOTAL CURRENT LIABILITIES	229,439,000	212,814,000	212,766,000	246,743,000	255,006,000	260,210,000	257,198,000	269,543,000	275,204,000	221,002,000
29	DEFERRED CREDITS AND OTHER LIABILITIES										
30	Deferred Income Taxes	594,511,000	601,684,000	609,844,000	619,292,000	619,292,000	619,292,000	619,292,000	619,292,000	619,292,000	619,292,000
31	Asset Retirement Obligations	5,398,000	5,398,000	5,398,000	5,398,000	5,398,000	5,398,000	5,398,000	5,398,000	5,398,000	5,398,000
32	Other	74,761,000	74,761,000	74,761,000	74,761,000	74,761,000	74,761,000	74,761,000	74,761,000	74,761,000	74,761,000
33	TOTAL DEFERRED CREDITS AND OTHER LIABILITIES	674,670,000	681,843,000	690,003,000	699,451,000	699,451,000	699,451,000	699,451,000	699,451,000	699,451,000	699,451,000
34	TOTAL EQUITY AND LIABILITIES	3,214,527,829	3,294,613,288	3,417,770,072	3,590,300,945	3,725,549,333	3,867,050,287	3,994,946,305	4,160,288,504	4,329,075,376	4,341,012,000

Duke Energy Ohio
Legacy Generation Assets
Projected Sources and Uses of Funds

Exhibit BDS - 3
Page 1 of 1

Line	Description	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	SOURCE OF FUNDS										
2	Net Income	73,732,829	89,537,459	115,044,784	129,105,873	126,985,388	136,296,953	130,908,019	152,997,199	163,125,873	66,138,623
3	AFUDC	-	-	-	-	-	-	-	-	-	-
4	Depreciation / Amortization	103,161,103	100,579,761	100,547,208	104,800,315	108,138,929	110,495,086	115,458,314	113,214,040	101,424,883	42,955,622
5	Deferred Income Taxes	(12,160,000)	7,173,000	8,160,000	9,448,000	-	-	-	-	-	-
6	Changes in Working Capital	41,664,942	209,471,761	176,376,772	236,896,429	374,472,501	442,619,470	482,696,985	449,383,177	640,288,774	687,432,077
7		206,398,874	406,761,981	400,128,764	480,250,618	609,596,818	689,411,509	729,063,317	715,594,416	904,839,530	796,526,322
8	APPLICATION OF FUNDS										
9	Capital Expenditures	123,068,991	196,692,400	256,846,981	182,834,531	97,548,246	178,645,070	206,288,817	299,525,047	73,645,158	61,950,943
10	Dividends Paid	-	-	-	-	-	-	-	-	-	-
11		123,068,991	196,692,400	256,846,981	182,834,531	97,548,246	178,645,070	206,288,817	299,525,047	73,645,158	61,950,943

	P.U.C.O. Electric No. 10
	Sheet No. 94.1
Duke Energy Ohio	~~P.U.C.O. Electric No.~~
~~10~~Cancels and Supersedes	
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RIDER BDP

BACKUP DELIVERY POINT CAPACITY RIDER

BACKUP DELIVERY POINT (TRANSMISSION/DISTRIBUTION) CAPACITY

The Company will normally supply service to one premise at one standard voltage at one delivery point and through one meter to a Non-Residential Customer in accordance with the provisions of the applicable rate schedule and the Electric Service Regulations. Upon customer request, the Company will make available to a Non-Residential Customer additional delivery points in accordance with the rates, terms and conditions of this Rider BDP. For hospitals that are members of the Greater Cincinnati Health Council, Rider BDP will be administered as specified in Case No. ~~08-920~~11-3549-EL-SSO, Stipulation ~~Attachment 9~~Page 21, Section I.

NET MONTHLY BILL

1. Connection Fee $300.00
   The Connection Fee applies only if an additional metering point is required.

2. Monthly charges will be based on the unbundled distribution and/or transmission rates of the customer's most applicable rate schedule and the contracted-for reserved backup delivery point capacity.

3. The Customer shall also be responsible for the acceleration of costs to the extent that the revenue requirement for such costs exceeds the monthly charges established in Section 2 above, if any, which would not have otherwise been incurred by Company absent such request for additional delivery points. The revenue requirement for the acceleration of costs shall be equal to the product of the capital investment which has been advanced and the levelized fixed charge rate. The terms of payment may be made initially or over a pre-determined term mutually agreeable to Company and Customers that shall not exceed the minimum term. In each request for service under this Rider, Company engineers will conduct a thorough review of the customer's request and the circuits affected by the request. The customer's capacity needs will be weighed against the capacity available on the circuit, anticipated load growth on the circuit, and any future construction plans that may be advanced by the request. The acceleration charges described in this paragraph (3.) will not apply to customers that already have a backup delivery point as of the effective date of this Rider.

TERMS AND CONDITIONS

The Company will provide such backup delivery point capacity under the following conditions:

1. Company reserves the right to refuse backup delivery capacity to any Customer where such backup delivery service is reasonably estimated by Company to impede or impair current or future electric transmission or distribution service.

	P.U.C.O. Electric No. 10
	Sheet No. 94.1
Duke Energy Ohio	~~P.U.C.O. Electric No.~~
~~10~~Cancels and Supersedes	
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2. The amount of backup delivery point capacity shall be mutually agreed to by the Company and the Customer because the availability of specific electric system facilities to meet a Customer's request is unique to each service location.

3. System electrical configurations based on Customer's initial delivery point will determine whether distribution and/or transmission charges apply to Customer's backup delivery point.

TERMS AND CONDITIONS (CONTINUED)

4. In the event that directly assigned facilities are necessary to attach Customer's backup delivery point to the joint transmission or distribution systems, Company shall install such facilities and bill Customer the Company's full costs for such facilities and installations.

5. Energy supplies via any backup delivery point established under this Rider BDP will be supplied under the applicable rate tariff and/or special contract.

6. Company and the Customer shall enter into a service agreement with a minimum term of five years. This service agreement shall contain the specific terms and conditions under which Customer shall take service under this Rider BDP.

7. Company does not guarantee uninterrupted service under this rider.

SERVICE REGULATIONS

The supplying of, and billing for, service and all conditions applying thereto, are subject to the jurisdiction of the Public Utilities Commission of Ohio, and to the Company's Service Regulations currently in effect, as filed with the Public Utilities Commission of Ohio.

Duke Energy Ohio
139 East Fourth Street
Cincinnati, Ohio 45202

RIDER BDP

BACKUP DELIVERY POINT CAPACITY RIDER

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NET MONTHLY BILL

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TERMS AND CONDITIONS

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3. System electrical configurations based on Customer's initial delivery point will determine whether distribution and/or transmission charges apply to Customer's backup delivery point.

TERMS AND CONDITIONS (CONTINUED)

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