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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

Consolidated Duke Energy Ohio, Inc. Rate	)	
Stabilization Plan Remand and Rider	)	Case Nos. 03-93-EL-ATA
Adjustment Cases.	)	03-2079-EL-AAM
	)	03-2080-EL-ATA
	)	03-2081-EL-AAM
	)	05-724-EL-UNC
	)	05-725-EL-UNC
	)	06-1068-EL-UNC
	)	06-1069-EL-UNC
	)	06-1085-EL-UNC

PREPARED TESTIMONY

OF

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ON BEHALF OF
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DATE: MARCH 9, 2007

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I. INTRODUCTION AND QUALIFICATIONS

Q1. PLEASE STATE YOUR NAME, OCCUPATION AND ADDRESS.

A1. My name is Neil H. Talbot. I am an economic and financial consultant affiliated with Synapse Energy Economics, Inc. My business address is 22 Pearl Street, Cambridge MA 02139.

Q2. ARE YOU THE SAME NEIL TALBOT WHO TESTIFIED PREVIOUSLY IN THIS MATTER?

A2. Yes, I submitted Prepared Testimony on May 6, 2004 and Supplemental Testimony on May 26, 2004. In my Prepared Testimony, I outlined my qualifications and included my professional resume as an attachment. In summary, I have degrees in economics and finance from Cambridge University, England and Boston College respectively, and have been an economic consultant for the past 38 years. Most of my consulting work has related to the electric utility industry.

Q3. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A3. I am testifying on behalf of the Office of the Ohio Consumers' Counsel (OCC).

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS CASE?

A4. In the context of the remand of the standard service offer for Duke Energy Ohio, Inc. ("Duke Energy Ohio" or "the Company") by the Ohio Supreme Court to the Commission for rehearing, my testimony relates to the pricing of Duke's current standard service offer. I analyze the rate components of the standard service offer and give my professional opinion as to whether, severally and in combination, they provide reasonably priced service either in terms of accounting costs or market pricing principles.

Q5. WHAT WAS THE SCOPE OF YOUR EARLIER TESTIMONY?

A5. In my earlier testimony I addressed the Market Based Standard Service Offer ("MBSSO") submitted by Cincinnati Gas & Electric Company ("CG&E"), now Duke Energy Ohio. This offer was first submitted by the Company in its January 10, 2003 Application, and was later referred to as the Competitive Market Option MBSSO ("CMO MBSSO" or "CMO standard service offer"). I also addressed briefly the modified MBSSO, which the Company submitted on January 26, 2004 as part of its Electric Reliability and Rate Stabilization Plan ("ERRSP"). This was developed by the Company in response to the concern expressed by the Commission that "the competitive retail market for electric generation has not developed as rapidly as anticipated..." The Commission said: "(W)e encourage electric utilities to consider the establishment of plans which will stabilize prices following the termination of their (Market Development Periods), and will allow additional time for competitive markets to grow." (Entry in Cases No. 03-93-EL-ATA, et al., December 9, 2004 at page 5) This MBSSO -- as modified by a stipulation, the Commission's subsequent order, the Company's application for rehearing and the Commission's entries on rehearing -- has been in place for non-residential customers since January 1, 2005 and for residential customers since

January 1, 2006. I will refer to it as "the RSP MBSSO" or simply "the standard service offer."

Q6. HOW IS YOUR TESTIMONY ORGANIZED?

A6. The following section (Section II) presents a summary of the points made in my testimony and my recommendations.

Section III contains an account of the regulatory framework of this case.

Section IV provides a detailed review of Duke Energy Ohio's standard service offer pricing and includes descriptions and critiques of each of the specific rate components separately. This section provides the detailed analyses and assessments on which my general assessment of the Company's standard service offer is based.

Section V explains my general assessment and discusses alternative directions for the Commission to take.

II. SUMMARY AND RECOMMENDATIONS

Q7. WHAT ARE YOUR SUMMARY POINTS AND RECOMMENDATIONS?

A7. I have the following points and recommendations:

1. Duke Energy Ohio's current standard service offer is a combination of six generation-related price components based on different and inconsistent pricing methodologies. The tariff generation charge ("TGC") is based on old historical costs; two are pure "estimates" that the Company finds it difficult to explain; and

three, including the Fuel and Economy Purchased Power component, are trackers that recover and reconcile actual accounting costs incurred by the company

2. The six generation-related price components fall into two groups, those that are part of the Price to Compare and are bypassable by customers who switch to a competitive retail electric supplier ("CRES"), and those that are part of the Company's Provider of Last Resort ("POLR") charges that are not fully bypassable.

3. Of the six generation-related price components, no fewer than four are part of the non-bypassable POLR charge. (Some of these components are bypassable by certain percentages of customer loads.)

4. The effect of the POLR components, including those that are partially bypassable, has been to almost eliminate CRES entry into the retail electricity market in Duke's service territory. The outcome is inconsistent with the Commission's stated objective of fostering competition.

5. The Supreme Court of Ohio remanded the standard service offer case to the Commission for rehearing on modifications to the standard service offer that had been introduced after the Commission's 2004 hearing.

6. In particular, the new System Reliability Tracker ("SRT") and Infrastructure Maintenance Fund ("IMF") were lacking justification. According to the Company, those charges are simply re-labeled components of the Reserve Margin charge. It is clear, however, that the SRT – which relates explicitly to the acquisition of adequate generation reserves -- is the sole successor to the Reserve Margin charge. In switching from an unreliable estimate of approximately $53 million, based on

the cost of building new peaking units, to the actual or expected cost of acquiring capacity in the regional electricity market, the Company's estimate for SRT was reduced by 72 percent to under $15 million. This new estimate, which was subject to true-up, was all that remained of the Reserve Margin charge.

7. The IMF had no remaining basis, because it referred to existing capacity, not an incremental reserve margin. The Company argues that the IMF is compensation for the opportunity cost or risk of making its capacity available to standard service offer consumers as opposed to being able to sell it, or electricity generated by it, on the deregulated market. However, no risk analysis or opportunity cost analysis was performed by the Company. Moreover, this argument is an incorrect use of risk analysis. Risk results from having an open or exposed position in the market, which would be the case if the Company had no assured outlet for its capacity. Standard service offer, by giving the Company a relatively assured outlet, *reduced* its exposure to market risk. No risk premium or other compensation such as the IMF is therefore justified.

8. The RSC, which was split off from generation charges into a separate, non-bypassable rate component, is also in need of a rationale. Like the IMF, it is supposed to be compensation for risk related to the Company's existing generation. This claim duplicates that of the IMF and likewise is a misuse of risk analysis, since the sale of electricity to standard service offer customers *reduces* the Company's risk. (Fluctuations in fuel and purchased power costs are flowed through to customers, so there is no risk to the Company in this component.) Like the IMF, the RSC is not based on verifiable market prices, nor is it based on

accounting costs. There is no basis for concluding that either of these charges provides for reasonably priced service.

9. The current standard service offer is neither consistently cost-based, nor consistently market-based, and its flaws are related to this problem. If the Commission does not wish to let the market place itself determine market prices for standard service offer, the next best proxy for market prices is a consistently cost-based standard service offer. This is the direction in which the Commission has been moving. Three of the six generation-related components – the Fuel and Purchase Power ("FPP"), the Annually Adjusted Component ("AAC") and the SRT – are now based on current accounting costs. Following this approach, the RSC and IMF, which have no cost basis, should be terminated. The largest charge, TGC for tariff generation charge, is a historical charge. If the Commission decides to rely more on a cost-based proxy for determining reasonable prices for the priced standard service offer, it should consider updating this cost component.

