

BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Duke)
Energy Ohio, Inc. for the Establishment Of) Case No. 12-2400-EL-UNC
a Charge Pursuant to Revised Code Section)
4909.18.)

In the Matter of the Application of Duke)
Energy Ohio, Inc., for Approval to Change) Case No. 12-2401-EL-AAM
Accounting Methods.)

In the Matter of the Application of Duke)
Energy Ohio, Inc., for Approval of a Tariff) Case No. 12-2402-EL-ATA
for a New Service.)

**DIRECT TESTIMONY OF RICHARD D. TABORS
ON BEHALF OF
FIRSTENERGY SOLUTIONS CORP.**

I. INTRODUCTION, PURPOSE AND SUMMARY

Q. WHAT IS YOUR NAME, BUSINESS ADDRESS AND POSITION?

A. My name is Richard D. Tabors. I am president of Across the Charles and a Senior Consultant at Greylock McKinnon Associates. My business address is 1 Memorial Drive, Suite 1410, Cambridge, MA 02142. In addition, I am on the faculty of Massachusetts Institute of Technology (“MIT”) on a part time basis, where I head the Utility of the Future Project within the MIT Energy Initiative.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. I received a MSc and PhD in Geography and Economics from the Maxwell School of Syracuse University and BA in Biology and pre-medical sciences from Dartmouth College.

I taught on the faculty of Arts & Science and Department of City & Regional Planning at Harvard University from 1970 to 1976. From 1976 to 2006, I directed research and taught at Massachusetts Institute of Technology. I am a visiting Professor of Electrical Engineering at the University of Strathclyde in Glasgow, Scotland and, as mentioned, I have returned to MIT on a part time basis.

At MIT, I was the Associate Director of the Laboratory for Electromagnetic and Electronic Systems, the power systems engineering group at MIT. I was a senior lecturer and associate head of the Technology and Policy Program and team-taught electric power systems course in the Department of Electrical Engineering & Computer Sciences. I led the MIT prime contract with the Department of Energy in Photovoltaics and led the development at MIT of the EPRI funded development of the Electric Generation Expansion Analysis System (“EGEAS”). EGEAS is today one of the standard long-term capacity planning models used in the industry. At present, I am the co-principal investigator of the

DOE ARPA E project on Transmission Topology Control, with Boston University as the Prime Contractor and involving two additional universities and three private companies. This research effort undertaken with PJM is developing the analytic tools that will allow PJM and other transmission operators during time of congestion to open transmission breakers when doing so will lower the overall cost of delivery of energy in the interconnection and can be done without compromising reliability.

Along with three co-authors (Schweppe, Caramanis & Bohn), I developed the theoretical underpinnings that now apply to all electric markets worldwide. That work resulted in the publication of *Spot Pricing of Electricity* which is considered the basic text in power system markets. The Locational Marginal Price (“LMP”) markets as implemented in North America, such as PJM and elsewhere, are based directly on this work. I have worked on power market theory and market design in every market in North America. In addition, I was involved in the initial development of the market in the United Kingdom and provided expert consulting in Australia, New Zealand, and Peru relating to the power markets in those nations. I have worked on energy economics and power systems economic planning in Asia and the Pacific as well as in multiple nations in the Middle East.

I have co-authored 5 books and nearly 100 articles, the majority of which deal specifically with electric power markets and, most recently, with a critical review of capacity markets. I have lectured and been a speaker at academic meetings, sponsored conferences and at the meetings of the Energy Bar Association where I have provided educational sessions on the basic structure and functioning of LMP markets.

In 1988, along with two colleagues I started Tabors Caramanis & Associates (“TCA”), which grew to be a premier engineering economics consulting firm in the

1 restructuring of the power industry. The firm's work focused, as mine does now, on
2 providing asset analysis and valuation of generation and transmission in LMP markets.
3 TCA and I provided analysis on and testified about the California Energy Crisis and its
4 aftermath at the Federal Energy Regulatory Commission ("FERC"). In May 2001, I led the
5 Amicus Brief of Electrical Engineers, Energy Economists and Physics in *State of New York*
6 *et al. v. FERC and Enron Power Marketing v. FERC* that received explicit recognition
7 from the court in their decision.

8 In 2006 Charles River Associates ("CRA") acquired TCA. At CRA, I became co-
9 head of the Energy & Environment Practice. I stepped down from that role in 2009 and
10 departed from CRA in June of 2012.

11 I am presently the President and Principal of Across the Charles, an engineering
12 economic practice focused on electricity, natural gas and water. In addition, I am a Senior
13 Consultant with Greylock McKinnon Associates ("GMA"), an economic litigation firm.
14 My work in this case is being provided through my affiliation with GMA. My resume is
15 Attachment RDT-1 to this Testimony.

16 **Q. ON WHOSE BEHALF ARE YOU TESTIFYING?**

17 A. I am testifying on behalf of FirstEnergy Solutions Corp. ("FES").

18 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

19 A. The purpose of my testimony is to: (1) explain certain aspects of the PJM capacity
20 market; (2) provide a calculation rate for capacity based on DEO's avoidable cost; (3)
21 comment upon specific issues within DEO's capacity rate calculation; and (4) address the
22 testimony of DEO witness Scott Neiman and specifically his assertions regarding: (a) the
23 relative risks faced by Fixed Resource Requirement ("FRR") entities versus other capacity

1 suppliers in PJM; (b) how the Reliability Assurance Agreement (“RAA”) establishes
2 capacity pricing for FRR entities; and (c) lack of price distortion.

3 **Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.**

4 A. I have six conclusions. First, the application by DEO represents an opportunistic
5 effort to collect additional revenues from Ohio ratepayers in direct contravention of the
6 stipulations that DEO signed with numerous signatory parties, filed April 26, 2011 in
7 (“PJM Stipulation” Attachment RDT-2)¹ and October 24, 2011 (“ESP Stipulation”
8 Attachment RDT-3).² In signing these stipulations, DEO was fully aware of the financial
9 structure of PJM, the revenue that DEO would receive from the PJM market structure for
10 capacity charges and the likely energy revenues that DEO would receive that would
11 provide additional revenue to cover, in part, DEO’s capital costs. In returning to the Public
12 Utilities Commission of Ohio (“PUCO”) to request additional revenue, DEO and DEO’s
13 witness Niemann are attempting to abrogate the intent of these Stipulations by arguing that
14 the PJM rules do not prevent them from doing so. This argument ignores that DEO had
15 agreed with the signatory parties that they would not do so in the first place.

16 Second, it is my conclusion that DEO’s argument with regard to any alleged hardship
17 suffered by virtue of receiving only market-based prices for its capacity and therefore
18 DEO’s attempt to justify the need for additional revenue is counter to the economic logic of
19 the PJM RAA. In setting the market value of capacity, only those costs that could be
20 avoided by either mothballing or retiring a generating resource should be considered. This

¹ *In the Matter of the Application of Duke Energy Ohio, Inc., for Approval of the Establishment of Rider BTR and Associated Tariffs*, Case No. 11-2641-EL-RDR et al., Stipulation and Recommendation, § VII.A (April 26, 2011).

² *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 Nos. 11-3549-EL-SSO et. al., Stipulation and Recommendation (Oct. 24, 2011).

1 amount should be netted by any incremental revenue that will be generated from the sale of
2 energy and ancillary services.

3 Third, the analyses undertaken by DEO to justify its application do not conform to the
4 PJM capacity compensation calculation procedures which represent an effort to arrive at
5 the market value of the DEO capacity. Simply put, the PJM Reliability Pricing Model
6 (“RPM”) derived revenue compensates DEO for the economic value of its operating
7 capacity.

8 Fourth, my analyses conclude that DEO is currently collecting the economically
9 correct amount for DEO’s capacity.

10 Fifth, I believe that DEO witness Niemann’s argument that DEO is subject to greater
11 risk by operating under FRR rules for capacity is neither correct nor relevant. DEO is not
12 at greater risk. In fact, DEO may arguably face lower risk through the time period from
13 August 1, 2012 through May 31, 2015 than other capacity suppliers within PJM. In
14 addition, independent of whether DEO is at greater or lesser risk than other capacity
15 suppliers within PJM, DEO was fully aware of any risk when it signed the PJM Stipulation
16 and ESP Stipulation, making any argument concerning risk irrelevant and immaterial to the
17 current filing.

18 Sixth, I believe that, were DEO to be allowed to collect revenues in excess of the
19 RPM value, all customers within the DEO load zone and within PJM as a whole would be
20 harmed both in terms of future costs and reliability. Those within the DEO load zone will
21 be paying more for capacity than DEO promised under the PJM Stipulation and ESP
22 Stipulation and will not have access to the competitive PJM capacity market as customers
23 do in the majority of load zones in PJM.

24 **Q. HOW IS YOUR TESTIMONY ORGANIZED?**

1 A. Section II of my testimony discusses DEO's choice to transition from the Midwest
2 ISO to PJM. Specifically, I focus on the economic underpinnings of the PJM
3 interconnection, its organization and rules with respect to capacity markets and the
4 importance of accepting the economic structure that has been vetted by all members of the
5 PJM interconnection and approved by the FERC as the most economically efficient manner
6 of implementing the capacity market. DEO's proposed Rider DR-CO should not be
7 accepted given that DEO was fully aware of the economics and corresponding financial
8 implications of its transition from MISO to PJM when elected to realign to PJM, DEO fully
9 understood the implications of FRR status and accepted those with its decision to transition
10 from MISO.

11 Section III of my testimony supports the economic rationale that, within a
12 competitive market, it is net avoidable costs – not embedded costs – that are the correct
13 measure for the value of capacity.

14 Section IV of my testimony demonstrates that the PJM Stipulation and ESP
15 Stipulation should preclude the relief that DEO seeks in this case.

16 Section V of my testimony presents my calculation of the net avoidable cost rate for
17 DEO's capacity – the economically correct transfer / transition price for DEO capacity with
18 the PJM RPM. This calculation shows that the capacity rate proposed by DEO will
19 significantly over-compensate DEO.

20 Section VI of my testimony responds to the testimony of DEO witness Niemann that:
21 (a) DEO faces significant additional risk associated with the requirement that until June 1st
22 of 2015 DEO be required as an FRR entity to supply capacity to all LSEs within its load
23 zone that do not have their own FRR plan; and (b) because of the structure of the PJM
24 forward capacity market, the rules for FRR entities are far more restrictive (therefore risky)

1 than those of other capacity resource owners in PJM. Further, I rebut Dr. Niemann's
2 premise that because FERC did not foreclose the possibility of a state choosing a method of
3 calculation of recoverable capacity cost differently from that of PJM, it is reasonable and
4 expected that DEO should file and the PUCO should approve additional compensation for
5 capacity. Finally, I rebut Dr. Niemann's conclusions that implementation of the DEO rider
6 will not distort prices.

7 **II. THE PJM MARKET AND DEO's CHOICE TO TRANSITION FROM MISO TO** 8 **PJM**

9 **Q. WHAT IS THE IMPORTANCE OF DEO TRANSITIONING FROM THE** 10 **MIDWEST ISO TO PJM?**

11 A. DEO, after significant evaluation and litigation, was allowed to transition from the
12 Midwest ISO to PJM. No decision of this nature is made lightly; it involves regulatory
13 interaction at the Federal and the State level. In making the decision to make this
14 transition, it must be presumed that DEO studied and knew the structure, policies and rules
15 of the PJM markets and particularly the fact that PJM's market rules are more aligned with
16 retail customer shopping than MISO's rules. It must also be presumed that DEO decided
17 that any near term cost (in terms of any inability to immediately recover its embedded
18 costs) would be outweighed by future revenues in an efficient market-based system of
19 compensation for capacity, energy and other services.

20 **Q. CAN YOU GIVE A BASIC OVERVIEW OF HOW PJM OPERATES?**

21 A. Yes. PJM is a Regional Transmission Organization that administers open access to
22 the transmission system, and independently operates efficient and competitive financial
23 markets for energy, capacity and ancillary services. PJM conducts long-term regional
24 transmission planning in order to ensure reliability is maintained by making the most cost-

effective additions and improvements to the integrated transmission system that it operates. The FERC-approved documents that govern PJM are primarily contained in the RAA and the Open Access Transmission Tariff (“OATT”).

Q. HOW DOES PJM MAKE SURE THERE IS ENOUGH CAPACITY AVAILABLE TO SERVE THE ENTIRE LOAD OF THE RTO?

A. PJM forecasts how many MW’s of resources (generation, demand response and energy efficiency) are required in order to supply the capacity requirements of the RTO at all times. This means that enough capacity must be available at any given time to meet the energy needs of all customers plus an additional reserve amount to cover contingencies such as a generation outage, transmission failure or higher than anticipated demand. PJM requires that enough capacity be committed at least three years ahead of anticipated capacity needs through either PJM’s : (1) the RPM auction process; or (2) FRR rules.

Q. PLEASE EXPLAIN THE RPM STRUCTURE AS IT IS CURRENTLY IMPLEMENTED WITHIN PJM.

A. The objective of the PJM RPM structure is to ensure sufficient generating capacity under the control of PJM in every delivery year.³ PJM begins the process roughly three and a half years before the beginning of every delivery year by qualifying existing and planned resources as potential capacity suppliers. Once qualified, these potential capacity suppliers are able to bid their capacity resources into several auctions that establish which resources will be relied upon to meet the capacity needs in the majority of PJM’s footprint. The first of these auctions for any given delivery year is called the Base Residual Auction (“BRA”). The BRA is held three years before the start of the delivery year. The PJM Market Monitor determines what, if any, caps and floors should apply to a given potential

³ The delivery year of PJM is defined to run from June 1 to May 31.

1 capacity suppliers' offers into the auctions based in large part on the economics of the
2 supplier's capacity resources. These caps and floors are designed to prevent anti-
3 competitive bidding behavior in the BRAs. This helps to ensure that uneconomic
4 generation retires when it should, economic generation remains in the market, and proper
5 economic incentives exist for new, more efficient generation to be constructed and enter
6 the market. PJM sets the quantity of required capacity by zone.

7 Within PJM, there is an administratively determined capacity demand curve that
8 relates the quantity of capacity resources acquired in each BRA to the price that is paid for
9 that capacity. Because the demand curve is fixed for a given auction, if, for instance, the
10 market clearing price in the auction is lower than the estimated value of the Cost of New
11 Entry (CONE), the amount of capacity that clears the auction will be greater than what
12 would have cleared at CONE. Under the design of the BRA auction, the lower the price for
13 capacity the greater the quantity of capacity that will clear in the BRA auction.

14 The auction that takes place in May of each year then provides the mechanism that
15 selects the least-cost set of capacity resources at the capacity price (auction clearing price)
16 that will be paid to all participants in the capacity market. Load Serving Entities ("LSEs"),
17 i.e., those entities with an obligation to provide electricity supply to end use customers
18 (including competitive suppliers like FES and utilities like DEO with a default service
19 obligation), are then charged the final capacity price for the delivery year. The PJM
20 capacity market is zonal based upon transmission delivery constraints. Zonal capacity
21 prices differ based on the difficulty of delivering capacity into a given area. LSE capacity
22 cost are assessed by zone and therefore vary across the PJM footprint as a function of the
23 ability of energy to be delivered into a specific area.

1 **Q. YOU REFER TO MOST PJM CAPACITY RESOURCES BEING ACQUIRED**
2 **THROUGH THE RPM AUCTION PROCESS, IS THERE AN ALTERNATIVE?**

3 A. Yes. The RAA provides an option that allows certain LSEs to “self-supply,” i.e., to
4 provide or acquire their own capacity resources. This is the FRR alternative. An FRR
5 entity, like DEO, will follow an alternative set of rules from those of other PJM members
6 who participate or participated in the relevant annual RPM auctions.

7 **Q. WHAT ARE THE OBLIGATIONS OF AN FRR ENTITY?**

8 A. The objective of both the RPM and the FRR is to assure resource adequacy. The
9 RAA allows certain entities to “self-supply” their capacity rather than be forced to offer to
10 sell and purchase capacity through the RPM auctions. While this option was primarily
11 designed to accommodate utilities that were still operating in states with traditionally
12 regulated markets or for municipal or cooperative utilities, it also has been utilized to
13 facilitate entities like DEO in their transition to retail deregulation and into the PJM
14 Interconnection when auctions and capacity commitments have already occurred. An FRR
15 entity must submit a plan for an initial minimum term of five years and must identify the
16 specific fixed generating units or demand resources that will be relied upon to satisfy the
17 capacity obligation. The FRR entity must demonstrate that the resources meet all
18 eligibility requirements as defined in Schedule 8.1 of the RAA (Attachment RDT-4). Only
19 one entity can meet the capacity resource needs for a given load zone, unless an LSE inside
20 that zone establishes its own FRR Plan within the required timeframe.

21 **Q. WHAT ARE THE DIFFERENCES BETWEEN THE OBLIGATIONS OF A**
22 **CAPACITY SUPPLIER PARTICIPATING IN THE RPM AUCTIONS VERSUS**
23 **THOSE OF AN FRR ENTITY?**

1 A. The critical differences between the FRR and RPM structures center on the purpose
2 for which the FRR procedures were established. The goal of the FRR was to allow an LSE
3 with a different business model from the majority of the LSEs in PJM (e.g., not
4 restructured) to self-provide all of the capacity required for it to meet its load. Participants
5 in the RPM process have their capacity requirement set annually; whereas for an FRR
6 entity, it is set once initially for five years. RPM participants are required to hold
7 additional capacity above their forecasted peak load, all priced at the market clearing point.

8 RPM participants are subject to significant uncertainty year on year and therefore are
9 at risk in terms of the future price that they will receive for their capacity. During the past
10 five BRA auctions, the clearing prices for “rest of market” has gone from a high of
11 \$174.29/MW-Day (for the 2010/11 delivery year) to a low of \$16.46/MW-Day (for the
12 2012/13 delivery year) with the most recent clearing price of \$125.99/MW-Day in the
13 2014/15 BRA (Attachment RDT-5).⁴ The traditional, self-supply FRR entity receives its
14 capacity revenues directly from its ratepayers and is independent of the RPM auction
15 capacity compensation structure.

16 The traditional FRR entity has the security of knowing, with only small variation for
17 the 5-year forward period, the level of its capacity revenue. As noted, DEO was fully
18 aware of what the RPM prices would be over the term of its FRR plan *and* the Stipulation
19 since those auctions had already occurred. Thus, while DEO agreed to RPM pricing, it did
20 not face any capacity price risk.

21 **Q. IS DEO AN FRR ENTITY?**

22 A. Yes.

⁴ <http://www.pjm.com/~media/markets-ops/rpm/rpm-auction-info/20120518-2015-16-base-residual-auction-report.ashx>, page 5.

1 **Q. DID DEO BECOME AN FRR ENTITY BECAUSE IT WAS A VERTICALLY**
2 **INTEGRATED UTILITY?**

3 A. No. The application of FRR to the current case with DEO is largely by default. DEO
4 is not a traditional, self-supply FRR holder and it is not the intention of DEO to remain an
5 FRR entity.

6 As noted, the PJM RPM market is a forward market, with BRAs held three years
7 before the delivery year for which the auction is procuring capacity. The first BRA after
8 DEO's migration into PJM was held in May 2012 for the 2015/16 delivery year. By
9 migrating into PJM prior to June 2015, DEO was foreclosed from offering and procuring
10 capacity through BRAs for the 2012/13, 2013/14 and 2014/15 delivery years because those
11 auctions had already been held and were closed. Thus, for the delivery years between the
12 time of DEO's migration into PJM and the 2015/16 delivery year, DEO was required to
13 self-supply through its own resources or through bilateral contracts with capacity resources
14 that were still available (*i.e.*, not already committed through forward RPM auctions).

15 **Q. WAS DEO REQUIRED TO BECOME AN FRR ENTITY?**

16 A. No. DEO was in control of the timing of its migration into PJM. Thus, for example,
17 DEO had the option of staying in the Midwest ISO until June of 2015, and still
18 participating in the RPM auctions held in 2012, 2013 and 2014 for delivery years 2015/16,
19 2016/17 and 2017/18 respectively. This would have allowed DEO to meet its capacity
20 obligations entirely through the RPM auctions once it migrated to PJM. DEO did not
21 pursue this option and instead voluntarily elected to become an FRR entity when it joined
22 PJM in January 2012.

23 **Q. DOES THE TIMING OF DEO'S FRR ELECTION AFFECT CRES PROVIDERS**
24 **OPERATING WITHIN DEO'S SERVICE AREA?**

1 A. Yes. As noted, CRES providers, as LSEs, could have elected to self-supply their
2 capacity. Yet, once DEO's FRR plan was in place, other LSEs in the DEO FRR area could
3 only self-supply by submitting their own FRR plan beginning once the term of DEO's plan
4 expires.

5 A CRES provider could have coordinated the implementation of its own FRR plan for
6 the customers it serves within DEO at the time of DEO's submission of its FRR plan.
7 However, neither CRES providers nor their customers had any indication at that time that
8 DEO was going to ask for compensation beyond RPM-based prices. Had they known of
9 DEOs intentions, customers wishing to be served by a CRES provider could have required
10 their CRES provider to provide capacity in a FRR Plan, thereby avoiding the current higher
11 cost proposal of DEO. This would have enabled DEO to avoid bilateral capacity purchases
12 and possibly to sell some of its excess capacity. Instead, under the current retroactive and
13 out-of time DEO proposal, customers are now left with no options.

14 **III. AVOIDED COST, NOT EMBEDDED COST, IS THE BASIS FOR PJM CAPACITY**
15 **PRICING.**

16 **Q. TURNING BACK TO THE RPM PROCESS, YOU INDICATED THAT THE**
17 **MARKET MONITOR DETERMINES WHEN AND IF IT IS NECESSARY FOR**
18 **THERE TO BE CAPS AND FLOORS TO THE BIDS. WHY IS THIS NEEDED**
19 **AND WHAT IS THE EFFECT?**

20 A. Within PJM, the owners of existing generating capacity must offer their capacity into
21 the RPM markets. Because the Market Monitor has determined that suppliers are
22 structurally concentrated (i.e., they can theoretically affect the market price in an

1 anticompetitive manner), all offers from existing resources are subject to offer caps in the
2 RPM auctions.

3 **Q. WHAT IS THE MECHANISM USED BY THE PJM MARKET MONITOR FOR**
4 **SETTING OFFER CAPS?**

5 A. The Market Monitor sets the caps based on the economic logic of “Avoidable Cost.”
6 The avoidable cost for a capacity supplier is based on the costs that a resource owner could
7 avoid by either retiring or mothballing a given generating resource. The procedure for
8 calculation of the Avoidable Cost Rate (“ACR”) is described in Section 6.8 of Attachment
9 DD of the OATT (Attachment RDT-6).

10 **Q. WHY ARE OFFERS CAPPED BASED ON THE AVOIDABLE COST RATE?**

11 A. The underlying economic and market logic is quite simple, and explains why the
12 ACR is the economically correct way to value capacity in competitive markets like PJM’s
13 (Attachment RDT-7). In electricity, as in all markets, sunk costs are sunk. In making the
14 decision to operate or not to operate (or in this instance to provide capacity or not to
15 provide capacity to the market), one will provide capacity only when the expected revenue
16 is greater than the going forward cost. Going forward costs are those costs that the
17 generator must pay if the unit is to remain in operation but would not be required were the
18 unit to be retired or mothballed. These costs include things like labor, environmental
19 chemicals for air quality, cooling water and others that would not be required but for the
20 fact that the unit will be operating. In addition, on a going forward basis, these costs
21 include capital costs for retrofits not yet made but that are required for the unit to keep
22 operating.

23 **Q: CAN YOU PROVIDE AN EXAMPLE OF THE CALCULATION OF AN ACR?**

1 A. Consider the following simple example. An older generating unit with an expected
2 lifetime of an additional 5 years has a total annual going forward cost of \$100 million that
3 is made up of two components. The first is labor and operating expenses and the second is
4 the annualized capital cost of equipment that must be added in order for the unit to operate
5 for the additional 5 years. Assume for this example that the PJM capacity market will
6 return \$110 million in annual revenue. The owner of the capacity will chose to keep the
7 unit available because the net revenue (revenue minus expense) is \$10 million greater than
8 the net revenue that would be available were the unit to be retired or mothballed. That \$10
9 million would go toward paying for the sunk (not going forward) costs of the unit.

10 **Q: WHAT DECISION WOULD BE MADE IF THE REVENUE RECEIVED WAS**
11 **LESS THAN THE GOING FORWARD COSTS?**

12 Were the revenue in the above example only \$90 million, it would be economically
13 rational either to retire or to mothball the unit. Although the sunk (not going forward) costs
14 remain, there is now a \$10 million additional and preventable loss.

15 **Q: WHAT WOULD BE THE IMPACT IF THE DECISION WERE MADE TO NOT**
16 **GO FORWARD EVEN THOUGH THE REVENUE WAS EVEN marginally**
17 **SUFFICIENT?**

18 A: Such a decision would not be economically rational and in the example of \$110
19 million in revenue noted earlier, the impact would be that of “leaving \$10 million on the
20 table.”

21 **Q. GIVEN YOUR DISCUSSION OF THE ECONOMIC LOGIC OF AVOIDABLE**
22 **COST, HOW DOES THIS COMPARE WITH RECOVERY OF EMBEDDED**
23 **COST?**

1 A. Calculation of embedded cost is an accounting concept, not an economic or market
2 concept. Embedded cost calculations account for the annualized recovery of: (a) all of the
3 non-depreciated costs (sunk and not going forward) of the generating unit; and (b) the
4 going forward costs. The critical difference is the impact that the use of embedded costs
5 has on market behavior. In the example above, the assumption was that the going forward
6 cost for both operations (labor) and capital was \$100 million and that the revenue was \$110
7 million. The correct economic decision is to keep the unit operating. If the decision were
8 based on the embedded cost (sunk and not going forward combined with the going
9 forward) and those costs were greater than \$110 million in revenues – a highly likely
10 outcome in this example – the decision would be to retire the unit. This would be the
11 wrong decision in a competitive economic structure such as PJM because the unit would
12 earn enough money to operate in the short term. Retiring at that point in time would
13 sacrifice any chance the unit has to recover its sunk or “embedded costs” should total
14 market prices including capacity, energy and ancillary services rise above its going forward
15 costs in the future.

16 **Q. DOES RPM GUARANTEE RECOVERY OF FULL EMBEDDED COST?**

17 A. No. RPM does not guarantee recovery of full embedded costs as calculated by DEO
18 in this case. The words “embedded costs” are not found in the OATT or the RAA, for
19 good reason. Embedded costs are not part of market operating and participation decisions
20 because, as I explain above, “sunk costs are sunk.” The structure of RPM ensures the
21 existence of sufficient capacity resources to maintain reliable operations of PJM. It does so
22 by creating a market for those resources with the agreement that the LSEs within PJM will
23 pay the delivery year market clearing price for capacity supplied.

1 **Q. HOW DOES THE PJM MARKET MONITOR USE THE INFORMATION ABOUT**
2 **A CAPACITY SUPPLIER’S AVOIDABLE COSTS IN ITS CALCULATION OF**
3 **THE MARKET CAP FOR GENERATORS IN THE BRA?**

4 A. The Market Monitor follows the procedures of Attachment DD of the PJM Tariff (see
5 pages 2346 – 2447) to derive the maximum allowable capacity bid. From this, the Market
6 Monitor subtracts its estimate of the earnings of the unit above its marginal operating costs
7 – its net energy revenue and returns for the ancillary services market, both valued at the
8 PJM spot market price and averaged over the three prior calendar years. This sum is called
9 the energy and ancillary services offset (“E&AS Offset”) and takes into account other
10 revenues that a capacity supplier can expect to earn from its capacity resources. Any given
11 generating unit can challenge the calculation of the net of the unit’s avoided costs (or ACR
12 minus the E&AS Offset), but generally the calculations are not challenged because these
13 values have been calculated with significant leeway by the Market Monitor. The
14 importance of ACR to the structure of PJM’s capacity market and RAA structure cannot be
15 overstated. Nothing in the PJM Tariff rules governing the FRR alternative entitles an FRR
16 entity to recover its full embedded cost, because even for such entities it is the ACR not
17 embedded cost that is the proper guide for them in making the “to go, or not to go” decision
18 with respect to their generation capacity resources.

19 **IV. DEO’S PRIOR COMMITMENTS SHOULD PRECLUDE THE RELIEF THAT IT**
20 **SEEKS HERE.**

21 **Q. PLEASE SUMMARIZE THE RATE REQUESTED BY DEO IN THIS CASE.**

22 A. DEO has requested that the PUCO approve a non-bypassable Rider Deferred
23 Recovery – Capacity Obligation (“DR-CO”) that will provide the revenue difference

1 between what DEO, based on a logic of embedded cost, argues it should receive for the
2 capacity it is providing to the DEO load zone customers and the revenue it is receiving
3 from the PJM RPM based capacity value that DEO has agreed to charge the LSEs within
4 the load zone.

5 **Q. DO YOU AGREE WITH THE LOGIC PUT FORTH BY DEO IN REQUESTING**
6 **APPROVAL OF RIDER DR-CO?**

7 A. No. DEO has attempted to argue that it is similarly situated to AEP Ohio and
8 therefore that the conclusions of the PUCO in Case No. 10-2929-EL-UNC are fully
9 applicable here. This is wrong.

10 **Q. ARE THERE DIFFERENCES BETWEEN THE APPLICATION OF DEO AND**
11 **THAT OF AEP?**

12 A. Yes. The most critical difference between the AEP Ohio case and DEO's request is
13 that DEO, as a part of its transition from MISO to PJM, agreed a state compensation
14 mechanism for capacity and specifically acknowledged that DEO would not seek additional
15 revenue for capacity.

16 Section D of Schedule 8.1 of the PJM RAA sets out the only methods of
17 compensation by other LSEs (i.e., competitive retail electric service providers) for a FRR
18 entity's capacity. DEO's compensation can only come through three mechanisms (in order
19 of priority): (1) the RPM price; (2) a state compensation mechanism; or (3) a filing at
20 FERC for a wholesale capacity charge.

21 The ESP Stipulation approved in DEO's most recent Electric Security Plan case,
22 states:

23 For the calendar years 2012, 2013, and 2014 of the ESP Duke
24 Energy Ohio shall recover annually, via a non-bypassable
25 generation charge called the Electric Service and Stability Charge

1 (Rider ESSC), an amount intended to provide stability and
2 certainty regarding Duke Energy Ohio's provision of retail electric
3 service as an FRR entity while continuing to operate under an
4 ESP.⁵

5 Moreover, the PJM Stipulation approved in DEO's proceeding to approve tariffs related to
6 DEO's PJM realignment, Case No. 11-2641-EL-RDR *et al.*, states:

7 Duke Energy Ohio agrees that it will not institute a filing at the
8 FERC under section D of Schedule 8.1 of the PJM Reliability
9 Assurance Agreement that requests FERC approval of a wholesale
10 capacity charge applicable to load serving entities based upon
11 Duke Energy Ohio's costs as a Fixed Resource Requirement entity
12 in PJM for the period between January 1, 2012 and May 31, 2016.⁶

13 DEO also committed in the PJM Stipulation that in its next ESP (the current ESP) it would not
14 charge its SSO customers twice for the same capacity.⁷

15 The RPM-based capacity charges to non-FRR LSEs operating in DEO's territory set out in
16 the ESP Stipulation established a state compensation mechanism under Section D of Schedule 8.1
17 of the RAA.⁸ With respect to Rider ESSC, the ESP Stipulation states that one of its purposes is to
18 compensate DEO for its services as an FRR entity. An FRR entity's services can only be capacity
19 services, since the FRR option only deals with capacity services. DEO agreed in its PJM
20 Stipulation not to go to FERC to seek additional or alternative capacity compensation through a
21 filing under Section 205 of the Federal Power Act, resolving the other avenue for it to otherwise
22 seek compensation for its capacity.⁹ Since under the ESP Stipulation the ESSC is explicitly

⁵ ESP Stipulation, § VII.A (emphasis added).

⁶ *In the Matter of the Application of Duke Energy Ohio, Inc., for Approval of the Establishment of Rider BTR and Associated Tariffs*, Case No. 11-2641-EL-RDR *et al.*, Stipulation and Recommendation, § 20 (April 26, 2011).

⁷ PJM Stipulation, § 7.

⁸ ESP Stipulation, §§ IV. A., II. B.

⁹ See Stipulation, Sections I.B & II.B, (stating respectively "...for so long as for so long as Duke Energy Ohio is a Fixed Resource Requirements (FRR) entity under PJM Interconnection, LCC, (PJM), it will provide capacity at the Final Zonal Capacity Price (FZCP) in the unconstrained regional transmission organization (RTO) region. For the period during which Duke Energy Ohio participates in PJM's Reliability Pricing Model (RPM) and Base Residual Auction (BRA), the capacity price is the FCZP for the DEOK load zone region, and capacity shall be provided pursuant to the PJM RPM process."; and "Acknowledging Duke Energy Ohio's status as an FRR entity in PJM, the Parties agree that Duke Energy Ohio shall supply capacity to PJM, which, in turn, will charge for capacity to all

described as compensation for DEO's FRR services (i.e. capacity services) all possible ways that DEO could reasonably expect to be compensated for FRR capacity have been addressed by the PJM and ESP Stipulations. By agreeing to these Stipulations, DEO explicitly agreed not to do what it is attempting to do here. Any attempts, however clever, to get around this language cut against the plain meaning and clear intent of the Stipulations.

Q. ON WHAT LOGIC IS DEO BASING ITS ARGUMENT THAT IT IS PERMITTED TO FILE ITS RIDER DR-CO?

A. DEO has based its filing for Rider DR-CO on the fact that it committed to not filing under Section D, Schedule 8.1, and therefore it is not forbidden from applying for additional capital recovery at the PUCO. In addition, DEO contends that the PUCO is not forbidden from allowing for embedded cost recovery.

This misreads the terms of the PJM Stipulation and ESP Stipulation. Because the ESP Stipulation set a state compensation mechanism using RPM-based prices to be collected from LSEs and also compensates DEO for its FRR capacity service through the ESSC, DEO already has been given whatever relief that it would be entitled to. Although the PJM Stipulation precludes DEO explicitly from making a filing at the FERC potentially seeking to set a non-RPM based capacity rate (as it otherwise may have the right to do under the RAA), the ESP Stipulation, by setting a state compensation mechanism and otherwise compensating DEO for its FRR capacity service, also precludes DEO from another try at seeking the same relief.

A reasonable interpretation of the PJM and ESP Stipulations is that DEO would not challenge the compensation it was otherwise receiving from the ESSC and the PJM market

wholesale supply auction winners for the applicable time periods of Duke Energy Ohio's ESP with the charge for said capacity determined by the PJM RTO, which is the FZCP in the unconstrained RTO region.”)

1 prices through the only other avenue left to it by the PJM RAA, a FERC filing. While
2 DEO appears to believe that the PJM Stipulation covers only the application to FERC
3 allowed under Section D of Schedule 8.1 of the PJM RAA, I do not believe that such an
4 interpretation is warranted. It is difficult to believe that any other signatory party to the
5 PJM Stipulation would have signed an agreement that would not have protected Ohio
6 consumers from all future changes in wholesale capacity charges not merely those that
7 could have been initiated through a filing at the FERC. From a laymen's perspective, DEO
8 appears to believe that there was a loophole in the agreements it signed that allows DEO to
9 take "another bite at the apple." A full reading of these agreements with an understanding
10 of Section D of Schedule 8.1 of the RAA makes it clear to me that no such loophole exists.

11 **V. THE ECONOMICALLY CORRECT TRANSFER OR TRANSITION PRICE FOR**
12 **DEO'S CAPACITY**

13 **Q. WHAT IS THE CORRECT PRICE FOR CAPACITY IN THE TRANSITION OF**
14 **DEO TO PJM?**

15 A. From the perspective of economics, the correct capacity price in the transition of
16 DEO to PJM is the economic value of the capacity. That economic value of capacity
17 within PJM during the transition period is a known amount, established through a market
18 mechanism, the BRA (and subsequent incremental auctions). The PJM RPM is structured
19 such that, in the long run, it will provide the correct incentives for both new cost-effective
20 resource entry into the system and the retirement of inefficient resources.

21 Given that the prices that result from PJM RPM auctions are economically efficient in
22 both the short and the long run, there is no economically justified argument for prices to be
23 set in other than this manner. Setting the price higher than the efficient level will, as I
24 discuss later, cause inefficiencies in the overall retail market in Ohio (as would setting the

1 prices lower than the RPM auctions) and in the wholesale market across the PJM footprint.

2 Thus, the correct price for capacity is the RPM auction clearing price for the delivery year.

3 **Q. DO YOU AGREE WITH THE CALCULATIONS PROVIDED BY DEO WITNESS**
4 **WATHEN IN THIS CASE?**

5 A. No. Mr. Wathen's calculations are based upon the incorrect theoretical structure.
6 The embedded cost methodology, as I describe above, is incorrect in the PJM market
7 context and makes little sense in the context of DEO's agreement that it would be
8 compensated for capacity based on PJM's competitive market prices.

9 First, embedded cost plays no role in market economics and is not a concept that is
10 used or is applicable in the PJM market structures. PJM is based upon the economic theory
11 of competitive markets. In competitive markets, sunk costs are sunk and their recovery
12 must come from market mechanisms such as the competitive capacity market, the energy
13 market and the ancillary services market in PJM.

14 Second, as a part of the Stipulation, DEO was allowed to recover \$330 million
15 through a non-bypassable Rider ESSC over the three-year period 2012 to 2014. Rider
16 ESSC represented a negotiated value that is, in effect, a payment for costs associated with
17 DEO's services as an FRR entity which it argued needed to be recovered. Again, FRR
18 services are synonymous with capacity services since FRR entities only exist as a feature of
19 PJM's capacity reliability construct. To the extent DEO felt it needed additional
20 compensation for its capacity resources above and beyond the competitive PJM capacity
21 market, DEO has explicitly agreed in the ESP Stipulation that the ESSC would provide that
22 additional compensation. The current request for a second non-bypassable rider represents
23 a second attempt to recover for the cost of its capacity resources.

24 **Q. HOW SHOULD DEO BE COMPENSATED FOR ITS CAPACITY?**

1 A. DEO should be compensated based on what it agreed to, *i.e.*, RPM-based prices and
2 the ESSC. If instead DEO's prior commitment is disregarded, from an economic
3 perspective, the proper way to determine how it should be compensated would be to
4 determine the economic value of that capacity. As described above, that methodology
5 would calculate the ACR and the Avoidable Project Investment Recovery Rate ("APIR")
6 for the DEO units. Using this methodology, it is possible to calculate the minimum amount
7 that a participant in the PJM capacity market would need to recover to pay all of its
8 avoidable costs and earn some, even if a small amount, toward embedded costs.
9 Conceptually, the analysis answers the following question: "How much revenue above my
10 marginal revenue from energy and ancillary services sales is needed to cover the avoidable
11 costs incurred by not retiring or mothballing the generating unit?"

12 **Q. HAVE YOU CALCULATED THIS VALUE FOR THE DEO GENERATING**
13 **FLEET?**

14 A. Yes, based generally upon publically available information. My calculations were
15 divided into two major efforts. The first effort identified the appropriate ACR and APIR
16 for the DEO Legacy Generating Assets. The second effort involved calculation of the
17 energy revenues and estimation of ancillary service revenues for each of the Legacy
18 Generating Assets.

19 **Q. WHAT WAS YOUR SOURCE OF INFORMATION FOR ACR VALUES?**

20 A. My primary source for ACR was the 2012 PJM Market Report that lists the PJM fleet
21 ACR values by unit type for each delivery year relevant to DEO's case. These values have
22 been calculated conservatively by PJM. In the case of DEO there are three unit types: (1)
23 Coal/Steam; (2) Combustion Turbine; and (3) Internal Combustion (Diesel).

24 **Q. DID YOU CONSIDER CALCULATION OF INCREMENTAL APIR VALUES?**

1 A. Yes. APIR is one element of the ACR provided by PJM and represents a calculated
2 value to account for necessary/planned additions to capital. Because APIR is included
3 within the values provided by PJM for ACR, I reviewed the environmental investment
4 requirements of the existing DEO units to identify capital expenditures beyond the level
5 assumed within the ACR values. Review of the publicly available information on DEO
6 generating units netted no specific, high capital cost investments planned for DEO units.
7 Given the already conservative ACR valuation procedures of PJM, my analysis used only
8 the published ACR values for calculation of the DEO avoidable costs.

9 **Q. WHAT WERE THE SOURCES OF DATA FOR THE MODELING OF ENERGY**
10 **REVENUES?**

11 A. Through discovery, FES requested specific data on DEO legacy generating assets'
12 hourly dispatch and LMP values as well as unit fuel costs. FES did not receive that data
13 from DEO. As a result, I have had to use publicly available data. Using publicly available
14 data, I performed two sets of calculations. The first set of calculations provided an estimate
15 of energy revenues for DEO Legacy Generating Assets over a historical period in 2012.
16 The second set of calculations provided for the same assets a forecast of future energy
17 revenues.

18 **Q. WHAT WERE THE PRIMARY SOURCES OF THE DATA THAT YOU USED IN**
19 **CALCULATING ENERGY REVENUES?**

20 A. The most critical of the data for calculation of the energy revenues is the heat rate for
21 individual units. I used (and will report the results for) two data sources. The first source
22 was a set of calculations based upon the EPA's Continuous Emission Monitory System
23 ("CEMS") data base for 2012. The second data set provided various data as reported by
24 SNL Financial.

- EPA CEMS data was also the source by hour for generation, fuel use and emissions.
- The cost of coal delivered to individual units was obtained through SNL Financial and assumed to be constant in all hours.
- The prices for natural gas we used historical and future prices at the Lebanon hub as reported by SNL Financial.
- Fuel oil prices were derived from historic and forward prices for #2 oil at New York Harbor.
- 2012 hourly PJM LMP Values were downloaded from the SNL Financial database.
- 2012 and future emission allowance costs for NOx and SOx were also obtained from SNL Financial.

In order to model future energy revenues, we required the following additional data

- Electricity futures at PJM Dayton Ohio trading hub for the period through 2015 were found in SNL Financial as reported traded as of the end of 2012
- Gas futures at Lebanon trading hub for the period through 2015 were found in SNL Financial as reported traded as of the end of 2012.
- Distillate fuel oil future prices were developed based on WTI crude oil futures through 2015 were found in SNL Financial as reported traded as of the end of 2012.
- Future delivered coal prices were assumed to remain at the 2012 level in real dollars

Q. PLEASE DESCRIBE THE APPROACH YOU USED TO ESTIMATE ACTUAL 2012 ENERGY REVENUES.

A. My approach is based on using actual market data, computing energy revenues on an hour basis and then summarizing the results for the 2012 period. Please refer to Attachment RDT-9 for a detailed description of this approach.

1 **Q. PLEASE DESCRIBE THE MODELING SYSTEM THAT WAS USED TO**
2 **CALCULATE FUTURE ENERGY REVENUES?**

3 A. I developed projections of energy revenues for 2013 through 2015 using the
4 proprietary Optimal Dynamic Dispatch Model developed by Newton Energy Group. The
5 model develops an optimal generating schedule for each generating unit by maximizing the
6 unit's operating margin for a period of 24 hours with a look-ahead of 24 hours or more.
7 The model algorithm utilizes the technique known as dynamic programming. For a more
8 complete discussion of the model and model result, see Attachment RDT-9.

9 **Q. WHAT ARE THE RESULTS OF YOUR ANALYSES?**

10 A. Using the data and models as described above and assuming no new environmental
11 retrofits we have calculated the market value of the DEO legacy generating fleet. PJM
12 provides a maximum ACR value by unit type for both mothballing of a unit and for retiring
13 a unit. We have calculated the value of ACR minus the revenue from energy and ancillary
14 services for two cases. The first case calculates the market value of the entire fleet were all
15 of the units to be mothballed based on the ACR for mothballing of the individual units in
16 the fleet. The second case calculates the market value of the entire fleet were all of the
17 units to be retired based on the ACR for retiring of the individual units in the fleet. In both
18 instances the ACR value is the maximum provided by the PJM Market Monitor;
19 \$182.16/MW-Day for mothballing of the units and \$199.94/MW-Day for full retirement.
20 The resulting economic value of the DEO fleet after accounting for \$66.06/MW-Day in
21 revenue from BRA-based recovery is "insufficient" \$3.48/MW-Day in the case of
22 mothballing of the units and \$21.27/MW-Day "insufficient" in the case of retirement of the
23 units. Based on the PJM methodology the DEO fleet revenues with the BRA-based

1 recovery is effectively a wash, that is from an economic perspective the units as a whole
2 are close to breaking even (Attachment RDT-10).

3 **Q. WHAT IS YOUR INTERPRETATION OF THESE RESULTS?**

4 A. The principal conclusion, not unexpectedly, is that the DEO Legacy Generating
5 Assets have, for the most part, reached the end of their useful life. Beckjord 1 through 6
6 are scheduled for retirement before the end of 2015. Only Killen 2, Miami Fort 8 and
7 Zimmer 1 are returning values in \$/kw-year that provide revenue above operating cost.
8 The result when looking at the full fleet is that these three units are, in many ways,
9 financially carrying the remainder of the fleet.

10 **Q. WHAT LEVEL OF REVENUE HAS DEO ARGUED IT REQUIRES TO COVER**
11 **ITS FRR OBLIGATION?**

12 A. DEO has argued that its required revenue for capacity to cover its FRR obligations is
13 \$224.15/MW-Day. DEO witness Wathen contends that DEO's revenue is \$66.07/MW-
14 Day thus requiring a "cost-based charge of approximately \$158.08/MW-Day."¹⁰

15 **Q. GIVEN YOUR DISCUSSION CONCERNING THE CORRECT ECONOMIC**
16 **VALUATION METHOD FOR THE DEO UNITS, WHAT IS YOUR CONCLUSION**
17 **IN TERMS OF THE AMOUNT OF ADDITIONAL REVENUE THAT DEO CAN**
18 **JUSTIFY?**

19 A. My analyses shows that the economic value of DEO's capacity units is effectively
20 equivalent to the ACR calculated value of the fleet. My values indicate a range from a
21 possible revenue deficit of \$3.48/MW-Day were the units to be mothballed to a deficit of
22 \$21.27/MW-Day if the units were to be retired. Given the use of publicly available data
23 and my conservative estimate of energy revenues, the DEO fleet RPM-based revenue is

¹⁰ Wathen Testimony p. 15 lines 4-9.

roughly equivalent to my estimate of their ACR-based required revenue. Thus, DEO's legacy generation fleet requires either minimal or no additional revenues to compensate DEO for its avoided cost of operating these units. Under no circumstances, given my analyses using the economically correct methodology, can DEO justify recovery of \$158.08/MW-Day. As I discuss above, this number was incorrectly derived and vastly overstates DEO's revenue shortfalls, to the extent there are any at all and this without even accounting for revenues from the ESSC charge.

VI. RESPONSE TO TESTIMONY OF DEO WITNESS NIEMANN

Q. DO YOU AGREE WITH THE TESTIMONY OF DEO WITNESS NIEMANN?

A. No. Dr. Niemann's testimony arrives at four conclusions with which I take issue in whole or in part. These are:

1. An FRR entity has substantial risks relative to an entity that participates in the PJM BRA.
2. The compensation mechanism proposed by DEO is compatible with existing PJM market rules.
3. The cost recovery proposed by DEO does not distort prices or outcomes in the wholesale or retail markets.
4. The recovery of the deferred costs will not affect the rate paid by LSEs for capacity or otherwise negatively affect the proper functioning of the RAA in Ohio and the PJM footprint as a whole.

Q. WHY DO YOU DISAGREE THAT AN FRR ENTITY FACES GREATER RISK THAN AN ENTITY THAT PARTICIPATES IN THE PJM BRA?

A. To be sure, Dr. Niemann has correctly described the responsibilities of an FRR entity. The FRR entity is required to supply the capacity needed for its footprint minus any self-

1 supply capacity that a given CRES provider has secured within the allowed time window.
2 The obligation (with a reserve margin) is set initially five years in advance. FRR entities
3 are subject to penalties if they fail to provide sufficient capacity and so to avoid penalty
4 must purchase it from the PJM capacity market if their own resources fall short.

5 Dr. Niemann suggests that each of these requirements equates to a distinct risk for
6 FRR entities. Yet, each of these requirements actually provides *advantages* to the FRR
7 entity from a risk perspective. Once contracted for, the amount and nature of the FRR
8 entity's obligations are known and the prices and quantities are fixed for the duration of the
9 FRR period. While the FRR entity may see some risk with regard to its customer base and
10 not have the annual flexibility that a capacity supplier in the RPM auctions may have, the
11 FRR entity will not see the price swings that may occur in RPM auctions.

12 Further, the argument of FRR risk in the case of DEO is also totally misplaced in
13 terms of justifying any additional compensation for DEO. DEO knew precisely what the
14 economic value of its capacity would be through the PJM transition period to 2015 if it
15 became part of the PJM RPM capacity market and received compensation based on the
16 RPM auctions. As discussed above, DEO had full knowledge of any risk associated with
17 recovery of capacity revenue when it signed the ESP and PJM Stipulations and chose to
18 transition to PJM at the time and in the manner that DEO did.

19 **Q. WHY DO YOU DISAGREE WITH DEO WITNESS NIEMANN THAT DEO'S**
20 **PROPOSED COMPENSATION MECHANISM IS COMPATIBLE WITH**
21 **EXISTING MARKET RULES?**

22 A. Allowing DEO to recoup its embedded costs for capacity in its zone would run
23 contrary to the FRR rules. Section D of Schedule 8.1 of the RAA is designed to address
24 compensation for capacity to FRR entities, like DEO, with other competitive LSEs

1 operating in the FRR zone. That section provides for a state compensation mechanism
2 where retail competition exists. Thus, the compensation provided to an FRR entity in
3 that case should be market based or based on avoided costs since these are the bases for
4 compensation in competitive markets.

5 Moreover, if customers of competitive retail suppliers in the DEO FRR zone have
6 to pay embedded costs for capacity to DEO, while also having to pay market prices for
7 energy, these customers would essentially be paying twice for the same thing, since under
8 the PJM market construct, to the extent they are recovered, “sunk” or embedded costs are
9 recovered through profits on energy and ancillary services. That is why the default rate
10 for capacity set in the RAA is the RPM price.¹¹

11 Using the RPM price assures that the pricing model for capacity in PJM, in
12 conjunction with PJM’s other markets, provides the correct signals for the entry of new
13 efficient capacity and the signals for the retirement of capacity that is no longer
14 competitive.

15 For DEO to seek an additional subsidy from its Ohio retail customers that allows the
16 DEO units to recover an amount in excess of the economic value of the units is asking
17 these customers, new participants in the PJM market, to pay a price for capacity during the
18 transition that is in excess of what they believed they would be receiving in terms of a
19 benefit from joining PJM and signing the ESP and PJM Stipulations. Had DEO’s retail
20 customers known that DEO would come back seeking yet more money they would likely
21 not have signed on to either Stipulation, and may have resisted DEO’s effort to transition
22 to PJM.

¹¹ Like the ESP Stipulation, the RAA, Section D of Schedule 8.1 calls for use of the capacity price in the unconstrained portion of the RTO.

1 **Q. WHY DO YOU DISAGREE WITH DEO WITNESS NIEMANN THAT THE**
2 **STRUCTURE OF THE PROPOSED COST RECOVERY DOES NOT DISTORT**
3 **PRICES OR OUTCOMES IN THE WHOLESALE MARKET?**

4 A. While it may be true that the structure cannot distort already established RPM prices
5 in the wholesale market as a matter of definition, the wholesale capacity market in PJM is
6 driven largely by the RPM's BRA, which sets initial capacity prices three years in advance
7 of the time of delivery. Given that initial prices for the delivery years through 2014/15
8 have been set by the BRA auctions for those years and that DEO was not a part of those
9 auctions, they cannot now affect the prices. In the same manner, DEO can also not
10 participate in the incremental auctions for those years. This, however, is not the whole
11 story.

12 Unfortunately, providing additional revenue for DEO will, in all likelihood, have the
13 effect of distorting both the short term and the longer term capacity markets. The reason
14 for this distortion is that old and inefficient DEO units that should be closed (because they
15 do not earn sufficient revenues to justify not being retired or mothballed) are receiving
16 additional revenues. This thus assures that they will not be retired during the period of the
17 transition. If DEO did not receive this additional revenue, these old and inefficient
18 generating units would be retired and DEO would have to enter the "available" capacity
19 market – a bilateral market – to purchase more capacity than they are now. DEO's possible
20 need to purchase additional "available" capacity in bilateral transactions will have an
21 impact on the price of capacity available bilaterally and could have an impact on prices in
22 the incremental auctions should there be a need for incremental capacity by participants in
23 the RPM market.

1 If DEO's units were properly economically valued and compensated, DEO would
2 likely be forced to retire some of its plants, and enter the capacity market to replace the
3 capacity represented by those retired plants. By doing so, DEO would increase demand for
4 capacity and potentially put upward pressure on capacity prices in the bilateral market.
5 This potential upward pressure would thus send a signal to potential new suppliers of
6 capacity and encourage newer, cleaner, more efficient resources to stay in or enter the
7 market. By failing to value and compensate DEO from a proper economic perspective,
8 capacity markets may be distorted by artificially decreasing demand, and therefore prices:
9 existing resources that otherwise would earn an amount sufficient to keep them in the
10 market or new entrants to the market will not be able to earn sufficient revenues to incent
11 that economically correct behavior. Setting aside the impropriety of allowing DEO to go
12 back on the promises it made in the PJM and ESP Stipulations (by charging customers yet
13 more money under Rider DR-CO), providing DEO this additional subsidy will deprive
14 customers of more efficient capacity resources. Such a distortion is bad for both DEO's
15 customers and for PJM market participants as a whole.

16 **Q. WHY DO YOU DISAGREE WITH DEO WITNESS NIEMANN THAT THE**
17 **STRUCTURE OF THE PROPOSED COST RECOVERY DOES NOT DISTORT**
18 **PRICES OR OUTCOMES IN THE RETAIL MARKETS?**

19 A. Even though all customers within the DEO load zone pay a non-bypassable rate, the
20 additional subsidy will have effects across the PJM footprint, which includes the DEO load
21 zone and the rest of Ohio. When old and inefficient generation units are not properly
22 incented to retire once they have reached the end of their economically useful life, it
23 prevents other more efficient resources from staying in the market and new resources from
24 entering the market in the first place. While the short run costs of this are appreciable, the

1 long run costs in both dollars and in overall reliability could be much greater. (Again, this
2 is setting aside the fact that DEO has already agreed to be compensated through the ESSC
3 and PJM capacity market prices for its capacity.) Simply put, under DEO's proposal,
4 customers inside the DEO load zone would be paying more than they otherwise should be.

5 **Q. WHY DO YOU DISAGREE WITH DEO WITNESS NIEMANN'S STATEMENT**
6 **THAT THE DEFERRED CHARGES UNDER RIDER DR-CO WILL NOT AFFECT**
7 **THE RATE PAID BY LSEs FOR CAPACITY?**

8 A. Even though technically correct, this statement is misleading. While the LSEs see no
9 change in the rate that they will pay, the more pertinent question is whether consumers
10 within the DEO load zone will see an increase in their electric bills because of the non-
11 bypassable charge. The answer to this question is yes.

12 Customers will be charged more than DEO promised it would charge for its FRR
13 capacity in the Stipulation, and will see this rider cost in their bill in the DEO load zone,
14 this will affect the retail market in Ohio as these industrial, commercial and residential
15 customers that reasonably relied on DEO to keep its word will face an unanticipated
16 economic disadvantage relative to other customers in Ohio who are not facing the
17 unanticipated additional subsidy represented by Rider DR-CO.

18 **Q. IS THERE ANOTHER QUESTION THAT DR. NIEMANN SHOULD HAVE**
19 **ASKED AND ANSWERED?**

20 A. Yes, Dr. Niemann should have asked, "From an economic perspective, what is the
21 long-term impact on the capacity market of DEO receiving additional monies through the
22 proposed rider?" The answer to this question is that the impact on the capacity market is
23 that the revenues received through this rider will allow resources to continue to operate
24 when they should be closed. By providing revenues to allow for their longer term

1 operation, the electric customers in the DEO load zone are paying for the survival of
2 existing units when the market forces should be (and are) signaling for retirement and,
3 assuming there is not over capacity, for the construction of new, cleaner, less costly and
4 more fuel efficient units.

5 **Q. DR. NIEMANN HAS IMPLICITLY FRAMED HIS TESTIMONY AROUND THE**
6 **CONCEPT THAT DEO NOW (SINCE THE START OF THE TRANSITION FROM**
7 **MISO TO PJM) NEEDS ADDITIONAL REVENUE TO COVER THE COST OF**
8 **ITS CAPACITY. DO YOU AGREE?**

9 A. No, I do not. Dr. Niemann ignores that DEO is not a naïve player in electric power
10 markets. The decision to transition from MISO to PJM and the timing of that transition
11 were made based upon considerable analysis. Further, DEO, as a sophisticated and
12 significant participant in the energy industry, negotiated its position in the PJM and ESP
13 Stipulations. There can be no question that DEO understood fully the financial
14 implications of its transition to PJM, fully understood the rules of the capacity market, and
15 the risks of the FRR Alternative. DEO was also able to forecast future energy markets as
16 well as any other participant in the market.

17 **VII. CONCLUSION**

18 **Q: DOES THIS CONCLUDE YOUR TESTIMONY?**

19 **A:** Yes, it does.

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Richard D. Tabors, Ph.D. is an economist and scientist with 35 years of domestic and international experience in energy planning and pricing, international development, and water and wastewater systems planning. He is currently President and Principal of *Across the Charles* an energy, water and wastewater consulting group in Cambridge, Senior Consultant at Greylock McKinnon of Cambridge and an Affiliate of the MIT Energy Initiative. Prior to forming *Across the Charles* Dr. Tabors was Vice President of Charles River Associates.

From 1976 until 2006 Dr. Tabors held a variety of position at Massachusetts Institute of Technology culminating in the title of Senior Research Engineer and Senior Lecturer. These positions involved research development and supervision as well as academic teaching and included being Assistant Director of the power systems engineering laboratory (LEES) and associated director of the Technology and Policy master's program. Prior to MIT Dr. Tabors was Assistant Professor of City and Regional Planning and a member of the teaching faculty of the College of Arts & Sciences at Harvard University. At present he is a visiting professor of Electrical Engineering at the University of Strathclyde, Glasgow, Scotland.

Dr. Tabors was a member of the team at MIT that developed the theory of spot pricing (*Spot Pricing of Electricity* Kluwer Academic, 1989) upon which real-time pricing (RTP) and locational marginal pricing (LMP) of electricity and transmissions services are based. While still at MIT Dr. Tabors and coauthors Michael Caramanis & Roger Bohn formed Tabors Caramanis & Associates (1988) that was sold to Charles River Associates in 2004.

Dr. Tabors provides expert assistance and testimony in regulatory and arbitration cases in the energy sector at the Federal, State and Provincial levels in North America and provides technical assistance in electricity markets and market development worldwide. His strength both in academia and in private practice is in the development and management of effective, client and problem focused teams that bring intellectual originality and rigor to the challenges of energy markets.

EXPERIENCE

- 2012–Present *President and Principal* Across the Charles, an Energy and Environmental Consulting Group, Cambridge, MA and Senior Consultant, Greylock McKinnon Associates
- 2004–2012 *Vice President*, Charles River Associates
- Co-director of Energy & Environment practice area.
- 2004–Present *Visiting Professor of Electrical Engineering*, University of Strathclyde, Glasgow, Scotland
- 1986–2006 *Senior Lecturer*, Technology and Policy Program, Massachusetts Institute of Technology (MIT)
- 1988–2004 *Founder and Principal*, Tabors Caramanis & Associates, Inc.
- 1989–1998 *Lecturer*, Department of Electrical Engineering and Computer Science, MIT
- “Introduction to Power Systems Operations and Planning.”
- 1992–1998 *Senior Research Engineer*, Laboratory for Electromagnetic and Electronic Systems, MIT
- 1985–1998 *Assistant Director*, Laboratory for Electromagnetic and Electronic Systems, MIT
- Responsible for laboratory administration and research in power systems economics and planning, research on power systems monitoring and control, principal investigator on research program in performance based monitoring and control.
- 1990–1993 *Principal Research Associate*, MIT
- Co-Faculty “Planning for Water and Sewerage” and “Dealing with the Complete System,” MIT Summer Session.
- 1984–1989 Co-Faculty “Power Systems Planning & Operation: Methodologies for Dealing with an Uncertain Future”, MIT Summer Session.
- 1978–1988 *Lecturer*, Department of Urban Studies and Planning, MIT
- 1973–1988 *Principal*, Meta Systems

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- utilities group in power systems planning, pricing and systems analysis
- 1985–1987 *Faculty*, Course 11.944, Department of Urban Studies and Planning (co-taught as KSG S115 with P. Rogers) “Energy Sector Planning in Developing Countries.”
- 1971–1976 *Research Associate and Member*, Center for Population Studies, Harvard University
- Research on resource and environmental planning in developing nations of South Asia and Africa.
- 1978–1984 *Program Manager*, Utility Systems, MIT Energy Laboratory
- Economic and systems research and development in electric and gas utility systems; including the integration of new generation systems (photovoltaics) into the grid.
- 1979-1983 *Project Manager and Principal Investigator*, Electric Generation Expansion Analysis System (EGEAS) Project, under contract to EPRI, MIT Energy Laboratory.
- 1977-1982 *Project Manager and Principal Investigator*, Photovoltaics Project, under contract to U. S. Department of Energy, MIT Energy Lab.
- 1976-1977 *Economist*, Photovoltaics Project, MIT Energy Laboratory and Lincoln Laboratory.
- 1976-1977 *Energy Economist*, New England Energy Management Information Systems (NEEMIS), Energy Laboratory, MIT.
- 1974-1976 *Assistant Professor of City and Regional Planning*, Harvard University.
- 1973-1976 *Research Fellow*, Environmental Systems Program, Division of Engineering and Applied Physics, Harvard University.
- 1971–1977 *Co-Faculty*, with Professor R. Revelle, Natural Science 118, & 119, Human Population and Natural Resources, and Population & Environment and in Urban Setting, Harvard University.
- 1973-1974 *Lecturer on City and Regional Planning*, Graduate School of Design, Harvard University.
- 1971 *Resident Representative*, Harvard University, East Pakistan (Bangladesh) Land, Water and Power System Study, Dacca, East Pakistan.
- 1970 *Graduate Administrative and Teaching Assistant* to A. K. Campbell, Dean, Maxwell Graduate School of Citizenship and Public Affairs, Syracuse University.
- 1969–1970 *Syracuse University Intern*, Economic Division, USAID Pakistan.

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- Informal advisor on Regional Economic Planning to the Urban Development Directorate, Planning Department, Government of East Pakistan (Bangladesh).

CONSULTING EXPERIENCE

- For the City of New York provided technical and analytic support in the evaluation of the possible closing of the Indian Point Nuclear Generating Station including analysis of the impact of the Fukushima Nuclear accident (2011)
- Provided technical and economic strategy and regulatory assistance to off-shore wind developer (2009 – Present)
- In cooperation with Merrill Energy, provide expert advice on implementation of legislation to recover capital cost of transmission investment in Peru. (2010)
- Direct and provide consulting advice to the Federal Electricity & Water Authority in the United Arab Emirates on corporate reorganization. (2007-2011)
- Provide expert testimony to major US independent power producer in arbitration with steam host. (2007 – Present)
- Direct and provide expert services and consulting advice to Electricite du Liban on revenue recovery through development of AMI systems. (2006 – Present)
- Direct and provide consulting services to Electricite du Liban on restructuring of distribution services. (2006 – Present)
- Provide expert testimony in multiple contract disputes between bankrupt Independent Power Producer and power marketer. (2004 – 2006)
- Provide expert analytic assistance to Private Equity Fund on purchase of generation assets within the United States (2006- 2007).
- Member, Board of Directors, NeuCo Corporation.
- Direct and provide consulting services to Abu Dhabi Water and Electricity Authority on distribution system performance. (2003–2005)
- Direct and provide expert testimony on the development of the MidWest Independent System Operator. (2002–Present)
- Direct and provide expert testimony on long-term contract market in California. (2002–Present)
- Direct and provide expert testimony in purchase, contracting and regulatory approval of Midwestern transmission system. (2002–2003)

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- Direct and provide expert testimony in 9-billion dollar California Electric refund case (2001–Present)
 - Direct and provide expert testimony and consulting to major U.S. market and generator in the redesign of the California electricity market. (2002–Present)
 - Member of the Blue Ribbon Task Force on design of electricity auctions of the California Power Exchange with Alfred Kahn, Peter Cramton and Robert Porter. (2000–2001)
 - Member, Board of Directors of Dynamic Knowledge Corporation, Glasgow, Scotland. (2001–Present)
 - Consultant to more than 20 power development companies for evaluation of locational value of new generation and transmission. (1999–Present)
 - Consultant to and member of Technology Advisory Board, Excelergy Corporation, development of utility billing and system auction software. (1999–Present)
 - Consultant to a Midwest utility for development of transmission congestion pricing structure. (1999–2001)
 - Consultant to transmission asset development team of major U.S. corporation. (1999–2000)
 - Consultant to and member of advisory board of Altra Energy Systems, electronic trading software and platform development company for electronic trading of electricity. (1998–2001)
 - Consultant to major U.S. paper manufacturer for federal regulatory change required to interconnect a new co-generation facility. (1998–2000)
 - Consultant to major Midwest utility in the development of an independent transmission company and the required tariffs. (1998–2002)
 - Consultant with Enron Capital and Trade Resources on U.S. electricity restructuring with specific assignments in California, New York, Massachusetts and New England. Includes testimony in California “Blue Book” en banc hearings and participation in California Competitive Power Market Working Group. (1994–2001)
 - Consultant to the Office of the Attorney General, Commonwealth of Massachusetts for Electric Utility Industry Restructuring. (1995–1998)
 - Consultant with Sithe Energy on electricity pricing and electric industry restructuring. (1995–1998)
 - Consultant with Independent Power Producers of New York (IPPNY) on restructuring of electric sector in New York. (1995–1998)

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- Consultant to the Department of the Attorney General, State of Rhode Island and Providence Plantation for electric utility industry restructuring. (1996–1997)
 - Consultant to the New England Competitive Power Coalition providing support for development of a blueprint for restructuring the New England Power Pool. (1995–1997)
 - Consultant to ABB/Systems Control on transmission pricing and power systems operations. (1994–1997)
 - Consultant to a major western utility for the development of transmission pricing strategies. (1994–1996)
 - Development of real-time pricing strategies and rates for Oglethorpe Power Company, Atlanta, GA. (1995–1996)
 - Consultant on the background to electric industry restructuring to Central Vermont Public Service. (1995)
 - Development of real-time pricing rate response experiments for NYSERDA, EPRI and ESSERCo in ConEd and NYSEG service territories: Response to real-time pricing. (1989–1994)
 - Development of marginal, cost-based, transmission system pricing system for the National Grid Company (NGC) of the United Kingdom. (1991–1993)
 - Development of real-time rate structure and evaluation of customer impacts for Central Maine Power Company. (1990–1991)
 - Development of purchase and transmission strategy for major U.S. independent power producer. (1990)
 - Conservation and load management analysis and testimony for Boston Gas Company. (1987–1988)
 - Development of Electric Power Systems Consulting Group, Meta Systems Inc. (1985–1988)
 - Variable energy cost/spot pricing studies under contract to Integrated Communications Systems of Atlanta. Utilities included Mid-South and Pacific Gas and Electric, Southern California Edison, Central and South West. (1984–1987)
 - Metcalf & Eddy Engineering, analysis of economic benefits of cogeneration/district heating for Columbia Point housing, Boston Redevelopment Authority. (1984–1985)
 - Value of reliability study for Public Service of New Mexico. (1984)
 - With East-West Center, Honolulu, Hawaii, study of electric futures of northeast Asia, Japan, Korea and Taiwan. (1983–1984)

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- Independent variable energy cost spot pricing studies for Georgia Power, Florida Power and Light, Florida Power Corp., Tampa Electric and Gulf Power. (1983–1984)
 - Petroleum pricing study, Philippines for IBRD. (1983–1984)
 - Lignite pricing for electric power generation, Thailand. For IBRD (1982–1983)
 - Independent, review of electric power futures for combustion engineering. (1982)
 - Consultant, Microwave Associates, Inc., on electric load management and control. (1980-1981)
 - Urban energy impact statement for HUD. (1979–1980)
 - Consultant, Urban Systems Research and Engineering. Projects included: Analysis of Boston wastewater management plan for C.E.Q.; definition of 'modal' urban areas for environmental impact analysis using the EPA developed SPACE/SEAS model; Interceptor project to evaluate the impact of EPA interceptor grants program on land use patterns in suburban and rural areas of EPA Regions 2, 4, 6; Rural growth project analyzing regional development in non-metropolitan multi-county areas in the United States. (1971–1977)
 - Urban systems research and engineering analysis of Boston wastewater management plan for C.E.Q. (1977)
 - Bangladesh energy study for Asian Development Bank and UNDP. (1975–1976)
 - Urban systems research and engineering, definition of model urban areas for environmental impact analysis using the EPA developed SPACE/SEAS model. (1975–1976)
 - Land use and environmental quality modeling and case study analysis of land use impacts on water and air quality. Case studies focused on the Mill River basin in the New Haven SMSA. (1974–1975)
 - Member, Technical Advisory Panel for Educational Evaluation in Massachusetts, Office of the Commissioner in Education, Commonwealth of Massachusetts. (1973–1974)
 - Lake Chad polder development study of agricultural development with low-lift irrigation pumping in the area immediately surrounding Lake Chad. (1974)
 - Urban systems research and engineering, interceptor sewer project to evaluate the impact of EPA interceptor grants program on land use patterns in suburban and rural areas of EPA Regions, 2,4,6. (1974)
 - Decision-making and flood plain management in the Connecticut River valley, study for New England River Basin Commission. (1973)

FIELDS OF EXPERTISE

- Energy economics / energy pricing
- Power systems operations and planning
- Asset valuation: Generation, Transmission and Generation
- Water and wastewater management
- Corporate strategic planning and analysis
- Corporate reorganization and management

PROFESSIONAL AFFILIATIONS

- Institute of Electrical and Electronic Engineers
- American Waterworks Association
- International Association of Energy Economists
- Energy Bar Association

PUBLICATIONS

Books, Book Chapters, and Monographs

The Definition of Multifunctional Planning Regions: A Case Study of East Pakistan. A report to the East Pakistan Land, Power and Water Study, Harvard University Center for Population Studies, May 1971.

"Preferences for Municipal Services of Citizens and Political Leaders: Somerville, MA, 1971." With M.A. Vinovskis. *Population Policymaking in the American States: Issues and Processes*, D.C. Heath and Co., May 1974.

The Syracuse Metropolitan Regions: A Background for Paretian Environmental Analysis. Environmental Systems Program, Harvard University (ESP Monograph), September 1974.

Population Policymaking in the American States: Issues and Processes. With Bergman, Elihu, D. Carter, R. Cook, and D. Weir. D.C. Heath and Co., May 1974.

"Framework for the Analysis of State and Local Population Policy." *Population Policymaking in the American States: Issues and Processes*, D.C. Heath and Co., May 1974.

Interceptor Sewers and Urban Sewers. With Binkley, Collins, Kanter. D.C. Heath and Co., October 1975.

Land Use and the Pipe: Planning for Sewerage. With M. Shapiro and P.P. Rogers. D.C. Heath and Co., November 1976.

"Infrastructure Planning." In ASPO, *Rural and Small Town Planning*, The Old West Regional Commission, 1978.

"Utility Services." In So, Stollman, Beal, and Arnold, eds., *The Practice of Local Government Planning*, International City Management Assoc., December 1979.

"Energy Demand Estimation." With R. deLucia, In Jacoby and deLucia, eds., *Energy Planning in Developing Countries: The Case of Bangladesh*, John Hopkins Press, 1982.

"Traditional/Renewable Energy Sources." With R. DeLucia. In Jacoby and deLucia, eds., *Energy Planning in Developing Countries: The Case of Bangladesh*, Johns Hopkins Press, 1982.

"Utility Spot Pricing to Coordinate Deregulated Utilities, Customers and Generators." With R. Bohn and F. Schweppe. In Plummer, Ferrar and Hughes, eds., *Electric Power Strategic Issues: Deregulation and Diversification*, Johns Hopkins Press, 1982.

Electric Generation Expansion Analysis System, Vols. 1 & 2. With M. Caramanis and F.C. Schweppe. With Stone & Webster Engineering, Vols. 3, 4 & 5, EPRI, Palo Alto, CA, Report No. EL-2561, 1983.

"Electrical Utility Load Management Systems." A.H. El-Abiad ed., *Power Systems Analysis and Planning*, McGraw-Hill, 1983.

"Cogeneration: Ownership and Operating Economics." A.H. El-Abiad ed., *Power Systems Analysis and Planning*, McGraw-Hill, 1983.

"The New (Alternative) Electric Generation Technologies: An Evaluation of Their Potential." A.H. El-Abiad ed., *Power Systems Analysis and Planning*, McGraw-Hill, 1983.

"Using Spot Pricing to Coordinate Deregulated Utilities, Customers and Generators." With R. Bohn, and F. Schweppe. In Plummer, Ferrar and Hughes, eds., *Electric Power Strategic Issues*, Public Utilities Reports Inc., 1983.

"An Approach to Deregulating the Generation of Electricity." With R. Bohn, B. Golub, and F.C. Schweppe. In Plummer, Ferrar and Hughes, eds., *Electric Power Strategic Issues: Deregulation and Diversification*, Public Utility Reports, 1984.

"Utility Finance and Planning in Japan, Korea and Taiwan." With M. Castillo-Bonet. In Kim, Smith and Rose, eds., *Electric Futures of Asia and the Pacific*, East West Press Center, Honolulu, 1986.

Electricity in Northeast Asia: The Experiences of Japan, Korea, and Taiwan. Greenwood Press, Westport, CT, 1987.

Spot Pricing of Electricity. With F.C. Schweppe, M.C. Caramanis, and R. Bohn. Kluwer Academic Press, 1988.

Energy Aftermath: How We Can Learn from the Blunders of the Past to Develop our Energy Future. With T.H. Lee and B.C. Ball. Harvard Business School Press, Boston, 1989.

"Transitional Strategies for Emissions Reduction in the Electric Power Sector." With B. L. Monroe, III. In J. Tester and N. Ferraro, eds., *Energy and Environment in the 21st Century*, MIT Press, 1991.

"Engineering Economic Analysis: Applications to Electric Utility Investment Planning." In M. Baughman ed., *Engineering Economic Analysis: Overview and Current Applications*, IEEE Tutorial, 1992.

"Unbundling the U.S. Electric Power Industry: A Blueprint for Change." With Fernando, Kleindorfer, Pickel, and Robinson. Tabors Caramanis & Associates, March, 1995.

Articles and Reviews

"A Preliminary View of Economic Change and Urbanization: Bangladesh 2000." In Thomas and Lavan, eds., *West Bengal and Bangladesh: Perspectives from 1972*, Asian Studies Center, Michigan State University, South Asia Series No. 21, 1973.

"Urbanization and War: Inertia in Urban Migration in Bangladesh." Presented to the XXVI Annual Meeting of the Association for Asian Studies, Boston, MA, April 1974.

"Land Values and Public Investment in Urban Fringe Areas: A Case Study of Clay, New York." With M. Shapiro. Papers and Proceedings of the Northeast Regional Science Association, 1975.

Review of Greenberg et al., "Solid Waste Planning in Metropolitan Regions" in *Annual of Regional Science*, June 1978.

"A Louisiana Case Study: Towards a Single System of Substrate Regions." With C. S. Binkley. *Growth and Change*, January 1980.

"Homeostatic Utility Control." With F. C. Schweppe, J. L. Kirtley, H. R. Outhred, F. H. Pickel, and A. J. Cox. *IEEE Transactions on Power Apparatus and Systems*, Vol. PAS-99, No. 3, May/June 1980.

"Rate and Penetration Analysis, the Impact of Distributed Photovoltaic Power Systems within the Utility Grid System." With A. Cox, S. Finger, and A. Burns. *IEEE Transactions, IEEE 14th Photovoltaic Specialists Conference*, 1980.

“Economic Integration of New Energy Technologies into the Grid Using Homeostatic Control.”
Invited paper, IEA Conference on New Energy Conversion Technologies, April 1981.

“Economic Operation of Distributed Power Systems within an Electric Utility.” With S. Finger and A. Cox. *IEEE Transactions on Power Apparatus and Systems*, Vol. PAS-100, No. 9, September 1981.

“Solar Energy/Utility Interface: The Technical Issues.” With D.C. White. *Energy, The International Journal*, January 1982.

“Homeostatic Control for Electric Power Usage.” With F. C. Schweppe and J. L. Kirtley. *IEEE Spectrum*, Vol. 19, No. 7, pp. 44–48, July 1982.

“The Introduction of Non-Dispatchable Technologies as Decision Variables in Long-Term Generation Expansion Models.” With M. C. Caramanis, K. S. Nochur, and F. C. Schweppe. *IEEE Transaction on Power Apparatus and Systems*, Vol. PAS-101, No. 8, August 1982.

“Wisconsin Study Shows Homeostatic Control has High Potential for Industrial Loads.” With F. C. Schweppe. *Modern Power Systems*, Vol. 3, No. 1, pp. 43-46, January 1983.

“Homeostatic Control: The Utility Customer Marketplace for Electric Power.” With F. C. Schweppe and J. L. Kirtley. In *Local Heat and Power Generation: A New Opportunity for British Industry*, Interscience Enterprise, U.K., 1983.

“Deregulating the Electric Utility Industry.” With F. C. Schweppe and R. Bohn. *The Energy Journal*, January 1984.

“Electricity Spot Prices in Developing Countries.” *National Development*, November 1984.

“Evaluation of Spot Price Based Electricity Rates.” With F.C. Schweppe and M. C. Caramanis. *IEEE Transactions on Power Apparatus and Systems*, Vol. PAS-104, no. 7 July 1985.

“Natural Gas Fired Combined Cycle Generators: Dominant Solutions in Capacity Planning.” With D. Flagg. *IEEE Transactions on Power Apparatus and Systems*, No. 85 SM 492-4, 1985.

Review of Munasinghe, “Energy Pricing and Demand Management” in *The Energy Journal*, 1987.

“Utility Experience with Real Time Rates.” With F. C. Schweppe and M. C. Caramanis. *IEEE Transactions on Power Systems*, Vol. 4, No. 2, May 1989.

“Coal to Natural Gas Seasonal Fuel Switching: An Option for Acid Rain Control.” *IEEE Transactions on Power Systems*, Vol. 4, No. 2, May 1989.

“Algorithms for a Spot Price Responding Residential Load Controller.” With B. Daryanian and F. C. Schweppe. *IEEE Transactions on Power Systems*, Vol. 4, No. 2, May 1989.

“Energy Systems for the Twenty-First Century.” With B. C. Ball and T. H. Lee. *International Journal of Global Energy Issues*, Vol. 1, Nos. 1/2, 1989.

“Planning for Future Uncertainties in Electric Power Generation: An Analysis of Transitional Strategies for Reduction of Carbon and Sulfur Emissions.” With B. L. Monroe, III. *IEEE Transactions on Power Systems*, 1991.

“Real Time Pricing as a Component of Least-Cost Power Strategies.” With M.C. Caramanis and B. Daryanian. *Proceedings of the American Power Conference*, 1991.

“An Experiment in Real Time Pricing for Control of Electric Thermal Storage Systems.” With B. Daryanian and R. E. Bohn, *IEEE Transactions on Power Systems*, 1991.