10. In either case, standard service offer generation charges should be fully bypassable by customers who switch to competitive suppliers. CRESs already take on the responsibility of lining up transmission and ancillary services such as spinning reserves. If the Commission is concerned about reliability of supply, it can, together with the Company, set financial and operational standards for CRESs to meet, such that CRESs as Load Serving Entities and Midwest ISO Transition Customers would take on the responsibility for generation capacity reserves to cover their capacity responsibilities with an appropriate reserve margin. This

would relieve the Company of this responsibility and clear the way for market entry by competitors who are currently blocked by POLR charges.

11. The quarterly tracking feature of the FPP is burdensome from a regulatory standpoint and can lead to price volatility for customers. The Commission should consider incorporating a smoothing mechanism in the FPP, or an annual adjustment with interim adjustments triggered by increases or decreases in fuel and economy purchased power costs over a certain level.

III. THE REGULATORY FRAMEWORK

Q8. WHAT WAS THE ORIGIN OF DUKE ENERGY OHIO'S CURRENT STANDARD SERVICE OFFER?

A8. In hearings which commenced on May 19, 2004, the Commission considered the Company's CMO MBSSO (originally filed on January 10, 2003) and its proposed Rate Stabilization Plan (RSP, filed on January 26, 2004). The latter consisted of its Market Based Standard Service Offer (RSP MBSSO) and Competitive Bid Process (CBP). The testimony of a number of witnesses, including myself, was taken. However, the hearings were adjourned because of settlement discussions, and on May 19, 2004 a Stipulation and Recommendation was entered into by several of the parties to the proceedings, but not by my client the OCC or certain other parties. I will refer to the version of the RSP standard service offer contained in the Stipulation as "the stipulated standard service offer." The hearings were then concluded, and on September 29, 2004, the Commission issued its Opinion and Order in the matter, approving the Stipulation with certain modifications. In an Application for Rehearing dated October 29, 2004, the Company asked the Commission to take one of the following three courses of action:

(1) Reinstate the Stipulation as filed;

(2) Adopt an Alternative Proposal (which was described in attachments); or,

(3) Allow the Company to implement its previously-filed MBSSO, which I refer to as the CMO MBSSO).

Q9. WHICH COURSE DID THE COMMISSION TAKE?

A9. The Commission, in its first Entry on Rehearing dated November 23, 2004, stated that it had "reviewed CG&E's proposed modifications of the opinion and order and believes that, with certain clarifications and provisions, the suggestions are meritorious." (Entry on page 9) The Commission accordingly accepted the Alternative Proposal (RSP MBSSO) with certain modifications. This modified rate plan is the MBSSO that was put into effect by the Company for its non-residential customers on January 1, 2005 and its residential customers on January 1, 2006, and which I refer to simply as "the standard service offer."

Q10. TO CLARIFY, WHICH STANDARD SERVICE OFFERS WILL YOU REFER TO IN YOUR TESTIMONY?

A10. I will refer to three offers – the original CMO MBSSO, the Stipulated MBSSO and the (current) standard service offer. This list is the same as that presented by Mr. Steffen in his Second Supplemental Testimony in this matter, filed February 28, 2007 (at page 2), except that I do not include his third offer, the Alternative Plan, which is one of the stepping stones between the Stipulated MBSSO and the current standard service offer. As a result, I number the current standard service as the third offer, while he numbers it as the fourth, which he calls "the Approved MBSSO."

Q11. IN ITS FIRST ENTRY ON REHEARING, WHICH ISSUES DID THE COMMISSION INCLUDE FOR REHEARING?

A11. The Commission first listed the issues that the Company had itemized in its assignments of error related to the Commission modifications of the standard service offer. These were (summarizing the Commission's listing of the items on pages 8 to 9 of the Entry):

(a) The Company would retain five of the modifications required by the Commission's Opinion and Order. These included "the calculation of a market price for returning nonresidential consumers based upon only CG&E's wholesale market costs," and "the calculation of actual AAC and FPP, including both cost decreases and increases in each cost category."

(b) As part of the non-bypassable POLR charge, introduce an Infrastructure Maintenance Fund (IMF) equal to 4 percent of "little g" during 2005 and 2006, and 6 percent of little g in 2007 and 2008.

(c) Recover the actual costs of power purchased to maintain system reliability through a System Reliability Tracker (SRT), not as part of the AAC, as previously requested.

(d) Make the remaining portion of the AAC avoidable by the first 50 percent of non-residential and 25 percent of residential load to switch to competitive retailers.

(e) Increase the avoidability of costs by moving the recovery of emission allowances from the AAC to the FPP.

(f) Set increases in the AAC for non-residential customers at 4 percent of little g in 2005, an additional 4 percent of little g in 2006, and allow increases based on actual costs incurred in 2007 and 2008. For residential customers, the increase would be 6 percent of little g in 2006, and increases in 2007 and 2008 would be based on actual costs incurred.

Q12. FOR PURPOSES OF THIS PROCEEDING, ARE THERE CERTAIN ITEMS IN THIS LIST THAT SHOULD BE ADDRESSED?

A12. Yes. I note two points in particular. One is that "actual AAC and FPP" should be charged to consumers, as opposed to using estimates. The other is the introduction of two new rate components -- the IMF rider and the SRT tracker.

Q13. WHAT FURTHER COMMENTS DID THE COMMISSION MAKE REGARDING THE COMPANY'S PROPOSALS?

A13. As noted earlier, the Commission generally regarded these proposed modifications as meritorious. It added certain clarifications and revisions, which were, in summary, as follows:

(a) Regarding the SRT, AAC and FPP, the Commission made it clear that it would not cede its review of costs incurred, but would "continue to consider the reasonableness of expenditures."

(b) The baselines above which costs would be recoverable through the SRT, AAC and FPP should be clarified. Regarding the SRT, "at the time of CG&E's last rate case, the Commission staff determined that CG&E had sufficient generation capacity to cover all of its peak load and provider of last resort obligations...As a result, all amounts in the SRT are in excess of the cost of capacity requirements which are a part of 'little g.'" (Entry at page 11) The baseline for AAC costs would be those incurred in 2000, and for FPP costs would be the level authorized in the Company's last Electric Fuel Component (EFC) proceeding.

(c) The SRT charge would be unavoidable in 2005, but the Commission determined that introduction of the Midwest ISO's Day 2 might change the situation, and stated that "the avoidability or unavoidability of the SRT for all subsequent years will be determined by the Commission." (Entry at pages 11-12.)

Q14. FOR PURPOSES OF YOUR ASSESSMENT, ARE THESE POINTS SIGNIFICANT?

A14. Yes. Of particular significance is the Commission's emphasis on reviewing the reasonableness of expenditures claimed in the SRT, AAC and FPP components. I read this consideration as referring to quantitatively measurable costs and primarily to accounting costs as traditionally assessed in regulated utility rate cases.

Q15. DID THE COMMISSION PROVIDE FURTHER JUSTIFICATION FOR ITS DECISIONS REGARDING THE COMPANY'S PROPOSALS AND THE REHEARING?