“A Computer Design Assistant for Induction Motors, Using Monte-Carlo Design Synthesis to Augment a Design Database.” With J. A. Moses, J. L. Kirtley, J. H. Lang and F. Cuadra. *Conference Record of the 1991 IEEE IAS Annual Meeting*, 1991.

“A Simulator of the Manufacturing of Induction Motors.” With C. L. Tucci, J. H. Lang, and J. L. Kirtley. *Conference Record of the 1991 IEEE IAS Annual Meeting*, 1991.

“A Framework for Integrated Resource Planning: The Role of Natural Gas Fired Generation in New England.” With S. R. Connors, C. G. Bespolka, D. C. White, and C. J. Andrews. *IEEE Transactions on Power Systems*, 1992.

“Optimal Demand-Side Response to Electricity Spot Prices for Storage-Type Customers.” With B. Daryanian and R. E. Bohn. *IEEE Transactions on Power Systems*, 1992.

“RTP-Based Energy Management Systems: Monitoring, Communication, and Control Requirements for Buildings under Real Time Pricing.” With B. Daryanian and L. K. Norford. *ASHRAE Transactions*, 1992.

“Benefit Optimization of Centralized and Decentralized Power systems in a Multi-Utility Environment.” With F. Nishimura, M. D. Ilic, and J. R. Lacalle-Melero. *IEEE Transactions on Power Systems*, 1993.

“Transmission System Management and Pricing: New Paradigms and International Comparisons.” Invited Paper, IEEE Power Systems Winter Meeting, February 1993, *IEEE Transactions on Power Systems*, 1993.

“Competitive Electric Market will Tailor Services to Everyone.” With D. J. Parquet. *California Manufacturer*, May 1995, pp 7-10.

“Smart Hardware: Large Power Transformer Monitoring.” With J. Kirtley, B. Lesieutre, W. Hagman, P. Warren, M. J. Boyd, and H.P. Chou IEEE. *Computer Applications in Power*, November 1995.

“The Electric Car Unplugged.” With R. deNeufville, S. R. Connors, F. R. Field III, D. Marks, and D. S. Sadoway. *Technology Review*, January 1996, Vol. 99, No. 1, pp.30–36.

“Lessons from the U.K. and Norway.” *IEEE Spectrum*, August 1996.

“Zonal Transmission Pricing: A Methodology and Preliminary Results from the WSCC.” *Proceedings of the Conference on Innovative Pricing*, San Diego, March, 1996 and *The Electricity Journal*, November 1996.

“A Market-Based Proposal for Transmission Pricing.” *The Electricity Journal*, November 1996.

“Zonal Transmission Pricing: Preliminary Results from the WSCC.” With S. Walton. *The Electricity Journal*, November 1996.

“The Regulatory Contract and Restructuring: A Modest Proposal.” With R. S. Hartman. *The Electricity Journal*, December 1996.

“Optimal Operating Arrangements in a Restructured World: Economic Issues.” With R. S. Hartman. *Energy Policy*, Vol. 26, No. 2, February 1998.

“Transmission Markets: Stretching the Rules for Fun and Profit.” With N. Rao. *Electricity Journal*, June 2000.

“Forward Markets for Transmission that Clear at LMP: A Hybrid Proposal.” *Proceedings of the Thirty-Fourth Annual Hawaii International Conference on System Sciences*, January 2001.

“Uniform Pricing or Pay-as-Bid Pricing: A Dilemma for California and Beyond.” With A. E. Kahn, P. C. Cramton, and R. H. Porter. *The Electricity Journal*, July 2001.

“Ex Ante and Ex Post Designs for Electric Market Mitigation: Past and Present Experience and Lessons from California.” With J. B. Cardell. *Proceedings of the Thirty-Sixth Annual Hawaii International Conference on System Sciences*, January 2003.

“The Role of Demand Underscheduling in the California Energy Crisis.” With E.D. Hausman. *Proceedings of the Thirty-Seventh Annual Hawaii International Conference on System Sciences*, January 2004.

“Evaluating the Benefits of Independently-Owned Transmission Companies.” *Journal of Structured Project Finance*, winter 2004.

“The use of Multi-Attribute Trade-Off Analysis in Strategic Planning For an Electric Distribution utility: An Analysis of Abu Dhabi Distribution Company” With Rick Hornby, *Proceedings of the Thirty-Fifth Annual Hawaii International Conference on System Sciences*, January 2005.

“Loss Hedging Rights: A Final Piece in the LMP Puzzle.” *Proceedings of the Thirty-Fourth Annual Hawaii International Conference on System Sciences*, with Aleksandr Rudkevich , Ezra Hausman , Jan Bagnall and Christopher Kopel, January 2005.

“Price Discrimination in Organized/Centralized Electric Power Markets.” With Seabron Adamson, *Proceedings of the Thirty-Ninth Annual Hawaii International Conference on System Sciences*, January 2006.

“Identification and Congestion Analysis of Transmission Corridors of the Eastern Interconnection.” With Aleksandr Rudkevich , Kaan Egilmez , Minghai Liu , Prashant Murti , Poonsaeng Visudhiphan , and Thomas J. Overbye, *Proceedings of the Fortieth Annual Hawaii International Conference on System Sciences*, January 2007

“Transmission Tariffs by Use of System and Economic Benefits.” With Daniel J. Camac , Raul C. Bastidas , Wilfredo Sifeuntes , and Hyde M. Merrill *Proceedings of the Forty-second Annual Hawaii International Conference on System Sciences*, January 2009.

“Interconnection in the GCC Grid: The Economics of Change.” *Proceedings of the Forty-Second Annual Hawaii International Conference on System Sciences*, January 2009

“Development of the Smart Grid: Missing Elements in the Policy Process” With Geoffrey Parker and Michael C. Caramanis *Proceedings of the Forty-Third Annual Hawaii International Conference on System Sciences*, January 2010.

“The Manufacture of Potable Water: Case Analyses of Electric System Alternatives” with Siddarth Nagendraprasad, Ayoob Hussain, Mounir Ayntrazi and Jonathan A. Brant *Proceedings of the Forty- Fifth Annual Hawaii International Conference on System Sciences*, January 2012. (Winner of the Best Paper Award in Power Systems Group)

“Carbitrage: Utility Integration of Electric Vehicles and the Smart Grid” with Edward Kim, Robert Stoddard and Todd Allmendinger. *The Electricity Journal* Vol. 25, Issue 2, March 2012.

“Who’s on First? The Coordination of Gas and Power Scheduling” with Scott Englander and Robert Stoddard *The Electricity Journal* Vol. 25, Issue 5, June 2012.

“Learning to Love Congestion: Competitive market problems and their implications for customers’ net costs” with Hyde M. Merrill *Public Utility Fortnightly*, July 2012.

“North American Resource Adequacy: “Déjà vu all over again” *Proceedings of the Forty-Sixth Annual Hawaii International Conference on System Sciences*, January 2012

Technical Reports

“U.S. Electrical Energy Demand and the Potential for Photovoltaics.” With M. Pope and R. Matlin. Technical Note, Lincoln Laboratory, MIT, November 1976 (TN 76-2).

"The Cost of a Cold Winter." With S. Raskin. *The NEEMIS Newsletter*, Energy Laboratory, MIT, No. 6, Vol. I, January 1977.

"Impacts of Dispersed Solar Space and Hot Water Heating on New England Electric Service." With S. Law and A. Burns. MIT Energy Laboratory, June 1978.

"A Uniform Economic Valuation Methodology for Solar Photovoltaic Applications Competing in a Utility Environment." With P. R. Carpenter. MIT Energy Laboratory Report No. MIT-EL 78-010, June 1978.

"SERI Venture Analysis." With S. Finger MIT Energy Laboratory Technical Report No. MIT-EL 78-032, July 1978.

"Methodology and Definition of Solar Photovoltaic Planning Regions." With P. R. Carpenter. MIT Energy Laboratory Report No. MIT-EL 78-034, July 1978.

"The Economics of Water Lifting for Small-Scale Irrigation in the Third World: Tradition and Photovoltaic Technologies." MIT Energy Laboratory Technical Report No. MIT-EL 79-011, May 1979.

"Homeostatic Control: Economic Integration of Solar Technologies into Electric Power Operations and Planning." MIT Energy Laboratory Report, No. MIT-EL-81-028, July 1981.

"Boston Harbor Management Study." With J. T. Kildow, principal investigator. MIT Sea Grant College Program, Report No. MITSG81-15, November 1981.

"Utility Spot Pricing Study: Wisconsin." With M.C. Caramanis and R. Stevenson. MIT Energy Laboratory Technical Report No. MIT-EL 82-025, June 1982.

"Market and Economic Analysis of Residential Photovoltaic Systems: Final Report." MIT Energy Laboratory Technical Report No. MIT-EL 82-024, June 1982.

"Industrial Interfuel Substitution Phase I Report: Model Development and Case Study." With G. Russo. MIT Energy Laboratory Technical Report No. MIT-EL 82-035, June 1982.

"Management Decisions for Cogeneration." With R.R. Radcliffe. MIT Energy Laboratory Technical Report No. MIT-EL 82-084, July 1982.

"Economic Analysis of the Photovoltaic Technology, Final Report." MIT Energy Laboratory Technical Report Draft, August 1982.

"Utility Spot Pricing: California." With F. C. Schweppe and M. Caramanis. Prepared for Pacific Gas and Electric and Southern California Edison, MIT Monograph, Cambridge, MA, October 1982.

"Deregulating the Electric Utility Industry." With R. Bohn, B. Golub and F. C. Schweppe. MIT Energy Laboratory Technical Report No. MIT-EL 82-003, January 1982.

“Management Decisions for Cogeneration: A Survey Analysis.” With R. Radcliffe. MIT Energy Laboratory Report, Report No. MIT-EL 82-025, June 1982.

“Management Decisions for Cogeneration: Discriminating Between Users and Non Users.” With R. Radcliffe. MIT Energy Laboratory Report, Report No. MIT-EL 82-029.

“Spot Pricing and Its Relation to Other Load Management Methods.” With M. Caramanis and F. C. Schweppe. MIT Energy Laboratory Report, MIT-EL 83-001, January 1983.

“Utility Spot Pricing: California II.” With F. C. Schweppe and M. C. Caramanis. Prepared for California Energy Commission, Final Report, January 1984.

“An Assessment of Public Infrastructure in Massachusetts.” Joint Center for Urban Studies, A Case Study prepared for the use of the Subcommittee on Economic Goals and Intergovernmental Policy of the Joint Economic Committee, Congress of the United States, February 25, 1984.

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FILE

**BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO**

In the Matter of the Application of Duke) Case No. 11-2641-EL-RDR
Energy Ohio, Inc., for Approval of the)
Establishment of Rider BTR and Associated)
Tariffs.)

In the Matter of the Application of Duke) Case No. 11-2642-EL-RDR
Energy Ohio, Inc., for Approval of the)
Establishment of Rider RTO and Associated)
Tariffs.)

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STIPULATION AND RECOMMENDATION

Rule 4901-1-30, Ohio Administrative Code, provides that any two or more parties to a proceeding may enter into a written stipulation covering the issues presented in such a proceeding. The purpose of this document is to set forth the understanding and agreement of the parties, which include Duke Energy Ohio, Ohio Energy Group, The Office of the Ohio Consumers' Counsel, and the Commission Staff¹ (Signatory Parties or Parties) that have signed below and to recommend that the Public Utilities Commission of Ohio (Commission) approve and adopt this Stipulation and Recommendation (Stipulation), which resolves all of the issues raised by the Parties in this case relative to Duke Energy Ohio's Application for Approval of the Establishment of Rider BTR and Associated Tariffs and for Approval of the Establishment of Rider RTO and Associated Tariffs (Application). This Stipulation is supported by adequate data and information including, but not limited to, Duke Energy Ohio's Application filed on April 25, 2011.

The Stipulation represents a just and reasonable resolution of the issues raised in this proceeding, violates no regulatory principle or precedent, and is the product of lengthy, serious

¹ The Commission Staff is a party for the purpose of entering into this Stipulation by virtue of O.A.C. 4901-1-10(C).

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bargaining among knowledgeable and capable Parties in a cooperative process, encouraged by this Commission and undertaken by the Parties representing a wide range of interests, including the Commission's Staff, to resolve the aforementioned issues. Although this Stipulation is not binding on the Commission, it is entitled to careful consideration by the Commission. For purposes of resolving all issues raised by this proceeding, the Parties stipulate, agree and recommend as set forth below.

This Stipulation is a reasonable compromise that balances diverse and competing interests and does not necessarily reflect the position that any one or more of the Parties would have taken had these issues been fully litigated. This Stipulation represents an agreement by all Parties to a package of provisions rather than an agreement to each of the individual provisions included within the Stipulation. The Signatory Parties' agreement to this Stipulation, in its entirety, shall not be interpreted in a future proceeding before this Commission as their agreement to only an isolated provision of this Stipulation.

Except for purposes of enforcement of the terms of this Stipulation, neither this Stipulation, the information and data contained therein or attached, nor the Commission's entries and orders on the Stipulation shall be cited as precedent in any future proceeding for or against any Party.

This Stipulation is expressly conditioned upon its adoption by the Commission in its entirety and without material modification. If the Commission rejects or materially modifies all or any part of this Stipulation in any entry or order in the above-captioned case, each and every Signatory Party shall have the right, within thirty days of issuance of the Commission's entry or order, to file an application for rehearing or to terminate and withdraw the Stipulation by filing a notice with the Commission. The Signatory Parties agree they will not oppose or argue against

any other Party's notice of termination or application for rehearing that seeks to uphold the original, unmodified Stipulation and Recommendation. If, in a ruling upon an application for rehearing, the Commission does not adopt the Stipulation in its entirety and without material modification, any Party may terminate and withdraw from the Stipulation. Termination and withdrawal shall be accomplished by filing a notice with the Commission, including service to all Signatory Parties, in this proceeding within thirty days of the Commission's order or ruling on rehearing, as applicable. Other Parties to this Stipulation agree to defend and shall not oppose the termination and withdrawal of the Stipulation by any other Party.² Upon the filing of a notice of termination and withdrawal, the Stipulation shall immediately become null and void.

Prior to the filing of such a notice, the Party wishing to terminate agrees to work in good faith with the other Parties to achieve an outcome that substantially satisfies the intent of the Stipulation and, if a new agreement is reached that includes the Party wishing to terminate, then the new agreement shall be filed for Commission review and approval. If the discussions to achieve an outcome that substantially satisfies the intent of the Stipulation are unsuccessful in reaching a new agreement that includes all Signatory Parties to the present Stipulation, all said Parties shall encourage the Commission to convene an evidentiary hearing such that the Parties are afforded the opportunity to present evidence through witnesses and cross-examination, present rebuttal testimony, and brief all issues that the Commission shall decide based upon the record and briefs as if this Stipulation had never been executed. Some or all of the Parties may submit a new agreement to the Commission for approval if the discussions achieve an outcome they believe substantially satisfies the intent of the present Stipulation.

² Any signatory Party has the right, in its sole discretion, to determine what constitutes a "material" modification for the purposes of that Party withdrawing from the Stipulation.

All the Signatory Parties fully support this Stipulation in its entirety and urge the Commission to accept and approve the terms herein.

The Signatory Parties agree that the settlement and resulting Stipulation are a product of serious bargaining among capable, knowledgeable Parties. This Stipulation is the product of an open process in which all Parties were represented by able counsel and technical experts. The Stipulation represents a comprehensive compromise of issues raised by Parties with diverse interests. The Signatory Parties have signed the Stipulation and adopted it as a reasonable resolution of all issues. The Signatory Parties believe that the Stipulation that they are recommending for Commission adoption presents a fair and reasonable result.

The Signatory Parties agree that the settlement, as a package, benefits customers and is in the public interest. The Signatory Parties agree that the settlement package does not violate any important regulatory principle or practice.

WHEREAS, all of the related issues and concerns raised by the Parties have been addressed in the substantive provisions of this Stipulation, and reflect, as a result of such discussions and compromises by the Parties, an overall reasonable resolution of all such issues;

WHEREAS, this Stipulation is the product of the discussions and negotiations of the Parties and is not intended to reflect the views or proposals that any individual Party may have advanced acting unilaterally;

WHEREAS, this Stipulation represents an accommodation of the diverse interests represented by the Parties and is entitled to careful consideration by the Commission;

WHEREAS, this Stipulation represents a serious compromise of complex issues and involves substantial benefits that would not otherwise have been achievable; and

WHEREAS, the Parties believe that the agreements herein represent a fair and reasonable solution to the issues raised in the case set forth above concerning Duke Energy Ohio's Application;

NOW, THEREFORE, the Parties stipulate, agree and recommend that the Commission make the following findings and issue its Opinion and Order in these proceedings approving this Stipulation in accordance with the following:

1. The Signatory Parties expressly agree and understand that the terms of this Stipulation are contingent upon Duke Energy Ohio exiting the Midwest Independent System Operator (Midwest ISO) and realigning its regional transmission organization (RTO) membership with PJM Interconnection LLC (PJM). Duke Energy Ohio currently anticipates joining PJM effective January 1, 2012. In the event Duke Energy Ohio does not realign its RTO membership by January 1, 2012, any Signatory Party may seek Commission approval to declare this Stipulation and Recommendation null and void and of no effect.

2. Duke Energy Ohio agrees not to seek recovery from retail customers of (a) Midwest ISO exit fees, except as otherwise provided with respect to Midwest ISO transmission expansion project costs in Paragraph 3 below; (b) PJM integration fees imposed upon Duke Energy Ohio through the Agreement to Implement Expansion of PJM Region For Duke Energy Ohio and Duke Energy Kentucky signed June 11, 2010, or subsequent revisions of such agreement; and, (c) internal costs associated with the RTO realignment, including Energy Management System upgrades, legal expenses, and other internal costs.³

³ The Midwest ISO exit fee is yet to be determined. The PJM integration fees are estimated at \$1.7 million and Duke Energy Ohio's internal costs are estimated at \$2 million.

3. Duke Energy Ohio shall recover through retail rates all Midwest ISO Transmission Expansion Projects (MTEP) costs, including but not limited to multi-value project (MVP) costs⁴ directly or indirectly charged to Duke Energy Ohio or the Duke Energy Ohio zone, other than such costs properly attributable to one or more of Duke Energy Ohio's operating company affiliates. Duke Energy Ohio shall recover MTEP costs, as described herein, through Rider BTR or any successor thereto.

a. On January 18, 2011, Duke Energy Ohio filed for rehearing of the Federal Energy Regulatory Commission's (FERC) order in Docket No. ER10-1791 (MVP Order) arguing, among other things, that non-usage-based allocation of costs of MVPs to a withdrawing transmission owner on the basis of project approval is unlawful. If Duke Energy Ohio's request for rehearing is denied by the FERC on substantive grounds, and it is determined that Duke Energy Ohio remains obligated to pay for such MVPs based upon a non-usage based allocation of costs of MVPs to withdrawing transmission owners on the basis of project approval, Duke Energy Ohio agrees to appeal the FERC decision. If the FERC rejects Duke Energy Ohio's request for rehearing of the MVP Order based upon a finding to the effect that the issue should instead be resolved in a subsequent proceeding on exit fees, Duke Energy Ohio agrees to argue the issue in that subsequent FERC proceeding on exit fees, and to seek rehearing and appeal with respect to any finding in such a proceeding that Duke Energy Ohio must pay an exit fee based upon a non-usage based allocation of MVP costs to withdrawing transmission

⁴ For purposes of this Stipulation, MTEP Obligations shall be defined as Duke Energy Ohio's obligation for MTEP costs that arise while it is a member of the Midwest ISO.

owners on the basis of project approval. Duke Energy Ohio will diligently prosecute its appeal of the MVP Order.

b. Duke Energy Ohio has argued in its request for rehearing of the FERC MVP Order that Duke Energy Ohio will not incur MVP obligations before Duke Energy Ohio withdraws from the Midwest ISO, among other things. However, recognizing that any FERC decision to allocate MVP costs to Duke Energy Ohio may or may not expressly agree with or address Duke Energy Ohio's argument, notwithstanding footnote 4 above, the Parties expressly agree that any MVP costs allocated to Duke Energy Ohio on a basis deemed consistent with the limits on transmission owner withdrawal obligations set forth in Article Five Section 2 of the Midwest ISO Transmission Owner's Agreement shall be recoverable under Paragraph 3.

4. Duke Energy Ohio shall recover through retail rates all costs that arise from Regional Transmission Expansion Plan (RTEP) projects that are charged to Duke Energy Ohio by PJM under PJM's FERC-approved rates. For the first \$121 million in RTEP costs, which include Legacy RTEP⁵ and Future RTEP⁶ costs, that are billed to Duke Energy Ohio by PJM, Duke Energy Ohio shall provide a credit to customers as described below in Paragraph 11 (the RTEP Commitment). After the RTEP Commitment is fulfilled, Duke Energy Ohio shall recover through Rider BTR or any successor thereto all RTEP costs charged to it by PJM, which may include Legacy RTEP costs and Future RTEP costs that are billed by PJM.

⁵ For purposes of this Stipulation, Legacy RTEP costs are those costs billed by PJM for projects that are approved by the PJM Board prior to the time that Duke Energy Ohio joins PJM.

⁶ Future RTEP costs are those costs billed by PJM for projects that are approved by the PJM Board after the time that Duke Energy Ohio joins PJM.

5. The Signatory Parties may contest, at the FERC or any federal court, the costs to be included in MTEP or RTEP. The Signatory Parties may also contest, at the FERC or any federal court, the propriety of allocating such costs to Duke Energy Ohio.

a. Such opposition at the FERC or any federal court shall not be inconsistent with the terms of this Stipulation.

b. Under no circumstances will the Parties oppose or in any way contest in any forum Duke Energy Ohio's right to recover through retail rates MTEP and/or RTEP costs consistent with Paragraphs 3 and 4 above.⁷

6. The Signatory Parties shall not, directly or indirectly, object to or otherwise contest, in any forum, Duke Energy Ohio's decision to exit the Midwest ISO and realign with PJM or any aspect of the process by which such decision was made. Furthermore, the Signatory Parties shall not, in any forum, directly or indirectly challenge or contest the prudence of Duke Energy Ohio's RTO realignment or the costs associated with same, including but not limited to MTEP and RTEP costs.

7. With regard to the standard service offer (SSO) that will supersede the ESP approved in Case No. 08-920-EL-SSO, Duke Energy Ohio commits to not charging its SSO customers twice for the same capacity.

8. Effective January 1, 2012, Rider BTR shall be created as a non-bypassable rider to allow for recovery of MTEP and RTEP charges, network integration transmission service (NITS) charges that will be paid by Duke Energy Ohio for all shopping and non-shopping load, and other non-market based charges, including but not limited to Commission audits.

⁷ This Stipulation does not preclude the Signatory Parties from opposing or in any way contesting the rights of utilities other than Duke Energy Ohio to recover MTEP and/or RTEP costs.

9. Effective January 1, 2012, Rider RTO shall be created as a bypassable rider to allow for recovery of market-based FERC and RTO charges billed to the Company in proportion to its SSO offer load.

10. With the approval of Rider BTR and RTO, Duke Energy Ohio's Rider TCR shall expire effective December 31, 2011, and a final true-up of Rider TCR shall occur as part of the annual adjustment of Rider BTR and Rider RTO.

11. Duke Energy Ohio shall seek recovery, through retail rates, of all transmission expansion project costs, including MTEP, Legacy RTEP, RTEP, and all other FERC-approved costs billed to it by either the Midwest ISO or PJM that are not specifically excluded as part of this Stipulation. The allocation to each rate schedule of MTEP, Legacy RTEP and RTEP costs shall be done on a demand basis, using the 12 CP results for each rate schedule. As Legacy RTEP or RTEP costs are billed by PJM, Duke Energy Ohio shall credit back to customers, via Rider BTR, the RTEP Commitment. The amount of the RTEP Commitment to be credited via Rider BTR will first be allocated between residential and non-residential customers using the 12 CP allocation method. The amount of the credit allocated to residential customers will be credited to these customers on an energy basis (*i.e.*, \$/kWh). The amount of the credit allocable to non-residential customers will also be credited back to non-residential customers on an equivalent energy basis (*i.e.*, same \$/kWh for all non-residential customers). Within thirty days of the RTEP Commitment having been fully credited back to customers, Duke Energy Ohio shall inform the Commission that said credits have ceased by filing a letter of termination with the Commission's Docketing Division.

12. To the extent the fees and costs described in Paragraph 2, above, are fixed costs, they will not be reflected in any attachment or schedule from which retail transmission rates, for

recovery by Duke Energy Ohio, are derived. In the event such fees or costs are not fixed costs and are therefore incorporated into an attachment or schedule, Duke Energy Ohio will demonstrate in its annual filings to adjust Rider BTR and Rider RTO that retail customers neither have paid nor will pay for said fees and costs, consistent with the commitments set forth in Paragraph 2.

13. Commission approval of the Company's Application for Approval of the Establishment of Rider BTR and Rider RTO and associated tariffs shall serve as authorization on the part of Duke Energy Ohio to recover costs consistent with the terms of this Stipulation, commencing January 1, 2012.

14. Nothing in this Stipulation will be construed as an agreement by the Stipulating Parties as to the proper interpretation and application of R.C. 4928.05.

15. The Signatory Parties agree that Rider BTR and Rider RTO shall be established, through Duke Energy Ohio's Application, to allow for the recovery of MTEP and RTEP charges consistent with the terms of this Stipulation. In addition, once Duke Energy Ohio has such information as is necessary to calculate actual transmission rates and rates for the recovery of RTEP charges consistent with the terms of this Stipulation, it shall, prior to January 1, 2012, provide such calculations to the Signatory Parties and, not less than ten days thereafter, file final tariff pages for Rider BTR and Rider RTO.

16. The Signatory Parties agree that Duke Energy Ohio will reconcile and update its Rider BTR and Rider RTO, consistent with O.A.C. 4901:1-36.

17. The Signatory Parties understand and acknowledge that time is of the essence insofar as Duke Energy Ohio's Application and this Stipulation are concerned. The Signatory Parties will not object to any request by Duke Energy Ohio for an accelerated procedural

schedule in the above-captioned proceeding. Further, in the above-captioned proceeding, the Signatory Parties shall not request a hearing, file any comments or testimony in opposition to the Stipulation, cross-examine of any witnesses who may offer testimony in support of this Stipulation, or otherwise present evidence contrary to the terms of this Stipulation. Further, the Signatory Parties shall not argue in any way against such establishment of Rider BTR or Rider RTO or against the waiver of any filing requirements for such rider establishment as such requirements may appear in O.A.C. Chapter 4901:1-36 or otherwise, or against the approval of such final tariffs in the above-captioned proceeding. The Signatory Parties also shall not argue for any delay in the above-captioned proceeding. Rather, all Signatory Parties shall support and recommend approval – on an expedited basis – of Duke Energy Ohio's Application, consistent with the terms of this Stipulation.

18. This Stipulation in no way precludes the Company from making a subsequent application under applicable statutes and regulations for recovery of FERC-approved costs assessed by the RTO that are not otherwise recovered through Rider BTR or Rider RTO or a subsequent application to establish successor riders thereto.

19. The Signatory Parties understand and acknowledge that, in light of the critical timing issues involved with the realignment, the Company may, in its sole exercise of discretion, withdraw its Application for Approval for the Establishment of Rider BTR and Rider RTO in the event that the Commission has not approved such Application by June 1, 2011. The Company's withdrawal of the Application shall render this Stipulation null and void.

20. Duke Energy Ohio agrees that it will not institute a filing at the FERC under Section D of Schedule 8.1 of the PJM Reliability Assurance Agreement that requests FERC approval of a wholesale capacity charge applicable to load serving entities based upon Duke

Energy Ohio's costs as a Fixed Resource Requirement entity in PJM for the period between January 1, 2012, and May 31, 2016.

21. Duke Energy Ohio's customers shall not incur an obligation as a result of any settlement or final disposition of the FERC proceeding, filed by the Midwest ISO under FERC Docket No. ER11-2059.

22. The Signatory Parties agree to the tariffs attached hereto as Exhibits 1 and 2, respectively, and request that the Commission approve said tariffs on an expedited basis.

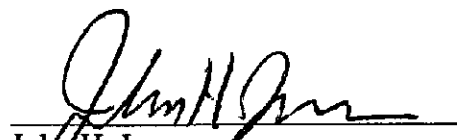
23. The Signatory Parties agree that the Stipulation and attachments thereto shall be tendered to the Commission and filed immediately following the filing of Duke Energy Ohio's Application in this docket. Each Signatory Party expressly consents to and urges approval of this Stipulation in its entirety.

24. The Signatory Parties agree to support the reasonableness of this Stipulation before the Commission and in any appeal from the Commission's adoption or enforcement of the Stipulation, pursuant to the terms set forth herein.

25. This Stipulation and Recommendation contains the entire agreement between the Signatory Parties and no additional consideration with regard to the above-captioned proceeding has been promised or agreed to by any Signatory Party.

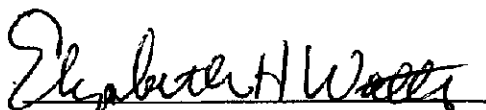
The undersigned Parties hereby stipulate and agree and each represents that it is authorized to enter into this Stipulation and Recommendation on this the 26th day of April 2011.

On behalf of Staff of the Public Utilities Commission of Ohio



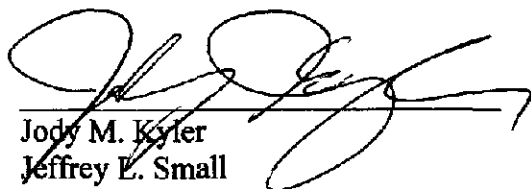
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On behalf of Duke Energy Ohio, Inc.



Amy B. Spiller
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On behalf of the Ohio Energy Group



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ETHW

EXHIBIT 1

RIDER BTR

BASE TRANSMISSION RIDER

APPLICABILITY

Applicable to all retail jurisdictional customers in the Company's electric service area.

CHARGE

The Base Transmission Rider charges detailed below are to recover transmission costs related to the provision of retail transmission service in Duke Energy Ohio's service territory. Costs recoverable in this rider include transmission-related costs charged to Duke Energy Ohio by the Federal Energy Regulatory Commission (FERC), a FERC-approved regional transmission organization, or the Public Utilities Commission of Ohio (PUCO) including:

Schedule 1	Scheduling, System Control, and Dispatch
Schedule 1A	Transmission Owner Scheduling, System Control, and Dispatch
Schedule 2	Reactive Supply and Voltage Control from Generation or Other Sources Service
Schedule 11	Transitional Market Expansion Charge
Schedule 12	Transmission Enhancement Charges

Network Integrated Transmission Service – Pursuant to Attachment H-XX
Transmission Expansion Planning Costs billed directly or indirectly from the Midwest ISO, Inc.
Consultant fees incurred by the PUCO and billed to Duke Energy Ohio
Other transmission-related costs incurred by Duke Energy Ohio as approved by the FERC and the PUCO.

Costs recoverable under Rider BTR are limited to those charges approved by the FERC and the PUCO subject to R.C. 4928.05 and O.A.C. 4901:1-36.

Rider BTR contains two components: a BTR charge and an RTEP credit to reflect a Stipulation approved by the Commission in Case No. 11-XXX-EL-RDR. Both components apply to all customers. The RTEP credit is a reduction to bills for all rate classes and reflects an agreement to credit the first \$121 million in RTEP costs billed to the Company's retail load.

Filed pursuant to an Order dated _____ in Case No. _____ before the
Public Utilities Commission of Ohio.

Issued:

Effective:

Issued by Julie Janson, President

RATE

The BTR charges and RTEP credits for each rate schedule are shown in the following tables. Both the BTR charge and the offsetting RTEP credit apply to all customers:

BTR Charge Tariff Sheet

BTR Charge
(per kWh/kW)

Rate RS, Residential Service
All kWh
Rate ORH, Optional Residential Service With Electric Space Heating
All kWh
Rate TD, Optional Time-of-Day Rate
All kWh
Rate CUR, Common Use Residential Rate
All kWh
Rate DS, Service at Secondary Distribution Voltage
All kW
Rate GS-FL, Optional Unmetered For Small Fixed Loads
All kWh
Rate EH, Optional Rate For Electric Space Heating
All kWh
Rate DM, Secondary Distribution Service, Small
All kWh
Rate DP, Service at Primary Distribution Voltage
All kW
Rate SFL-ADPL, Optional Unmetered Rate For Small Fixed Loads Attached Directly
to Company's Power Lines
All kWh
Rate TS, Service at Transmission Voltage
All kVA
Rate SL, Street Lighting Service
All kWh
Rate TL, Traffic Lighting Service
All kWh
Rate OL, Outdoor Lighting Service
All kWh
Rate NSU, Street Lighting Service for Non-Standard Units
All kWh
Rate NSP, Private Outdoor Lighting for Non-Standard Units
All kWh
Rate SC, Street Lighting Service - Customer Owned
All kWh
Rate SE, Street Lighting Service - Overhead Equivalent
All kWh
Rate UOLS, Unmetered Outdoor Lighting Electric Service
All kWh

Filed pursuant to an Order dated _____ in Case No. _____ before the
Public Utilities Commission of Ohio.

Issued:

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Effective:

RTEP Credit

Tariff Sheet

RTEP Credit
(per kWh)

Rate RS, Residential Service
Rate ORH, Optional Residential Service With Electric Space Heating
Rate TD, Optional Time-of-Day Rate
Rate CUR, Common Use Residential Rate
Rate DS, Service at Secondary Distribution Voltage
Rate EH, Optional Rate For Electric Space Heating
Rate DM, Secondary Distribution Service, Small
Rate DP, Service at Primary Distribution Voltage
Rate SFL-ADPL, Optional Unmetered Rate For Small Fixed Loads Attached Directly
to Company's Power Lines
Rate TS, Service at Transmission Voltage
Rate SL, Street Lighting Service
Rate TL, Traffic Lighting Service
Rate OL, Outdoor Lighting Service
Rate NSU, Street Lighting Service for Non-Standard Units
Rate NSP, Private Outdoor Lighting for Non-Standard Units
Rate SC, Street Lighting Service - Customer Owned
Rate SE, Street Lighting Service - Overhead Equivalent
Rate UOLS, Unmetered Outdoor Lighting Electric Service

Filed pursuant to an Order dated _____ in Case No. _____ before the
Public Utilities Commission of Ohio.

Issued:

Issued by Julie Janson, President

Effective:

EXHIBIT 2

RIDER RTO

REGIONAL TRANSMISSION ORGANIZATION RIDER

APPLICABILITY

Applicable to all jurisdictional retail customers in the Company's electric service area, except those customers receiving generation service from a Certified Supplier.

CHARGE

Rider RTO charges include only those costs charged to or imposed upon Duke Energy Ohio by the Federal Energy Regulatory Commission (FERC), FERC-approved regional transmission organizations, or similar organizations approved by the FERC and/or the Public Utilities Commission of Ohio (PUCO) under approved tariffs. Costs recoverable under Rider RTO include ancillary service charges but exclude any transmission costs recovered in Rider BTR. For customers who receive their energy from a Certified Supplier, the specific rates, terms, and conditions of the Company's FERC Open Access Transmission Tariff apply as such tariff may be amended from time to time and as incorporated herein by reference. The charges for the respective electric service schedules, effective beginning with the first billing cycle of January 2012 and updated on an annual basis, are as follows:

RTO Charge Tariff Sheet

RTO Charge (per kWh)

Rate RS, Residential Service
Rate ORH, Optional Residential Service With Electric Space Heating
Rate TD, Optional Time-of-Day Rate
Rate CUR, Common Use Residential Rate
Rate DS, Service at Secondary Distribution Voltage
Rate GS-FL, Optional Unmetered For Small Fixed Loads
Rate EH, Optional Rate For Electric Space Heating
Rate DM, Secondary Distribution Service, Small
Rate DP, Service at Primary Distribution Voltage
Rate SFL-ADPL, Optional Unmetered Rate For Small Fixed Loads Attached Directly
to Company's Power Lines
Rate TS, Service at Transmission Voltage
Rate SL, Street Lighting Service
Rate TL, Traffic Lighting Service
Rate OL, Outdoor Lighting Service
Rate NSU, Street Lighting Service for Non-Standard Units
Rate NSP, Private Outdoor Lighting for Non-Standard Units
Rate SC, Street Lighting Service - Customer Owned
Rate SE, Street Lighting Service - Overhead Equivalent
Rate UOLS, Unmetered Outdoor Lighting Electric Service

Costs recoverable under Rider RTO are limited to those charges approved by the FERC and the PUCO subject to R.C. 4928.05 and O.A.C. 4901:1-36.

Filed pursuant to an Order dated _____ in Case No. _____ before the
Public Utilities Commission of Ohio.

Issued:

Effective:

Issued by Julie Janson, President

FILE

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) Case No. 11-3549-EL-SSO
 an Electric Security Plan, Accounting)
 Modifications and Tariffs for Generation)
 Service.)

In the Matter of the Application of Duke)
 Energy Ohio for Authority to Amend its) Case No. 11-3550-EL-ATA
 Certified Supplier Tariff, P.U.C.O. No. 20.)

In the Matter of the Application of Duke)
 Energy Ohio for Authority to Amend its) Case No. 11-3551-EL-UNC
 Corporate Separation Plan.)

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STIPULATION AND RECOMMENDATION

Rule 4901-1-30, Ohio Administrative Code (O.A.C.), provides that any two or more parties to a proceeding may enter into a written stipulation covering the issues presented in such a proceeding. The purpose of this document is to set forth the understanding and agreement of the parties that have signed below (Signatory Parties or Parties) and to recommend that the Public Utilities Commission of Ohio (Commission) approve and adopt this Stipulation and Recommendation (Stipulation), which resolves all of the issues raised by the parties in this case relative to Duke Energy Ohio's Application for Approval of an Electric Security Plan and Associated Tariffs, for Approval to Amend its Certified Supplier Tariff, and for Approval to Amend its Corporate Separation Plan (Application). This Stipulation is supported by adequate

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 technician SM Date Processed OCT-25-2011

data and information including, but not limited to, Duke Energy Ohio's Application and testimony filed on June 20, 2011, and the Attachments filed herewith.

The Stipulation represents a just and reasonable resolution of the issues raised in these proceedings, violates no regulatory principle or precedent, and is the product of lengthy, serious bargaining among knowledgeable and capable Parties in a cooperative process, encouraged by this Commission and undertaken by the Parties representing a wide range of interests, including the Commission's Staff, to resolve the aforementioned issues. Although this Stipulation is not binding on the Commission, it is entitled to careful consideration by the Commission. For purposes of resolving all issues raised by these proceedings, the Parties stipulate, agree, and recommend as set forth below.

This Stipulation is a reasonable compromise that balances diverse and competing interests and does not necessarily reflect the position that any one or more of the Parties would have taken had these issues been fully litigated. This Stipulation represents an agreement by all Parties to a package of provisions rather than an agreement to each of the individual provisions included within the Stipulation. The Signatory Parties' agreement to this Stipulation, in its entirety, shall not be interpreted in a future proceeding before this Commission as their agreement to only an isolated provision of this Stipulation.

This Stipulation is submitted for purposes of these proceedings only, and neither this Stipulation nor any Commission Order considering this Stipulation shall be deemed binding in any other proceeding nor shall this Stipulation or any such Order be offered or relied upon in any other proceedings, except as necessary to enforce the terms of this Stipulation.

The Signatory Parties agree that the settlement and resulting Stipulation are a product of serious bargaining among capable, knowledgeable Parties. This Stipulation is the product of an

open process in which all parties were represented by able counsel and technical experts. The Stipulation represents a comprehensive compromise of issues raised by Parties with diverse interests. The Signatory Parties, which include Duke Energy Ohio, Ohio Energy Group, Industrial Energy Users-Ohio, The Office of the Ohio Consumers' Counsel, Ohio Manufacturer's Association, the Commission Staff,¹ City of Cincinnati, Ohio Partners for Affordable Energy, Retail Energy Supply Association, The Greater Cincinnati Health Council, The Ohio Environmental Council, People Working Cooperatively, Inc., Environmental Law & Policy Center, the Kroger Company, Constellation NewEnergy, Inc., Constellation Energy Commodities Group, Inc., FirstEnergy Solutions Corp., EnerNOC, Inc., Vectren Retail, LLC d/b/a/ Vectren Source, AEP Retail Energy Partners LLC, PJM Power Providers Group, Direct Energy Services, LLC, Direct Energy Business LLC, Miami University, the University of Cincinnati, COMPETE Coalition, Duke Energy Retail Sales, LLC, American Municipal Power, Inc., Interstate Gas Supply, Inc., Exelon Generation Company, LLC, the Natural Resources Defense Council, Wal-Mart Stores East, LP, Sam's East, Inc., Cincinnati Bell Inc., and the Council of Smaller Enterprises have signed the Stipulation and adopted it as a reasonable resolution of all issues.² The Signatory Parties believe that the Stipulation that they are recommending for Commission adoption presents a fair and reasonable result.

The Signatory Parties agree that the settlement, as a package, benefits ratepayers, and is in the public interest. The Signatory Parties agree that the settlement package does not violate any important regulatory principle or practice.

¹ The Commission Staff is a party for the purpose of entering into this Stipulation by virtue of O.A.C. 4901-1-10(C).

² Industrial Energy Users-Ohio (IEU-Ohio) supports the Stipulation. However, IEU-Ohio takes no position regarding Sections VI.B., VII.A., VII.M., VIII.A., IX.M., IX.U.(ii), and IX.AA., or does not support or oppose such sections, so that IEU-Ohio's support for the Stipulation may not be used as precedent in any other proceeding.

WHEREAS, all of the related issues and concerns raised by the Parties have been addressed in the substantive provisions of this Stipulation, and reflect, as a result of such discussions and compromises by the Parties, an overall reasonable resolution of all such issues;

WHEREAS, this Stipulation is the product of the discussions and negotiations of the Parties and is not intended to reflect the views or proposals that any individual Party may have advanced acting unilaterally;

WHEREAS, this Stipulation represents an accommodation of the diverse interests represented by the Parties and is entitled to careful consideration by the Commission;

WHEREAS, this Stipulation represents a serious compromise of complex issues and involves substantial benefits that would not otherwise have been achievable; and

WHEREAS, the Parties believe that the agreements herein represent a fair and reasonable resolution to the issues raised in the case set forth above concerning Duke Energy Ohio's Application;

NOW, THEREFORE, the Parties stipulate, agree, and recommend that the Commission make the following findings and issue its Opinion and Order in these proceedings approving this Stipulation in accordance with the following:

I. TERM

- A. The Parties agree that Duke Energy Ohio's Electric Security Plan (ESP) will be for the period of January 1, 2012, through May 31, 2015. The Parties further agree that Duke Energy Ohio shall file its next application, pursuant to R.C. 4928.141, for a standard service offer (SSO) no later than June 1, 2014. This subsequent application shall make provision for SSO supply procurements via a descending-clock format, competitive bid process (CBP) and the Parties hereby expressly

waive any rights that they may have to contest the use of such a CBP for the purpose of establishing Duke Energy Ohio's next SSO. The Parties agree to hold a collaborative meeting prior to March 31, 2014, to discuss lessons learned and potential improvements to the bid process, including, but not limited to, the need, if any, to address changes to the rules regarding switching between SSO and CRES providers, for consideration in Duke Energy Ohio's next SSO. Through the CBP to be included in its next SSO application, Duke Energy Ohio will seek to procure, on a slice of system basis, the aggregate wholesale full requirements SSO supply, which includes energy and capacity, market-based transmission service,³ and market-based transmission ancillary services requirements, for the period of its next SSO. Said process shall be conducted by an independent bid manager and consistent with the bid documents submitted as a part of Duke Energy Ohio's Application in the above-referenced proceeding, as modified in this Stipulation and the Attachments hereto. The Parties further acknowledge and agree that they shall expressly support the use, by Duke Energy Ohio, of such a CBP for purposes of acquiring all of the supply needed to serve its SSO load under the next SSO. The Parties reserve all other rights that they may have to support, contest, or recommend modification of Duke Energy Ohio's next SSO. Consistent with paragraph B, below, Duke Energy Ohio expressly reserves all rights to withdraw its next SSO application.

³ "Market-based transmission services," for purposes of this Stipulation, include those PJM (as defined below) charges and credits assigned to competitive retail electric service providers and those identified on the sample PJM Invoice as being assigned to wholesale suppliers. The PJM Sample Invoice is provided in the Master Supply Agreement, Attachment D to this Stipulation.

- B. In the event the Commission rejects Duke Energy Ohio's next SSO application or substantially modifies it such that Duke Energy Ohio withdraws the application, the Parties expressly acknowledge and agree that the auction-based pricing and cost-recovery provisions of the SSO structure under which Duke Energy Ohio is operating as of May 31, 2015, shall persist until such time as a subsequent SSO is approved and not withdrawn, as provided for in R.C. 4928.143(C)(2)(a), by Duke Energy Ohio. Any such withdrawal by Duke Energy Ohio shall be filed within 30 days following the issuance of the Commission's final order. Specifically, for the term commencing June 1, 2015, unless a new SSO is approved by the Commission and not withdrawn by Duke Energy Ohio, prior to April 1, 2015, Duke Energy Ohio will procure, through a descending clock, auction-based SSO procurement process substantially similar to the auctions conducted under the ESP described herein, a full requirements load following product for a term that is not less than quarterly or more than annually until a new SSO is approved and not withdrawn, with retail generation rates being determined based on the results of those auction-based SSO load procurements. The Parties agree and recommend that the Commission determine the term for the procurement process upon the filing of any Duke Energy Ohio withdrawal of its next SSO application. For purposes of this paragraph, the Parties also agree that, for so long as Duke Energy Ohio is a Fixed Resource Requirements (FRR) entity under PJM Interconnection, LCC, (PJM), it will provide capacity at the Final Zonal Capacity Price (FZCP) in the unconstrained regional transmission organization (RTO) region. For the period during which Duke Energy Ohio participates in PJM's Reliability Pricing

Model (RPM) and Base Residual Auction (BRA), the capacity price is the FCZP for the DEOK load zone region, and capacity shall be provided pursuant to the PJM RPM process. The Parties agree that the Commission's oversight of said procurement process shall be consistent with the oversight afforded it in the ESP discussed herein. For purposes of this paragraph, a full requirements load following product shall include energy and capacity delivered to the DEOK load zone, as well as market-based transmission service, and market-based transmission ancillary service, plus the reasonable costs to procure.

II. SSO SUPPLY

- A. Duke Energy Ohio agrees to procure all of its energy, capacity, market-based transmission service, and market-based transmission ancillary services requirements for its SSO load, for the duration of the ESP, through the CBP outlined in Duke Energy Ohio's Application in these proceedings and testimony filed in support thereof, except as modified in this Stipulation and the Attachments hereto. The auction schedule shall proceed consistent with Attachment A, hereto.
- B. Acknowledging Duke Energy Ohio's status as an FRR entity in PJM, the Parties agree that Duke Energy Ohio shall supply capacity to PJM, which, in turn, will charge for capacity to all wholesale supply auction winners for the applicable time periods of Duke Energy Ohio's ESP with the charge for said capacity determined by the PJM RTO, which is the FZCP in the unconstrained RTO region.
- C. Duke Energy Ohio will implement Rider RC (Retail Capacity) and Rider RE (Retail Energy) to recover the costs associated with serving its SSO load, with the

aggregate sum of the revenues under said riders equal to the auction clearing prices, as converted into retail rates. Rider RC shall recover the cost of capacity consistent with paragraph B above and Rider RE shall recover all remaining auction costs, including energy, market-based transmission service, and market-based transmission ancillary services. Rider RC and Rider RE are unconditionally bypassable by all non-SSO customers. Rider RC and Rider RE will be put into effect through updated rates for each of the PJM planning years for which all tranches for the delivery period have been approved by the Commission.

- D. Duke Energy Ohio shall implement conditionally bypassable Rider SCR (Supplier Cost Reconciliation) to recover any difference between the payments made to suppliers for SSO service and the amount of revenue collected from Rider RC and Rider RE. Rider SCR will also be used to recover all prudently incurred costs associated with conducting the auctions for SSO service and any costs resulting from supplier default. Rider SCR will be filed quarterly in this docket and will be subject to annual audits by the Commission at its discretion. The monthly accumulated balance of over- or under-recovery will accrue a carrying charge equal to Duke Energy Ohio's overall cost of long-term debt, as approved in its most recent distribution rate case (*e.g.*, Case No. 08-709-EL-AIR, *et al.*).

Rider SCR shall be bypassable by shopping customers during the time that they purchase retail electric generation service from a competitive retail electric service (CRES) provider, as long as the balance of said Rider is less than 10 percent of Duke Energy Ohio's overall actual SSO revenue (*i.e.*, all revenue

collected for SSO service under Riders RE, RC, RECON, and AER-R) for the most recent quarter for which data is available at the time of the filing. If the balance of Rider SCR becomes equal to or greater than 10 percent of Duke Energy Ohio's overall actual SSO revenue, Duke Energy Ohio shall apply to the Commission for confirmation that Duke Energy Ohio should modify the Rider such that it becomes non-bypassable (whether the balance in the Rider results from over- or under-recovery). Rider SCR will again become bypassable for shopping customers if the balance of said Rider falls below 10 percent of Duke Energy Ohio's overall actual SSO revenue.

- E. Upon Commission approval of the bids, Duke Energy Ohio shall determine the rates for Rider RE and Rider RC by converting the clearing prices from each auction into retail rates pursuant to the methodology contained in Attachment B. The conversion of the auction prices into Rider RC and Rider RE will include applicable losses.
- F. Affiliates and subsidiaries of Duke Energy Ohio shall be permitted to participate and compete in the SSO auctions on the same fair and non-discriminatory manner as all other participants. Duke Energy Ohio shall not give any competitive advantage to an affiliate or subsidiary participating in the SSO auctions. Notwithstanding the above, Duke Energy Ohio agrees that, for the period during which Rider ESSC (referenced and defined below in Section VII.A.) is in place, and irrespective of ownership of its generation assets (Generation Assets),⁴ it shall not participate in the SSO auctions. Rather, during said period and irrespective of

⁴ For purposes of this Stipulation, "Generation Assets" shall refer to all generation assets currently, directly owned by Duke Energy Ohio, whether operating or retired, but shall not include any generation assets currently owned by an affiliate or subsidiary of Duke Energy Ohio.

ownership, Duke Energy Ohio shall cause the energy from all of its Generation Assets to be sold into the Day Ahead or Real Time PJM energy markets, or on a forward basis through a bilateral arrangement. Any forward bilateral sales must be done at a liquid trading hub (*i.e.*, Western Hub, AD-Hub, Cinergy Hub) at the then current market wholesale equivalent price. ICE (Intercontinental Exchange) or a similar publicly available document shall be used as a form of measure of the then current market wholesale equivalent pricing. The Commission Staff, or, at the Commission's discretion, an independent auditor, shall semi-annually audit Duke Energy Ohio records to ensure compliance with this provision. The cost of any such audits shall be recovered through Rider SCR.

- G. The Parties agree that there shall be load caps applicable to each auction conducted during the term of the ESP, with no one supplier being able to bid upon or awarded more than 80 percent of the tranches in any one auction.
- H. The Parties agree that the bidding process as described in the Company's Application, and as modified herein, shall be conducted by an independent bidding manager, CRA International, dba Charles River & Associates (CRA International), except as provided below in Section II.I. The Parties further agree that the Commission may also retain a consultant who may monitor the bidding process and the costs of such consultant shall be recovered under Rider SCR.
- I. Within the first 30 days following Commission approval of the results of each auction, Commission Staff may notify Duke Energy Ohio of its desire to evaluate the use of an independent auction manager other than CRA International. Within 30 days of such notification, Duke Energy Ohio and Commission Staff shall

jointly: (1) confirm whether CRA International will continue to serve as the independent auction manager; or (2) identify a new independent auction manager; or (3) identify a process to determine the new auction manager. In order to avoid disruption to the auction schedule, the substitution of the independent auction manager shall occur no sooner than 6 months after confirmation of such a substitution. If Commission Staff does not provide notice, as set forth above, CRA International shall continue to serve as the auction manager until such time as a substitution is confirmed. In no event shall the substitution of the independent auction manager delay or otherwise alter the bidding schedule as delineated in Attachment A or result in a modification of the CBP or bidding documents detailed in Duke Energy Ohio's Application, and as modified herein, except to revise the identification of, and contact information for, the auction manager. The Parties agree that any costs associated with the substitution of independent auction managers shall be recovered through Rider SCR.

J. The Parties agree that the Commission may reject the results of any auction, by means of an order filed within 48 hours of the conclusion of each such auction, based upon a report from the independent auction manager or the Commission's consultant that the auction violates a specific CBP rule in such a manner so as to invalidate the auction or if the Commission determines that one or more of the following criteria were not met:

- i. The bidding process was oversubscribed based upon bidder indicative offers submitted as part of the Part 2 Application, such that the amount of the supply bid upon was greater than the amount of the load bid out;

- ii. There were four or more bidders; or,
- iii. Consistent with the load cap, no bidder won more than 80 percent of the tranches in any one auction.

III. TRANSMISSION SERVICES

- A. Transmission services shall be provided consistent with the Opinion and Order issued by the Commission on May 25, 2011, in Case No. 11-2641-EL-RDR, *et al.*, except that the Parties hereby agree that PJM Schedule 1 (Scheduling, System Control, and Dispatch) shall not be included in Rider BTR and will be billed directly to wholesale auction winners and CRES providers by PJM.

IV. CAPACITY FOR SHOPPING CUSTOMERS

- A. Consistent with Section II.B., above, the Parties agree that Duke Energy Ohio shall supply capacity resources to PJM, which, in turn, will charge for capacity resources to all CRES providers in its service territory for the term of the ESP, with the exception of those CRES providers that have opted out of Duke Energy Ohio's FRR plan, for the period during which they opted out. The Parties further agree that, during the term of the ESP, Duke Energy Ohio shall charge CRES providers for capacity as determined by the PJM RTO, which is the FZCP in the unconstrained RTO region, for the applicable time periods of its ESP. When computing the capacity allocations for PJM, Duke Energy Ohio shall use an allocation formula in common use in PJM.

V. FUTURE CAPACITY SUPPLY

- A. Upon Duke Energy Ohio's signing of this Stipulation, it will provide its generating unit commitment information to PJM as soon as reasonably possible

but no later than February 1, 2012. Provided that Duke Energy Ohio does not withdraw the ESP approved in a Commission Order prior to February 29, 2012, it will terminate its election of an FRR plan and provide written notice by March 2, 2012, to the PJM Office of the Interconnection of its intent to participate in the RPM and the BRA for the 2015/2016 planning year. If Duke Energy Ohio is required to make a filing with the Federal Energy Regulatory Commission (FERC) to terminate its FRR status for the 2015/2016 planning year, the Parties agree not to intervene in said proceeding for the purpose of contesting, opposing, or otherwise objecting to the termination of the election; nor shall the Parties seek to delay the proceeding. Nothing herein prohibits the Parties from intervening in such proceeding for the purpose of supporting the filing. In the event Duke Energy Ohio is precluded from terminating its FRR plan for the 2015/2016 planning year and, in addition, the Commission's final order in these proceedings permits full legal corporate separation as set forth in this Stipulation, Duke Energy Ohio will provide notice to PJM (pursuant to Schedule 8.1 of the Reliability Assurance Agreement) no later than March 2013 that it intends to participate in the RPM and BRA for the 2016/2017 planning year. Further, in the event Duke Energy Ohio is precluded from terminating its FRR plan for the 2015/2016 planning year, it shall supply capacity to PJM, which, in turn, shall charge all wholesale auction winners, generation suppliers for the PIPP (as defined below) contract load, and CRES providers for capacity as determined by the PJM RTO, which is the FZCP in the unconstrained RTO region.

VI. RENEWABLE ENERGY CREDITS

- A. Duke Energy Ohio will implement Rider AER-R as proposed in its Application to recover the costs incurred in complying with the requirements of R.C. 4928.64, *et seq.* The Parties agree and recommend that Rider AER-R shall not expire upon the termination of the ESP on May 31, 2015, but instead shall continue in order to enable recovery of all reasonable and prudently incurred costs for the acquisition of renewable energy credits (RECs), including brokerage fees, REC tracking participation expenses, gains and losses realized from the sale of RECs, and carrying costs at the long term cost of debt, as approved in Duke Energy Ohio's most recent distribution rate case (*e.g.*, Case No. 08-709-EL-AIR, *et al.*). Rider AER-R shall remain bypassable for customers taking generation service from a CRES provider. Rider AER-R will be filed quarterly and will include true-up provisions, with annual audits conducted by Commission Staff, or an independent auditor at the discretion of the Commission, in a manner similar to that employed in Duke Energy Ohio's current fuel and purchased power tracker.
- B. Within 60 days of Commission issuance of a final order adopting the Stipulation that does not result in Duke Energy Ohio's withdrawal of its SSO Application, Duke Energy Ohio will engage in collaborative discussions with interested parties to prepare an application to revise certain elements of the current R.C. 4928.64 residential solar REC (SREC) purchase program. With the common goal of expanding customer participation in the program, Duke Energy Ohio will work with the Signatory Parties to identify mutually agreeable modifications aimed at

enhancing clarity, transparency, and certainty of contractual terms. These changes may include, but may not be limited to, features such as the assignment of a known SREC price over the length of the contract, an up-front rebate with certain output standards, or another, mutually agreed solution as yet to be developed. AEP Ohio's program, as stated and approved in Case No. 09-1872-EL-ACP, will be evaluated as a potential model for Duke Energy Ohio's modified program, in addition to other potential program modifications. If the Parties are unable, within 60 days of the start of the collaborative process, to agree on changes to Duke Energy Ohio's existing SREC tariff, Duke Energy Ohio shall file a letter at the Commission indicating that the Parties could not reach agreement. In such event, the other Parties retain the right to petition the Commission to make changes to Duke Energy Ohio's existing SREC tariff. The Commission will become the final arbiter in the event of such a dispute.

- C. Within 60 days of the Commission's issuance of a final order adopting the Stipulation that does not result in Duke Energy Ohio's withdrawal of its SSO application, Duke Energy Ohio will initiate collaborative work in consultation with the Ohio Environmental Council, Environmental Law & Policy Center, and other interested Signatory Parties on an evaluation and report on Combined Heat and Power. This commitment is identified in the stipulation filed in Case No. 10-503-EL-FOR on March 21, 2011.

VII. OHIO POLICY

- A. For the calendar years 2012, 2013, and 2014 of the ESP, Duke Energy Ohio shall recover annually, via a non-bypassable generation charge called the Electric

Service Stability Charge Rider (Rider ESSC), an amount intended to provide stability and certainty regarding Duke Energy Ohio's provision of retail electric service as an FRR entity while continuing to operate under an ESP.⁵ Duke Energy Ohio shall be permitted to implement an ESSC rate to collect \$110 million per year for a period of three years commencing January 1, 2012, with the collection to be trued-up annually and the total equal to \$330 million, allocated in accordance with Attachment B. The revenue collected under Rider ESSC shall stay with Duke Energy Ohio and shall not be transferred to any subsidiary or affiliate.

- B. For calendar year 2012, Duke Energy Ohio commits to a \$1,000,000 contribution to support economic development efforts in its service territory. For each of the two remaining calendar years of the ESP, Duke Energy Ohio agrees to provide \$1,000,000, annually, to support economic development efforts, provided Duke Energy Ohio's return on equity (ROE), as determined in its then most recent annual significantly excessive earnings test (SEET) review, exceeds 10 percent for the prior calendar year. Said funds will be provided from Duke Energy Corporation shareholders and Duke Energy Ohio shall have sole discretion to direct the use and allocation of the funding, which shall be available to customers in Duke Energy Ohio's service territory on a competitively neutral basis and without regard to their status as a shopping or non-shopping customer.

⁵ The Office of the Ohio Consumers' Counsel (OCC), FirstEnergy Solutions, and the Ohio Manufacturer's Association (OMA) support the Stipulation. However, the OCC, FirstEnergy Solutions, and OMA take no position regarding Section VII.A., or do not support or oppose the paragraph, so that the OCC's, FirstEnergy Solutions', and OMA's support for the Stipulation may not be used as precedent in any other proceeding.

- C. For calendar year 2012, Duke Energy Ohio commits to a \$100,000 contribution to the OMA to support economic development and energy efficiency initiatives among its members within Duke Energy Ohio's service territory. For each of the remaining two calendar years of the ESP, Duke Energy Ohio agrees to provide \$100,000 annually, to support economic development and energy efficiency efforts provided Duke Energy Ohio's ROE, as determined in its then most recent annual SEET review, exceeds 10 percent for the prior calendar year. Said funds will be provided from Duke Energy Corporation shareholders and shall be available to OMA members in Duke Energy Ohio's service territory on a competitively neutral basis and without regard to their status as a shopping or non-shopping customer.
- D. For the term of this ESP, while percentage of income payment plan (PIPP) customers will remain retail generation customers of Duke Energy Ohio, their metered, retail load and usage will be supplied by FirstEnergy Solutions at a 5 percent discount off the applicable residential price to compare, excluding Rider AER-R. Duke Energy Ohio will enter into a wholesale bilateral contract with FirstEnergy Solutions at such pricing for the full requirements supply including capacity, energy, market-based transmission services, and market-based transmission ancillary services for the term of the ESP, with power flow under such wholesale contract commencing January 1, 2012. While Duke Energy Ohio is an FRR entity, it will continue to supply the capacity at the FZCP for the unconstrained RTO region. Duke Energy Ohio will continue to supply RECs associated with the PIPP load, as required under the alternative energy resource

requirements of the Commission, with cost recovery through Rider AER-R. Under the bilateral contract, FirstEnergy Solutions will supply power to Duke Energy Ohio at wholesale in an amount sufficient to meet the requirements of all PIPP customers taking service under Duke Energy Ohio's tariffs and riders for generation service. For purposes of this section, a PIPP customer shall be defined as any customer who is a PIPP customer as of January 1, 2012, and any customer who thereafter is enrolled in the PIPP program during the period of this ESP. Within five days of the filing of this Stipulation, Duke Energy Ohio will enter into the bilateral agreement with FirstEnergy Solutions as referred to herein, with performance obligations thereunder expressly conditioned upon Duke Energy Ohio's acceptance of the Commission's order approving or modifying and approving the Stipulation.⁶

- E. For calendar year 2012, Duke Energy Ohio commits to a \$1,000,000 contribution for low-income weatherization efforts in its service territory, to be administered by People Working Cooperatively (PWC). For each of the two remaining calendar years of the ESP, the Company agrees to provide \$1,000,000 annually to support low-income weatherization, provided Duke Energy Ohio's ROE, as determined in its then most recent annual SEET review, exceeds 10 percent for the prior calendar year. Said funds will be provided from Duke Energy Corporation shareholders and shall be available to customers in Duke Energy Ohio's service

⁶ The Retail Energy Supply Association; Constellation NewEnergy, Inc.; Constellation Energy Commodities Group, Exelon Generation Company, LLC; Direct Energy Services, LLC; Direct Energy Business LLC; Interstate Gas Supply, Inc; Vectren Retail, LLC d/b/a Vectren Source; Wal-Mart East, LP; Sam's East, Inc.; PJM Power Providers Group; and AEP Retail Energy Partners LLC support the Stipulation but do not endorse Section VII, Paragraph D.

territory on a competitively neutral basis and without regard to their status as a shopping or non-shopping customer.

- F. Duke Energy Ohio and PWC will jointly undertake a pilot energy efficiency project. This pilot will utilize Duke Energy Ohio funds provided to PWC for low-income weatherization. PWC will use Duke Energy Ohio dollars to leverage additional energy efficiency funds from non-utility public and private sources for both electric and gas energy efficiency for low-income households. The leveraged energy efficiency funds will provide funding for low-income weatherization services that will yield energy efficiency that is enhanced by additional improvements in the home and funded by other sources. It is anticipated that the enhanced energy efficiency services will yield better results as measured by the total resource cost test. Duke Energy Ohio and PWC will provide the results of the pilot energy efficiency project to the energy efficiency collaborative and will jointly file such results with the Commission and seek the Commission's approval of inclusion of the enhanced energy efficiency attributes in Duke Energy Ohio's portfolio of programs for energy efficiency. The project shall be available to customers in Duke Energy Ohio's service territory on a competitively neutral basis and without regard to their status as a shopping or non-shopping customer.
- G. For calendar year 2012, Duke Energy Ohio commits to a \$350,000 fuel fund contribution to benefit electric consumers in its service territory who are at or below 200 percent of poverty level. The fund will be managed in conjunction with the Ohio Department of Development or its successor, in a manner

consistent with the operation of the fuel fund provided by Duke Energy Ohio during the current ESP. Assistance will be provided through the agencies in the Duke Energy Ohio service territory that provide assistance under the Emergency Home Energy Assistance Program in the Duke Energy Ohio service territory. For each of the two remaining calendar years of the ESP, Duke Energy Ohio agrees to provide \$350,000 in continued support of the fuel fund, provided Duke Energy Ohio's ROE, as determined in its then most recent annual SEET review, exceeds 10 percent for the prior calendar year. Said funds will be provided from Duke Energy Corporation shareholders and shall be available to customers in Duke Energy Ohio's service territory on a competitively neutral basis and without regard to their status as a shopping or non-shopping customer.

- H. For calendar year 2012, Duke Energy Ohio commits to a \$325,000 contribution for low-income weatherization efforts in its service territory in Adams, Brown, Butler, Clermont, Clinton, Highland, Montgomery, and Warren Counties. The contribution shall be made to OPAE, which shall receive an administrative fee of \$25,000. The funds shall be available until expended for the benefit of the appropriate agencies within Duke Energy Ohio's service territory. Duke Energy Ohio and OPAE shall agree to the amount of distribution to each agency, program parameters, and reporting requirements.⁷ For each of the two remaining calendar years of the ESP, Duke Energy Ohio agrees to provide \$325,000 annually to support low-income weatherization programs of OPAE member organizations, provided Duke Energy Ohio's ROE, as determined in its then most recent annual

⁷ The program parameters shall be substantially similar to the programs currently managed by OPAE for American Electric Power, The Dayton Power & Light Company, and FirstEnergy operating companies.

SEET review, exceeds 10 percent for the prior calendar year. Said funds will be provided from Duke Energy Corporation shareholders and shall be available to customers in Duke Energy Ohio's service territory on a competitively neutral basis and without regard to their status as a shopping or non-shopping customer. The Duke Energy Community Partnership shall review the results of the program and make recommendations regarding continuation of the program as a part of Duke Energy Ohio's demand-side management portfolio.

- I. The Parties expressly agree that Duke Energy Ohio will continue to provide existing distribution reserve capacity at no charge for existing load for Greater Cincinnati Health Council (GCHC) member hospitals for the term of this ESP. Duke Energy Ohio agrees to consider similar reasonable arrangements for new hospital construction and/or expansion up to 4,000 kVa during the term of this ESP, provided the requesting hospital(s) and Duke Energy Ohio can reach agreement on appropriate compensation to Duke Energy Ohio if it is necessary to upgrade facilities for the purpose of (i) a secondary distribution service; and/or (ii) reserve capacity. Duke Energy Ohio agrees to meet with any requesting GCHC member hospitals to discuss Duke Energy Ohio's electric distribution system serving the member hospital, including but not limited to any system enhancements planned and the age and performance of the system. Also, for the term of the ESP, Duke Energy Ohio will work with GCHC member hospitals to understand and evaluate service quality concerns, particularly with regard to secondary feeders for reliability purposes, and to enhance communication between members and Duke Energy Ohio to facilitate better understanding of

overall service quality. Duke Energy Ohio and GCHC will hold meetings upon request to discuss, at least annually, any service quality or reliability concerns. Within 90 days of the approval of this Stipulation, Duke Energy Ohio will meet with GCHC to identify ways to leverage and better utilize Duke Energy Ohio's non-residential custom and prescriptive energy efficiency programs to benefit GCHC member hospitals.

For the term of the ESP, Duke Energy Ohio agrees to continue to compensate GCHC member hospitals that participate in PowerShare agreements consistent with the terms of the PowerShare program as approved by the Commission in Case No. 09-1999-EL-POR and any subsequent program approved by the Commission.

- J. For the term of the ESP, the Parties agree to establish, on a revenue neutral basis among all demand metered customer classes, a non-bypassable demand charge and non-bypassable energy credit designed to stabilize electric service by enhancing some of the benefits associated with high load factor customers under current rates. For customers served under Rates DS, DP, and TS, there will be a non-bypassable demand charge of \$8/kW per month and a non-bypassable energy credit of \$0.020961/kWh to produce net revenues of \$0 for Rates DS, DP, and TS as a group. The energy credit referred to in this paragraph is to be trued up quarterly to maintain net revenue neutrality.
- K. The University of Cincinnati (UC) operates a Commission-certified renewable energy generation facility at its Main Campus in Cincinnati (See Case No. 10-1382-EL-REN), which is not directly metered by Duke Energy Ohio. For the

term of this ESP, UC will establish for its Main Campus demand usage for rate purposes including for Rider ESSC (Section VII.A.) and the load factor adjustment (Section VII.J.) by using the 5 CP demand determinate established by PJM for purposes of assessing capacity costs. Until PJM establishes an actual demand determinate for PJM 2012/2013 planning year, which is anticipated to occur in October 2011, Duke Energy Ohio shall use 12,475 kW, which is the 5 CP demand factor for UC for the 2011/2012 PJM planning year. The commodity billing determinates for both Rider ESSC and the load factor adjustment shall be the kWh received by UC at its side of the substation.

- L. Council of Smaller Enterprises (COSE) and Duke Energy Ohio will work with small and mid-sized businesses in the Duke Energy Ohio service territory to educate such entities with respect to services provided by both Duke Energy Ohio and COSE related to energy efficiency during the term of this ESP.

To the extent such customers can provide energy savings as a result of implementing energy efficiency measures, Duke Energy Ohio will compensate COSE through its Commission-approved energy efficiency programs for services performed on behalf of the businesses that they work with, at a rate to be determined in the future and similar to the compensation rate paid to other vendors, provided the savings contribute to Duke Energy Ohio's mandated energy efficiency requirements.

COSE will participate in Duke Energy Ohio's Energy Efficiency Collaborative and provide its views and input with respect to the design of energy efficiency products and programs for small- and mid-sized businesses.

M. The Parties agree that, in the aggregate, the ESP as agreed to herein is better than the results that would be expected under a market rate offer (MRO) and that the ESP is consistent with and advances state policy, as set forth in R.C. 4928.02, as it:

- Is quantitatively better than the results expected under the MRO, as provided in Attachment D;
- Allows customers to benefit from a fully competitive market as soon as practicable;
- Encourages and supports the development of competitive retail markets in Ohio;
- Results in stability and certainty in respect of retail electric service;
- Provides for a stable electric distribution utility;
- Encourages the development of renewable resources in Ohio;
- Supports economic development;
- Provides low-income assistance;
- Ensures PIPP customers a discount from the SSO;
- Continues and expands the ability of retail electric consumers served by Duke Energy Ohio to choose from among CRES providers on a competitive basis;
- Expands wholesale competition;
- Mandates divestiture of Duke Energy Ohio's Generation Assets;

- Constitutes a State Regulatory Structural Change, within the meaning of Section 1.81 and Section C.3 of Schedule 8.1 of the PJM Reliability Assurance Agreement; and
- Allows Duke Energy Ohio to terminate its FRR plan due to such State Regulatory Structural Change, subject to any necessary governmental approvals, by providing notice of termination pursuant to Section C.3 of Schedule 8.1 of the PJM RAA at least two months prior to the May 2012 PJM Base Residual Auction.⁸

VIII. GENERATING ASSETS

- A. The Parties agree that Duke Energy Ohio will transfer title, at net book value, to all of its Generation Assets out of Duke Energy Ohio. Such transfer shall occur on or before December 31, 2014, and Duke Energy Ohio commits to using its best commercial efforts to complete the transfer as soon as practicable upon its acceptance of a Commission order approving the Stipulation and upon receipt of necessary regulatory approvals. Staff, or an independent auditor at the Commission's discretion and with costs thereof to be recovered through Rider SCR, shall audit the terms and conditions of the transfer of the Generation Assets to ensure compliance with this Section VIII of the Stipulation and shall also audit Duke Energy Ohio's compliance with R.C. 4928.17 and the Commission's Corporate Separation Rule, O.A.C. 4901:1-37 and any successors to that rule, to ensure that no subsidiary or affiliate of Duke Energy Ohio that owns competitive generation assets has any competitive advantage due to its affiliation with Duke

⁸ The OCC supports the Stipulation. However, the OCC takes no position regarding Section VII.M., or does not support or oppose that paragraph, so that the OCC's support for the Stipulation may not be used as precedent in any other proceeding.

Energy Ohio. The Parties further expressly support Duke Energy Ohio's request for a waiver of the Commission's rule requirements, as set forth in O.A.C. 4901:1-37-09(B), (C), and (D), relating to the sale or transfer of generating assets. The Parties agree that approval of this Stipulation shall constitute the Commission consent required by paragraphs (A) and (E) of that rule, and that no hearing is required under paragraphs (D) and (E) of that rule. Further, the Parties agree that this paragraph provides the Commission Staff with access to books and records in compliance with paragraph (F) of that rule.

- B. Approval of this Stipulation will serve as the Commission's approval of full legal corporate separation (as contemplated by R.C. 4928.17(A) and also known as structural corporate separation) such that the transmission and distribution assets of Duke Energy Ohio will continue to be held by the distribution utility and all of Duke Energy Ohio's Generation Assets shall be transferred to an affiliate. Full legal corporate separation will be implemented as soon as reasonably possible after necessary regulatory approvals are obtained. Following the transfer of the Generation Assets, Duke Energy Ohio shall not without prior Commission approval: 1) provide or loan funds to; 2) provide any parental guarantee or other security for any financing for; and/or 3) assume any liability or responsibility for any obligation of subsidiaries or affiliates that own generating assets, provided however, that contractual obligations arising before the signing of the Stipulation shall be permitted to remain with Duke Energy Ohio without Commission approval for the remaining period of the contract but only to the extent that assuming or transferring such obligations is prohibited by the terms of the

contract or would result in substantially increased liabilities for Duke Energy Ohio if Duke Energy Ohio were to transfer such obligations to its subsidiary or affiliate. On and after the signing of this Stipulation, Duke Energy Ohio shall ensure that all new contractual obligations have a successor-in-interest clause that transfers all Duke Energy Ohio responsibilities and obligations under such contracts and relieves Duke Energy Ohio from any performance or liability under the contracts upon the transfer of the Generation Assets to its subsidiaries. This provision does not restrict Duke Energy Ohio's ability to receive and pass through to the subsidiary(ies) that own the Generation Assets equity contributions from its parent that are in support of the Generation Assets, nor does it restrict Duke Energy Ohio's ability to receive dividends from the subsidiary(ies) that own the Generation Assets and pass through such dividend(s) to its parent. Generation-related costs associated with implementing corporate separation shall not be recoverable from customers. Any subsidiary of Duke Energy Ohio to which Generation Assets are transferred shall not use or rely upon the rating(s) from credit rating agency(ies) for Duke Energy Ohio. If such subsidiary currently does not maintain separate rating(s) from the credit rating agency(ies), then upon transfer of any of the Generation Assets, it shall either seek to establish such rating(s) or shall tie its credit rating to Duke Energy Corp. as soon as practicable but no later than six months following such transfer.

- C. The Parties expressly agree that full legal corporate separation is in the public interest and, as such, will not intervene in the FERC proceeding to transfer Duke Energy Ohio's Generation Assets to contest, challenge, or in any way oppose the

transfer. Parties are not precluded from intervening in said FERC proceeding for purposes other than those prohibited by this paragraph.⁹

IX. MISCELLANEOUS

- A. The Parties agree that Duke Energy Ohio shall implement Rider RECON as proposed in Duke Energy Ohio's Application and testimony filed in support thereof. The Parties further agree that Rider RECON shall terminate no later than two quarters after the filing of a final entry in the docket initiated by the Commission for purposes of conducting its final audit of Rider PTC-FPP.
- B. Effective January 1, 2012, Duke Energy Ohio shall implement an uncollectible expense rider, Rider UE-GEN, applicable to all retail jurisdictional customers including those taking generation service from a CRES provider, except for those customer accounts designated by CRES providers as not part of Duke Energy Ohio's Purchase of Accounts Receivable (PAR) Program. Rider UE-GEN shall be bypassable by dual-billed customer accounts and customer accounts designated by CRES providers as not part of the PAR Program, but shall be non-bypassable by all other retail customers, including SSO customers and customer accounts designated by CRES providers as part of the PAR Program. Accordingly, uncollectible expense generated by customer accounts of CRES providers that utilize dual billing and customer accounts of CRES providers that utilize consolidated billing but are not designated as part of the PAR program are excluded from Rider UE-GEN and, instead, remain the liability of said CRES provider. Rider UE-GEN will initially be set at zero in these proceedings. Duke

⁹ The OMA supports the Stipulation. However, the OMA takes no position regarding Section VIII.C., or does not support or oppose that paragraph, so that the OMA's support for the Stipulation may not be used as precedent in any other proceeding.

Energy Ohio's initial application to establish a rate for Rider UE-GEN shall be filed in conjunction with Duke Energy Ohio's UE-ED filing. Thereafter, Duke Energy Ohio will file annual applications to adjust Rider UE-GEN in conjunction with and governed by the same review process applicable to adjustments to Rider UE-ED as provided in the March 31, 2009, stipulation approved by the Commission in Case No. 08-709-EL-AIR, *et al.* As with Rider UE-ED, Duke Energy Ohio shall not accrue carrying charges on the monthly unrecovered uncollectible expense balances for which recovery is sought through Rider UE-GEN. Rider UE-GEN shall be in form set forth in Attachment E.

- C. After the effective date of Rider UE-GEN, Duke Energy Ohio shall purchase the customer accounts receivable of CRES providers that designate accounts to participate in the PAR Program at no discount and shall pay such CRES providers for such receivables no later than twentieth day of the month after the month in which the billing occurs. Paragraph 11.6 of Duke Energy Ohio's Supplier Tariff shall be amended as shown in Attachment E to memorialize this change to the PAR Program. Duke Energy Ohio agrees to amend any existing Account Receivables Purchase Agreements with CRES providers participating in the PAR Program to make them consistent with this Section IX.C. of the Stipulation.
- D. Duke Energy Ohio agrees to modify Section XI, Sheet No. 40.4, Paragraph 11.6, and Sheet 26.5, Paragraph 7.5, of its Certified Supplier Tariff and to modify Section III, Sheet No. 22.7, Section 4(d) and Section 10 of its Electric Tariff, and to make any other tariff modifications that are necessary to eliminate the

prohibition against customers enrolling in the PAR Program where such customers have outstanding arrears of more than \$50 or 30 days.

- E. CRES providers may designate which of their customer accounts will be billed using a dual billing method, which of their customer accounts will be billed using consolidated billing but with no purchase of receivables by Duke Energy Ohio, and which of their customer accounts will be billed using consolidated billing with purchase of receivables. Duke Energy Ohio will accommodate different methods of billing and collections by a CRES provider so long as alternative methods of billing and collection are distinguished as sub-accounts to PJM. The responsibility for, and PJM costs related to, creating a PJM sub account shall be that of the CRES providers.
- F. Duke Energy Ohio withdraws its proposed Rider PSM and Advance Southwest Ohio Fund, as well as the funding for same.
- G. The bid documents pursuant to which the auctions will be conducted are those attached as Attachments C through G of Duke Energy Ohio's Application, except as modified herein in Stipulation Attachments C, F, and G.
- H. Duke Energy Ohio withdraws its Rider DR as proposed in these proceedings. Within 45 days of an executed Stipulation in these proceedings, Duke Energy Ohio shall file, in a separate proceeding, for Commission approval of a distribution revenue decoupling mechanism that will adjust rates between rate cases to effectively remove Duke Energy Ohio's through-put incentive, with all parties retaining their rights to due process in such proceeding. The decoupling mechanism to be filed through such application shall not be applicable to Rates

TS, DS, and DP. Nothing in this Stipulation is intended, or shall be interpreted, to signify Parties' agreement with such application. Further, nothing in this Stipulation shall affect Duke Energy Ohio's existing SmartGrid recovery mechanism, which shall continue under Rider DR-IM.