A15. The Commission referred to its three standards for rate stabilization plans, namely that they "should provide rate certainty for consumers, provide financial stability for utility companies, and encourage the development of competition." (November 23, 2004 Entry at page 13) Regarding the encouragement of competition, the Commission argued that, "The opinion and order modified the stipulation in a variety of aspects designed to encourage the development of competitive markets." (Id.) Its specific views were as follows:

> "First, the percentage of nonresidential consumers that can avoid the RSC and the AAC was increased by the opinion and order from 25 percent to 50 percent. Second, the opinion and order decreased the total cost of service for residential consumers by extending the residential discount until December 31, 2005; by

> terminating the collection of Regulatory Transition Charges ("RTCs") as of December 31, 2008; and by charging only nonresidential consumers for the cost of certain capital investments in CG&E's distribution system. The revisions to the opinion and order which are being made by this entry on rehearing would leave all of these modifications in place and would also make two other positive changes. First, the opinion and order will be modified to increase the price to compare for all shoppers by moving the cost of emission allowances ("EAs") from the unavoidable portion of the price to the avoidable portion of the price. Second, the opinion and order will be modified to further increase the price to compare by making the AAC permanently avoidable for a percentage of each class of consumers." (Id. at pages 13-14.)

Q16. DID THE COMMISSION GRANT REHEARING ON ANY OTHER ISSUES?

A16. Yes. The Commission agreed to reconsider the issue of the appropriate pricing for returning customers.

Q17. WHAT WAS THE RESULT AT THE SUPREME COURT OF OHIO AS IT RELATES TO YOUR TESTIMONY?

A17. The OCC appealed the Commission's decision to the Supreme Court of Ohio which, in a decision dated November 22, 2006, remanded the case to the

Commission for rehearing on issues related to generation price components which, together with related issues, are the primary subject of my testimony.

Q18. ON WHICH GENERAL ISSUES HAS THE SUPREME COURT OF OHIO REMANDED THE MATTERTO THE PUCO?

A18. The court "remand(ed) this matter to the commission for further clarification of all modifications made in the first rehearing entry to the order approving the stipulation." (Decision at Paragraph 36) The court found that the Commission "made several modifications on rehearing without any reference to record evidence and without thoroughly explaining its reasons." (Decision at Paragraph 35) It found that "(t)he portion of the commission's first rehearing entry approving CG&E's alternative proposal is devoid of evidentiary support." (Decision at Paragraph 28) It was not clear to the court that the modifications would meet the three-part test that has guided the Commission: providing rate certainty for consumers, ensuring financial stability for the Company and encouraging the development of competitive markets. It is clear that the specific modifications such as the infrastructure maintenance fund and the system reliability tracker are in need of a sound rationale if they are to be retained.

Q19. PLEASE PROVIDE SPECIFIC DETAILS.

A19. The remand covers "the alternative proposal," and in particular those features of the alternative proposal that differed from the commission's original order. The court said:

Paragraph 24. Under the stipulation approved by the commission's original order, CG&E's market-based standards service offer consisted of two components: the price-to-compare and the provider-of-last-resort ("POLR") component. The price-to-compare component represents that portion of the market-based standard service offer that consumers switching to a competitive retail electric service provider may avoid paying to CG&E. The POLR component, which the commission refers to as the "unavoidable" or "nonbypassable" component, represents charges incurred by CG&E for risks associated with its statutory obligation...as default provider, or provider of last resort, for customers who opt for another provider who then fails to provide service....

Paragraph 25. These components are themselves made up of separate components. The POLR component comprises a rate-stabilization-charge component and an annually adjusted component. The annually adjusted component was designed to maintain adequate electric capacity reserves in excess of expected demand and to recover costs associated with homeland security, taxes, environmental compliance, and emissions allowances. Neither CG&E nor the commission identified the purpose of the rate-stabilization charge. Nevertheless, the charge is self-defining, and the signatory parties agreed to it.

> Paragraph 26. In its first application for rehearing, CG&E proposed modifying the stipulation approved in the commission's order. Under CG&E's proposal, the POLR component would include four components. In addition to the rate-stabilization charge and the annually adjusted component, the POLR component would also include an "infrastructure maintenance fund" component and a "system reliability tracker" component. The infrastructure maintenance fund charge was intended "to compensate CG&E for committing its generation assets to serve market-based standard service offer consumers." The system reliability-tracker was intended to permit CG&E "to recover its annually committed capacity, purchased power, reserve capacity, and other market costs necessary to serve market-based standard service offer consumers." CG&E suggested other changes as well, and after reviewing these suggestions, the commission found that with certain clarifications and modifications of its own, CG&E's proposed modifications were meritorious."

It is clear that all these specific modifications – the infrastructure maintenance fund, system reliability tracker, and the other modifications – are in need of a sound rationale if they are to be retained.

Q20. FROM A TECHNICAL STANDPOINT, IS IT FEASIBLE TO CONSIDER THESE ITEMS IN ISOLATION?

A20. No. Since these specific items are parts of broader components, which in turn are parts of rates paid by customers, I urge the Commission to consider on remand the overall reasonableness of these broader items and the reasonableness of the rates that they constitute. There should be no overlap or duplication of items and the components should work together to achieve standard service offer rates that provide for reasonably priced service and meet the three standards of rate stability for customers, financial stability for the company, and encouragement of competition.

Q21. DID THE COURT POINT TO ANY OTHER SPECIFIC CONCERNS?

A21. Yes.

(1) CG&E claimed that the infrastructure maintenance fund and system reliability tracker represent the reserve capacity charge set forth in the stipulation as part of the annually adjusted component. However, the respective roles of these two charges in compensating the Company for maintaining adequate reserve capacity requirements was not clear to the court.

(2) The baseline for determining certain cost components, specifically the system-reliability tracker, annually adjusted component, and the fuel and economy purchased power component, was not supported or explained.

(3) CG&E claimed that the alternative proposal merely resulted in an increased price to compare and set the unavoidable POLR charges at lower levels. However, the court found that it is not clear that the POLR charges would be lower. Admittedly, moving the emission allowance from the annually adjusted component to the price-to-compare component, and increasing the percentage of customers who could avoid paying the annually adjusted component, would seemingly lower the POLR charge. However, other modifications – such as the infrastructure maintenance charge, the system-reliability-tracker charge, and presetting the annually adjusted component charge -- might increase it. The net effect was uncertain.

Q22. DO YOU CONSIDER THESE POINTS IN YOUR TESTIMONY?

A22. Yes.

IV. ANALYSIS AND CRITIQUE OF DUKE ENERGY OHIO'S STANDARD SERVICE OFFER PRICE COMPONENTS

A. Overall Structure

Q23. IN THE CURRENT STANDARD SERVICE OFFER, WHAT IS THE STRUCTURE OF THE COMPANY'S PRICING?

A23. The Company's standard service offer pricing is built from various components, riders and trackers. The traditional components of transmission and distribution costs are relatively non-controversial, at least in principle, and I will not address them here. (In Ohio, meter reading, billing and other customer services are still within the scope of regulated distribution services and have not been opened up to competition.) This leaves the components related to electricity generation and related services, which are the areas most affected by restructuring and are now actually or potentially bypassable by those retail customers who choose to switch to competitive retail electric suppliers.

Q24. PLEASE CATEGORIZE THE VARIOUS COMPONENTS OF DUKE ENERGY OHIO'S CHARGES FOR GENERATION AND RELATED SERVICES.

A24. Broadly, the charges fall into two categories – components of the Price to Compare and charges that, according to the Company, are necessary in order to fulfil its Provider of Last Resort (POLR) responsibilities and therefore should in its opinion not be bypassable. The Price to Compare includes "little g," which is historical generation costs less a stranded cost component, and Fuel and Economy Purchased Power costs (FPP).

Q25. WHAT COMPONENTS HAVE BEEN INCLUDED IN THE PROVIDER OF LAST RESORT CHARGE?