- I. The Parties recommend that the Commission approve this settlement on or before November 15, 2011, so that Duke Energy Ohio may conduct, in December 2011, its first auction under the CBP for the procurement of supply necessary to serve its SSO load effective January 1, 2012.
- J. Duke Energy Ohio shall conduct collaborative meetings, on or before November 15, 2011, with all interested wholesale suppliers, retail suppliers, and transmission owners to confirm the charges from PJM that shall be paid by Duke Energy Ohio and the charges from PJM that shall be paid by CRES providers.
- K. Duke Energy Ohio shall be permitted to amend its certified supplier tariff, as proposed in its Application and testimony filed in support thereof, as modified herein.
- L. Duke Energy Ohio agrees to withdraw from these proceedings the proposed amendment to Section XIV.C. of its Third Amended Corporate Separation Plan that, if approved, would enable Duke Energy Ohio to provide Special Customer Services, as described in proposed Tariff 19, Sheet 23, Section 6. Duke Energy Ohio expressly reserves the right to seek revision of its Corporate Separation Plan to incorporate this proposal to provide Special Customer Services in a subsequent proceeding. Except as modified herein, Duke Energy Ohio shall be permitted to adopt its Third Amended Corporate Separation Plan, as proposed in its

Application and testimony filed in support thereof. The Parties also recognize that the Third Amended Corporate Separation Plan will be amended to identify additional affiliates and parties to agreements following the anticipated merger of Duke Energy Corporation and Progress Energy, Inc., and the Parties agree not to oppose such amendment. Within ninety days after the effective date of full legal corporate separation, Duke Energy Ohio agrees to file for approval of a Fourth Amended Corporate Separation Plan that will address any issues with the full legal corporate separation.

- M. The Parties agree that the SEET, as provided for under R.C. 4928.143(F), shall be administered to Duke Energy Ohio with an ROE threshold of 15 percent for the term of this ESP. The methodology for applying the SEET is outlined in Attachment H.
- N. During the term of this ESP, transmission voltage customers, whether shopping or non-shopping, with loads in excess of 10 MW at a single site shall have the option to annually nominate any part of their load as being subject to interruption through Duke Energy Ohio. Any such nomination shall have an effective date no earlier than June 1, 2012. For any customer electing to nominate load subject to interruption through Duke Energy Ohio, such load: (1) must be registered with PJM and abide by all of PJM's requirements for the demand response (DR) program chosen by the customer, by March 1 of the upcoming PJM planning year; (2) must not have been previously sold or committed to PJM or another party as a DR resource for the same planning year; and, (3) will have Duke Energy Ohio serve as its curtailment service provider (CSP). The customer

acknowledges that Duke Energy Ohio may use such interruptible load in Duke Energy Ohio's FRR plan and any capacity resource revenues associated with this DR resource will be credited to the economic competitiveness fund (Rider DR-ECF). The interruptible credit for load subject to interruption will be one half of the PJM Net Cost Of New Entry (CONE) on a \$/MW-day basis for the planning year in which the interruptible load is nominated (net CONE equals 2011/2012 = \$160.76, 2012/2013 = \$276.09, 2013/2014 = \$317.95, 2014/2015 = \$342.23 per MW-day). The maximum amount of interruptible load under this program shall be 250 MW in the DEOK zone. The amount of this interruptible credit shall be recoverable by Duke Energy Ohio through Rider DR-ECF. Duke Energy Ohio shall file a separate application to amend Rider DR-ECF.

- O. Duke Energy Ohio agrees to work with interested CRES providers and Commission Staff to jointly develop a secure, web-based system that will provide electronic access to key customer usage and account data that can be accessed via a secure, supplier website that presents the following data and information in a format that can be automatically retrieved, by the CRES provider authorized by the customer, subject to appropriate limitations reflecting legally mandated customer privacy issues, including compliance with protections addressed in the Ohio Administrative Code and specifically including but not limited to Rules 4901:1-10-29, 4901:1-10-24, O.A.C., and any successors to such Rules. The following data and information, in a format that can be automatically retrieved, will be the subject of the web-based system:

- Account Numbers

- Meter numbers
- Names
- Service Address, including zip codes
- Billing Address, including zip code
- Email address (if available)
- Meter Reading Cycle Dates
- Meter Types
- Indicator if Customer has an Interval Meter
- Rate Code Indicator
- Load Profile Group Indicators
- PLC and NSPL values (capacity and transmission obligations)
- 24 months of consumption data (in kWh) by billing period including
- 24 months of demand data (in kW)
- 24 months of interval data
- Indicator if SSO customer
- Identifier as to whether customer is participating in the Budget Billing Plan

Duke Energy Ohio shall use commercially reasonable efforts to add to the existing web system the Load Profile Group Indicators and the customer service addresses by March 1, 2012, but shall complete such additions no later than June 1, 2012. Duke Energy Ohio shall make a commercially reasonable effort to add the other items by June 1, 2013, but agrees to complete the additional data items no later than June 1, 2014, and will work with Commission Staff and interested

CRES providers to stage the implementation of various portions of this website, as possible. Additionally, Duke Energy Ohio shall add an indicator to the pre-enrollment list, noting whether a customer is an SSO customer or is shopping, by no later than June 1, 2012.

Duke Energy Ohio shall recover the actual costs to develop said web-based system, recovery not to exceed \$500,000, on a non-bypassable basis. Duke Energy Ohio shall be permitted to create a regulatory asset for purposes of recording said costs for future recovery through electric distribution rates. The carrying charge on said regulatory asset shall not exceed Duke Energy Ohio's long-term cost of debt from the then most recent distribution rate case (*e.g.*, Case No. 08-709-EL-AIR, *et al.*).

In addition, the following types of data would be provided via EDI transactions:

- 867 Historical Usage (HU) and Historical Interval (HI)
- 867 Monthly Usage (MU) and Monthly Interval (MI) data
- Network Service Peak Load (NSPL) and Peak Load Contribution (PLC) in 867HUs, 867HIs, and 814 Accepted Enrollment Responses
- Meter read cycle and load profile segment information to be in 867HUs no later than 12/31/12, as agreed to in the Ohio EDI Working Group – Change Control #82 (current rate code already included in 867HUs)

Duke Energy Ohio shall confirm that accounts requested together in the same EDI envelope come back together, unless there would be an unnecessary delay for a particular subset of accounts. Duke Energy Ohio shall make available,

upon request, a quarterly updated sync list to CRES providers on a confidential basis showing the accounts that are enrolled with the CRES provider. The list would contain information such as service start date, bill method, NSPL values, and PLC values. Duke Energy Ohio confirms that Validation, Error Detection, and Editing (VEE) rules and processes are now in place and will continue to be applied to raw meter read data before Duke Energy Ohio transmits such usage data to the CRES providers via EDI.

Effective January 1, 2012, Duke Energy Ohio shall increase the required interval meter threshold size requirement from 100kW to 200kW and will make such tariff changes as are necessary to accomplish this result.

Duke Energy Ohio agrees to conduct a collaborative process to discuss the deployment of an electric vehicle (EV) ecosystem that works in tandem with a competitive retail market, including, but not limited to customer education and additional billing system functionality to support various EV deployment programs and charging platforms. All interested persons shall be encouraged to participate in the EV collaborative process. The first such EV collaborative meeting shall occur in the first quarter of 2012 and continue to be held periodically, but not less often than three times a year for the first two years thereafter. At the conclusion of the EV collaborative process, the participants in the EV Collaborative shall prepare a report to the Commission discussing the progress of the collaborative and any recommended regulatory or legislative changes to facilitate the development of an EV ecosystem.

Duke Energy Ohio shall host annual meetings or conference calls with registered CRES providers to discuss supplier coordination issues affecting CRES providers, including but not limited to CRES consolidated billing.

- P. All energy efficiency programs and rebates shall be made available at the same terms and conditions to customers, regardless of whether they purchase generation service from a CRES provider or Duke Energy Ohio. Duke Energy Ohio shall maintain its policy to make SmartGrid meters and data available to all customers on a competitively neutral basis and without regard to their status as a shopping or non-shopping customer.
- Q. Duke Energy Ohio shall provide, from shareholder funds, a one-time economic development/energy efficiency grant of \$50,000 for Industrial Energy Users-Ohio to be distributed among its members.
- R. For the term of this ESP, Duke Energy Ohio will maintain its existing procedures contained in its tariff (*e.g.*, bulking of meters, power factor adjustments, demand ratchets) for metering and calculating billing determinants that are used in the calculation of retail bills.
- S. For the term of this ESP, Duke Energy Ohio will continue the retail Real Time Pricing Program (Rate RTP, Sheet No. 90). Current Customer Base Line (CBL) and Billing Demand History (BDH) values will continue for each customer taking service under RTP as of October 18, 2011, subject to the terms of Rate RTP, as modified to be consistent with this Stipulation.
- T. Duke Energy Ohio agrees to reduce its switching fee, as set forth in Rate CS, Sheet No. 52.2, of its Certified Supplier Tariff, from \$7.00 to \$5.00. Duke

Energy Ohio will make bill-ready billing functional and available as soon as commercially and reasonably practicable, but in no event later than September 30, 2013. In addition, Sheet 52.2 of the Certified Supplier Tariff shall be modified to reduce the per-bill charges for consolidated, bill-ready billing to 50 percent of the existing rate. Duke Energy Ohio agrees to continue its current practice of not imposing a per-bill charge for rate-ready consolidated billing services.

- U. Retail customers in Duke Energy Ohio's territory are permitted to participate in PJM DR programs including through Aggregators of Retail Customers (ARCs) or CSPs and the following conditions apply:
 - i. Duke Energy Ohio retail customer DR capacity may be utilized to satisfy either FRR or non-FRR capacity obligations (such as DR that clears in a PJM RPM auction);
 - ii. The Parties agree that any customer that is already receiving an incentive payment through a reasonable arrangement, including but not limited to EE/PDR, economic development arrangements, unique arrangements, and other special tariff schedules that offer service discounts from the applicable tariff rates and would currently or would like to participate in PJM programs must agree to commit to the electric distribution utility the peak demand response attributes that have cleared in the PJM market in a manner consistent with applicable statutes and rules at no cost to the utility for the duration of the arrangement. This provision shall not be interpreted as modifying the express specific terms of any agreement; and

- iii. Duke Energy Ohio may issue a request for proposal to meet its peak demand reduction mandates under Amended Sub. Senate Bill 221.
- V. The Parties agree that the “Summary of Riders Impacted by the ESP,” attached as Attachment I, provides an accurate recitation of Duke Energy Ohio’s riders for electric distribution, transmission, and generation service, effective January 1, 2012. In this regard, the Parties agree to the elimination Rider RTC (regulatory transition charge) and Rider DRI (distribution reliability investment), as said riders expired for all customers on December 31, 2010.
- W. Duke Energy Ohio shall make all applicable changes to customer or supplier tariffs and to all operational rules or procedures, in order to ensure compliance and consistency with all applicable provisions of this Stipulation.
- X. All Attachments to this Stipulation are incorporated herein and are an integral part of this Stipulation.
- Y. In the event the Commission approves Duke Energy Ohio’s next SSO, and Duke Energy Ohio does not withdraw the application therefor, for the period beginning June 1, 2015, by an order issued on or before March 1, 2015, the Parties agree that the Commission’s approval will function to demonstrate compliance with the requirement, under R.C. 4928.143(E), to compare the prospective results of the ESP detailed herein with the prospective results under the MRO provisions. Nothing in this paragraph shall be interpreted to limit Parties’ rights to object at any time, in whole or in part, to any proposal by Duke Energy Ohio regarding its next SSO.

Z. The Signatory Parties' agreement to this Stipulation, in its entirety, shall not be interpreted in a future proceeding before this Commission as their agreement to only an isolated provision of this Stipulation. The agreement of the Signatory Parties reflected in this document is expressly conditioned upon its acceptance in its entirety and without alteration by the Commission. The Signatory Parties agree that if the Commission or any court of competent jurisdiction rejects all or any material part of this Stipulation, or otherwise materially modifies its terms, all Signatory Parties agree to work in good faith with all other Signatory Parties to achieve a revised stipulation that substantially satisfies the intent of the original agreement or make such other agreements as may be necessary to maintain the economic benefit to each party that would have been achieved had the Stipulation not been so modified. Any such revised stipulation will be filed with the Commission for approval and all Signatory Parties agree to fully support such modifications or agreements. Should the Signatory Parties be unable to reach a modified agreement, any adversely affected Signatory Party shall have the right to file, in this docket and with service to all parties, an application for rehearing, a motion for reconsideration, or a notice withdrawing from the Stipulation.¹⁰ Other Parties agree that they will not oppose or argue against any other Party's application for rehearing or motion for reconsideration that seeks to uphold the original, unmodified Stipulation. If such application or motion is filed, and if the Commission or court does not, on rehearing or reconsideration, accept the Stipulation without material modification within 45 days of the filing of such

¹⁰ Parties have the right, at their sole discretion, to determine what constitutes a "material" part for purposes of withdrawing from the Stipulation.

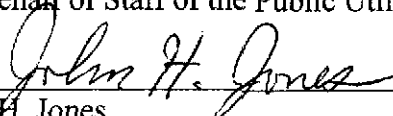
application or motion, then, within 30 days thereafter, the adversely affected Signatory Party may terminate its Signatory Party status without penalty or cost and regain its rights as a non-Signatory Party as if it had never executed the Stipulation by filing a notice with the Commission and the other Signatory Parties. Other Parties agree not to oppose a termination and withdrawal from the Stipulation by any other Party.

- AA. Unless the Signatory Party exercises its right to terminate its Signatory Party status as described above, each Signatory Party agrees to and will support the reasonableness of this ESP and this Stipulation before the Commission in these proceedings and to take no position contrary to the support for the reasonableness of the ESP and this Stipulation in any appeal from the Commission's adoption and/or enforcement of this ESP and this Stipulation. The Parties agree that testimony and related exhibits that support this Stipulation will be offered at a hearing, provided that such testimony and related exhibits may be used only for the purpose of the Commission's approval of this Stipulation. At any hearing and in any documents or briefs filed with the Commission in respect of the Stipulation, each Signatory Party agrees to support the Stipulation and to do nothing, directly or indirectly, to undermine the Stipulation or the Commission's approval of it, including through cross-examination or taking positions that are contrary to supporting the Commission's approval of the Stipulation without modification.
- BB. This Stipulation is submitted for purposes of these proceedings only and neither this Stipulation nor any Commission order considering this Stipulation shall be

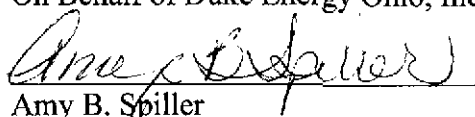
deemed binding in any other proceeding nor shall this Stipulation or any such Order be offered or relied upon by any Party in any proceedings except as necessary to enforce the terms of this Stipulation.

CC. This Stipulation contains the entire agreement between the Parties (including persons who belong to membership organizations that are Parties hereto) and no additional consideration with regard to the above-captioned proceedings has been promised or agreed to by any Party (including persons who belong to membership organizations that are Parties hereto).

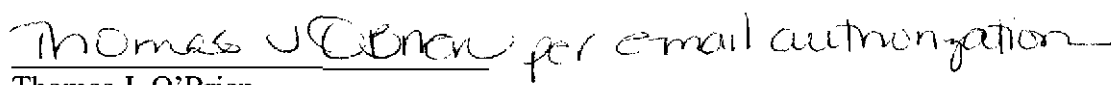
On Behalf of Staff of the Public Utilities Commission of Ohio


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On Behalf of City of Cincinnati


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On Behalf of Ohio Partners for Affordable Energy

Colleen L. Mooney per verbal authorization

Colleen L. Mooney

Ohio Partners for Affordable Energy

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On Behalf of Environmental Law & Policy Center

Tara C. Santarelli

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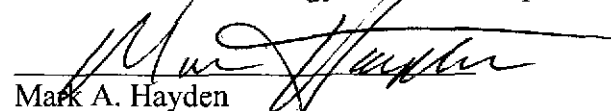
On Behalf of the Kroger Company


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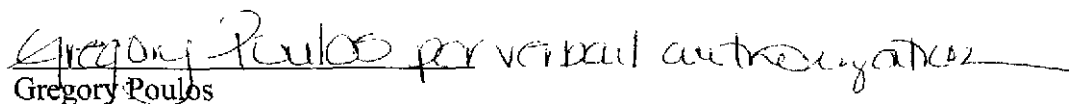
On Behalf of Constellation NewEnergy, Inc. and Constellation Energy Commodities Group, Inc.


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Michael J. Settineri
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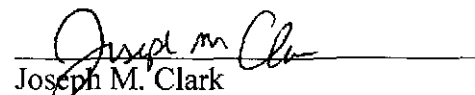
On Behalf of FirstEnergy Solutions Corp.


Mark A. Hayden
FirstEnergy Service Company
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Akron, OH 44308

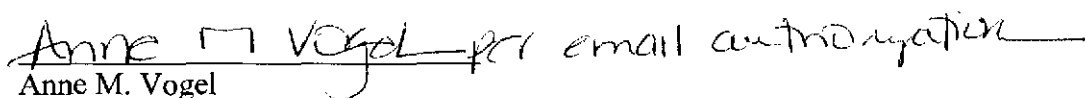
On Behalf of EnerNOC, Inc.


Gregory Poulos
EnerNOC, Inc.
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Boston, MA 02110

On Behalf of Vectren Retail, LLC d/b/a/ Vectren Source

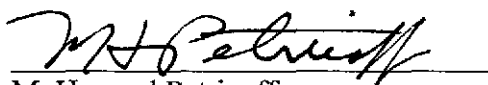

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On Behalf of AEP Retail Energy Partners LLC

 *per email authorization*

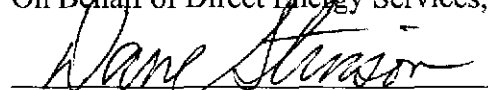
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Corporation
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On Behalf of PJM Power Providers Group



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Stephen Howard
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On Behalf of Direct Energy Services, LLC, and Direct Energy Business, LLC



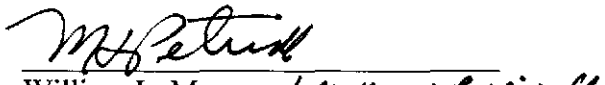
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On Behalf of Miami University and the University of Cincinnati



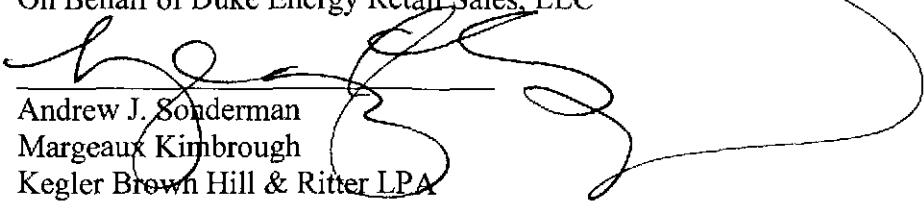
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On Behalf of COMPETE Coalition

 */ M. Howard Petricoff*

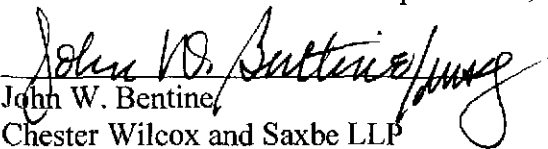
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On Behalf of Duke Energy Retail Sales, LLC



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Margeaux Kimbrough
Kegler Brown Hill & Ritter LPA
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On Behalf of American Municipal Power, Inc.



John W. Bentine
Chester Wilcox and Saxbe LLP
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Columbus, Ohio 43215

On Behalf of Interstate Gas Supply, Inc.



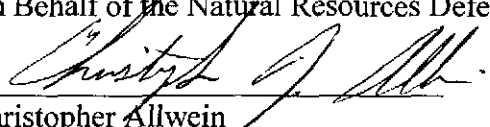
Vincent Parisi
Matthew White
Interstate Gas Supply, Inc
6100 Emerald Parkway
Dublin OH 43016

On Behalf of Exelon Generation Company, LLC



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Lija Kaleps- Clark
Vorys, Sater, Seymour, and Pease, LLP
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On Behalf of the Natural Resources Defense Council



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On Behalf of Wal-Mart Stores East, LP and Sam's East, Inc.

Richard Chamberlain per verbal authorization

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Oklahoma City, OK 73105

On Behalf of Cincinnati Bell Inc.

Douglas E. Hart per verbal authorization

Douglas E. Hart
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Cincinnati, OH 45202

On Behalf of Council of Smaller Enterprises

Matthew R. Cox per verbal authorization

Matthew R. Cox
McDonald Hopkins
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Columbus, OH 43215

The following parties in these proceedings take no position with regard to the Stipulation:

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Matthew Satterwhite
Erin Miller
American Electric Power Service Corporation
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Columbus OH 43215

On Behalf of Dominion Retail, Inc.

Barth E. Royer per verbal authorization

Barth E. Royer
Bell & Royer Co., LPA
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Attachment A

ESP Period 3 years and 5 months

Auction Date	Tranches	Delivery Period Beginning		
		1/1/2012 - 17 months	6/1/2013	6/1/2014
Auction 1 Dec 2011	33	33		
	33	33	33	
	34	34	34	34
Auction 1 May 2012	17		17	17
Auction 2 Nov 2012	16		16	16
Auction 1 May 2013	17			17
Auction 2 Nov 2013	16			16
TOTAL TRANCHES		100	100	100

PJM BRA dates

May-11 2014-2015

Duke Energy Ohio
Methodology for Calculating Average Riders RC and RE (For Illustration Purposes Only)

	Month	Auction 1				Auction 2	Auction 3	Auction 4	Auction 5	Avg Auction Prices for Delivery Period						
		Jan 12-May 13	Jan 12-May 14	Jan 12-May 15	33%	Jun 13-May 15	17%	Jun 13-May 15	16%	Jun 14-May 15	17%	Jun 14-May 15	16%	Total ⁽¹⁾	RC ⁽²⁾	RE
Auction 1	Dec 2011				34%											
	Jan 2012	\$ XX	\$ XX	\$ XX									\$62.70	\$4.11	\$58.59	
	Feb	\$ XX	\$ XX	\$ XX									62.70	4.11	58.59	
	Mar	\$ XX	\$ XX	\$ XX									62.70	4.11	58.59	
Auction 2	Apr	\$ XX	\$ XX	\$ XX									62.70	4.11	58.59	
	May	\$ XX	\$ XX	\$ XX									62.70	4.11	58.59	
	Jun	\$ XX	\$ XX	\$ XX									62.70	4.11	58.59	
	Jul	\$ XX	\$ XX	\$ XX									62.70	4.11	58.59	
Auction 3	Aug	\$ XX	\$ XX	\$ XX									62.70	4.11	58.59	
	Sep	\$ XX	\$ XX	\$ XX									62.70	4.11	58.59	
	Oct	\$ XX	\$ XX	\$ XX									62.70	4.11	58.59	
	Nov	\$ XX	\$ XX	\$ XX									62.70	4.11	58.59	
Auction 4	Dec	\$ XX	\$ XX	\$ XX									62.70	4.11	58.59	
	Jan 2013	\$ XX	\$ XX	\$ XX									62.70	4.11	58.59	
	Feb	\$ XX	\$ XX	\$ XX									62.70	4.11	58.59	
	Mar	\$ XX	\$ XX	\$ XX									62.70	4.11	58.59	
Auction 5	Apr	\$ XX	\$ XX	\$ XX									62.70	4.11	58.59	
	May	\$ XX	\$ XX	\$ XX									62.70	4.11	58.59	
	Jun	\$ XX	\$ XX	\$ XX									71.04	2.45	\$68.59	
	Jul	\$ XX	\$ XX	\$ XX									71.04	2.45	68.59	
Auction 6	Aug	\$ XX	\$ XX	\$ XX									71.04	2.45	68.59	
	Sep	\$ XX	\$ XX	\$ XX									71.04	2.45	68.59	
	Oct	\$ XX	\$ XX	\$ XX									71.04	2.45	68.59	
	Nov	\$ XX	\$ XX	\$ XX									71.04	2.45	68.59	
Auction 7	Dec	\$ XX	\$ XX	\$ XX									71.04	2.45	68.59	
	Jan 2014	\$ XX	\$ XX	\$ XX									71.04	2.45	68.59	
	Feb	\$ XX	\$ XX	\$ XX									71.04	2.45	68.59	
	Mar	\$ XX	\$ XX	\$ XX									71.04	2.45	68.59	
Auction 8	Apr	\$ XX	\$ XX	\$ XX									71.04	2.45	68.59	
	May	\$ XX	\$ XX	\$ XX									71.04	2.45	68.59	
	Jun	\$ XX	\$ XX	\$ XX									87.13	\$10.94	\$76.19	
	Jul	\$ XX	\$ XX	\$ XX									87.13	10.94	76.19	
Auction 9	Aug	\$ XX	\$ XX	\$ XX									87.13	10.94	76.19	
	Sep	\$ XX	\$ XX	\$ XX									87.13	10.94	76.19	
	Oct	\$ XX	\$ XX	\$ XX									87.13	10.94	76.19	
	Nov	\$ XX	\$ XX	\$ XX									87.13	10.94	76.19	
Auction 10	Dec	\$ XX	\$ XX	\$ XX									87.13	10.94	76.19	
	Jan 2015	\$ XX	\$ XX	\$ XX									87.13	10.94	76.19	
	Feb	\$ XX	\$ XX	\$ XX									87.13	10.94	76.19	
	Mar	\$ XX	\$ XX	\$ XX									87.13	10.94	76.19	
Auction 11	Apr	\$ XX	\$ XX	\$ XX									87.13	10.94	76.19	
	May	\$ XX	\$ XX	\$ XX									87.13	10.94	76.19	
	Jun	\$ XX	\$ XX	\$ XX									87.13	10.94	76.19	
	Jul	\$ XX	\$ XX	\$ XX									87.13	10.94	76.19	

NOTE: ⁽¹⁾ Auction prices are based on estimates of retail market prices, AT THE METER, from Judah Rose Exhibit W transformed from calendar year to delivery period.

Ultimate prices for each delivery period will be the weighted-average of all tranches auctioned for the applicable delivery period.

⁽²⁾ Average capacity prices, AT THE METER, as calculated on Exhibit 1-B, page 2.

Duke Energy Ohio
Convert Capacity and Energy Prices for Proposed Delivery Periods

Period	Methodology for Calculating Average Price for Rider RC				
	Underlying Capacity Price		Days in Period	Capacity Cost To Recover ⁽³⁾	Projected MWh in Period ⁽⁴⁾
	Demand ⁽¹⁾	FZCP ⁽²⁾			
Jan '12 - May '12	4,732	\$116.16	152	\$88,980,437	8,533,333
Jun '12 - May '13	4,732	16.46	365	30,277,293	20,473,777
Jun '13 - May '14	4,732	27.73	365	51,007,857	20,810,354
Jun '14 - May '15	4,732	125.99	365	231,751,890	21,177,162
					Average Capacity Price ⁽⁵⁾
					\$4.11
					2.45
					10.94

Note: ⁽¹⁾ Reliability Obligation as reported to PJM. (Will need to update future years for any growth).
⁽²⁾ PJM's Final Zonal Capacity Price. Prices shown for June 2012 through May 2015 are based on the results of the Base Residual Auctions for those delivery periods.
⁽³⁾ FZCP Prices are at load zone. Gross up by 6.5% for average T&D losses.
⁽⁴⁾ Estimated MWh sales as shown in Attachment WDW-2.
⁽⁵⁾ Assumes first delivery period is January 2012 through May 2014.

Calendar Year	Calculate Average Price for Rider RE	
	Mkt Price ⁽¹⁾	Avg Energy
Jan '12 - Dec '12	\$61.40	\$56.19
Jan '13 - Dec '13	66.30	64.35
Jan '14 - Dec '14	78.70	71.62
Jan '15 - Dec '15 ⁽³⁾	90.40	79.46

Delivery Period	Price for Period	
	Wtd Energy ⁽⁴⁾	Avg Cap
Jan '12 - May '13	\$58.59	\$4.11
Jun '13 - May '14	68.59	2.45
Jun '14 - May '15	76.19	10.94

⁽¹⁾ Total Projected Retail Market Price from JLR Testimony, Exhibit W. At the meter.
Figures in Exhibit W are in Calendar Year.
⁽²⁾ Weighted average capacity price converted to average per MWh.
⁽³⁾ ESP ends on May 31, 2015.
⁽⁴⁾ Weighted by months of calendar year prices from Exhibit W in each delivery period.

Duke Energy Ohio
Allocations of Capacity Costs for Rate Design - January 2012 - May 2013

No	Description	Allocation of Rider RC Revenue Requirement ⁽¹⁾		
		Percent of Total	Allocated \$	kWh Sales ⁽²⁾
				Rate (¢/kWh) ⁽³⁾
<i>Rate Schedule:</i>				
1	Residential (RS, TD, ORH)	39.12%	\$46,658,850	10,195,029,765
2	Electric Space Heating (EH)	0.47%	\$561,859	146,825,619
3	Secondary Distribution - Small (DM)	3.05%	\$3,638,480	785,510,905
4	Unmetered Small Fixed Load (GSFL, ADPL)	0.17%	\$200,728	44,017,767
5	Secondary Distribution (DS)	36.60%	\$43,648,928	9,390,338,772
6	Primary Distribution (DP)	9.66%	\$11,525,976	3,248,073,423
7	Transmission Voltage (TS)	10.33%	\$12,324,786	4,695,906,496
8	Lighting	0.59%	\$698,123	152,543,234
9	Total	100.00%	\$119,257,730	28,658,245,981
				0.46
				0.38
				0.46
				0.46
				0.46
				0.46
				0.35
				0.26
				0.46
				0.42

Note: ⁽¹⁾ Rider RC is allocated in the following manner: First, the total amount is allocated to DP and TS based on 1 CP allocator. The allocation among all other classes is based on energy.

⁽²⁾ Projected kWh sales for the period January 1, 2012, through May 31, 2013.

⁽³⁾ Average Rider RC rates are shown for comparison only. The actual rates for each class are calculated on Exhibit 2 (Attachment B), page 2.

	January 2012 - May 2013			January 2012 - May 2013			June 2013-May 2014 ⁽²⁾	June 2014-May 2015 ⁽²⁾
	kWh; kW; kVA	Base Gen Revenue	% of Rate Group	Allocated Cap Cost	Allocated Revenue	Rates (\$/kWh; kW; kVA)	Rates (\$/kWh; kW; kVA)	Rates (\$/kWh; kW; kVA)
Rate RS, Residential Service				\$46,658,850				
Summer, First 1000 kWh	2,576,581,344	\$109,105,337	27.505%		\$12,833,698	\$0.004981	\$0.002969	\$0.013258
Summer, Additional kWh	1,327,367,209	74,684,316	18.828%		8,784,868	\$0.006818	\$0.003945	\$0.017617
Winter, First 1000 kWh	4,519,744,433	191,388,578	48.249%		22,512,402	\$0.004981	\$0.002969	\$0.013258
Winter, Additional kWh	1,624,472,012	15,871,092	4.001%		1,866,864	\$0.001149	\$0.000685	\$0.003059
Rate ORH, Optional Residential Service								
Summer, First 1000 kWh	1,101,570	\$42,522	0.011%		\$5,002	\$0.004541	\$0.002707	\$0.012086
Summer, Additional kWh	1,353,915	65,600	0.017%		7,718	\$0.005899	\$0.003397	\$0.015170
Summer, kWh greater than 150 times demand	370,589	17,956	0.005%		2,112	\$0.005899	\$0.003397	\$0.015170
Winter, First 1000 kWh	2,455,194	94,768	0.024%		11,147	\$0.004540	\$0.002706	\$0.012085
Winter, Additional kWh	3,973,169	58,203	0.015%		6,846	\$0.001723	\$0.001027	\$0.004587
Winter, kWh greater than 150 times demand	1,548,105	7,773	0.002%		914	\$0.000591	\$0.000352	\$0.001572
Rate TD, Optional Time-of-Day Rate								
Summer, On-Peak kWh	58,616	\$8,028	0.002%		\$709	\$0.012093	\$0.007208	\$0.032188
Summer, Off-Peak kWh	146,462	827	0.000%		97	\$0.000664	\$0.000396	\$0.001768
Winter, On-Peak kWh	83,280	6,536	0.002%		769	\$0.009232	\$0.005503	\$0.024573
Winter, Off-Peak kWh	270,376	1,528	0.000%		180	\$0.000665	\$0.000396	\$0.001769
Rate CUR, (Rev. Class 01, 02, 04, 16 & 18 only)								
Summer, First 1000 kWh	29,075,378	\$1,294,930	0.326%		\$152,318	\$0.005239	\$0.003123	\$0.013944
Summer, Additional kWh	12,424,148	733,199	0.185%		86,244	\$0.006942	\$0.004138	\$0.018477
Winter, First 1000 kWh	67,530,351	3,007,599	0.758%		353,774	\$0.005239	\$0.003123	\$0.013944
Winter, Additional kWh	26,473,613	282,156	0.071%		33,189	\$0.001254	\$0.000747	\$0.003337
Rate DS, Secondary Distribution Voltage				\$43,648,928				
First 1000 kWh (\$ per kW)	27,649,575	\$238,159,617	58.704%		\$25,623,583	\$0.926726	\$0.552428	\$2.466760
Additional kW (\$ per kW)	1,558,138	10,623,655	2.619%		1,142,999	\$0.733098	\$0.437004	\$1.951357
Billing Demand Times 300	7,357,051,038	144,801,479	35.692%		15,579,185	\$0.002118	\$0.001262	\$0.005637
Additional kWh	2,033,287,734	12,112,295	2.986%		1,303,161	\$0.000641	\$0.000382	\$0.001706
Rate GS-FL, Optional Unmetered				\$200,728				
kWh Greater Than or Equal to 540 Hours	43,169,346	\$2,947,042	98.041%		\$196,796	\$0.004559	\$0.002717	\$0.012134
kWh Less Than 540 Hours	88,295	6,993	0.233%		467	\$0.005289	\$0.003153	\$0.014078
Rate SFL-ADPL, Optional Unmetered								
All kWh	760,126	\$51,892	1.726%		\$3,465	\$0.004559	\$0.002717	\$0.012134
Rate EH, Optional Electric Space Heating				\$561,859				
All kWh	146,825,619	\$3,688,700	100.000%		\$561,859	\$0.003827	\$0.002281	\$0.010186
Rate DM, Secondary Dist. Service, Small				\$3,638,480				
Summer, First 2800 kWh	238,553,508	\$16,008,372	41.597%		\$1,513,485	\$0.006344	\$0.003782	\$0.016888
Summer, Next 3200 kWh	47,820,876	382,041	0.993%		36,119	\$0.000755	\$0.000450	\$0.002010
Summer, Additional kWh	10,015,181	(23,285)	-0.061%		(2,201)	-0.000220	-0.000131	-0.000585
Winter, First 2800 kWh	427,316,388	21,741,612	56.494%		2,055,524	\$0.004810	\$0.002867	\$0.012804
Winter, Next 3200 kWh	50,840,723	406,119	1.055%		38,396	\$0.000755	\$0.000450	\$0.002010
Winter, Additional kWh	10,964,228	(30,065)	-0.078%		(2,842)	-0.000259	-0.000155	-0.000690
Rate DP, Service at Primary Dist. Voltage				\$11,525,976				
First 1000 kWh (\$ per kW)	3,287,744	\$25,573,387	25.394%		\$2,926,934	\$0.890256	\$0.530688	\$2.369684
Additional kW (\$ per kW)	4,022,054	24,679,725	24.507%		2,824,652	\$0.702291	\$0.418641	\$1.869358
Billing Demand Times 300	2,073,948,813	41,588,896	41.298%		4,759,946	\$0.002295	\$0.001368	\$0.006109
Additional kWh	1,174,124,610	8,863,467	8.801%		1,014,444	\$0.000864	\$0.000515	\$0.002300
Rate TS, Service at Transmission Voltage				\$12,324,786				
First 50,000 kVA (\$ per kVA)	6,188,130	\$58,352,211	50.574%		\$6,233,108	\$1.007268	\$0.600440	\$2.681147
Additional kVA (\$ per kVA)	2,703,572	18,377,803	15.928%		1,963,093	\$0.726111	\$0.432840	\$1.932762
Billing Demand Times 300	2,548,358,420	25,580,422	22.171%		2,732,468	\$0.001072	\$0.000639	\$0.002854
Additional kWh	2,147,548,076	13,069,978	11.328%		1,396,118	\$0.000650	\$0.000388	\$0.001730
Rate TL, Traffic Lighting Service				\$698,123				
All kWh	4,548,583	\$41,328	2.139%		\$14,932	\$0.003283	\$0.001957	\$0.008738
Rate SL, Street Lighting Service								
Rate OL, Outdoor Lighting Service	57,082,930	\$1,078,182	55.802%		\$389,565	\$0.006825	\$0.004068	\$0.018166
Rate NSU, Street Lighting	30,712,095	580,090	30.023%		209,596	\$0.006825	\$0.004068	\$0.018166
Rate NSP, Private Outdoor Lighting	1,478,824	27,932	1.446%		10,092	\$0.006825	\$0.004068	\$0.018166
Rate SE, Street Lighting Service	1,946,181	36,759	1.902%		13,282	\$0.006825	\$0.004068	\$0.018166
All kWh	7,699,591	145,430	7.527%		52,546	\$0.006825	\$0.004068	\$0.018166
Rate SC, Street Lighting								
Energy Only - All kWh	30,761,946	\$3,938	0.204%		\$1,423	\$0.000046	\$0.000028	\$0.000123
Units - All kWh	451,237	8,523	0.441%		3,079	\$0.006825	\$0.004068	\$0.018166
Rate UOLS, Unmetered Outdoor Lighting								
All kWh	17,861,867	\$9,985	0.517%		\$3,608	\$0.000202	\$0.000120	\$0.000538
Totals	28,658,245,981	\$1,065,563,469		\$119,257,730	\$119,257,730			

Average Capacity Price AT THE METER (\$/MWh) (From Exhibit 1 B, page 2)

\$4.11	\$2.45	\$10.94
	59.6%	268.2%
Percent Change from 2012 Delivery Period		

Note: ⁽¹⁾ Final figures will be adjusted for applicable transmission and distribution losses.⁽²⁾ Changes in Rider RC rates from first delivery period to second and third is proportional to the average price of capacity for all load (as shown on Exhibit 1 B, page 2).