A25. As set out in item 3 of the Stipulation of May 19, 2004, POLR charges initially included a Rate Stabilization Charge (RSC), and an Annually Adjusted Component (AAC). In the Company's Application for Rehearing of October 29, 2004, (revised paragraph 3), the scope of the AAC was reduced and two new components were added. These were an Infrastructure Maintenance Fund (IMF) and a System Reliability Tracker (SRT). Thus, there are now four generation cost-related POLR charges – the RSC, the AAC, the IMF and the SRT – as well as two bypassable generation-related components – little g (actually 85 percent of little g) and FPP – for a total of six generation-related charges.

Q26. IS THE COMPANY STILL COLLECTING RESTRUCTURING TRANSITION COSTS?

A26. Yes. The Company's rates include a Regulatory Transition Charge (RTC). The charge will be included in residential rates until December 31, 2008, and non-residential rates until December 31, 2010.

Q27. HOW SIGNIFICANT ARE THESE VARIOUS ITEMS, AND WHAT ARE THE RELATIVE MAGNITUDES OF THE POLR CHARGES AND PRICE TO COMPARE?

A27. The magnitudes are illustrated by a breakdown of the Company's standard service offer revenue for 2006, the first year in which residential as well as non-residential customers were included:

Rate Component	2006 Revenue	Percent of Total
Tariff Gen. Charge (TGC)	$654,280,074	62.7%
Fuel & Ec. Purchased Power	194,302,151	18.6%
Annually Adjusted Comp.	55,008,125	5.3%
Total Fully Bypassable	$903,590,350	86.6%
Rate Stabilization Charge	$114,747,660	11.0%
System Reliability Tracker	(6,031,653)	(0.6%)
Infrastr. Maintenance Fund	31,549,495	3.0%
Total Not Fully Bypassable	$140,265,502	13.4%
Grand Total	$1,043,855,852	100.0%

Source: Company Response to OCC-INT-O6-RI148.[1]

While the fully bypassable charges for generation, fuel, etc. predominate in the rate structure, the components that are not fully passable (*i.e.*, bypassable, if at all, by only a certain percentage of customers) are quantitatively very significant. A Competitive Retail Electricity Supplier (CRES) trying to match the Company's

[1] DE-Ohio's Response to OCC-INT-06-RI148, NHT Attachment 1.

prices *and* compensate customers for charges up to 13.4 percent of the Company's standard service offer price would have to be a very smart or lucky competitor to make any money. (A minor point is that the negative SRT rate is obviously anomalous; in a normal year, it would be a positive number.)

B. Little g

Q28. WHAT IS "LITTLE G"?

A28. Little g, a significant charge of about 40 mills per kilowatt-hour, is based on historical generation costs that go back to the last general rate case. It is equal to the historical generation rate, "g," less the Regulatory Transition Charge (RTC). This rate component has a stabilizing effect by locking in some of the generation costs associated with legacy coal-fired generation.

Q29. DO YOU HAVE ANY FURTHER OBSERVATIONS REGARDING LITTLE G?

A29. I would note that little g is an avoidable component of the Price to Compare. However, the avoidable component is more accurately described as 85 percent of little g, since the remaining 15 percent of little g was moved into the Rate Stabilization Charge (RSC) and made a component of the Company's Provider of

Last Resort (POLR) charge. (I sometimes loosely refer to the remaining 85 percent of little g as "little g." The meaning should be clear from the context.)

Q30. IN YOUR OPINION, IS THIS REALLOCATION OF GENERATION COSTS TO A NON-BYPASSABLE RATE COMPONENT APPROPRIATE?

A30. No, this is inappropriate. I will refer to this issue later in connection with the IMF and RSC.

C. Fuel and Economy Purchased Power

Q31. WHAT IS THE FPP CHARGE?

A31. A baseline cost per kilowatt-hour of fuel and purchased power was calculated in the former Electric Fuel Component in Case No. 99-103-EL-EFC. Cost increases for fuel and economy purchased power over and above that baseline are included in the FPP charge. According to the Stipulation of May 19, 2004, "CG&E shall calculate the bypassable fuel cost component of the price to compare by using the average costs for fuel consumed at CG&E's plants, and economy purchased power costs, for all sales in CG&E's Certified Service Territory." (Stipulation, page 17)

Q32. IS THE FPP RIDER A REASONABLY WELL-BASED CHARGE?

A32. In principle, the FPP charge seems similar to other standard fuel adjustment mechanisms, which allows the Company to flow changes in fuel and economy purchased power costs through to customers. However, the devil is in the details, and the FPP charge exemplifies the problems of a hybrid system of pricing that is partly market-based and partly cost-based, and might include purchases from affiliated companies.

Q33. WAS THE COMMISSION SATISFIED WITH THE STIPULATION'S PROPOSED PROCEDURES FOR INCREASING FPP COST RECOVERY?

A33. No. In its Opinion and Order of September 29, 2004, the Commission modified the Stipulation by requiring quarterly filings of FPP increases. The increases should also be net of any offsetting reductions in FPP costs. The Commission also ordered an annual review of the preceding four quarters' filings "to determine whether they accurately reflect actual costs incurred by CG&E." (Order at page 17.)

Q34. AS A RESULT OF THIS REQUIREMENT BY THE COMMISSION, THE FPP HAS BEEN SUBJECTED TO AN AUDITOR'S REVIEW. DID THE AUDITOR EXPRESS ANY CONCERNS ABOUT THE FPP?

A34. Yes. In the second audit (dated October 12, 2006.), the auditor notes that "during this transition period, CG&E operated as a deregulated entity." The auditor states: "The re-entry into regulatory oversight with respect to the FPP created a host of issues related to both the allocation of utility assets and CG&E's approach to fuel procurement." (Auditor's Report, pages 1-3) According to the Auditor:

> "DE-Ohio considers itself to be unregulated because native customers are not obligated to purchase power from DE-Ohio.

(The auditor) considers DE-Ohio to be at least partly regulated because the RSP and FPP provide for recovery of costs included in the RSP such as fuel costs." (Auditor's Report, pages 1-6)

There is confusion between FPP costs and other costs, with "very significant ratepayer impacts":

"CG&E was required to make a number of decisions in computing the FPP. Because the order did not lay out the specifics, CG&E believed that it had the license to evaluate and select which approach to use. Not surprisingly, the range of alternative approaches was large and CG&E's elections had *very significant* ratepayer impacts. Compounding the auditing problems, CG&E continuously modified its approach to many of these items." (Auditor's Report, October 12, 2006, pages 1-3.)

I share the Auditor's evident concern that Duke Energy Ohio has too much latitude in making decisions regarding the setting of its FPP charges in a semi-deregulated situation.

Q35. WERE ALLOCATION ISSUES IDENTIFIED IN THE PREVIOUS AUDIT, DATED OCTOBER 7, 2005?

A35. Yes. The auditor noted that in the previous audit, "many issues were raised regarding the appropriateness of CG&E allocations." (Auditor's Report, October 12, 2006, page 1-3) A stipulation was entered into, in which, among other things:

> "The parties agree to discuss criteria for the equitable assignment of benefits and costs of CG&E's coal contract sales margins regarding contracts executed on or after January 1, 2005. If the parties are unable to agree upon such criteria, then the FPP auditor shall review the criteria in the next FPP audit…In addition, the FPP auditor shall review the application of such criteria and verify the equitable assignment to FPP customers of the benefits and costs of coal contract sales executed on or after January 1, 2005." (Auditor's Report, October 12, 2006, pages 1-4.)

Regarding rising fuel costs, the auditor had the following to say:

> "According to the FERC form 423 filings made by DE-Ohio, average fuel costs increased by almost 10 percent on a cents per MMBTU basis between the current and prior audit periods. The increase is due to higher contract coal prices and a higher percent of spot coal purchases. The reported delivered coal prices are higher than they would have been if large quantities of older below-market contract purchases had not been resold. The increased cost was mitigated in part by the credits for the margins on the re-sold contracts which were allocated to the FPP pursuant to…the stipulation." (Auditor's Report, pages1-6.)

During the audit period, "DE-Ohio did not pass through over $35 million in margins generated from the resale of coal covered by…the stipulation." (Auditor's Report, pages 1-7.)

Q36. DOES THE FPP DISTORT THE WAY IN WHICH THE COMPANY PURCHASES FUEL AND EMISSION ALLOWANCES?

A36. Yes, the Auditor finds that this is the case. "DE-Ohio continues to purchase fuel and emission allowances in a manner that is inconsistent with best industry practices among regulated utilities. Namely, DE-Ohio is not maintaining a contract portfolio but, pursuant to directives by DE-Ohio management, DE-Ohio actively looks to limit commitments beyond the end of the RSP period." (Auditor's Report at page 8) As a result, prices could be significantly more volatile after the end of the RSP period.

Q37. STEPPING BACK, IS THE FPP A COST-BASED OR MARKET PRICE-BASED CHARGE?

A37. This question confuses anybody who tries to understand Duke's standard service offer, as I will show in my discussions of other components of the Company's standard service offer pricing. In the case of the FPP, I would say that the practical answer is clear: it is a cost-based tracker that is adjusted to market quarterly. And by costs here I mean first and foremost *accounting* costs. This is why an audit and review can be performed annually. However, the Company regards it as primarily a market price: "The FPP market price is calculated using accounting costs....The FPP is a market price, not a cost-based rate."[2]

[2] DE-Ohio's Response to OCC-INT-04-RI78 (d) and (e), NHT Attachment 2.

Q38. THE FPP IS A QUARTERLY TRACKER. IS THIS A DESIRABLE FEATURE?

A38. It assures the Company quick recovery of its fuel and economy purchased power costs, which are its largest out-of-pocket expenditures. However, this is not desirable for the Commission and for consumers. For the Commission, there is the problem of monitoring frequent adjustments. For consumers, there is the problem of rate volatility. This latter problem could be addressed by changes in the Company's fuel procurement and fuel price hedging strategies, but it could also be addressed by changing the FPP.

Q39. WOULD A SWITCH TO AN ANNUAL FPP ADJUSTMENT BE DESIRABLE FOR THE COMMISSION AND CONSUMERS?

A39. Since price stability is one of the Commission's objectives for standard service offer, a switch to annual adjustments would have the advantage of greater stability, as well as regulatory efficiency.

Q40. COULD A SWITCH TO ANNUAL FPP ADJUSTMENTS JEOPARDIZE THE COMPANY'S FINANCIAL STABILITY?

A40. By means of forward pricing and hedging, the Company should be able to significantly reduce the risk of exposure to fuel and purchased power price volatility during the following year. However, we know that fuel and purchased power prices can be unpredictable and volatile. It would seem desirable to supplement any annual procedure with a trigger or some similar provision for passing through to consumers at least part of any extreme price changes (up or down) during the year.

Q41. COULD FLUCTUATIONS IN FUEL COSTS BE REDUCED WHILE RETAINING QUARTERLY ADJUSTMENTS?

A41. Yes. A smoothing mechanism could be introduced into the quarterly adjustments whereby there are limits on quarterly changes, with under- or over-recovery in the case of large fluctuations being reconciled over several future quarters.

D. Annually Adjusted Component

Q42. TURNING FROM THE PRICE TO COMPARE TO THE PROVIDER OF LAST RESORT COMPONENTS, WHAT IS THE AAC?

A42. The AAC is a charge that recovers from Duke's customers the costs of certain specific items.

Q43. HOW DOES YOUR TESTIMONY RELATE TO THAT OF OCC WITNESS HAUGH IN THIS MATTER?

A43. Mr. Haugh's testimony focuses on the Company's applications to increase the AAC and adjust the SRT in 2007 according to previous Commission orders and entries. My references to the AAC and the SRT are in the broader context of the standard service offer.

Q44. WHAT WAS THE ORIGIN OF THE AAC?

A44. The AAC originated in the Stipulation of May 19, 2004, and was one of the two components of the non-bypassable Provider of Last Resort charge. This charge was "for maintaining adequate capacity reserves and to recover costs associated with homeland security, taxes, environmental compliance, and emission allowances." (Stipulation at pages 4-5.)

Q45. HOW WAS THE AAC TO BE CALCULATED?

A45. The language of the Stipulation did not make it clear what the base of this charge would be. It did set out, however, alternative means of calculating increases in the AAC, expressed as percentages of little g, or alternatively based on actual costs incurred by the Company for the expenditure items covered. In 2005, this charge applied only to non-residential customers, and from 2006 it applied to residential customers as well. During 2005 and 2006, the rider was established as a fixed percentage of little g. For those years, the Company apparently did not track the costs that were covered.[3] For 2007, the rider is recovering actual accounting costs incurred.

Q46. HAS THE COMPANY SHOWN HOW THE AAC WAS CALCULATED?

A46. Yes. Originally, in Exhibit 1 of the Stipulation of May 19, 2004, the Company provided details of what it labeled "The POLR Charge" for 2005. Of the total

[3] DE-Ohio's Response to OCC-INT-04-RI61(b), NHT Attachment 3.

amount of $107.5 million to be recovered, Reserve Margin accounted for 49 percent, Environmental Compliance 40 percent, Emission Allowances 10 percent and Homeland Security 1 percent.

Q47. DID THE CHARGES APPEAR TO BE REASONABLE?

A47. No. In both the Reserve Margin and Environmental Compliance calculations, which together accounted for nearly 90 percent of the total, there were features that are not reasonable.

Q48. WHAT WAS THE PROBLEM WITH THE RESERVE MARGIN CALCULATION?

A48. The Reserve Margin calculation covered the cost of the *margin*, not the capacity for the expected load. Let me give an example. Say the customer load being planned for was 100 megawatts, and the required reserve margin was 17 percent.[4] Suppliers would need to line up (and pay for) 117 megawatts, not just 17 megawatts, and yet it is apparently only the 17 megawatts for which the Company is claiming cost recovery. In this case it was claiming recovery for 826.54 megawatts of "reserve margin" capacity at an estimated $64 per kw-year, not for projected 2005 peak demand (switched and non-switch) of 4,862 megawatts. This would only be the correct amount of the Company's shortfall in capacity costs under the assumption that the Company's existing resources covered none of the

[4] At the time, the Company was planning for a 17 percent reserve margin. Currently, the planned margin is 15 percent.

margin and accordingly the Company had to purchase the entire amount of 17 megawatts. As far as I am aware, the Company has not presented data to support this requirement.

Q49. DO YOU HAVE ANY OTHER CONCERNS WITH THE WAY IN WHICH THE RESERVE MARGIN COMPONENT WAS CALCULATED AT THAT TIME?