DUKE ENERGY OHIO
ILLUSTRATIVE JAN 2012 - MAY 2015 RETAIL ENERGY RATES CONVERTED FROM AUCTION PRICE
FOR DISCUSSION ONLY

	2012			% of Rate Group	January 1, 2012 - May 31, 2012				June 1, 2012 - May 31, 2013				June 1, 2013 - May 31, 2014				June 1, 2014 - May 31, 2015			
	kWh, kW, kVA	Base Gen + FPP @ 3.1¢/kWh ⁽¹⁾			Revenue Requirement	Allocated Revenue	Rates (\$/kWh; kW, kVA)	Revenue Requirement	Allocated Revenue	Rates (\$/kWh; kW, kVA)	Revenue Requirement	Allocated Revenue	Rates (\$/kWh; kW, kVA)	Revenue Requirement	Allocated Revenue	Rates (\$/kWh; kW, kVA)				
Rate RS, Residential Service																				
Summer, First 1000 kWh	1,817,099,832	\$133,275,187	26.526%	\$421,073,266	\$111,694,944	\$0.061469	\$432,955,453	\$130,762,592	\$0.071962	\$547,585,355	\$145,253,856	\$0.079937								
Summer, Additional kWh	936,108,126	81,689,476	16.259%		68,462,117	0.073135		\$80,149,410	0.085620		\$89,031,662	0.095108								
Winter, First 1000 kWh	3,187,489,838	233,786,442	46.531%		186,931,172	0.061468		\$229,378,941	0.071962		\$254,798,984	0.079937								
Winter, Additional kWh	1,146,637,349	46,707,635	9.296%		39,144,621	0.034168		\$45,827,071	0.040001		\$50,905,680	0.044434								
Rate ORH, Optional Residential Service																				
Summer, First 1000 kWh	728,227	\$50,695	0.010%		\$42,478	\$0.058331		\$49,729	\$0.068288		\$55,241	\$0.075856								
Summer, Additional kWh	895,048	71,113	0.014%		59,599	0.066587		\$69,773	0.077954		\$77,505	0.086593								
Summer, kWh greater than 150 times demand	244,990	19,465	0.004%		16,313	0.066586		\$19,098	0.077953		\$21,214	0.086592								
Winter, First 1000 kWh	1,623,082	112,965	0.022%		94,673	0.058329		\$110,835	0.068287		\$123,118	0.075854								
Winter, Additional kWh	2,626,587	119,901	0.024%		100,487	0.038257		\$117,641	0.044788		\$130,678	0.049752								
Winter, kWh greater than 150 times demand	1,023,423	36,865	0.007%		30,896	0.030189		\$36,170	0.035342		\$40,179	0.039259								
Rate TD, Optional Time-of-Day Rate																				
Summer, On-Peak kWh	40,768	\$5,458	0.001%		\$4,575	\$0.112155		\$5,356	\$0.131302		\$5,949	\$0.145853								
Summer, Off-Peak kWh	101,916	3,734	0.001%		3,130	0.030709		\$3,664	0.035951		\$4,070	0.039935								
Winter, On-Peak kWh	57,950	6,344	0.001%		5,317	0.091754		\$6,225	0.107417		\$6,915	0.119321								
Winter, Off-Peak kWh	188,142	6,895	0.001%		5,779	0.030716		\$6,765	0.035959		\$7,515	0.039944								
Rate CUR, (Rev. Class 01, 02, 04, 16 & 18 only)																				
Summer, First 1000 kWh	19,963,145	\$1,507,956	0.300%		\$1,283,784	\$0.063306		\$1,479,527	\$0.074113		\$1,643,490	\$0.082326								
Summer, Additional kWh	8,530,416	767,857	0.153%		643,524	0.076439		\$753,381	0.088317		\$836,871	0.098104								
Winter, First 1000 kWh	46,366,316	3,502,373	0.697%		2,935,260	0.063306		\$3,436,344	0.074113		\$3,817,163	0.082326								
Winter, Additional kWh	18,176,774	757,208	0.151%		634,599	0.034913		\$742,933	0.040873		\$825,265	0.045402								
Rate DM, Secondary Dist. Service, Small																				
Summer, First 2800 kWh	170,200,668	\$16,697,707	37.246%	\$32,835,499	\$12,229,826	\$0.071855	\$38,440,907	\$14,317,602	\$0.084122	\$42,700,974	\$15,904,296	\$0.093444								
Summer, Next 3200 kWh	34,118,740	1,330,256	2.967%		974,313	0.028557		\$1,140,640	0.033431		\$1,267,047	0.037136								
Summer, Additional kWh	7,145,527	204,898	0.457%		150,073	0.021002		\$175,692	0.024588		\$195,162	0.027313								
Winter, First 2800 kWh	304,877,239	24,963,043	55.682%		18,283,569	0.059970		\$21,404,791	0.070208		\$23,776,895	0.077988								
Winter, Next 3200 kWh	36,273,309	1,414,224	3.155%		1,035,813	0.028556		\$1,212,639	0.033431		\$1,347,025	0.037135								
Winter, Additional kWh	7,822,643	221,052	0.493%		161,904	0.020697		\$189,543	0.024230		\$210,548	0.026915								
Rate TS, Service at Transmission Voltage																				
All Other Rate Classes						\$0.056753			\$0.066441			\$0.073804								
All kWh						\$0.058589			\$0.068591			\$0.076182								
Totals				\$453,908,765	\$453,908,765		\$531,396,361	\$531,396,361		\$590,286,329	\$590,286,329									
Retail Energy Price AT THE METER from Exhibit 1 B, page 2																				
						\$0.058589			\$0.068591			\$0.076182								

Note: (1) For purposes of allocated retail energy price among rate blocks for these customer classes, use total base generation revenue plus fuel (PTC-BG + PTC-FPP).
Fuel rate is the Q4 2011 rate for PTC-FPP, excluding reconciliation adjustments.

DUKE ENERGY OHIO
CALCULATION OF LOAD FACTOR ADJUSTMENT RIDER (LFA)

	Allocations from JRB-1			Rates for January 2012 - May 2014 ⁽¹⁾	
	kWh; kW; kVA	2010	Base Gen Revenue	% of Rate Group	LFA Rates (\$/kWh; kW; kVA)
Rate DS, Secondary Distribution Voltage					
First 1,000 kW (\$ per kW)	19,796,503	\$170,517,176		58.704%	\$8.00
Additional kW (\$ per kW)	1,116,309	\$7,606,309		2.619%	\$8.00
Billing Demand Times 300	5,267,490,696	\$103,674,752		35.692%	-\$0.020961
Additional kWh	1,455,790,393	\$8,672,143		2.986%	-\$0.020961
			\$167,302,497		
Rate DP, Service at Primary Dist. Voltage					
First 1,000 kW (\$ per kW)	2,382,401	\$18,531,268		25.394%	\$8.00
Additional kW (\$ per kW)	2,914,505	\$17,883,692		24.507%	\$8.00
Billing Demand Times 300	1,502,847,469	\$30,136,600		41.298%	-\$0.020961
Additional kWh	850,807,016	\$6,422,742		8.801%	-\$0.020961
			\$42,375,245		
Rate TS, Service at Transmission Voltage					
First 50,000 kVA (\$ per kVA)	4,400,833	\$41,498,535		50.574%	\$8.00
Additional kVA (\$ per kVA)	1,922,708	\$13,069,803		15.928%	\$8.00
Billing Demand Times 300	1,812,324,514	\$18,192,113		22.171%	-\$0.020961
Additional kWh	1,527,278,893	\$9,295,019		11.328%	-\$0.020961
			\$50,588,332		
Total (kWh)	12,416,538,981	\$445,500,152	\$260,266,074		-\$260,263,074

Note: ⁽¹⁾ Energy credit will be true-up to ensure the total revenue collected from demand charge and energy credits equal \$0.

Duke Energy Ohio
Allocation of ESSC Revenue Requirement

Line No	Description	Allocation of Rider ESSC Revenue Requirement ⁽¹⁾			
		Percent of Total	Allocated \$	Annual kWh ⁽³⁾	Rate (¢/kWh) ⁽⁴⁾
1	Residential (RS, TD, ORH)	41.90%	\$46,095,319	7,186,901,948	0.64
2	Electric Space Heating (EH)	0.21%	233,456	86,543,565	0.27
3	Secondary Distribution - Small (DM)	2.99%	3,286,029	560,438,126	0.59
4	Unmetered Small Fixed Load (GSFL, ADPL)	0.14%	149,575	30,918,310	0.48
5	Secondary Distribution (DS)	32.09%	35,303,352	6,723,281,089	0.53
6	Primary Distribution (DP)	10.83%	11,908,440	2,353,654,485	0.51
7	Transmission Voltage (TS)	11.58%	12,733,756	3,339,603,407	0.38
8	Lighting	0.26%	290,074	107,532,461	0.27
9	Total	100.00%	\$110,000,000 ⁽²⁾	20,388,873,391	0.54

Notes: ⁽¹⁾ Annual ESSC Revenue Requirement as agreed to in the Stipulation.

⁽²⁾ Average Rider ESSC rates are shown for comparison purposes only. Actual rates for each rate class are shown on page 2 of Exhibit 1 (Attachment B-1).

⁽³⁾ Projected kWh sales for the period January 1, 2012, through December 31, 2012.

⁽⁴⁾ The annual ESSC Revenue Requirement is allocated in the following manner. First, Residential, Electric Space Heating and Lighting are allocated a share of the total ESSC revenue requirement based on an average of 1 CP and energy. The balance of the ESSC revenue requirement not allocated to Residential, Electric Space Heating, and Lighting, is allocated among the remaining rate classes based on 1 CP.

Duke Energy Ohio
ESSC Revenue Requirement for Rate Design
Illustrative for Discussion Purposes Only

	2012			Calculation of Rider ESSC Price for January 2012 - December 2012			Jan 2013-Dec 2013 ²⁰	Jan 2014-Dec 2014 ²⁰
	kWh; kW; kVA	Base Revenue	% of Rate Group	ESSC Revenue Requirement	Allocated Revenue	Rates (\$/kWh; kW; kVA)	Rates (\$/kWh; kW; kVA)	Rates (\$/kWh; kW; kVA)
Rate RS, Residential Service				\$46,095,319				
Summer, First 1000 kWh	1,817,099,832	\$76,945,092	27.518%		\$12,683,771	\$0.006980	\$0.006980	\$0.006980
Summer, Additional kWh	936,108,126	52,670,124	18.835%		8,682,240	\$0.009275	\$0.009275	\$0.009275
Winter, First 1000 kWh	3,187,489,838	134,974,257	48.268%		22,249,406	\$0.006980	\$0.006980	\$0.006980
Winter, Additional kWh	1,145,637,349	11,192,877	4.003%		1,845,055	\$0.001611	\$0.001611	\$0.001611
Rate ORH, Optional Residential Service								
Summer, First 1000 kWh	728,227	\$28,110	0.010%		\$4,634	\$0.006363	\$0.006363	\$0.006363
Summer, Additional kWh	895,048	43,367	0.016%		7,149	\$0.007987	\$0.007987	\$0.007987
Summer, kWh greater than 150 times demand	244,990	11,870	0.004%		1,957	\$0.007987	\$0.007987	\$0.007987
Winter, First 1000 kWh	1,623,082	62,649	0.022%		10,327	\$0.006363	\$0.006363	\$0.006363
Winter, Additional kWh	2,626,587	38,477	0.014%		6,343	\$0.002415	\$0.002415	\$0.002415
Winter, kWh greater than 150 times demand	1,023,423	5,139	0.002%		847	\$0.000828	\$0.000828	\$0.000828
Rate TD, Optional Time-of-Day Rate								
Summer, On-Peak kWh	40,788	\$4,194	0.001%		\$691	\$0.016950	\$0.016950	\$0.016950
Summer, Off-Peak kWh	101,916	575	0.000%		95	\$0.000930	\$0.000930	\$0.000930
Winter, On-Peak kWh	57,950	4,548	0.002%		750	\$0.012937	\$0.012937	\$0.012937
Winter, Off-Peak kWh	188,142	1,063	0.000%		175	\$0.000931	\$0.000931	\$0.000931
Rate CUR, (Rev. Class 01, 02, 04, 16 & 18 only)								
Summer, First 1000 kWh	19,963,145	\$889,099	0.318%		\$146,561	\$0.007342	\$0.007342	\$0.007342
Summer, Additional kWh	8,530,416	503,414	0.180%		82,984	\$0.009728	\$0.009728	\$0.009728
Winter, First 1000 kWh	46,366,316	2,065,017	0.738%		340,401	\$0.007342	\$0.007342	\$0.007342
Winter, Additional kWh	18,176,774	193,728	0.069%		31,934	\$0.001757	\$0.001757	\$0.001757
Rate DS, Secondary Distribution Voltage				\$35,303,352				
First 1000 kW (\$ per kW)	19,796,503	\$170,517,176	58.704%		\$20,724,412	\$1.046872	\$1.046872	\$1.046872
Additional kW (\$ per kW)	1,116,309	7,606,309	2.619%		924,460	\$0.828139	\$0.828139	\$0.828139
Billing Demand Times 300	5,267,490,696	103,674,752	35.692%		12,600,460	\$0.002392	\$0.002392	\$0.002392
Additional kWh	1,455,790,393	8,672,143	2.968%		1,054,000	\$0.000724	\$0.000724	\$0.000724
Rate GS-FL, Optional Unmetered				\$149,575				
kWh Greater Than or Equal to 540 Hours	30,320,485	\$2,069,889	98.035%		\$146,636	\$0.004836	\$0.004836	\$0.004836
kWh Less Than 540 Hours	62,015	4,912	0.233%		348	\$0.005611	\$0.005611	\$0.005611
Rate 3FL-ADPL, Optional Unmetered								
All kWh	535,810	\$36,578	1.732%		\$2,591	\$0.004836	\$0.004836	\$0.004836
Rate EH, Optional Electric Space Heating				\$233,456				
All kWh	88,543,565	\$2,174,234	100.000%		\$233,456	\$0.002698	\$0.002698	\$0.002698
Rate DM, Secondary Dist. Service, Small				\$3,286,029				
Summer, First 2800 kWh	170,200,668	\$11,421,486	41.597%		\$1,366,883	\$0.008031	\$0.008031	\$0.008031
Summer, Next 3200 kWh	34,118,740	272,575	0.993%		32,621	\$0.000956	\$0.000956	\$0.000956
Summer, Additional kWh	7,145,527	(16,613)	-0.061%		(1,988)	\$0.000278	\$0.000278	\$0.000278
Winter, First 2800 kWh	304,877,239	15,511,849	56.494%		1,856,404	\$0.006089	\$0.006089	\$0.006089
Winter, Next 3200 kWh	36,273,309	289,751	1.055%		34,676	\$0.000956	\$0.000956	\$0.000956
Winter, Additional kWh	7,822,643	(21,450)	-0.078%		(2,567)	\$0.000328	\$0.000328	\$0.000328
Rate DP, Service at Primary Dist. Voltage				\$11,908,440				
First 1000 kW (\$ per kW)	2,382,401	\$18,531,268	25.394%		\$3,024,058	\$1.269332	\$1.269332	\$1.269332
Additional kW (\$ per kW)	2,914,505	17,883,692	24.507%		2,818,382	\$1.001330	\$1.001330	\$1.001330
Billing Demand Times 300	1,502,847,469	30,136,600	41.298%		4,817,894	\$0.003272	\$0.003272	\$0.003272
Additional kWh	850,807,016	6,422,742	8.801%		1,048,106	\$0.001232	\$0.001232	\$0.001232
Rate TS, Service at Transmission Voltage				\$12,733,758				
First 50,000 kVA (\$ per kVA)	4,400,833	\$41,498,535	50.574%		\$6,439,939	\$1.463345	\$1.463345	\$1.463345
Additional kVA (\$ per kVA)	1,922,708	13,069,803	15.928%		2,028,234	\$1.054884	\$1.054884	\$1.054884
Billing Demand Times 300	1,812,324,514	18,192,113	22.171%		2,823,138	\$0.001558	\$0.001558	\$0.001558
Additional kWh	1,527,278,893	9,295,019	11.328%		1,442,445	\$0.000944	\$0.000944	\$0.000944
Rate TL, Traffic Lighting Service				\$290,074				
All kWh	3,192,189	\$29,004	2.061%		\$6,036	\$0.001891	\$0.001891	\$0.001891
Rate SL, Street Lighting Service								
Rate OL, Outdoor Lighting Service	41,743,673	\$788,454	56.565%		\$164,081	\$0.003931	\$0.003931	\$0.003931
Rate NSU, Street Lighting	21,512,921	406,336	29.151%		84,560	\$0.003931	\$0.003931	\$0.003931
Rate NSP, Private Outdoor Lighting	1,093,169	20,648	1.481%		4,297	\$0.003931	\$0.003931	\$0.003931
Rate SE, Street Lighting Service	1,360,791	25,703	1.844%		5,349	\$0.003931	\$0.003931	\$0.003931
All kWh	5,764,110	108,873	7.811%		22,657	\$0.003931	\$0.003931	\$0.003931
Rate SC, Street Lighting								
Energy Only - All kWh	21,608,323	\$2,766	0.198%		\$576	\$0.000027	\$0.000027	\$0.000027
Units - All kWh	316,965	5,987	0.430%		1,246	\$0.003931	\$0.003931	\$0.003931
Rate UOLS, Unmetered Outdoor Lighting								
All kWh	10,940,320	\$6,116	0.439%		\$1,273	\$0.000116	\$0.000116	\$0.000116
Totals	20,388,873,391	\$758,270,849		\$110,000,000	\$110,000,000	100%	100%	100%

Duke Energy Ohio
Allocation Factors for Rider ESSC and Rider RC

Line No.	Description	1 CP Allocation ⁽¹⁾		kWh Sales		1 CP & Energy for RS, EH, Lighting; 1 CP for All Others ⁽²⁾		1 CP for DP and TS, All Others on Energy ⁽³⁾	
		1 CP	% of Total	Energy	% of Total	Energy	% of Total	Energy	% of Total
		(a)	(b)	(c)	(d)	(e)	(f)		
<i>Rate Schedule:</i>									
1	Residential (RS, TD, ORH)	2,065,765	48.56%	7,186,901,948	35.25%				39.12%
2	Electric Space Heating (EH)	-	0.00%	86,543,565	0.42%		41.90%		0.47%
3	Secondary Distribution - Small (DM)	113,450	2.67%	560,438,126	2.75%		2.99%		3.05%
4	Unmetered Small Fixed Load (GSFL, ADPL)	5,164	0.12%	30,918,310	0.15%		0.14%		0.17%
5	Secondary Distribution (DS)	1,218,849	28.65%	6,723,281,089	32.98%		32.09%		36.60%
6	Primary Distribution (DP)	411,139	9.66%	2,353,654,485	11.54%		10.83%		9.66%
7	Transmission Voltage (TS)	439,633	10.33%	3,339,603,407	16.38%		11.58%		10.33%
8	Lighting	-	0.00%	107,532,461	0.53%		0.26%		0.59%
9	Total	4,254,000	100.00%	20,388,873,391	100.00%		100.00%		100.00%

Notes: ⁽¹⁾ Per Duke Energy Ohio load research data.

⁽²⁾ Allocate first to all customers on average of 1 CP and energy (kWh sales). Then allocate among non-Residential based on 1 CP.

⁽³⁾ Allocate DP and TS using 1 CP. Then allocate among all remaining classes on energy.

Attachment C

Bidding Rules for Duke Energy Ohio, Inc.'s Competitive Bidding Process Auctions

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1. INTRODUCTION

These Bidding Rules apply to the competitive bidding process ("CBP") auctions for Duke Energy Ohio to procure supply for the provision of Standard Service Offer supply ("SSO Supply") for all of their retail customers that take retail generation from Duke Energy Ohio.

Bidders also need to be familiar with other documents for the auctions including the Master Standard Service Offer Supply Agreement ("Master SSO Supply Agreement"), the Part 1 Application, the Part 2 Application, the Communications Protocols, and the Glossary. Bidders also should visit the Information Website regularly for up-to-date information including information specific to each auction.

The URL for the Information Website is <http://www.duke-energyohiocbp.com>. It contains relevant data, the schedule and key dates for participating in the auction process, frequently asked questions, and other information.

Unless noted otherwise, "days" refer to business days and times refer to prevailing Eastern Time. Unless noted otherwise, all capitalized terms are defined in the Glossary found on the Information Website.

Examples in these Bidding Rules are illustrative only.

These Bidding Rules may be modified from time to time by the Auction Manager in order: (i) to facilitate a more competitive process, (ii) to make any necessary corrections and/or clarifications, (iii) to account for any change in ESP products, (iv) to conform to any change in state or federal law or rule, and (v) for any other reason deemed necessary at the discretion of the Auction Manager. Such modifications will be carried out in consultation with Duke Energy Ohio but without prior consent from the Public Utilities Commission of Ohio ("PUCO") or any past, current, or potential bidder and will be posted to the Information Website.

1.1 Auction Manager

The Auction Manager is CRA International d/b/a Charles River Associates, Inc. The Auction Manager can be contacted by sending an email to duke-energyauctionmanager@crai.com. The full contact information for the Auction Manager is as follows:

CRA International, Inc.
John Hancock Tower
200 Clarendon Street, T-33
Boston, MA 02116-5092
Phone: 617.425.3365
Fax: 617.425.6574
Email: duke-energyauctionmanager@crai.com
Attn: Robert Lee, Principal / Auction Manager

2. THE PRODUCTS BEING PROCURED

This section summarizes the common elements of the products to be procured in the auctions. The Information Website provides details about the products to be procured in a specific auction, including the delivery periods, the number of tranches, the nominal MW size of the tranches, and the seasonal price factors.

2.1 SSO Load

Standard Service Offer ("SSO") Load will be Duke Energy Ohio's full electricity requirements for SSO Service for SSO Customers and it will include distribution losses. For purposes of these Bidding Rules, an "SSO Customer" means residential customers, commercial customers, and industrial customers and lighting customers, including special contract customers taking SSO supply during the delivery period but excluding PIPP customers and interruptible service customers taking SSO supply from Duke Energy Ohio during the delivery period until either PJM or Duke Energy Ohio calls for interruption. SSO Load will exclude the requirements of customers served by Competitive Retail Electric Service suppliers ("CRES Suppliers"). CRES Suppliers are certified by the PUCO and serve shopping customers.

SSO Load will also exclude the requirements of customers served via the Percentage of Income Payment Plan ("PIPP Customers") and interruptible service customers taking SSO supply from Duke Energy Ohio during the delivery period until either PJM or Duke Energy Ohio calls for interruption.. For purposes of the CBP auctions, a PIPP Customer is defined as any customer who takes service under Duke Energy Ohio's percentage of income payment plan as of January 1, 2012 and any customer who is thereafter enrolled in the PIPP program through May 31, 2015. SSO Load will include the requirements of any Special Contract customers of Duke Energy Ohio who are served under special contracts.

2.2 Full Requirements Service

The auctions are designed to procure all elements of full requirements service for SSO Customers of Duke Energy Ohio. Winning bidders will assume all responsibilities of a Load Serving Entity ("LSE") and will be responsible for supplying all obligations associated with full requirements service. Full requirements service includes energy, capacity, market-based transmission service and market-based transmission ancillaries, and any other LSE service or other service as may be required by PJM to serve the SSO Load of Duke Energy Ohio. While Duke Energy Ohio is an FRR entity, it will continue to supply the capacity resources, all other responsibilities related to the full requirements service will be the responsibility of bidders.

Duke Energy Ohio also will provide distribution services and will be responsible for Network Integrated Transmission Services ("NITS") charges and for other non-market-based FERC approved transmission charges for shopping and non-shopping load.

Full requirements service and the LSE obligations of winning bidders are defined in the Master SSO Supply Agreement.

2.3 Tranches

SSO Load will be divided into identical units called tranches, each representing an equivalent percentage of SSO Load. Each tranche represents one percent (1%) of the actual hourly energy required for SSO Load for the applicable delivery period.

The number of tranches intended to be procured for each product in the auction is referred to as the "tranche target" for that product. The Auction Manager may reduce the tranche targets prior to the auction if indications of interest in the auction are such that doing so is required to promote more competitive bidding.

3. PRICES PAID TO SSO SUPPLIERS

The payment to SSO Suppliers for tranches won will be a seasonal function of the auction prices. The summer payment for a tranche, paid to the winning bidder of the tranche from June 1 through September 30 during each year of the applicable delivery period, will be higher than the winning price for that tranche. The winter payment for the same tranche, paid to the winning bidder of that tranche for the remaining months in the calendar year during each year of the applicable delivery period, will be lower than the winning price for that tranche. The seasonal factors are multiplied by the winning price for a tranche in determining the summer and winter payments for that tranche. Duke Energy Ohio reserves the right to calculate the seasonal factors in advance of each auction in response to changing market conditions. The seasonal factors will be announced to suppliers prior to the auction and will be constant during the duration of the Master SSO Supply Agreement.

Example 1. Seasonal Supplier Payments

Assume the summer factor is 1.0727 and the winter factor is 0.9580, and the delivery period is June 1, 2013 through May 31, 2015.

Assume a bidder in the auction wins three (3) 24-month tranches at a price of \$60.00/MWh. The size of each tranche is 1% of the SSO Load. Thus, the bidder will serve 3% of the SSO Load from June 1, 2013 through May 31, 2015. The bidder will receive \$64.36 ($\60.00×1.0727) for each MWh of SSO Load served in the summer months and \$57.48 ($\60.00×0.9580) for each MWh of SSO Load served in the winter months.

4. PRIOR TO THE START OF BIDDING

4.1 Information Provided to Bidders

Duke Energy Ohio will make available certain information to suppliers in advance of qualification. This information will be posted on the Information Website.

4.1.1 Load Data

Duke Energy Ohio will provide:

- Load data for a historical three-year period.
- Historical hourly load data for total retail load and SSO Load.
- Historical switching statistics and historical load profiles.
- Customer counts, peak demand and NSPL for eligible and SSO load by customer class
- Monthly information specific to municipal opt-out aggregation programs that includes peak load and number of accounts for existing programs and programs that are proposed for commencement during the term of an SSO.
- Monthly consumption information specific to the PIPP load that includes estimates of peak load, hourly consumption, and number of accounts.
- Monthly information specific to voltage customers with loads in excess of 10MW at a single site that includes peak load, hourly consumption, and number of accounts.
- For the larger nonresidential customer base, a distribution of the number of customers above and below 500kW within a rate class.
- Above information provided in a useable or active electronic format such as Excel where possible.

4.1.2 Minimum and Maximum Starting Prices

The Auction Manager will announce a minimum starting price and a maximum starting price for each product in the auction. The minimum and maximum starting prices establish the range for the possible round 1 prices for the auction.

4.1.3 Tranche Size, Tranche Target

No later than eight (8) days prior to the Part 1 Application Due Date, the Auction Manager will announce for each product in the auction:

- The tranche target or the number of tranches being procured.
- The size (%) and MW-measure of the tranches in the auction.

No later than four (4) days prior to the Part 2 Application Due Date, the Auction Manager will announce:

- Any update to the MW-measure of the tranches in the auction.

4.2 Qualification Process

There are two parts to the application process. In Part 1, prospective bidders apply to become Qualified Bidders. In Part 2, each Qualified Bidder provides certifications and its indicative offer and pre-bid security in order to become a Registered Bidder.

4.2.1 Part 1 Application: Certifications and Other Qualified Bidder Requirements

In the Part 1 Application process, prospective bidders will be required to:

- Submit an application from a person with the power to bind the bidder.
- Agree to comply with all rules of the auction.
- Agree that if they become winning bidders, they will execute the Master SSO Supply Agreement with Duke Energy Ohio within 3 business days following the close of the auction.
- Show either that they are a PJM Market Participant and Load Serving Entity in PJM, or that there exist no impediments to them becoming a PJM Market Participant and Load Serving Entity in PJM by the start of the applicable delivery period.
- Agree that if they become winning bidders, they will comply with the creditworthiness requirements set forth in the Master SSO Supply Agreement.
- Certify that if they qualify to participate, they will not disclose information regarding the list of Qualified Bidders or confidential information that may be obtained during the bidding process about Qualified Bidders.
- Certify that if they qualify to participate, they will not substitute another entity in their place, transfer their rights to another entity, or otherwise assign their status as Qualified Bidders to another entity.

Part 1 Applications must be submitted to the Auction Manager no later than 12:00 p.m. noon prevailing Eastern Time on the Part 1 Application Due Date. Prospective bidders will be notified by the Auction Manager no later than three (3) days after the Part 1 Application Due Date whether they succeeded in becoming a Qualified Bidder.

A prospective bidder that has qualified during the Part 1 Application process becomes a Qualified Bidder. The Auction Manager will send a list of all Qualified Bidders to relevant parties that have undertaken to maintain the confidentiality of the list of Qualified Bidders. The relevant parties that will receive this list of Qualified Bidders are as follows:

- Each Qualified Bidder.
- Other parties as necessary to oversee the proper conduct of the auction, including representatives from Duke Energy Ohio, PUCO Staff, and any advisor ("PUCO Consultant") that PUCO Staff may have retained for this purpose.

All parties receiving a list of Qualified Bidders will be subject to the confidentiality requirements as specified below and in the Communications Protocols.

4.2.2 Part 2 Application: Certifications, Indicative Offer, and Pre-Bid Security

For each auction, Qualified Bidders must successfully complete the Part 2 Application process in order to become a Registered Bidder that can bid in the auction. Only Qualified Bidders may submit a Part 2 Application.

Part 2 Applications must be submitted to the Auction Manager no later than 12:00 p.m. noon prevailing Eastern Time on the Part 2 Application Due Date. Qualified Bidders will be notified by the Auction Manager whether they succeeded in the Part 2 Application process no later than three (3) days after the Part 2 Application Due Date.

Certifications

In the Part 2 Application, each Qualified Bidder will make a number of certifications regarding associations to ensure that they are participating independently of other Qualified Bidders and to ensure the confidentiality of information regarding the auction.

A Qualified Bidder is associated with another Qualified Bidder if the two bidders have ties that could allow them to act in concert or that could prevent them from competing actively against each other. The competitiveness of the auction and the ability of the auction to produce competitive prices may be harmed by the coordinated or collusive behavior that associations facilitate. As the Auction Manager relies on a number of factors to assess and promote competitive bidding, including the number of independent competitors, using inaccurate information or insufficient disclosure of associations in the Part 2 Application is prohibited.

Indicative Offer

With its Part 2 Application, a Qualified Bidder will be required to submit an indicative offer and to post pre-bid security sufficient for this indicative offer. A Qualified Bidder's indicative offer specifies two (2) numbers of tranches for each product in the auction. For each product, the first number represents the number of tranches that the Qualified Bidder is willing to serve at the minimum starting price for the product and the second number represents the number of tranches that the Qualified Bidder is willing to serve at the maximum starting price for the product. For each product, the number of tranches specified in the indicative offer at the minimum starting price cannot exceed the number of tranches specified at the maximum starting price.

Indicative offers are important in two respects. First, the Auction Manager may use the indicative offers to inform the setting of the starting price for each product (i.e., round 1 announced price). Second, the total number of tranches indicated by the Qualified Bidder at the maximum starting prices is used to determine the Qualified Bidder's initial eligibility (i.e., the maximum total number of tranches the Qualified Bidder can bid across all products in round 1 of the auction). The Qualified Bidder's initial eligibility is set to the sum of the number of tranches at the maximum starting prices across all products in the Qualified Bidder's indicative offer. During the auction, bidders are free to switch their tranches among products in response to changes in announced prices (subject to any bidding restrictions). However, a bidder will never be able to bid a total number of tranches across products that exceeds the bidder's initial eligibility. Thus, the number of tranches for each product at the maximum starting prices in the Qualified Bidder's indicative offer does not limit the number of tranches the Qualified Bidder can bid on a particular product, but the total number of tranches at the maximum starting prices across all products in the indicative offer must be equal to the Qualified Bidder's desired initial eligibility across all products.

Restrictions on the Indicative Offer

A Qualified Bidder may have restrictions on its initial eligibility — due to a credit-based tranche cap and/or due to load caps — and therefore may have restrictions on its indicative offer.

A Qualified Bidder may have a credit-based tranche cap that limits the Qualified Bidder's initial eligibility. Thus, the total number of tranches at the maximum starting prices across all products in the Qualified Bidder's indicative offer must not exceed the Qualified Bidder's credit-based tranche cap. This credit-based tranche cap is based on the credit rating of the Qualified Bidder or its Guarantor. A Qualified Bidder's credit-based tranche cap is determined as follows. The Qualified Bidder or Guarantor must:

- Be rated by at least one of the following rating agencies: Standard & Poor's Rating Services ("S&P"), Moody's Investors Service, Inc. ("Moody's"), or Fitch, Inc. ("Fitch") and
- Have a senior unsecured debt rating (or, if unavailable, corporate or issuer rating).

If the Qualified Bidder or Guarantor is rated by only one rating agency, that rating will be used. If the Qualified Bidder or Guarantor is rated by only two rating agencies, and the ratings differ, the lower of the two ratings will be used. If the Qualified Bidder or Guarantor is rated by three rating agencies and the ratings differ, the lower of the two highest ratings will be used provided that, in the event that the two highest ratings are common, such common rating will be used. The credit-based tranche cap for a Qualified Bidder or its Guarantor is determined as shown in the following table:

Table 1. Credit-Based Tranche Cap

Credit Rating of Qualified Bidder or Guarantor			
	S&P	Moody's	Fitch
	Credit-Based Tranche Cap		
BB and above	Ba2 and above	BB and above	No Cap
BB-	Ba3	BB-	10
Below BB-	Below Ba3	Below BB-	5

The parameters in the table above may vary by auction and over time, at Duke Energy Ohio's sole discretion. The credit-based tranche cap is in effect only during the bidding process. After the Master SSO Supply Agreement has been executed by a winning bidder, the credit-based tranche cap will no longer be in effect and the SSO Supplier will be required to meet the credit terms in accordance with Article 5: Credit and Performance Security in the Master SSO Supply Agreement.

In addition to any credit-based tranche cap, a Qualified Bidder will be subject to a load cap that limits the number of tranches the bidder can bid on and win. The load cap will be 80 percent on an aggregated load basis across all auction products for each auction date such that no bidder may bid on and win more tranches than the load cap. The load cap will be implemented by ensuring that each bidder's initial eligibility does not exceed the load cap in an auction.

Pre-Bid Security

Each Qualified Bidder must post pre-bid security sufficient for its indicative offer at the maximum starting prices. Each Qualified Bidder must post pre-bid security in an amount equal to \$250,000 per tranche for all products included in the bidder's indicative offer at the maximum starting prices. Either cash or a letter of credit will be accepted as pre-bid security. Some bidders may be subject to additional credit requirements or may be required to submit a letter of intent from a Guarantor or a letter of reference from a bank. The standard form of the letter of credit and other security documents that are in a form acceptable to Duke Energy Ohio will be posted to the Information Website.

If a draft letter of credit, alternate guaranty, letter of intent, letter of reference, or any alternate security submitted by the prospective bidder with the Part 1 Application does not conform to the standard form, the prospective bidder shall indicate clearly any and all modifications in electronic, redlined format from the standard form. Duke Energy Ohio will assess, in their sole and exclusive discretion, whether such modifications are acceptable. The prospective bidder, in its Part 2 Application, must provide the required executed credit documents that either use the standard form or incorporate only those modifications to the standard form accepted by Duke Energy Ohio upon review of the bidder's Part 1 Application.

The following is an example calculation of the pre-bid security.

Example 2. Pre-Bid Security

A Qualified Bidder submits an indicative offer of 5 tranches for Product 1 at the minimum starting price and 10 tranches for Product 1 at the maximum starting price, 3 tranches for Product 2 at the minimum starting price and 6 tranches for Product 2 at the maximum starting price, and 2 tranches for Product 3 at the minimum starting price and 4 tranches for Product 3 at the maximum starting price. The Qualified Bidder must submit with this indicative offer of 20 tranches at the maximum starting prices cash or a letter of credit of \$250,000 per tranche. The Qualified Bidder thus posts cash or a letter of credit of \$5.0 million (20 tranches multiplied by \$250,000 per tranche).

Depending on whether the Qualified Bidder is relying on its own financial standing or on that of a Guarantor, and depending on the results of the creditworthiness assessment at the time of the Part 1 Application, the Qualified Bidder may be required additionally to submit a letter of intent to provide a guaranty from its Guarantor or to provide a letter of reference from its bank. Any such additional requirements would be communicated to the Qualified Bidder at the time of qualification during the Part 1 Application process.

For a Part 2 Application to be accepted, it must be complete, including the Qualified Bidder's indicative offer, letter of credit, and additional security (if required). After its Part 2 Application is accepted, a Qualified Bidder becomes a Registered Bidder. The Auction Manager will send each Registered Bidder a summary of its indicative offer, pre-bid security amount, and the Registered Bidder's initial eligibility.

The Auction Manager also will send simultaneously to each Registered Bidder, and to those other parties as necessary to oversee the proper conduct of the auction, a list of Registered Bidders, and the total initial eligibility aggregated across all Registered Bidders. The list of Registered Bidders and the total initial eligibility will not be released publicly. Qualified Bidders, in their Part 2 Applications, will have undertaken to maintain the confidentiality of the list of Registered Bidders and the total initial eligibility, and to destroy documents including electronic files with this information provided by the Auction Manager within five (5) days following the conclusion of the auction, as explained further in the Part 2 Application.

Letters of credit and additional security (if required) will remain in full force, at a minimum, until the fifth calendar day after the conclusion of the auction. Subsequently, a bidder's financial guaranty will be marked cancelled and returned:

- As soon as practicable if the bidder has won no tranches.
- After the bidder has signed the Master SSO Supply Agreement and has complied with all creditworthiness requirements of the Master SSO Supply Agreement for the tranches that it has won.

Duke Energy Ohio can collect on the financial guarantees of bidders that win tranches but that fail to sign the Master SSO Supply Agreement or fail to comply with the creditworthiness requirements immediately following the close of the auction.

4.2.3 Sanctions for Failing to Comply with the Part 1 and Part 2 Applications

Sanctions can be imposed on a bidder for failing to disclose information relevant to determining associations, for coordinating with another bidder, or for failing to abide by any of the certifications that it will have made in its Part 1 and Part 2 Applications. Such sanctions can include, but are not limited to, termination of the Master SSO Supply Agreement, loss of all rights to provide supply for Duke Energy Ohio to serve any load won by such bidder, forfeiture of financial guarantees and other fees posted or paid, prosecution under applicable state and federal laws, debarment from participation in future competitive bidding process, and other sanctions that may be appropriate. For any failure to disclose information or for any violation of the certifications, the Auction Manager will make a recommendation on a possible sanction.

4.3 Starting Prices (Round 1 Prices)

No later than three (3) days before bidding starts for an auction, the Auction Manager will inform all Registered Bidders of the starting price for each product in the auction, which are the announced prices that will be in effect for round 1. For each product, the starting price will be no higher than the maximum starting price and no lower than the minimum starting price for the product. The Auction Manager will set the starting prices.

4.4 Extraordinary Events

The Auction Manager, in consultation with Duke Energy Ohio, may determine that, due to extraordinary events, the minimum starting prices and the maximum starting prices require revision. In this event, the schedule for the auction process also may be revised. If the indicative offers have already been received, the Auction Manager will request that the Registered Bidders (or the Qualified Bidders if the Part 2 Application process had not been completed) revise their indicative offers on the basis of the revised minimum starting prices and the revised maximum starting prices.

For such a revision to be necessary, an extraordinary event must occur between the time at which the minimum starting prices and the maximum starting prices are announced and the day on which bidding starts. An extraordinary event must be agreed to by Duke Energy Ohio and the Auction Manager. Such events could include, but are not limited to, the advent of war, the disruption of a major supply source for potentially extended periods, or other events that could affect significantly the cost of supply.

If an extraordinary event occurs during that time, the Auction Manager in consultation with Duke Energy Ohio will determine revised minimum starting prices and revised maximum starting prices. New indicative offers based on these prices will be required from bidders. To the extent practicable, the determination of new minimum and maximum starting prices, the submission of new indicative offers, and if necessary the announcement of new starting prices, will be carried out so as to afford bidders sufficient time. If an extraordinary event occurs during that time that causes a possible change in the schedule, the Auction Manager in consultation with Duke Energy Ohio will determine a revised schedule.

5. BIDDING FORMAT

In order to participate in the auction, bidders must have been successful in the Part 1 Application process and the Part 2 Application process. Only Registered Bidders are permitted to participate in the auction. Registered Bidders will bid in the auction by accessing the Auction Manager's secure Bidding Website.

5.1 Descending-Price Clock Format

The auction format is a simultaneous, multiple-round, descending-price clock format for "N" rounds. The number of rounds "N" for the auction is not pre-determined. Instead, it is determined by the closing rule for the auction. All products are available to bid on simultaneously in the auction. Bids are submitted during bidding rounds. Prices are announced for the products prior to each bidding round, and during a bidding round, a bidder submits for each product the number of tranches it would supply at the product's announced price. If the total number of tranches bid on a product exceeds the product's tranche target — i.e., the product is over-subscribed — the announced price for the product will be reduced for the next round. Announced prices will tend to decline round by round until the number of tranches bid falls sufficiently so that no product is over-subscribed and the auction closes.

An important rule is that a bidder cannot reduce the number of tranches it bids on a product if the product's announced price does not fall from one round to the next, the bidder can only maintain or increase the number of tranches it bids on the product (subject to other rules).

5.1.1 Rounds

Each bidding round has a specified start time and a specified end time. These start and end times are enforced by the Bidding Website. Prior to the start of the auction, the initial schedule of rounds will be available on the Bidding Website. As the auction progresses, the Auction Manager will keep bidders informed of the start and end times of subsequent rounds through the Bidding Website. The Auction Manager retains the option of pausing a round, delaying the start or end of a round, or otherwise adjusting the round times. The Auction Manager will inform bidders through the Bidding Website if it exercises this discretion to change the start time or end time of a round.

Bidders submit bids only during a round. When a round ends, the bids submitted during that round are processed and results of that round are reported to all bidders as explained in the section "Reporting Round Results" below. Each bidder then prepares to submit a bid for the next round if the auction remains open.

5.1.2 The Announced Prices and a Bid

Prior to the start of each round, the Auction Manager announces the price that will be in effect for each product for the round. The announced prices are specified in dollars per MWh or \$/MWh. The price announced by the Auction Manager for a product applies to all the product's tranches. Each bidder decides how many tranches it is willing and able to supply for each product at the product's announced price. A bid by a bidder is, for each product, the number of tranches that the bidder is willing to supply at that announced price for the product. All bids are irrevocable and binding upon the bidders.

At sufficiently high announced prices there will be excess supply for a product causing it to be over-subscribed; that is, the number of tranches bid on the product will exceed the product's tranche target. Excess supply for a product is measured as the total number of tranches bid across all bidders on the product in the round minus the product's tranche target.

5.1.3 Reservation Prices and Starting Prices

There are reservation prices for the auction. The reservation price for a product is the price above which tranches for the product will not be purchased. If, at the conclusion of the auction, the reservation price for a product has not been met, no tranches for that product will be awarded. At the conclusion of the auction, the Auction Manager will inform bidders through the Bidding Website if the reservation price for a product has not been met.

Starting prices for the auction are determined after reservation prices are determined. The starting price for a product will be no lower than the reservation price for the product. The starting price may be the same as or higher than the reservation price for the product. The Auction Manager will not announce the reservation prices to bidders in advance of an auction.

5.1.4 Restrictions on What a Bidder Can Bid

The total number of tranches a bidder bids across all products in a round cannot exceed the bidder's eligibility for that round. That is, a bidder's eligibility to bid in a round is the maximum number of tranches it is allowed to bid across all products in that round. A bidder's eligibility for a round simply is the number of tranches the bidder bid across all products in the preceding round. Thus, a bidder cannot increase its eligibility from round to round; its eligibility can only stay the same or decrease from round to round.

A bidder is not allowed to bid more tranches on a product in a round than the product's tranche target.

A bidder is not allowed to bid a number of tranches that would violate either its credit-based tranche limit or any applicable load cap.

If the announced price for a product has been reduced from one round to the next round, the bidder can reduce the number of tranches it bid on that product.

If the announced price for a product has not been reduced from one round to the next round, the bidder cannot reduce the number of tranches it bid on that product.

Subject to the rules above, in each round a bidder is free to bid its tranches of eligibility across products however it would like to. Thus, subject to the rules above, bidders are free to reduce the tranches it bids and/or to switch tranches across products from round to round in response to changes in the announced prices for the products.

As discussed above, a bidder's initial eligibility is its eligibility for round 1 of the auction and is determined by the total number of tranches across products at the maximum starting prices in the bidder's indicative offer. During the course of the auction, the bidder's eligibility will decline or remain unchanged depending on the total number of tranches bid by the bidder across all products in each round of the auction.

If a bidder's eligibility falls to zero tranches, it will not be allowed to bid in any more rounds of the auction.

5.1.5 Multiple Bids by a Bidder

Because a bidder may decide to change a bid it submitted previously within the current open round, a bidder is allowed to make multiple bid submissions in a round as long as the round remains open for bidding, with each new confirmed bid fully replacing any prior bids it submitted in the round. If a bidder submits multiple bids in a round, the only bid considered in the round for that bidder is the last confirmed bid it submitted in the round.

5.1.6 Default Bid

After the end of a round, a default bid is submitted automatically on behalf of a bidder if the bidder:

- Entered the round with positive eligibility, and
- Did not submit a confirmed bid in the round.

If the announced price for a product declined from the prior round, then zero tranches will be the default bid for that product.

If the announced price for a product did not decline from the prior round, then the number of tranches that the bidder bid on the product in the prior round as determined by the end-of-round ("EOR") procedure following the prior round will be the default bid for the product.

Each bidder is solely responsible for ensuring it submits a confirmed bid prior to the end of the round in order to avoid a default bid of being submitted on the bidder's behalf.

5.1.7 The EOR Procedure

At the end of each round, the EOR procedure is used to process the confirmed bids submitted during the round. The EOR procedure includes the following steps.

- (a) The supply for each product is measured by summing up — across the confirmed bids for all bidders — the number of tranches bid for each product.
- (b) The subscription level for each product is measured by comparing the supply for the product to the tranche target for the product. A product is over-subscribed, subscribed, or under-subscribed if supply (i.e., the number of tranches bid) is greater than, equal to, or less than the product's tranche target, respectively.
- (c) If a product has become under-subscribed in a round after being over-subscribed or subscribed the preceding round, then tranches will be rolled back to the point that the product is subscribed. That is, at least some of the tranches that were bid on the product in the preceding round but that were not bid on the product this round will be deemed to still be bid on the product. The price at which a rolled-back tranche is deemed to have been bid simply is the announced price at which the bidder had bid the tranche. There is a priority for selecting tranches to roll back: tranches that otherwise would no longer be bid on any product in the auction and therefore would be reductions in bidders' eligibilities are rolled back first (referred to as "eligibility reduction tranches"), and then if needed, tranches that were switched from being bid on the product to being bid on another product are selected next for rollbacks (referred to as "switched tranches"). Eligibility reduction tranches are selected for rollback proportionally tranche by tranche, not bidder by bidder. Likewise, switched tranches are selected for rollback proportionally tranche by tranche, not bidder by bidder. More precisely, because integer tranches are needed, the actual selection mechanism uses a random number generator to select rollbacks tranche by tranche (first for eligibility reduction tranches and then for switched tranches), but on average the selection process results in proportional rollbacks (with priority given to rolling back eligibility reduction tranches first and then switched tranches second). All tranches that are rolled back maintain their eligibility for the bidder. Any bidder subjected to a rollback will be notified through the Bidding Website that a rollback has taken place and will be informed about the number of tranches deemed bid on each product and the price at which those tranches have been deemed bid.

For example, suppose a bidder bids five tranches on a product and no tranches on other products in round 8, and the price for that product is reduced for round 9 and the bidder bids only 1 tranche on the product and no tranches on other products for round 9. Absent any EOR rollbacks following round 9, the bidder's eligibility would fall from 5 tranches to 1 tranche. But during the EOR procedure, suppose two of the bidder's 4 "eligibility reduction tranches" are rolled back on the product, so after the EOR procedure the bidder is deemed to have bid 3 tranches on the product — one at the announced price of the round just ended and two at the announced price of the preceding round — and therefore the bidder is deemed to have 3 tranches of eligibility for round 10.

- (d) "Free eligibility tranches" are determined as follows. A product's "bid stack" is just a list of the tranches currently deemed bid on the product and the price at which each tranche was bid for the product. Because of rollbacks, a product's bid stack could have tranches bid at two different prices: some tranches bid at the earlier, higher announced price and some tranches bid at the current, lower announced price. Any new tranche bid on such a product necessarily will be bid at the current, lower announced price. This new tranche will displace a tranche in the product's bid stack at the earlier, higher announced price. The displaced tranche becomes a "free eligibility tranche". The free eligibility tranche counts as eligibility for the bidder and the bidder can bid the tranche on any product next round, or the bidder can choose not to bid the tranche at all. But if the bidder does not bid the free eligibility tranche next round, it will be withdrawn from the auction permanently and will reduce the bidder's eligibility by one tranche after the next round.
- (e) In some cases, the Auction Manager may reduce the tranche targets. The criteria that could lead to such a reduction will be determined prior to the auction but will not be announced to bidders. Once certain pre-specified criteria related to excess supply and related to the reservation price have been met, the discretion to reduce a product's tranche target because of insufficient supply will be eliminated. Thus, any tranche target reduction would be more likely in the earlier rounds of the auction. If the Auction Manager reduces the tranche target for a product, bidders will be informed of the revised tranche target. Any bidder that otherwise would have eligibility exceeding the new tranche targets will have its eligibility reduced so as not to exceed the new tranche targets.
- (f) A determination is made as to whether the auction has concluded. The auction concludes if either case (1) or case (2) holds as follows:

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- (1) If no product is over-subscribed and no bidder has free eligibility tranches, then the auction has concluded. Note that it is possible for the auction to continue with no reductions in announced prices: if no product is over-subscribed there will be no reductions in announced prices but if there are free eligibility tranches (which "expire" after one round), the auction will remain open for one more round (subject to case (2) described next), allowing bidders with free eligibility to bid those tranches.
 - (2) If this is the Nth consecutive round in which no product is over-subscribed, and the number of tranches of free eligibility across all bidders as a percentage of the sum of the tranche targets across all products is less than or equal to X percent, then the auction has concluded. The parameter values for N and X will be determined before the auction and disclosed to bidders. The likelihood that this case (2) would occur in a particular auction is expected to be low.
- (g) If the auction has concluded, then winning tranches, winning bidders, and winning prices are determined as described below.
- (h) If the auction has not concluded, then each bidder's eligibility is determined for the next round and the price decrement (if any) is determined for each product for the next round.

5.1.8 Price Decrements

The announced prices will decrease round by round by a price decrement for over-subscribed products. Pre-specified price guidelines are used to determine the price decrements. Generally the price decrement for a product will be larger for the earlier rounds in the auction and when the excess supply for the product is greater. The price decrement is expected to be between 0.5 percent and 5 percent of the announced price for the most recently completed round.

The Auction Manager reserves the right to override the price decrement guidelines. The exercise of that right is expected to occur rarely and only if doing so is believed to facilitate timely progression of the bidding process.

5.2 Determination of Winning Tranches, Winning Bidders, and Winning Prices

At the close of the auction, the winning tranches, winning bidders, and winning prices will be determined as follows.

As a result of the EOR procedure as described above, there are two possible scenarios for a product at the close of the auction.

5.2.1 Bid Stack for a Product has All Tranches at the Same Price

In this scenario, there are no rolled-back tranches in the product's bid stack: all tranches in the bid stack were bid at the last announced price, including any tranches bid on the product in the last round of the auction as determined by the EOR procedure. That announced price is the product's clearing price, and all tranches in the product's bid stack are winning tranches if the clearing price satisfies the product's reservation price. Bidders who bid those tranches are winning bidders for those tranches, and all bidders with winning tranches on a product are paid the same price — i.e., the clearing price — for each winning tranche on the product. Note that this scenario includes the case in which a product was over-subscribed at some point in the auction and later became subscribed, as well as the case in which a product was always under-subscribed in the auction (i.e., it was never subscribed or over-subscribed in the auction).

5.2.2 Bid Stack for a Product has Tranches at Two Different Prices

In this scenario, there are rolled-back tranches in the product's bid stack: some tranches in the bid stack were bid at the last announced price (including any tranches bid on the product in the last round of the auction as determined by the EOR procedure), and some tranches in the bid stack were bid at the next most recent announced price. In this case, the product's clearing price is the next most recent announced price — which necessarily is higher than the last announced price for the product. All tranches in the product's bid stack are winning tranches if the clearing price satisfies the product's reservation price. Bidders who bid those tranches are winning bidders for those tranches, and all bidders with winning tranches on a product are paid the same price — i.e., the clearing price — for each winning tranche on the product.

5.3 Example of Round by Round Bidding

Appendix A provides an illustrative example of round by round bidding.

5.4 Reporting Round Results

During a round, a bidder will see the current status of the auction and the status of the current round including the announced price for each product as well as the bidder's own bidding status. A bidder will not see information about other bidders.

Between rounds the Bidding Website will report the results for the most recently completed round. Results for all prior rounds also will be accessible. The round results for each completed round in the auction will show:

- The announced price for each product and a range of total supply across all bidders and all products (that is, a range that includes the total number of tranches bid). The range of total supply will be defined by two different integers. Actual total supply will not be reported but will be at least as high as the lower of the two integers and no higher than the higher of the two integers. There is an exception to reporting total supply as a range of two integers: if and when total supply has declined below a pre-determined level, total supply will be reported simply as being below that level. The reporting ranges will be made available to bidders in advance of each auction.
- For each bidder, that bidder's bid for the round — i.e., the number of tranches bid on each product — and the bidder's eligibility for the next round. (Each bidder does not see information about other bidders.)
- The announced price for each product for the next round if the auction will continue with the next round.

5.5 Frequency of Rounds

The early rounds of bidding may be longer in duration than later rounds. The duration of a bidding round will be at least five (5) minutes.

The time between early rounds of bidding may be longer in duration than for later rounds. The time between bidding rounds will be at least five (5) minutes.

The schedule of rounds and any changes to the schedule will be made available to bidders through the Bidding Website.

5.6 Auction Pause Declared by Auction Manager

At any time during the auction, the Auction Manager may decide to pause the auction. This is not expected to happen often and it may not happen at all. If the Auction Manager pauses the auction, bidders will be notified and bidders will be notified if there are any changes to the schedule of rounds.

6. AFTER THE AUCTION CLOSES

6.1 Notification of Results

At the close of the auction, if the Auction Manager determines that the auction did not violate the competitive bidding process rules in such a manner so as to invalidate the auction, the Auction Manager will notify Duke Energy Ohio, the PUCO, the PUCO Consultant (if one has been retained), and the bidders as follows.

- The Auction Manager will notify Duke Energy Ohio, the PUCO, and the PUCO consultant of the identity of winning bidders, the number of tranches won by each winning bidder, and the prices for the tranches won.
- The Auction Manager will notify each winning bidder of how many tranches the bidder has won and at what prices. The Auction Manager also will notify the unsuccessful bidders that they have not won any tranches.

The names of the winning bidders, the number of tranches won by each bidder, and the winning prices will remain confidential until released publicly by the PUCO or as required by law.

The PUCO may reject the results of the auction, through an Order filed within forty-eight (48) hours of the conclusion of the auction, based upon a report from the independent auction manager or the Commission's consultant that the auction violates a specific CBP rule in such a manner so as to invalidate the auction or if the PUCO determines that one or more of the following criteria were not met:

1. The bidding process was oversubscribed based on bidder indicative offers submitted as part of the Part 2 Application, such that the amount of the supply bid upon was greater than the amount of the load bid out;
2. There were four or more bidders; or
3. Consistent with the load cap, no bidder won more than 80% of the initial tranche target for the auction.

Otherwise, the Commission shall approve the auction results.

6.2 Execution of Master SSO Supply Agreement

The winning bidders and Duke Energy Ohio will execute the Master SSO Supply Agreements three (3) business days following the close of the auction once the specific pricing information and load obligations have been inserted upon completion of the auction. Each winning bidder must demonstrate compliance with the creditworthiness requirements set forth in the Master SSO Supply Agreement.

6.3 Sanctions for Failure to Execute the Master SSO Supply Agreement

A winning bidder's financial guaranty posted with its Part 2 Application may be forfeited if the winning bidder does not execute the Master SSO Supply Agreement within three (3) business days following the close of the auction, if it fails to demonstrate compliance with the creditworthiness requirements set forth in the Master SSO Supply Agreement, or if it fails to agree to any of the terms of the Master SSO Supply Agreement. If Duke Energy Ohio exercises its right to collect on the financial guarantees, then any contractual rights or other entitlements of the winning bidder will terminate immediately without further notice by Duke Energy Ohio. In addition, the winning bidder will be liable for damages incurred by Duke Energy Ohio, which will be determined in accordance with the terms of the Master SSO Supply Agreement as though the winning bidder were a defaulting party to the Master SSO Supply Agreement.

7. USE OF THE BIDDING WEBSITE

Bidders will bid in the auction by accessing the Auction Manager's secure Bidding Website. An Authorized Representative of a bidder will access the Bidding Website using their own Web browser. The URL address for the Bidding Website, as well as user names and passwords, will be provided to Registered Bidders prior to the start of the auction.

The Bidding Website provides Web pages that allow a Registered Bidder to submit and confirm bids, to verify its status, to view results from prior rounds, to view the schedule of rounds, and to view messages from the Auction Manager.

7.1 Importance of Confirmed Bids

Submitting a bid on the Bidding Website involves three steps:

- (1) Web page for entry and submission of the bid quantities. The bidder enters its desired bid and then submits the bid in order to proceed to the next step.
- (2) Web page for validation of the bid. The bidder is asked to review the bid it submitted in the first step before proceeding to the confirmation step.
- (3) Web page showing confirmation of the bid. The bidder receives a unique confirmation ID for the bid and the time-stamp at which the bid was recorded by the Bidding Website server.

It is important to note that a bid is not accepted and recorded as an accepted bid until and unless the bidder reaches the third step in which the bid confirmation Web page displays the unique confirmation ID and time-stamp for the bid.

7.2 Requirements for Using the Bidding Website

Access to the Bidding Website requires all of the following:

- User name and password provided by the Auction Manager.
- Access to the Internet.
- Compatible Web browser.
- Status as a Registered Bidder.

A bidder loses access to the Bidding Website after it no longer is possible to win tranches in the auction.

7.3 Messaging

The Bidding Website displays messages from the Auction Manager. These messages from the Auction Manager are displayed for all bidders with access to the Bidding Website.

8. BACKUP BIDDING PROCEDURE

In case a bidder has technical difficulties, and as a result is not able to submit a bid via the Bidding Website in a round, a backup bidding procedure will be provided as follows. The bidder uses the Backup Bidding Fax Number to submit its bid via facsimile. It is recommended that the bidder call the Help Desk and inform the operator that it has submitted a bid using the backup bidding procedure. Reasonable efforts will be made to contact the bidder if the backup bid is not received via facsimile in the time expected. Once the backup bid is received via facsimile, a member of the Auction Manager team will attempt to enter the bid on the Bidding Website on behalf of the bidder.

Prior to the auction, bidders will be provided with the Backup Bidding Fax Number and with forms to use for faxing a bid using the backup bidding procedure.

Bidders must be aware and understand that there is no guarantee or other assurance that if it submits a bid using the backup bidding procedure that its bid will be submitted and confirmed on its behalf by the Auction Manager team consistent with the intentions of the bidder and in time before the round ends.

If a backup bid submitted by a bidder is not accepted and confirmed by the Bidding Website because the round has ended, a default bid will be entered for the bidder as described above in the sections on default bids.

If a backup bid submitted by a bidder is not accepted and confirmed by the Bidding Website for other reasons (e.g., the number of tranches bid is greater than a bidder's eligibility or violates the bidder's credit-based tranche limit or applicable load cap), the Auction Manager team will use reasonable efforts to inform the bidder that a new bid must be submitted.

If a backup bid submitted by a bidder is confirmed by the Bidding Website, the Auction Manager team will contact the bidder by faxing confirmation of the accepted bid to the bidder.

Bidders use the backup bidding procedure at their own risk. In all cases involving backup bids, the Auction Manager team does not accept any responsibility, obligation, or liability for errors, omissions, timeliness, or otherwise, related to whether a backup bid is entered into and confirmed by the Bidding Website on behalf of the bidder or as intended by the bidder.

9. WHO TO CONTACT IN CASE OF PROBLEMS DURING THE AUCTION

A bidder should contact the Help Desk if it has questions or problems. The phone number for the Help Desk will be provided to bidders prior to the start of the auction.

10. CONTINGENCY PLAN TO PURCHASE TRANCHES

10.1 If Fewer Tranches than the Tranche Target are Purchased in the Auction

In the event that fewer tranches than a product's tranche target are purchased in the auctions in a given year, Duke Energy Ohio will implement a Contingency Plan for the unfilled tranches. Under that plan, any unsubscribed tranches from the first auction in a year will be rolled over to the second auction in the year. If all tranches are not fully subscribed after all the auctions in any given year, the remaining tranches will be offered to current Duke Energy Ohio SSO Suppliers. These suppliers will have won tranches in the current or a prior Duke Energy Ohio CBP auction. An SSO Supplier will be considered a current SSO Supplier from the conclusion of the CBP auction in which such supplier won tranches until the termination of the prevailing Master SSO Supply Agreement. Suppliers will be assigned a random number and each unfilled tranche will be offered to current SSO Suppliers in descending order of random number, subject to any credit-based tranche limits and any applicable load caps for such suppliers. The tranches will be offered to current suppliers at the clearing price, starting price, or reservation price, whichever is lowest.

If, after the conclusion of the steps above used to assign unfilled tranches there still are unfilled tranches, then the necessary SSO supply requirements will be met through PJM-administered markets at prevailing Day-ahead, Real-time zonal spot prices, and, unless otherwise instructed by the PUCO, Duke Energy Ohio will not enter into hedging transactions to attempt to mitigate the associated price or volume risks to serve these tranches.

10.2 If a Winning Bidder Defaults Prior to or During the SSO Delivery Period

In the event a winning bidder defaults prior to or during the delivery of SSO Load requirements, Duke Energy Ohio will implement a Contingency Plan for the open tranches. Open tranches will be offered to other current SSO Suppliers using the same procedure as used for unfilled tranches at the auction as described above.

If tranches still remain open after the procedures above are applied, the necessary SSO supply requirements will be met through PJM-administered markets at prevailing Day-ahead, Real-time zonal spot prices, and, unless instructed otherwise by the PUCO, Duke Energy Ohio will not enter into hedging transactions to attempt to mitigate the associated price or volume risks to serve these tranches.

Additional costs incurred by Duke Energy Ohio in implementing the Contingency Plan will be assessed first against the defaulting supplier's credit security, to the extent available.

11. ASSOCIATION AND CONFIDENTIAL INFORMATION RULES

The Association and Confidential Information rules are described below.

11.1 Process for Reporting Associations, Identifying Concerns and Remedies

A prospective bidder applying to qualify to bid will be required to disclose in its Part 1 Application any bidding agreement or arrangement in which it may have entered. A prospective bidder will be required to certify in its Part 1 Application that, should it qualify to participate, it will not disclose information regarding the list of Qualified Bidders. A prospective bidder also will be required to certify that it accepts the terms of the Master SSO Supply Agreement and, should it win tranches, it will sign the applicable Master SSO Supply Agreement and comply with all creditworthiness requirements by the stated deadline.

Once entities are qualified to bid, each Qualified Bidder will be asked in its Part 2 Application to make a number of certifications, each detailed in the Part 2 Application, and each bidder may be required to provide additional information to the Auction Manager if a certification cannot be made. Each Qualified Bidder will be asked to certify that it will undertake to appropriately restrict its disclosure of Confidential Information relative to its bidding strategy and Confidential Information regarding the auction. A Qualified Bidder also will be asked to certify that it has not and will not come to any agreement with another Qualified Bidder with respect to bidding in the auction, except as disclosed and approved by the Auction Manager in its Part 1 Application.

Before obtaining sealed documentation necessary to participate in the auction, Registered Bidders will be required to certify that they will continue to maintain the confidentiality of any information that they will have acquired through their participation in the auction.

11.2 Confidential Information

Confidential Information relative to bidding strategy means information relating to a bidder's bid(s) in the auction, whether in writing or verbally, which if it were to be made public likely would have an effect on any of the bids that another bidder would be willing to submit. Confidential Information relative to bidding strategy includes (but is not limited to): a bidder's strategy; a bidder's indicative offer; the quantities that a bidder wishes to supply; the bidder's estimation of the value of a tranche; the bidder's estimation of the risks associated with serving the load for the auction; and a bidder's contractual arrangements for purchasing power to serve such load were the bidder to win tranches in the auction.

Confidential Information regarding the auction means information that is not released publicly by the PUCO, Duke Energy Ohio or the Auction Manager and that a bidder acquires as a result of participating in the auction, whether in writing or verbally, which if it were to be made public could impair the integrity of current or future competitive bidding processes, impair the ability of Duke Energy Ohio to hold future competitive bidding processes, or harm consumers, bidders or applicants. Confidential Information regarding the auction includes (but is not limited to): the list of Qualified Bidders, the list of Registered Bidders, the initial eligibility, the status of a bidder's participation, and all non-public reports of results and announcements made by the Auction Manager to any or all bidders in this auction.

Absolute protection from public disclosure of the bidders' data and information filed in this auction process cannot be provided. By participating in this auction process, each bidder acknowledges and agrees to the confidentiality provisions set forth herein, as well as any limitations thereto.

In addition, the bidder agrees the bidder's data and information submitted in this auction process will be disclosed if required by any federal, state or local agency (including, without limitation, the PUCO) or by a court of competent jurisdiction. However, Duke Energy Ohio will endeavor to notify the bidder in advance of such disclosure. In any event, neither Duke Energy Ohio nor the Auction Manager, nor any of their employees or agents, will be responsible to the bidders or any other party, or liable for any disclosure of such designated materials before, during or subsequent to this auction. Notwithstanding the above, Duke Energy Ohio and the Auction Manager reserve the right to use and communicate publicly and/or to third parties any and all information/data submitted as part of this auction process in any proceedings before FERC, the PUCO, and any other regulatory body and the courts, if necessary, without the prior consent/approval of, or notice to, any such bidder.

11.3 Certifications and Disclosures to Be Made

A prospective bidder will be required in its Part 1 Application to disclose any bidding agreement or any other arrangement in which the prospective bidder may have entered and that is related to its participation in the auction. A prospective bidder that has entered into such an agreement or arrangement must name the entities with which the prospective bidder has entered into a bidding agreement, or a joint venture for the purpose of participating in the auction, or a bidding consortium, or any other arrangement pertaining to participating in the auction. A bidding consortium is a group of separate businesses or business people joining together to submit joint bids in the auction.

In addition, a prospective bidder will be required to make the certifications listed in the Part 1 and Part 2 Applications.

The PUCO may publicly release the winning prices and the names of the winning bidders from the auction. The PUCO may choose to release additional information. After the auction, a winning bidder itself may release information regarding the number of tranches it has won, and a non-winning bidder itself may release information only regarding the fact that it participated in the auction. The winning bidders and the non-winning bidders otherwise continue to be bound by their certifications as described previously. In particular, no winning bidder and no non-winning bidder itself can reveal the winning prices of the auction prior to these being publicly released by the PUCO.

11.4 Actions to Be Taken if Certifications Cannot Be Made

If a bidder cannot make all the certifications above, the Auction Manager will decide within five (5) days following the deadline to submit the Part 2 Application on a course of action on a case-by-case basis. To decide on this course of action, the Auction Manager may make additional inquiries to understand the reason for the inability of the bidder to make the certification.

If Qualified Bidders do not comply with additional information requests by the Auction Manager regarding certifications required in the Part 2 Application, the Auction Manager may reject the application.

11.5 Sanctions for Failure to Comply

Sanctions may be imposed on a Qualified Bidder for failing to properly disclose information relevant to determining associations, for coordinating with another bidder without disclosing this fact, for releasing Confidential Information or disclosing information during the auction (aside from only the specific exceptions provided above with respect to entities explicitly named in the Part 1 Application as entities that are part of a bidding agreement or other arrangement, to an Advisor; or bidders with which it is associated), and in general for failing to abide by any of the Communications Protocols. Such sanctions can include, but are not limited to, any one or more of the following: termination of the Master SSO Supply Agreement; the loss of all rights to provide tranches won by such bidder; the forfeiture of letters of credit and other fees posted or paid; action (including prosecution) under applicable state and/or federal laws; attorneys' fees and court costs incurred in any litigation that arises out of the bidder's improper disclosure; debarment from participation in future competitive bidding processes; and/or other sanctions that may be appropriate. Should such an event occur, the Auction Manager will make a recommendation to Duke Energy Ohio regarding sanctions. The imposition of such sanctions will be at the discretion of Duke Energy Ohio.

12. MISCELLANEOUS

12.1 Warranty on Information

The information provided for the auction, including but not limited to information provided on the Information Website, has been prepared to assist bidders in evaluating the auction process. It does not purport to contain all the information that may be relevant to a bidder in satisfying its due diligence efforts. Neither Duke Energy Ohio nor the Auction Manager make any representation or warranty, expressed or implied, as to the accuracy or completeness of the information, and shall not, either individually or as a corporation, be liable for any representation expressed or implied in the auction process or any omissions from the auction process, or any information provided to a bidder by any other source. A bidder should check the Information Website frequently to ensure it has the latest documentation and information. Neither Duke Energy Ohio, nor the Auction Manager, nor any of their representatives, shall be liable to a bidder or any of its representatives for any consequences relating to or arising from the bidder's use of information.

12.2 Hold Harmless

Bidder shall hold Duke Energy Ohio and the Auction Manager harmless of and from all damages and costs, including but not limited to legal costs, in connection with all claims, expenses, losses, proceedings or investigations that arise in connection with the auction process or the award of a bid pursuant to the auction process.

12.3 Bid Submissions Become Duke Energy Ohio's Property

All bids submitted by bidders participating in the auction will become the exclusive property of Duke Energy Ohio upon conclusion of the auction process.

12.4 Bidder's Acceptance

Through its participation in the auction process, a bidder acknowledges and accepts all the terms, conditions and requirements of the auction process and the Master SSO Supply Agreement.

12.5 Permits, Licenses, Compliance with the Law and Regulatory Approvals

Bidders shall obtain all licenses and permits and status that may be required by any governmental body, agency or organization necessary to conduct business or to perform hereunder. Bidders' subcontractors, employees, agents and representatives of each in performance hereunder shall comply with all applicable governmental laws, ordinances, rules, regulations, orders and all other governmental requirements.

12.6 Auction Intellectual Property

All title, interests and other intellectual property rights in and to the auction design, the auction format and methodology, the auction software, the source code (including all modifications, enhancements, customization, adaptations and derivative works made by the Auction Manager) and associated documentation, including but not limited to these Bidding Rules, and the screen formats and forms designed by the Auction Manager (the "Auction Software"), are proprietary to the Auction Manager and all rights, title, and interest to the Auction Software remain with the Auction Manager. The Auction Manager grants Qualified Bidders a non-exclusive, non-transferable, limited license to use the Auction Software, solely for use in connection with the auction, subject to the terms and conditions set forth herein, and not for copying, relicensing, sublicensing, distribution or marketing by the Qualified Bidder. No other interest is conveyed to the Qualified Bidder other than the license expressly granted herein. The foregoing use license shall immediately terminate upon disqualification of the Qualified Bidder or upon termination or completion of the auction process. If at any time it is determined in the Auction Manager's sole discretion that the Qualified Bidder is in breach of this section 12.6, the Auction Manager shall be entitled to terminate the Qualified Bidder's access rights to the Auction Software.

Notwithstanding anything herein to the contrary, and without limiting the Qualified Bidder's other obligations herein, the Qualified Bidder shall not, nor shall it permit any third party to: (i) modify, translate or otherwise create derivative works of the Auction Software; (ii) reverse engineer, decompile, decode, disassemble or translate any Auction Software, or output thereof, or otherwise attempt to reduce to human readable form or derive the source code, protocols or architecture of any Auction Software; (iii) use or study any Auction Software, or output thereof, for the purpose of developing any software that is intended to replace, or that has functions, structure or architecture similar to, such Auction Software, or any part thereof; (iv) publish, or otherwise make available to any third party, any benchmark or other testing information or results concerning the Auction Software; (v) permit any other person who is not authorized to access or use all or any part of the Auction Software or (vi) copy the Auction Software, distribute the Auction Software, remove or obscure any proprietary labeling on or in the Auction Software, create any derivative works based on the Auction Software, or modify the Auction Software, in each case, except to the extent expressly permitted by the Auction Manager in writing.

In using the Auction Software, a Qualified Bidder shall take steps to prevent any virus, worm, built-in or use-driven destruction mechanism, algorithm, or any other similar disabling code, mechanism, software, equipment, or component designated to disable, destroy or adversely affect the Auction Software from being introduced into the systems.

APPENDIX A — EXAMPLE OF ROUND BY ROUND BIDDING

The illustrative example below shows for two bidders (BidderA and BidderB) and two products (Product-1 and Product-2) the confirmed bids (pre-EOR) and the post-EOR results for each round. In the example, the auction closes after round 4.

Round 1

For round 1, the announced prices are \$75.00 and \$82.00 for Product-1 and Product-2, respectively. At those announced prices, BidderA bids 55 tranches and 85 tranches on Product-1 and Product-2, respectively. BidderB bids 80 tranches and 27 tranches on Product-1 and Product-2, respectively.

When the round closes the EOR procedure is executed. Each product is over-subscribed: 135 tranches were bid on Product-1 which has a tranche target of 100, and 112 tranches were bid on Product-2 which has a tranche target of 100.

The announced price for Product-1 will be reduced from \$75.00 to \$72.50 for round 2. The announced price for Product-2 will be reduced from \$82.00 to \$78.60 for round 2.

BidderA will have eligibility of $55+85 = 140$ tranches for round 2, and BidderB will have eligibility of $80+27 = 107$ tranches for round 2.

Round 2

At the announced prices for round 2, BidderA bids 40 tranches and 85 tranches on Product-1 and Product-2, respectively. Thus, BidderA reduced its tranches bid on Product-1 from 55 to 40 tranches. BidderB bids 50 tranches and 57 tranches on Product-1 and Product-2, respectively. Thus, BidderB switched 30 tranches from Product-1 to Product-2.

When the round closes the EOR procedure is executed. Product-1 is under-subscribed by 10 tranches: only 90 tranches bid against the tranche target of 100 tranches: BidderA's bid represents a reduction in its eligibility by 15 tranches, while BidderB's bid maintained its eligibility. Thus, 10 of the 15 eligibility reduction tranches of BidderA are rolled back on Product-1. Those 10 tranches are priced at the announced price for Product-1 at which they were bid in round 1: \$75.00. The announced price for Product-1 will remain at \$72.50 for round 3.

Product-2 is over-subscribed by 42 tranches. The announced price for Product-2 will be reduced from \$78.60 to \$76.10 for round 3.

BidderA will have eligibility of $50+85 = 135$ tranches for round 3 (including the 10 tranches rolled back on Product-1), and BidderB will have eligibility of $50+57 = 107$ tranches for round 3.

Round 3

At the announced prices for round 3, BidderA bids 99 tranches and 36 tranches on Product-1 and Product-2, respectively. Thus, BidderA is switching 49 of the tranches bid from Product-2 to Product-1. BidderB bids 50 tranches and 35 tranches on Product-1 and Product-2, respectively. Thus, BidderB is reducing its tranches bid on Product-2 from 57 to 35 tranches.

When the round closes the EOR procedure is executed. Product-1 is over-subscribed by 49 tranches. Product-2 is under-subscribed by 29 tranches: only 71 tranches bid against the tranche target of 100 tranches: BidderA's bid maintained its eligibility while BidderB's bid represents a reduction in its eligibility by 22 tranches. Thus, all 22 of the eligibility reduction tranches of BidderB are rolled back on Product-2. Those 22 tranches are priced at the announced price for Product-2 at which they were bid in round 2: \$78.60. Even after rolling back those 22 eligibility reduction tranches of BidderA, Product-2 still is under-subscribed — by 7 tranches. So 7 tranches that BidderA had switched from Product-2 to Product-1 are rolled back to Product-2. Those 7 tranches are priced at the announced price for Product-2 at which they were bid in round 2: \$78.60.

After rolling back 7 tranches from Product-1 to Product-2 for BidderA, BidderA still has increased the number of tranches it is bidding on Product-1: from 50 tranches bid in round 2 (10 tranches at \$75.00 and 40 tranches at \$72.50) to 92 tranches bid in round 3 (10 tranches at \$75.00 and 82 tranches at \$72.50). Product-1 is over-subscribed as a result, so higher-priced tranches in Product-1's bid stack can be removed. All 10 of BidderA's higher-priced tranches are removed from Product-1's bid stack, and these 10 tranches become BidderA's free eligibility for round 4. In round 4, BidderA can bid any of the 10 tranches on any product, but to the extent those 10 tranches are not bid on a product in round 4, those free eligibility tranches and their associated eligibility for BidderA will be permanently removed from the auction after round 4.

Because Product-1 is over-subscribed, the announced price for Product-1 will be reduced from \$72.50 to \$70.15 for round 4. Because Product-2 is not over-subscribed, the announced price for Product-2 will remain at \$76.10 for round 4.

BidderA will have eligibility of $82+43+10 = 135$ tranches for round 4, and BidderB will have eligibility of $50+57 = 107$ tranches for round 4 (including the 22 tranches rolled back on Product-2).

Round 4

At the announced prices for round 4, BidderA bids 46 tranches and 43 tranches on Product-1 and Product-2, respectively. Thus, BidderA reduced its tranches bid on Product-1 from 82 to 46 tranches. BidderB bids 32 tranches and 57 tranches on Product-1 and Product-2, respectively. Thus, BidderB reduced its tranches bid on Product-1 from 50 to 32 tranches.

When the round closes the EOR procedure is executed. Product-1 is under-subscribed by 22 tranches: only 78 tranches bid against the tranche target of 100 tranches: BidderA's bid represents a reduction in its eligibility by 36 tranches, while BidderB's bid represents a reduction in its eligibility by 18 tranches. Of the 54 fewer tranches bid on Product-1, 36 were eligibility reductions from BidderA and 18 were eligibility reductions from BidderB. Of those 54 fewer tranches bid, $100 - 78 = 22$ tranches need to be rolled back on Product-1. The selection of which tranches are rolled back is done by assigning random numbers tranche by tranche (not bidder by bidder) to each of the 54 fewer tranches bid on Product-1. On average, the selection of the rolled back tranches will be proportional based on the number of tranches by which each bidder reduced its bid on the product. Thus, if the assignment of random numbers and selection of rolled back tranches were repeated many times, the number of rolled back tranches for BidderA on Product-1 would be expected to be 15 on average or $(82 - 46) / (132 - 78) * (100 - 78) = 36 / 54 * 22$, rounded, and the number of rolled back tranches for BidderB on Product-1 would be expected to be 7 on average: $(50 - 32) / (132 - 78) * (100 - 78) = 18 / 54 * 22$, rounded.

Auction Close

After the rollback is done for Product-1, it is determined that no product is over-subscribed and no bidder has free eligibility tranches. Thus, the criteria are met for closing the auction.

Product-1's bid stack has tranches bid at \$72.50 and tranches bid at \$70.15. So Product-1's clearing price is the higher of the two, or \$72.50. BidderA wins 61 tranches and BidderB wins 39 tranches for Product-1. All 100 tranches procured for Product-1 are paid the price of \$72.50.

Product-2's bid stack has tranches bid at \$78.60 and tranches bid at \$76.10. So Product-2's clearing price is the higher of the two, or \$78.60. BidderA wins 43 tranches and BidderB wins 57 tranches for Product-2. All 100 tranches procured for Product-2 are paid the price of \$78.60.