A49. Yes, I have one other concern at this point. The cost of capacity of $64 per kw-year was estimated based upon "the annualized cost of a peaking unit using EPRI TAG costs." (Footnote to Exhibit 1, Stipulation at page 6) This estimate, which was supposed to be a market price estimate, did not bear any close relationship to either then-current market prices for peaking capacity or to the Company's historical embedded costs of peaking capacity. It was an overestimate, because at that time there was considerable regional excess generation capacity. This is a good example of my concern that estimation procedures for measuring what are supposedly market prices may be way off the mark.

Q50. WHAT IS YOUR CONCERN ABOUT THE COMPANY'S CLAIM FOR ENVIRONMENTAL COST COMPLIANCE?

A50. My concern relates to the manner in which this supposed "market" price component is calculated as a "Revenue Requirement," which is a term that applies to regulatory pricing, not market pricing. This ambiguity, which is discussed further below, causes confusion about the way in which the calculation is done: it includes a return on "Construction Work in Progress," which is most certainly a regulatory term, without any justification for its inclusion in what is the equivalent of rate base in this context. If CWIP is a rate base item, is it correctly included in rate base without Commission approval? If it is an element of market-based pricing, does the market typically charge customers for equipment not yet in service? The answer to both questions is "no." General Motors does not recover the costs of a new plant until it sells cars produced at that plant. The Company does not throw any light on this situation, it merely says: "The AAC is not a regulated rate. It is a market price and has no 'rate base.'"[5] The claimed pre-tax return of 14.22 percent on the Company's June 30, 2004 environmental investments CWIP of $175.9 million is $25 million, which appears to be an overcharge.

Q51. DID THE COMMISSION ACCEPT THE AAC CHARGE AS PROPOSED IN THE STIPULATION?

A51. No, in its order of September 29, 2004 the Commission modified the proposal by making the AAC charge completely avoidable by shopping customers in 2005, finding that "additional encouragement of this market is appropriate." (Order at page 32) The Commission limited the amount of costs to be recovered under the AAC, noting that "the Commission is convinced that CG&E may be recovering some percentage of those costs through off-system sales…" It also said that it would "determine whether any subsequent AAC increases or changes to the level

[5] DE-Ohio's Response to OCC-INT-04-RI61(l), NHT Attachment 3.

of avoidability are reasonable, not anticompetitive, and not likely to create a subsidy…" (Order at page 33.) In evaluating such changes, the Commission would consider cost savings as well as increases.

Q52. WAS THE AAC MODIFIED LATER IN 2004?

A52. Yes, in the Company's Application for Rehearing of October 29, 2004, the scope of the AAC was reduced by excluding the costs of "maintaining adequate capacity reserves." These costs, or similar ones, were now to be included in two other POLR charges – an Infrastructure Maintenance Fund (IMF) and a System Reliability Tracker (SRT), which are described below.

Q53. WERE ANY OTHER ITEMS REMOVED FROM THE AAC?

A53. Yes, the cost of emission allowances was excluded from the AAC and included in the FPP, where it would be subject to quarterly tracking and annual review and would also be completely avoidable by shopping customers.

Q54. HOW WAS THE AAC TO BE CALCULATED?

A54. For non-residential consumers there were now to be increases of 4 percent of little g in 2005 (an increase from zero, implicitly, not some unstated base level), and an additional 4 percent in 2006. For residential customers, for whom the Market Development Period would end on December 31, 2005, the 2006 charge would be 6 percent of little g. For 2007 and 2008, the charge would be "the revenue requirement of (the Company's) actual net costs incurred for homeland security, taxes, and environmental compliance during each year." (Application for Rehearing, Attachment 1, page 2, revised item 3.)

Q55. PLEASE EXPLORE THE QUESTION WHETHER THE AAC IS A COST-BASED ITEM OR A COMPONENT OF MARKET-BASED PRICING?

A55. The AAC is supposedly a component of market-based standard service offer prices. "The AAC component is DE-Ohio's market price for generation service." [6] However, the Company presents its AAC proposals as if the SRT were based on costs. For example, in his direct testimony of September 1, 2006 in Case No. 06-1085-EL-UNC, Mr. Wathen builds up what he calls the Rider AAC *Revenue Requirement,* which is clearly a term from cost-based regulatory ratemaking. (See Attachment WDW-2 to Mr. Wathen's testimony, for example.) In reviewing the Company's case, Staff "approached this investigation as it would any cost based rate proceeding." (Testimony of Mr. Tufts in that proceeding, dated November 28, 2006.) The Company's claim for 2007 was based on costs for the twelve months ending May 31, 2006. Yet Mr. Tufts, who is in the Staff's Accounting and Electricity Division, found that, "The Applicant filed a minimal amount of information in its Application and the supporting documentation was not readily available...Staff was unable to make some findings due to the lack of information necessary to provide a recommendation." (Testimony at page 2) Likewise, Mr. Tufts's colleague Ms. Smith testified that, "Staff had been unable to determine the

[6] DE-Ohio's Response to OCC-INT-04-RI61, NHT Attachment 3.

appropriate rate of return." (Trisha J. Smith, Testimony Dated Nov. 28, 2006, at page 2)

Q56. CURRENTLY, TO WHAT DEGREE IS THE AAC CHARGE AVOIDABLE?

A56. The first 25 percent of residential load and the first 50 percent of non-residential load, by customer rate class, to switch to a certified supplier is exempted from having to pay the AAC charge.

E. Infrastructure Maintenance Fund

Q57. WHAT IS THE IMF?

A57. The Infrastructure Maintenance Fund (IMF), which was introduced in the Company's Application for Rehearing of October 29, 2004, was described as a "charge to compensate CG&E for committing its generation assets to serve market-based standard service offer customers." (Application, Attachment 1, page 1, revised item 3) Later in the application the IMF is related to generation "capacity." (Application, page 7, item 4.1), and it is set at 4 percent of little g in 2005 (for non-residential customers) and 2006 (for all customers), and 6 percent of little g in 2007 and 2008. The Company has also said, "The fixed percentage of little g that DE-Ohio receives for the IMF as a component of its MBSSO is compensation for its opportunity cost associated with committing its assets at first call to MBSSO load."[7] Mr. Steffen provides a somewhat longer account of the IMF:

> "DE-Ohio has the sole obligation to provide POLR service to consumers within its service territory. Accordingly, it must be compensated for the risks inherent in this obligation. The IMF is part of the compensation for this service. It is compensation for the first call dedication of its generation assets to native load consumers and the foregone opportunity to sell that energy and capacity and take advantage of pure retail market prices. The IMF allows DE-Ohio to provide stable prices to its consumers *and provides some level of revenue certainty to the Company.* Similarly, the IMF provides consumers with a dedicated capacity supply that DE-Ohio cannot contract to a third party, assuring consumers of adequate capacity to maintain system reliability." (Mr. Steffen's Second Supplemental Testimony at pages 25-26, italics added)

Q58. WHAT DO YOU MAKE OF THIS CLAIM?

A58. The argument seems to be couched in terms of risk. The Company claims it is taking the risk of guaranteeing a stable price to customers. In reviewing this claim I note at the outset that the greatest risk facing an electric utility is the risk of fuel

[7] DE-Ohio's Response to OCC-INT-04-RI67(a) and (c), NHT Attachment 5 and DE-Ohio's Response to OCC-INT-04-RI73, NHT Attachment 10.

and purchased power price fluctuations, and in Duke's case that risk is passed on to customers dollar-for-dollar by means of the Fuel and Economy Purchased Power tracker. And the risk of acquiring capacity in the market place is passed on to customers dollar-for-dollar by means of the SRT tracker. Secondly, the basis for the IMF charge seems to be similar, if not identical, to that of the RSC charge – compensation for providing customers with stable prices over time. And both apparently refer to costs related to existing capacity.