Example 3. Round by Round Bidding with Pre-EOR and Post-EOR Results

Round	Product-1					Product-2					Next-Round Eligibility	
	Announced Price	Tranche Target	Tranches Bid	@ Price	Excess Supply	Announced Price	Tranche Target	Tranches Bid	@ Price	Excess Supply	Free	Total
1	\$75.00					\$82.00						
Pre-EOR		100	135		35		100	112		12		
BidderA			55	@ \$75.00				85	@ \$82.00		—	140
BidderB			80	@ \$75.00				27	@ \$82.00		—	107
Post-EOR		100	135		35		100	112		12		
BidderA			55	@ \$75.00				85	@ \$82.00		—	140
BidderB			80	@ \$75.00				27	@ \$82.00		—	107
2	\$72.50					\$78.60						
Pre-EOR		100	90		(10)		100	142		42		
BidderA			40	@ \$72.50				85	@ \$78.60		—	125
BidderB			50	@ \$72.50				57	@ \$78.60		—	107
Post-EOR		100	100		0		100	142		42		
BidderA			50	10 @ \$75.00 40 @ \$72.50				85	@ \$78.60		—	135
BidderB			50	@ \$72.50				57	@ \$78.60		—	107

Round	Product-1					Product-2					Next-Round Eligibility	
	Announced Price	Tranche Target	Tranches Bid	@ Price	Excess Supply	Announced Price	Tranche Target	Tranches Bid	@ Price	Excess Supply	Free	Total
3	\$72.50					\$76.10						
Pre-EOR		100	149		49		100	71		(29)		
BidderA			99	10 @ \$75.00 89 @ \$72.50				36	@ \$76.10		—	135
BidderB			50	50 @ \$72.50				35	@ \$76.10		—	85
Post-EOR		100	132		32		100	100		0		
BidderA			82	@ \$72.50				43	7 @ \$78.60 36 @ \$76.10		10	135
BidderB			50	@ \$72.50				57	22 @ \$78.60 35 @ \$76.10		—	107
4	\$70.15					\$76.10						
Pre-EOR		100	78		(22)		100	100		0		
BidderA			46	@ \$70.15				43	7 @ \$78.60 36 @ \$76.10		—	89
BidderB			32	@ \$70.15				57	22 @ \$78.60 35 @ \$76.10		—	89
Post-EOR		100	100		0		100	100		0		
BidderA			61	15 @ \$72.50 46 @ \$70.15				43	7 @ \$78.60 36 @ \$76.10		—	104
BidderB			39	7 @ \$72.50 32 @ \$70.15				57	22 @ \$78.60 35 @ \$76.10		—	96

	Product-1			Product-2			Tranches Won
	Clearing Price	Tranche Target	Tranches Won	Clearing Price	Tranche Target	Tranches Won	
Results	\$72.50	100	100	\$78.60	100	100	100
BidderA			61			43	104
BidderB			39			57	96

Duke Energy Ohio

Present Value Benefit of ESP Compared to MRO ^(a)

Line		Jan '12-Dec '12 2012	Jan '13-Dec '13 2013	Jan '14-Dec '14 2014	Jan '15-May '15 2015
Price Forecasts					
1	Projected Legacy ESP Price ^(b)	\$79.19	\$74.45	\$76.22	\$75.44
2	Projected Retail Market Price ^(c)	\$61.38	\$66.31	\$78.65	\$89.00
3	MRO Blend % (of Market Price)	10%	20%	30%	40%
4	MRO Price Blended Rate (\$/MWh)	<u>\$77.41</u>	<u>\$72.82</u>	<u>\$76.95</u>	<u>\$80.86</u>
5	Projected Retail Market Price (Line 2)	\$61.38	\$66.31	\$78.65	\$89.00
6	Electric Security Stabilization Charge ^(d)	5.37	5.29	5.19	-
7	Proposed SSO Price in ESP	<u>\$66.75</u>	<u>\$71.60</u>	<u>\$83.85</u>	<u>\$89.00</u>
Revenue Comparison (MRO v. ESP)					
8	Total Revenue at MRO Rate	\$1,584,804,517	\$1,515,400,007	\$1,629,570,849	\$700,610,416
9	Total Revenue at ESP Rates				
10	All kWh at Average ESP Rate	\$1,366,630,966	\$1,489,967,594	\$1,775,667,622	\$771,119,852
11	Less: Discount for PIPP Load <i>(see workpaper)</i> ^(e)	<u>(1,034,686)</u>	<u>(1,175,033)</u>	<u>(1,458,150)</u>	<u>(556,176)</u>
12	Total Revenue at ESP Rates	\$1,365,596,280	\$1,488,792,561	\$1,774,209,472	\$770,563,676
Other Benefits of ESP (Per Stipulation) ^(f)					
13	Economic Development	\$1,150,000	\$0	\$0	\$0
14	Weatherization/Fuel Fund	1,700,000	-	-	-
15	Total Other Quantifiable Unconditional Benefits	<u>\$2,850,000</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>
16	Present Value ^(g) of MRO Revenue	\$4,586,339,265			
17	Present Value ^(g) of ESP Revenue	<u>\$4,524,279,806</u>			
18	Net Benefit of ESP to Customers (ESP v. MRO)	\$62,059,459			
Other Assumptions					
19	Projected Total Retail Sales (MWh) ^(h)	20,473,777	20,810,354	21,177,162	8,664,268
20	Projected Total PIPP Sales (MWh) ⁽ⁱ⁾	297,409	302,298	307,627	125,860

Notes: ^(a) The table below includes only quantifiable benefits. See Supplemental Testimony of Julia S. Janson for other benefits of the ESP Stipulation filed on October 24, 2011.

^(b) As shown in the Direct Testimony of Judah L. Rose, Exhibit B.

^(c) As shown in the Direct Testimony of Judah L. Rose, Exhibit 8B.

^(d) Per Stipulation, Rider ESSC set at \$110 million per year, subject to true-up.

^(e) Per Stipulation, PIPP Discount is 5% of Residential PTC, excluding AER-R, (i.e., Rider RC+Rider RE+Rider SCR+Rider RTO).

^(f) Includes shareholder contributions to various entities per Stipulation. Stipulation provides for additional funding for years after 2012 subject to meeting earnings thresholds for Duke Energy Ohio. Only 2012 amounts are shown as these are the only contributions that are guaranteed per the Stipulation.

^(g) Discounted at weighted-average cost of capital as shown in Attachment WDW-1 of Direct Testimony of William Don Wathen Jr.

^(h) Projected MWh sales, at the meter, as shown in Attachment WDW-2 of Direct Testimony of William Don Wathen Jr.

⁽ⁱ⁾ Current PIPP MWh sales escalated at overall growth in load.

Attachment E

Duke Energy Ohio
139 East Fourth Street
Cincinnati, Ohio 45202

P.U.C.O. Electric No. 20
Original Sheet No. 88
Page 1 of 2

RIDER UE-GEN
UNCOLLECTIBLE EXPENSE - ELECTRIC GENERATION RIDER

APPLICABILITY

Applicable to all retail jurisdictional customers in the Company's electric service territory, including those customers taking generation service from a Certified Retail Electric Service (CRES) provider, except for those customer accounts not designated for Duke Energy Ohio's Purchase of Accounts Receivable Program.

DESCRIPTION

This rider enables the recovery of uncollectible accounts expense related generation service, including Percentage of Income Payment ("PIPP") customer installments not collected through the Universal Service Fund Rider. The amounts in the Rider, exclusive of uncollectible PIPP installments, will only be collected from the class (residential or non-residential) that created the uncollectible accounts expense. Uncollectible accounts expense associated with PIPP will be allocated in the manner consistent with the Universal Service Fund Rider. The first application shall be filed in the second quarter of 2012.

CHARGE

A charge of \$0.000000 per kWh shall be applied to all kWh delivered to residential customers. A charge of \$0.00 per bill shall be applied to each non-residential customer.

Filed pursuant to an Order dated _____ in Case No. _____ before the Public Utilities Commission Ohio.

Issued:

Effective:

Issued by Julie Janson, President

Duke Energy Ohio
139 East Fourth Street
Cincinnati, Ohio 45202

Page 2 of 2

* * * *

11.6 Purchase of Accounts Receivable (PAR)

- a) In order to participate in the Company's PAR program, a Certified Supplier must first sign an Account Receivables Purchase Agreement with the Company, which may include, but will not be limited to, the following provisions:
- i) Purchase price, procedures, and fees
 - ii) Obligations of the parties
 - iii) Representations and warranties
 - iv) Covenants of Seller
 - v) Conditions Precedent
 - vi) Administration and Collection
 - vii) Termination
 - viii) Indemnification
- b) Notwithstanding any provisions of an existing Account Receivables Purchase Agreement to the contrary, the Company shall purchase the receivables of a Certified Supplier that has entered into an Account Receivables Purchase Agreement with the Company at zero discount and shall pay the Certified Supplier for such receivables no later than the twentieth day of the month after the month in which the billing occurs.

Filed pursuant to an Order dated _____ in Case No. _____ before the Public Utilities Commission Ohio.

Issued:

Effective:

Issued by Julie Janson, President

MASTER STANDARD SERVICE OFFER (“SSO”)
SUPPLY AGREEMENT
BY AND BETWEEN
DUKE ENERGY OHIO, INC.
AND
EACH SSO SUPPLIER SET FORTH ON ATTACHMENT A HERETO

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MASTER SSO SUPPLY AGREEMENT

This Master SSO Supply Agreement ("Agreement"), dated as of _____, ____ 2011 ("Effective Date"), is by and between Duke Energy Ohio, Inc., an Ohio corporation with offices at 139 East Fourth Street, Cincinnati, Ohio ("Duke Energy Ohio") and each of the suppliers listed on Attachment A severally, but not jointly, (each an "SSO Supplier" and collectively "SSO Suppliers"). Duke Energy Ohio and each SSO Supplier are hereinafter referred to individually as a "Party" or collectively as the "Parties").

RECITALS

WHEREAS, Duke Energy Ohio is an Ohio public utility that engages, inter alia, in providing SSO Service within its service territory; and

WHEREAS, the PUCO found that, commencing on and after _____, it would serve the public interest for Duke Energy Ohio to secure SSO Supply through a competitive bidding process; and

WHEREAS, on _____, 2011, Duke Energy Ohio conducted and completed a successful Solicitation for SSO Supply; and

WHEREAS, each SSO Supplier was one of the winning bidders in the Solicitation for SSO Supply; and

WHEREAS, the PUCO has authorized Duke Energy Ohio to contract with winning bidders for SSO Supply to serve SSO Load in accordance with the terms of this Agreement; and

WHEREAS, as authorized pursuant to order of the Federal Regulatory Commission ("FERC") dated October 21, 2010 (Docket No. ER10-2254-000; 133 FERC ¶61,058), the Duke Energy Zone became integrated into the PJM Balancing Authority Area effective as of January 1, 2012;

WHEREAS, Duke Energy Ohio provided and/ or procured Capacity Resources in an amount which fulfills its FRR obligations for the DEOK Load Zone; and

WHEREAS, during the Term, each SSO Supplier, as an LSE in the DEOK Load Zone, will satisfy its Capacity obligations under the PJM Agreements associated with its respective SSO Supplier Responsibility Share at the Final Zonal Capacity Price for the unconstrained portion of the region; and

WHEREAS, Duke Energy Ohio and the SSO Suppliers desire to enter into this Agreement setting forth their respective obligations concerning the provision of SSO Supply.

NOW, THEREFORE, for and in consideration of the mutual covenants contained herein, and for other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties intending to be legally bound hereby agree as follows:

ARTICLE 1

DEFINITIONS

The following definitions and any terms defined in this Agreement shall apply hereunder.

“Affiliate” means, with respect to any Person, any other Person (other than an individual) that, directly or indirectly, through one or more intermediaries, controls, or is controlled by, or is under common control with, such Person. For this purpose, “control” means the direct or indirect ownership of fifty percent (50%) or more of the outstanding capital stock or other equity interests having ordinary voting power.

“Ancillary Services” has the meaning set forth in the PJM Agreements.

“Bankrupt” means with respect to any entity, that such entity (i) files a petition or otherwise commences or acquiesces in a proceeding under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it and such petition is not withdrawn or dismissed within thirty (30) days after such filing, (ii) makes an assignment or any general arrangement for the benefit of creditors, (iii) otherwise becomes bankrupt or insolvent (however evidenced), (iv) has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets, or (v) is unable to pay its debts as they fall due.

“Bankruptcy Code” means those laws of the United States of America related to bankruptcy, codified and enacted as Title 11 of the United States Code, entitled “Bankruptcy” and found at 11 U.S.C. § 101 et seq.

“Billing Period” means hour ending 0100 on the first day of a calendar month through hour ending 2400 on the last day of the applicable calendar month.

“Billing Statement” has the meaning set forth in Section 6.1(a).

“Business Day” means any day except a Saturday, Sunday or a day PJM declares to be a holiday, as posted on the PJM website. A Business Day shall open at 8:00 a.m. and close at 5:00 p.m. prevailing Eastern Time, unless otherwise agreed to by the Parties in writing.

“Capacity” means “Unforced Capacity” as set forth in the PJM Agreements, or any successor measurement of capacity obligation of an LSE as may be employed in PJM (whether set forth in the PJM Agreements or elsewhere).

“Charge” means any fee, charge, PJM charge, the Energy Share Adjustment if in favor of Duke Energy Ohio, or any other amount that is billable by Duke Energy Ohio to the SSO Supplier under this Agreement.

“Commercial Customer” means a Customer taking service under one of Duke Energy Ohio’s non-residential rates (Rate DS, Rate DM, Rate DP, Rate CUR, Rate EH, Rate GSFL, Rate SFL-ADPL, Rate RTP, or Rate TS).

“Costs” mean, with respect to the Non-Defaulting Party, all reasonable attorney’s fees, brokerage fees, commissions, PJM charges and other similar transaction costs and expenses reasonably incurred by such Party either in terminating any arrangement pursuant to which it has hedged its obligations or entering into new arrangements which replace this Agreement; and all reasonable attorney’s fees and expenses incurred by the Non-Defaulting Party in connection with the termination of this Agreement as between Duke Energy Ohio and the applicable SSO Supplier.

“Credit Limit” means an amount of credit, based on the creditworthiness of an SSO Supplier or its Guarantor, if applicable, determined pursuant to Section 5.6, granted by Duke Energy Ohio to such SSO Supplier to be applied towards the Total Exposure Amount for such SSO Supplier.

“CRES Supplier” means a Person that is duly certified by the PUCO to offer and to assume the contractual and legal responsibility to provide Standard Service Offer pursuant to retail open access programs approved by the PUCO to Customers who are not SSO Customers of Duke Energy Ohio.

“Cross Default Amount” means an amount equal to five percent (5%) of a Defaulting Party’s or Defaulting Party’s Guarantor’s (as applicable) Tangible Net Worth.

“Customer” means any Person who receives distribution service from Duke Energy Ohio in accordance with the Legal Authorities.

“Default Allocation Assessment” has the meaning set forth in the PJM Agreements.

“Default Damages” means direct damages, calculated in a commercially reasonable manner, that the Non-Defaulting Party incurs as a result of an Event of Default by the Defaulting Party. Default Damages may include: (i) the positive difference (if any) between the price of SSO Supply hereunder and the price at which Duke Energy Ohio or the SSO Supplier is able to purchase or sell (as applicable) SSO Supply (or any components of SSO Supply it is able to purchase or sell) from or to third parties including other SSO Suppliers and PJM; (ii) Emergency Energy charges; (iii) additional transmission or congestion charges incurred to purchase or sell SSO Supply; and (iv) Costs.

“Defaulting Party” has the meaning set forth in Section 7.1.

“Delivery Period” means the Original Delivery Period, unless this Agreement is terminated earlier in accordance with the provisions hereof.

“Delivery Point” means the DEOK Load Zone as defined within PJM.

“Duke Energy Ohio Indemnified Party” has the meaning set forth in Section 10.1(a).

“DEOK Load Zone ” means that set of electrical locations, designated by PJM as Pnode ID number 124076095, determined pursuant to the applicable PJM Tariff, rules, agreements and procedures, representing the aggregate area of consumption for Duke Energy Ohio within PJM and used for the purposes of scheduling, reporting withdrawal volumes, and settling Energy transactions at aggregated load levels, to facilitate Energy market transactions.

“Early Termination” has the meaning set forth in Section 2.3.

“Early Termination Date” means, as between Duke Energy Ohio and the applicable SSO Supplier, the date upon which an Early Termination becomes effective as specified in Section 7.2(b).

“Effective Date” has the meaning set forth in the preamble.

“Emergency” means (i) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; (ii) a condition that requires implementation of emergency operations procedures; or (iii) any other condition or situation that Duke Energy Ohio, transmission owner(s) or PJM deems imminently likely to endanger life or property or to affect or impair Duke Energy Ohio’s electrical system or the electrical system(s) of other Person(s) to which Duke Energy Ohio’s electrical system is directly or indirectly connected (a “Connected Entity”). Such a condition or situation may include potential overloading of Duke Energy Ohio’s subtransmission or distribution circuits, PJM minimum generation (“light load”) conditions, or unusual operating conditions on either Duke Energy Ohio’s or a Connected Entity’s electrical system, or conditions such that Duke Energy Ohio is unable to accept Energy from the SSO Supplier without jeopardizing Duke Energy Ohio’s electrical system or a Connected Entity’s electrical system.

“Emergency Energy” has the meaning set forth in the PJM Agreements.

“Energy” means electric energy of the character commonly known as three-phase, sixty-hertz electric energy that is delivered at the nominal voltage of the Delivery Point, expressed in MWh.

“Energy Share Adjustment” means for any Billing Period, the monetary amount due to an SSO Supplier or Duke Energy Ohio, as the case may be, in order to reconcile any difference between the Estimated Monthly Energy Share used for the purpose of calculating estimated payments made to such SSO Supplier for a given month and the Final Monthly Energy Share used for calculating the final payments due to the SSO Supplier for such month, as more fully described in Article 6.

“Estimated Monthly Energy Share” means a quantity of Energy expressed in MWh which, for any Billing Period, is the preliminary calculation of the SSO Supplier’s SSO Supplier Responsibility Share.

“Event of Default” has the meaning set forth in Section 7.1.

“Excess Collateral” has the meaning set forth in Section 5.7

“FERC” means the Federal Energy Regulatory Commission or such succeeding organization.

“Final Monthly Energy Share” means a quantity of Energy expressed in MWh which, for any Billing Period, is the Estimated Monthly Energy Share adjusted for any billing or metering errors found subsequent to the calculation of the Estimated Monthly Energy Share of which PJM is notified prior to the last date on which PJM issues a settlement statement for a previous operating day for the Billing Period.

“Final Zonal Capacity Price” has the meaning set forth in the PJM Agreements.

“Firm Transmission Service” has the meaning ascribed to “Network Integration Transmission Service” under the PJM Agreements. In the event the PJM Agreements are modified such that “Network Integration Transmission Service” is no longer offered, Firm Transmission Service means the type of transmission service offered under the PJM Agreements that is accorded the highest level of priority for scheduling and curtailment purposes.

“Forward Market Prices” means forward market prices for a specific geographic Market Price Hub, as adjusted by Duke Energy Ohio to reflect impact of load shape.

“Gains” means an amount equal to the present value of the economic benefit to the Non-Defaulting Party, if any, exclusive of Costs, resulting from an Early Termination.

“Governmental Authority” means any federal, state, local, municipal or other governmental entity, authority or agency, department, board, court, tribunal, regulatory commission, or other body, whether legislative, judicial or executive, together or individually, exercising or entitled to exercise any administrative, executive, judicial, legislative, policy, regulatory or taxing authority or power over a Party to this Agreement.

“Guarantor” means any Person having the authority and agreeing to guarantee an SSO Supplier’s financial obligations under this Agreement, provided that such party meets Duke Energy Ohio’s creditworthiness requirements for SSO Suppliers.

“Guaranty” means the ICT Guaranty or the Total Exposure Guaranty, as applicable.

“ICR Collateral” has the meaning set forth in Section 5.4(d).

“ICRT” has the meaning set forth in Section 5.3.

“ICT Guaranty” means a guaranty, in the form substantially set forth in Attachment D, provided by a Guarantor in favor of Duke Energy Ohio guaranteeing an SSO Supplier’s financial obligations in connection with ICT.

“Indemnification Losses” has the meaning set forth in Section 10.1(a).

“Indemnified Supplier” has the meaning set forth in section 10.1(b).

“Independent Credit Requirement or ICR” means an amount per Tranche required as security under Section 5.3, to mitigate the risk to Duke Energy Ohio of Energy price movements between the date of an Early Termination caused by an Event of Default by an SSO Supplier and the date the final calculation of Default Damages owing to Duke Energy Ohio under Section 7.2(c) is made.

“Independent Credit Threshold or ICT” means an amount of credit, based on the creditworthiness of an SSO Supplier or its Guarantor, if applicable, determined pursuant to Section 5.4, granted by Duke Energy Ohio to such SSO Supplier to be applied towards the satisfaction of such SSO Supplier’s Independent Credit Requirement.

“Industrial Customer” means a Customer taking service under Duke Energy Ohio’s non-residential rates (Rate DS, Rate DM, Rate DP, Rate EH, Rate GSFL, Rate SFL-ADPL, Rate RTP or Rate TS).

“Interest Rate” means, for any date, the lesser of (a) the per annum rate of interest equal to the prime lending rate (“Prime Rate”) as may be published from time to time in the Federal Reserve Statistical Release H.15; or (b) the maximum lawful interest rate.

“Kilowatt or kW” means a unit of measurement of useful power equivalent to 1,000 watts.

“Kilowatt-hour or kWh” means one kilowatt of electric power used over a period of one hour.

“Legal Authorities” means, generally, those federal and Ohio statutes and administrative rules and regulations that govern the electric utility industry in Ohio.

“Letter of Credit” means a standby irrevocable letter of credit in the form set forth in Attachment E, or in such other form as Duke Energy Ohio deems acceptable in its sole discretion, and in each case conforming to all of the requirements specifically set forth in Section 5.9(b).

“LIBOR” means the rates published daily as the London Inter-Bank Offered Rates for U.S. dollar deposits. For discounting purposes, the rates will be converted into a series of monthly

rates representing the equivalent forward LIBOR rate from the valuation date to the month of delivery.

“Lighting Customer” means a Customer taking service under Duke Energy Ohio’s lighting rates (Rate SL, Rate SC, Rate NSU, Rate NSP, Rate SE, Rate UOLS, or Rate TL).

“Load Serving Entity or LSE” has the meaning set forth in the applicable PJM Agreements.

“Losses” means an amount equal to the present value of the economic loss to the Non-Defaulting Party, if any, exclusive of Costs, resulting from an Early Termination.

“Margin” means, at any time, the amount by which the Total Exposure Amount exceeds the Credit Limit of the SSO Supplier or its Guarantor.

“Margin Call” has the meaning set forth in Section 5.6(d).

“Margin Collateral” has the meaning set forth in Section 5.6(d).

“Mark-to-Market Exposure Amount” means an amount calculated daily for each SSO Supplier reflecting the exposure to Duke Energy Ohio due to fluctuations in market prices for Energy as set forth in Section 5.5.

“Market Price Hub” means a liquid pricing point located within PJM’s geographic footprint.

“Midwest ISO Tariff” means the Open Access Transmission, Energy and Operating Reserve Markets Tariff for the Midwest Independent Transmission System Operator, Inc., or the successor, superseding or amended versions of the Open Access Transmission, Energy and Operating Reserve Markets Tariff that may take effect from time to time.

“Minimum Margin Threshold” means \$100,000.

“Minimum Rating” means a minimum senior unsecured debt rating as defined in Section 5.4(a).

“MW” means megaWatt.

“MWh” means megaWatt hour.

“NERC” means the North American Electric Reliability Corporation or its successor.

“Non-Defaulting Party” means (i) where an SSO Supplier is the Defaulting Party, Duke Energy Ohio; (ii) where Duke Energy Ohio is the Defaulting Party with respect to an Event of Default, the SSO Supplier to which the applicable obligation was owed.

“Ohio Sales and Use Taxes” has the meaning set forth in Section 12.8.

“Original Delivery Period” has the meaning set forth in Attachment A.

“Other SSO Supply Agreement” has the meaning set forth in Section 7.3(c).

“Party” has the meaning set forth in the preamble to this Agreement, and includes such Party’s successors and permitted assigns.

“Performance Assurance” means collateral in the form of cash, letters of credit, or other security reasonably acceptable to the Requesting Party.

“Person” means an individual, partnership, joint venture, corporation, limited liability company, trust, association or unincorporated organization, any Governmental Authority, or any other entity.

“PIPP Customers” means Customers that take service under Duke Energy Ohio’s percentage of income payment plan.

“PJM” means PJM Interconnection, L.L.C. or any successor organization thereto.

“PJM Agreements” means the PJM OATT, PJM Operating Agreement, PJM RAA and any other applicable PJM manuals or documents, or any successor, superseding or amended versions thereof that may take effect from time to time.

“PJM Balancing Authority Area” means the control area recognized by NERC as the PJM Balancing Authority Area.

“PJM E-Account” means an account obtainable through PJM which provides access to web-based PJM settlement, accounting, marketing and other informational and economic systems.

“PJM OATT or PJM Tariff” means the Open Access Transmission Tariff of PJM or the successor, superseding or amended versions of the Open Access Transmission Tariff that may take effect from time to time.

“PJM Operating Agreement” means the Amended and Restated Operating Agreement of PJM or the successor, superseding or amended versions of the Amended and Restated Operating Agreement that may take effect from time to time.

“PJM RAA” means the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region or any successor, superseding or amended versions of the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region that may take effect from time to time.

“Price” means, with respect to each SSO Supplier, the price in \$/MWh set forth in Attachment A, resulting from Duke Energy Ohio’s Solicitation for the opportunity to provide SSO Supply. The Price is the basis for financial settlement of SSO Supply supplied by an SSO Supplier for SSO Customers under this Agreement.

“PUCO” means the Public Utilities Commission of Ohio, or any successor thereto.

“Residential Customer” means a Customer taking service under Duke Energy Ohio’s residential rates (Rate RS, Rate ORH, Rate TD, Rate TD-AM, Rate RS3P, or Rate RSLI).

“Seasonal Billing Factor” means a numerical factor, as set forth in Attachment B, one amount applicable during the summer months of June through September, and one amount applicable during the non-summer months of October through May, applied to the Price in accordance with

the provisions of Article 6 and thereby used to adjust Duke Energy Ohio's payments to SSO Suppliers.

"Settlement Amount" means the net amount of the Losses or Gains, and Costs, expressed in U.S. Dollars, which the Non-Defaulting Party incurs as a result of Early Termination, calculated from the Early Termination Date through the end of the Original Delivery Period. For purposes of calculating the Settlement Amount, the quantity of Energy (and other components of SSO Supply) provided for under this Agreement for the period following the Early Termination Date through the remainder of the Original Delivery Period will be determined by the Non-Defaulting Party in a commercially reasonable manner reflecting estimated SSO Load for un-switched customers as of the Early Termination Date based on the then most recent load switching report filed by Duke Energy Ohio with the PUCO as of the Early Termination Date. The calculation of Settlement Amount with respect to an Early Termination shall exclude Default Damages calculated pursuant to Section 7.3(a).

"Special Contract Customers" means Customers that take retail generation service from Duke Energy Ohio under terms and conditions different than the otherwise applicable tariff.

"Specified Indebtedness" with respect to a Party means as of any date, without duplication, (i) all obligations of such Party for borrowed money, (ii) all indebtedness of such Party for the deferred purchase price of property or services purchased (excluding current accounts payable incurred in the ordinary course of business), (iii) all indebtedness created or arising under any conditional sale or other title retention agreement with respect to property acquired, (iv) all indebtedness under leases which shall have been or should be, in accordance with generally accepted accounting principles, recorded as capital leases in respect of which such Party is liable as lessee, (v) the face amount of all outstanding letters of credit issued for the account of such Party (other than letters of credit relating to indebtedness included in indebtedness of such Party pursuant to another clause of this definition) and, without duplication, the unreimbursed amount of all drafts drawn thereunder, (vi) indebtedness secured by any lien on property or assets of such Party, whether or not assumed (but in any event not exceeding the fair market value of the property or asset), (vii) all direct guarantees of indebtedness referred to above of another Party, (viii) all amounts payable in connection with mandatory redemptions or repurchases of preferred stock or member interests or other preferred or priority equity interests and (ix) any obligations of such Party (in the nature of principal or interest) in respect of acceptances or similar obligations issued or created for the account of such Party.

"Solicitation" means the competitive bidding process by which the counterparty, quantity, pricing and other terms of this Agreement are established.

"SSO Customers" means Residential Customers, Commercial Customers, Industrial Customers and Lighting Customers, including Special Contract Customers, but excluding PIPP Customers and interruptible service customers, taking SSO Supply from Duke Energy Ohio during the Delivery Period when either PJM or Duke Energy Ohio calls for an interruption.

"SSO Load" means the full electricity requirements for SSO Service of SSO Customers.

"SSO Service" means Standard Service Offer service that is not provided by a CRES Supplier.

“SSO Supplier” has the meaning set forth in the preamble.

“SSO Supplier Responsibility Share” means, for each SSO Supplier, the fixed percentage share of the SSO Load for which the SSO Supplier is responsible as set forth in Attachment A. The stated percentage is determined by dividing the number of Tranches won by the SSO Supplier in the Solicitation by the total number of Tranches.

“SSO Supply” means unbundled Energy, Capacity and Ancillary Services, including, to the extent not expressly assumed by Duke Energy Ohio pursuant to Section 3.2, all transmission and distribution losses and congestion and imbalance costs associated with the provision of such services, as measured and reported to PJM, and such other services or products that an SSO Supplier may be required to provide, by PJM or other Governmental Authority, in order to meet the requirements of SSO Service.

“Standard Service Offer” means a market-based standard service offer of all competitive retail electric services necessary to maintain essential electric service to Customers, including unbundled Energy, Capacity, Ancillary Services and Firm Transmission Service, including all transmission and distribution losses, congestion and imbalance costs associated with the provision of the foregoing services, other obligations or responsibilities currently imposed or that may be imposed by PJM, and such other services or products that are provided by a CRES Supplier or an SSO Supplier to fulfill its obligations to serve customer load, as required by Section 4928.141 of the Ohio Revised Code.

“Tangible Net Worth” or “TNW” means total assets less intangible assets and total liabilities. Intangible assets include benefits such as goodwill, patents, copyrights and trademarks, each as would be reflected on a balance sheet prepared in accordance with generally accepted accounting principles.

“Taxes” have the meaning set forth in Section 12.8.

“Term” has the meaning set forth in Section 2.1.

“Termination Payment” has the meaning set forth in Section 7.3(c).

“Total Exposure Amount” means an amount calculated daily for each SSO Supplier reflecting the total credit exposure to Duke Energy Ohio and consisting of the sum of: (i) the Mark-to-Market Exposure Amount arising under this Agreement; (ii) any amount(s) designated as the “mark-to-market exposure amount” (or similar designation) under any Other SSO Supply Agreement; and (iii) the amount designated as the “credit exposure” (or similar designation) under any Other SSO Supply Agreement; less (iv) amounts due to such SSO Supplier pursuant to Section 6.1; provided that in the event the amount calculated for any day is a negative number, it shall be deemed to be zero for such day.

“Total Exposure Amount Guaranty” means a guaranty, in substantially similar form as set forth in Attachment D, provided by a Guarantor in favor of Duke Energy Ohio guaranteeing an SSO Supplier’s financial obligation with respect to its Total Exposure Amount.

“Tranche” means a fixed percentage share of the SSO Load as determined for the purposes of the Solicitation conducted to procure SSO Supply for the SSO Load.

ARTICLE 2

TERM AND TERMINATION

2.1 Term

The Term of this Agreement shall begin on the Effective Date and extend through and include the end of the Delivery Period (“Term”) unless terminated earlier or extended pursuant to the terms of this Agreement; provided, however, that the provision of SSO Supply by SSO Suppliers will commence on _____ at 12:01 a.m. prevailing Eastern Time.

2.2 Mutual Termination

Duke Energy Ohio and any SSO Supplier may terminate this Agreement at any time during the Term on such terms and under such conditions as they mutually agree.

2.3 Early Termination

This Agreement may be terminated by a Party prior to the end of the Term due to an occurrence of an Event of Default and the declaration of an Early Termination Date by the Non-Defaulting Party pursuant to Section 7.2 (an “Early Termination”).

2.4 Effect of Termination

The applicable provisions of this Agreement shall continue in effect and survive the termination of this Agreement to the extent necessary to provide for final accounting, billing, billing adjustments, resolution of any billing disputes, realization of any collateral or other security, set-off, final payments, or payments pertaining to liability and indemnification obligations arising from acts or events that occurred in connection with this Agreement during the Term.

ARTICLE 3

GENERAL TERMS AND CONDITIONS

3.1 SSO Supplier's Obligations to Provide SSO Supply and Other Obligations

Each SSO Supplier hereby agrees, severally, but not jointly, as follows:

(a) during the Delivery Period, such SSO Supplier shall sell, deliver and provide SSO Supply on a firm and continuing basis in order to meet its SSO Supplier Responsibility Share, in accordance with this Agreement and the PJM Agreements;

(b) during the Term, each SSO Supplier shall purchase from Duke Energy Ohio (and, unless Duke Energy Ohio directs otherwise, provide payment for the same to PJM in accordance with Section 6.2(b)) the Capacity at the Final Zonal Capacity Price for the unconstrained portion of the RTO region necessary to fulfill the Capacity obligation associated with such SSO Supplier's SSO Supplier Responsibility Share pursuant to the PJM Agreements;

(c) (i) except with respect to Capacity, each SSO Supplier's obligation under Section 3.1(a) and (b) will result in physical delivery and not financial settlement; (ii) the quantity of SSO Supply that such SSO Supplier must deliver will be determined by the requirements of the SSO Load, which may be different than the amount indicated in the Solicitation; and (iii) this Agreement does not provide for an option by such SSO Supplier with respect to the quantity of SSO Supply to be delivered;

(d) each SSO Supplier shall be responsible for all other costs and expenses related to transmission and Ancillary Services in connection with the provision of SSO Supply in proportion to its SSO Supplier Responsibility Share. PJM billing statement line items are set forth in Attachment F;

(e) during the Term, each SSO Supplier is responsible, at its sole cost and expense, for any changes in PJM products and pricing, except for any changes to products, or the pricing of such products, that are the responsibility of Duke Energy Ohio pursuant to Section 3.2;

(f) each SSO Supplier is responsible for all transmission and distribution losses and congestion and imbalance costs incurred to supply its SSO Supplier Responsibility Share;

(g) each SSO Supplier shall be at all times during the Delivery Period (i) a member in good standing of PJM; (ii) qualified by PJM as a "Market Buyer" and "Market Seller" pursuant to the PJM Agreements, and (iii) qualified as a PJM "Load Serving Entity;"

(h) each SSO Supplier shall be responsible, and be liable, to PJM for the performance of its LSE obligations associated with the provision of SSO Supply under this Agreement; and

(i) each SSO Supplier shall have and maintain, throughout the Delivery Period, FERC authorization to make sales of Energy, Capacity, and Ancillary Services at market-based rates within PJM.

3.2 Duke Energy Ohio's Obligation to Take SSO Supply and other Obligations

Duke Energy Ohio hereby agrees as follows:

(a) during the Delivery Period, Duke Energy Ohio shall purchase and receive, or cause to be received, the SSO Supply provided by an SSO Supplier pursuant to Section 3.1 at the Delivery Point and shall pay the SSO Supplier the Price;

(b) during the Delivery Period, Duke Energy Ohio shall be a member in good standing of PJM;

(c) Duke Energy Ohio shall be responsible for the provision of Firm Transmission Service from the Delivery Point;

(d) Duke Energy Ohio shall be responsible, at its sole costs and expense, for:

(i) charges assessed under, Schedule 1A (Transmission Owner Scheduling, System Control and Dispatch Services), Schedule 2 (Reactive Supply and Voltage Control from Generation or Other Sources Services), "Network Integration Transmission Service (NITS)" under the PJM Agreements, and Schedule 12 (Transmission Enhancement Charge) of the PJM Tariff; Generation Deactivation charges; and charges that result from PJM's implementation of its revised Economic Load Response (ELR) program, in compliance with the FERC March 15, 2011, Order (Order No. 745) regarding demand response compensation in organized wholesale energy markets;

(ii) Midwest ISO Transmission Expansion Plan (MTEP) charges assessed under Schedule 26 of the Midwest ISO Tariff, whether assessed directly by the Midwest Independent Transmission System Operator, Inc., PJM or American Transmission Systems, Incorporated;

(iii) other non-market-based costs, fees or charges imposed on or charged to Duke Energy Ohio by FERC or a regional transmission organization, independent transmission operator, or similar organization approved by FERC; and

(iv) such services and schedules as they may be modified or superseded from time to time;

(e) Duke Energy Ohio will be responsible for (i) metering, billing and delivery with respect to SSO Customers (and SSO Suppliers will have no responsibility with respect thereto) and (ii) distribution services (and SSO Suppliers will have no responsibility with respect thereto); and

(f) Duke Energy Ohio shall be responsible, at its sole cost and expense, for the provision of any renewable energy resource requirement as set forth in Ohio Rev. Code Ann. Sections 4928.64 and 4928.65 and regulations promulgated in respect thereto.

3.3 PJM E-Accounts

Each SSO Supplier and Duke Energy Ohio shall work with PJM to establish any PJM E-Accounts necessary for such SSO Supplier to provide SSO Supply. Each SSO Supplier may manage its PJM E-Accounts in its sole discretion; provided such SSO Supplier acts in accordance with the standards set forth in the PJM Agreements.

3.4 Reliability Guidelines

Each Party agrees to adhere to the applicable operating policies, criteria and guidelines of the NERC, PJM, their successors, and any regional and sub-regional requirements.

3.5 Regulatory Authorizations

(a) Duke Energy Ohio and each SSO Supplier shall obtain and maintain throughout the Delivery Period all regulatory authorizations necessary to perform their respective obligations under this Agreement.

(b) Each SSO Supplier shall cooperate in good faith with Duke Energy Ohio in any regulatory compliance efforts as may be required to maintain the ongoing legitimacy and enforceability of the terms of this Agreement and to fulfill any regulatory reporting requirement associated with the provision of SSO Supply before the PUCO, FERC or any other Governmental Authority.

3.6 PJM Member Default Cost Allocation

In the event PJM imposes a Default Allocation Assessment upon Duke Energy Ohio relating to a default during the Term, Duke Energy Ohio may, in its sole discretion, invoice each SSO Supplier, based on its SSO Supplier Responsibility Share, for amounts determined, in Duke

Energy Ohio's sole discretion, to be properly payable by such SSO Supplier from the Default Allocation Assessment and each SSO Supplier shall pay such amounts within three (3) Business Days after receipt of such invoice, subject to the dispute resolution procedures set forth in Section 11.

3.7 Status of SSO Supplier

In order to meet Duke Energy Ohio's service obligations under Legal Authorities, it is the intent of the Parties that each SSO Supplier shall be deemed a LSE for the duration of the Delivery Period pursuant to the PJM Agreements and Legal Authorities.

3.8 Sales for Resale

All SSO Supply provided by an SSO Supplier to Duke Energy Ohio shall be sales for resale, with Duke Energy Ohio reselling such SSO Supply to SSO Customers.

ARTICLE 4

SCHEDULING, FORECASTING AND INFORMATION SHARING

4.1 Scheduling

(a) Each SSO Supplier shall schedule SSO Supply and make all necessary arrangements for the delivery of SSO Supply through the PJM Office of Interconnection pursuant to the PJM Agreements.

(b) Duke Energy Ohio will provide to each SSO Supplier and to PJM all information required by PJM for the purpose of calculating each SSO Supplier's SSO Supply obligations, including the magnitude of each SSO Supplier's SSO Supply obligation, as required by the PJM Office of Interconnection.

4.2 Load Forecasting

Duke Energy Ohio shall not be required to provide to any SSO Supplier any load forecasting services.

4.3 Disconnection and Curtailment by Duke Energy Ohio

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Case No(s). 12-2400-EL-UNC, 12-2401-EL-AAM, 12-2402-EL-ATA

Summary: Testimony of Richard D. Tabors on Behalf of FirstEnergy Solutions Corp.
electronically filed by Ms. Lindsey E Sacher on behalf of FirstEnergy Solutions Corp.