Q59. HAS THE COMPANY TAKEN A BALANCED VIEW OF THE ISSUE OF RISK AND RISK-AVOIDANCE?

A59. No. It has taken a completely one-sided view. The sale of electricity at a stable market price cuts both ways. For a utility like Duke Energy Ohio with generation resources, there is a benefit to price stability, which is a hedge against volatility of sales prices and profits. If the Company did not have captive consumers – and I use the word "captive" advisedly, considering how few customers are actually shopping – it would have an open or unhedged "long" position in the electricity market. It would, simply stated, have no assured market for the output of its generation assets, and it would be at the mercy of the market. Market prices can go down as well as up, and with standard service offer customers the Company is hedged against those fluctuations.

Q60. MS. MEYER SAYS IN HER TESTIMONY THAT "UNDER THE RSP, DE-OHIO ASSUMED THE RISK ASSOCIATED WITH MARKET VOLATILITY...." (DIRECT TESTIMONY AT PAGE 9). DO YOU AGREE?

A60. No, she is also looking at only one side of the picture.

Q61. WITHOUT A BALANCED RISK ASSESSMENT, IS THERE ANY JUSTIFICATION FOR THE IMF?

A61. No. The Company cannot show what level of risk it is taking on. it cannot even claim that it is taking on any net risk at all and on the face of it standard service offer reduces risk. And the Company has not justified its claims in terms of any quantitative risk analysis.

Q62. WHAT DOES THE TERM "OPPORTUNITY COST" MEAN?

A62. Opportunity cost is not an accounting cost term, it is a term of economics. It is "the value of the forgone alternative action...(A)n accountant and economist may well define the cost of an action quite differently." (MIT Dictionary of Economics) It is, in effect, the market price at which some asset could have been sold or leased out to provide services to the market as opposed to providing service to standard service offer consumers.

Q63. HAS THE COMPANY ESTIMATED THE OPPORTUNITY COST OF MAKING THIS CAPACITY AVAILABLE TO STANDARD SERVICE OFFER CONSUMERS?

A63. No. The Company was asked the following question, "What is the 'opportunity cost' (i.e., the cost foregone) and how has the opportunity cost been calculated?" The reply was, "The opportunity cost is the market price of incremental capacity and energy to non-MBSSO customers. The Company has not performed such a calculation."[8]

Q64. DID THE COMPANY PROVIDE ANY EXPLANATION REGARDING THE LEVELS AT WHICH THE IMF HAS BEEN SET?

A64. No. Mr. Steffen hardly even makes an attempt. "The IMF pricing methodology as percentages of little g are simply the way DE-Ohio proposed to calculate an *acceptable dollar figure* to compensate DE-Ohio for the first call dedication of generating assets and the opportunity costs of not simply selling its generation into the market at potentially higher prices." (Mr. Steffen's Second Supplemental Testimony at page 26, italics added)

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[8] DE-Ohio's Response to OCC-INT-06-RI140, NHT Attachment 4.

Q65. IS THE COMPANY ENTITLED TO COMPENSATION FOR ANY RISKS THAT IT TAKES IN CONNECTION WITH COMMITTING ITS ASSETS TO STANDARD OFFER SERVICE?

A65. No. It is not appropriate to charge for taking risk, if any, without a thorough risk analysis. I will return to the issue of risk when I discuss the RSC below. I will show that arguably the Company should compensate consumers for providing an assured market for their generation. The one-sided nature of the Company's view of the risks involved is repeated in Mr. Steffen's testimony.

> "All consumers in DE-Ohio's certified territory benefit by having a first call on DE-Ohio's physical generating capacity at a price certain. Otherwise, consumers would be subject to price volatility in the energy and capacity markets and decreased reliability should capacity be unavailable." Mr. Steffen's Second Supplemental Testimony at page 27)

Again, Mr. Steffen does not provide a balanced assessment in which, absent the assurance of sales to standard service offer consumers, the Company would also be subject to "price volatility in the energy and capacity markets." And in bringing the assurance of *reliability* into the equation, he is muddying the water by referring to a cost element supposedly covered by the SRT, not the IMF.

Q66. WAS THE IMF A COMPONENT OF LITTLE G?

A66. No, it is *additional* to little g. It is not clear why it is expressed as a percentage of little g.

Q67. IS IT CLEAR WHICH GENERATION CAPACITY COSTS ARE ASSIGNED TO THE IMF, LITTLE G, THE SRT AND THE RSC RESPECTIVELY?

A67. No. In a recent response to a discovery question referring to the IMF, the Company stated that the committed assets in question are electric generating plants, all or part of which are owned by DE-Ohio. "(C)onsumers in DE-Ohio's certified service territory have the right to receive generation capacity from these units before it can be sold to anyone else." On the issue of the opportunity cost of this capacity, the Company says, "The opportunity cost is the market price of incremental capacity and energy to non-MBSSO customers." How was the opportunity cost calculated? "The Company has not performed such calculation." [9]

Q68. HAS THE COMPANY PROVIDED FURTHER ELUCIDATION OF THE IMF CHARGE IN RESPONSES TO DISCOVERY QUESTIONS?

A68. Yes. Noting that the SRT represents the direct costs for incremental capacity to maintain a 15% reserve margin, the Company states that, "Little g and the IMF represent compensation for the Company's *existing* capacity.[10] Confusingly, it does not mention the RSC, which is also a capacity charge, in this context. There appears to be over-charging for existing capacity to the extent that little g and the RSC and the IMF are all recovering the costs or risks of existing capacity. There is no assurance that these charges are not duplicative.

[9] DE-Ohio's Response to OCC-INT-06-RI140 (f) and (h), NHT Attachment 4.

[10] DE-Ohio's Response to OCC-INT-06-RI142, NHT Attachment 6. (emphasis added).

Q69. ARE THESE GENERATION UNITS OPERATED ENTIRELY FOR THE BENEFIT OF STANDARD SERVICE OFFER CUSTOMERS?

A69. No. "For 2006, the percentage of energy (from the committed generation assets) not needed by DE-Ohio's FPP consumers was approximately 11%.[11]

Q70. IS THIS OR IS THIS NOT A COST-BASED RATE COMPONENT?

A70. Here, as elsewhere, the Company avoids detailed scrutiny of the "costs" that are the building blocks of its standard service offer rates. On the one hand it calls them costs, but if these were accounting costs, some sharing would occur in the case of assets that are only partly used for standard service offer customers. In answer to the question whether the revenues of such sales are credited to MBSSO customers, the Company replied: "None. DE-Ohio's market price does not include a credit for revenue from the sale of power to non-MBSSO consumers."[12] And again, even capacity costs of base and intermediate load generation plants should be allocated in part to energy sales.

Q71. IS THE IMF AVOIDABLE FOR CUSTOMERS WHO SWITCH TO COMPETITIVE RETAILERS?

A71. No, it is payable by all customers, whether they continue to take service from DE-Ohio or switch to another provider.

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[11] DE-Ohio's Response to OCC-INT-06-RI140(k), NHT Attachment 4.

[12] DE-Ohio's Response to OCC-INT-06-RI140(l), NHT Attachment 4.

Q72. WHAT OTHER CLAIMS DOES THE COMPANY MAKE REGARDING THE IMF COMPONENT?

A72. The Company states: "The Company is willing to commit its generation at 1st call to MBSSO consumers for an additional two years. In exchange for such commitment, DE-Ohio's position is that the proposed increase in the IMF component is appropriate."[13] DE-Ohio also states: "Since 2004, various costs and risks have increased. Additionally, opportunities and prices in the electric power market have increased."[14] Although the present cases do not involve the extension for two additional years, I note these responses because they are purely qualitative; there is no specific quantitative justification for this request either in terms of accounting costs, or market costs of longer-term commitments or hedges, for example. This is a failing of the Company for all time periods.

F. System Reliability Tracker

Q73. WHAT IS THE SYSTEM RELIABILITY TRACKER?

A73. The System Reliability Tracker (SRT), like the IMF, was introduced in the Company's Application for Rehearing of October 29, 2004. It was described as a "tracker to permit CG&E to recover is annually committed capacity, purchased power, reserve capacity, and other market costs necessary to serve market-based standard service offer consumers." (Application, Exhibit 1, pages 1-2, item 3.)

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[13] DE-Ohio's Response to OCC-INT-06-RI149(a), NHT Attachment 7.

[14] DE-Ohio's Response to OCC-INT-06-RI150, NHT Attachment 8.

Q74. DID THE APPLICATION FOR REHEARING PROVIDE ANY FURTHER EXPLANATION FOR THE SRT?

A74. The Company said the tracker was "to maintain the reliability of service to consumers...(and would cover) purchases necessary to maintain a sufficient reserve margin...purchased power costs, capacity costs, and other market costs necessary to maintain a reliable generation supply and adequate reserve margin." (Application, page 7, item 4.2) The Company also refers to recovering "these *incremental* costs." (Application page 8, line 2. Emphasis added.) No explanation was provided regarding any base level over which these charges would be an increment. The Company has also said, "The SRT is DE-Ohio's market price for the cost of purchasing capacity to maintain a 15% reserve margin under its provider of last resort obligation...The Company calculates its market price for Rider SRT based upon the price to purchase various capacity products in the market. The products and their cost are included in the quarterly SRT update filings."[15]

Q75. DOES MR. STEFFEN THROW LIGHT ON THE COVERAGE OF THE SRT IN HIS SECOND SUPPLEMENTAL TESTIMONY?

A75. Mr. Steffen makes it clear that the SRT is supposed to cover only *incremental* capacity costs. "(A)ll amounts in the SRT are in excess of the cost of capacity

[15] DE-Ohio's Response to OCC-INT-04-RI68 (a) and (c), NHT Attachment 9.

requirements which are part of little g." (Second Supplemental Testimony at page 23.)

Q76. ***IS THE SRT THE SUCCESSOR TO THE RESERVE MARGIN COMPONENT OF THE AAC?***

A76. Yes. Apart from reducing the reserve margin from 17 percent to 15 percent, it is an improvement on the AAC's reserve margin component in two respects. First, it covers actual costs incurred by the Company, as opposed to estimating those costs using the cost of a peaking unit as a proxy. Second, it is designed to recover costs for the actual amount of capacity acquired. For example, where peak demand is 100 megawatts and the desired reserve margin is 15 megawatts, for a total capacity requirement of 115 megawatts, the Company presumably would acquire the exact amount of its capacity shortfall. If it already had 105 megawatts, it would acquire 10 megawatts, not 15 megawatts.

Q77. ***WHAT EFFECT DID THESE CHANGES HAVE ON THE DOLLAR AMOUNT OF THE RESERVE MARGIN CHARGE?***

A77. The switch from the "reserve margin" component to the SRT shows the benefits of basing such charges on actual costs rather than estimated costs. The claim for actual costs for 2005 was only 28 percent of the amount "estimated" using the cost of building new peaking capacity – down from $52,898,560 to $14,898,00. (Mr. Steffen's Second Supplemental Testimony at page 24)

Q78. IS THIS CHARGE WELL-BASED?

A78. To the extent the charge is based on actual costs incurred by the Company in acquiring services in the market place, it is much better based than it was before, and is better based than the remaining "estimated" components of Duke's standard service offer. It meets the double standard of reflecting measurable accounting costs and verifiable market costs. (I leave to one side the issue of purchases from affiliates, which raises regulatory issues regarding the appropriate transfer prices. The Commission has to approve any purchases from Duke Energy North America.)

Q79. MR. STEFFEN CLAIMS THAT "EVEN WITH THE ADDITION OF THE COST-BASED SRT ($14,898,000) FOR RESERVE CAPACITY, AND TAKING THE IMF AT ITS FULLY IMPLEMENTED (I.E., RESIDENTIAL AND NON-RESIDENTIAL) LEVEL, DE-OHIO IS CHARGING LESS THAN THE $52,898,560 ORIGINALLY PROPOSED AND SUPPORTED BY THE COMPANY AS ITS MARKET PRICE FOR RESERVE MARGIN AND THE DEDICATION OF ITS PHYSICAL CAPACITY." (MR. STEFFEN'S SECOND SUPPLEMENTAL TESTIMONY AT PAGE 27) DO YOU AGREE?

A79. No. Mr. Steffen's statement is misleading and, at best, only correct for the year 2006.

Q80. IN WHAT WAY IS IT MISLEADING?

A80. The SRT is the only true successor to the Reserve Margin charge, which was calculated strictly in terms of reserve margin and did not relate to the dedication of existing capacity. There is no justification for the IMF on the record. The apples to apples comparison would be a reduction from an (estimated) Reserve Margin charge of $52,898,560 to a cost-based SRT of $14,898,000, a 72 percent reduction to only 28 percent (based on actual costs subject to true-up) of the earlier "estimate." This would have reduced the Company's rates by about $38 million. It is incorrect to say that, between the Stipulation and the current standard service offer, "these underlying costs were merely reduced, repositioned, made avoidable or carved out into the IMF and SRT charges." (Mr. Steffen, Second Supplemental Testimony at page 30) In fact, the IMF is a brand new charge.

Q81. IF YOU ADD IN THE IMF, ISN'T THE COMBINED TOTAL STILL UNDER THE EARLIER RESERVE MARGIN CHARGE?

A81. No. The introduction of the IMF more than recovers the amount the Company lost by switching from estimated to actual reserve margin costs. In his Attachment JPS-SS1, Mr. Steffen combines the IMF with the SRT ($30,080,000 and $15,000,000 respectively, to get a total of $45,080,000, which is somewhat less than the previous $52,898,560. However, in 2007 the IMF increases from 4 percent of little g to 6 percent, or approximately $45 million. The combined total, other things being equal, will now be about $60 million, a higher level than the earlier reserve margin charge of approximately $53 million.

Q82. ATTACHMENT 2 TO THE COMPANY'S APPLICATION FOR REHEARING OF OCTOBER 29, 2004 CONTAINED SRT GUIDELINES. DID THESE CLARIFY THE RELATIONSHIP BETWEEN THE VARIOUS CHARGES?

A82. The Guidelines throw light on one important issue, namely the relationship between the FPP, which is bypassable, and the SRT, which is not. In a nutshell, the FPP is a charge for *energy*, and the SRT is a charge for *capacity*.

Q83. DID THE FPP AUDIT, WHICH ALSO COVERED THE SRT, DEAL WITH THESE CONCERNS?

A83. The audit highlighted the problem of affiliate transactions, specifically the purchase of capacity from Duke Energy North America (DENA).

> "(The auditor) does not believe that DE-Ohio provided data or evidence which would support the authorization for DE-Ohio to purchase reserve capacity from DENA assets as part of the SRT. (The auditor) believes that the market for reserve capacity is not liquid and transparent enough for there to be an audit trail to assure that affiliate purchases from DENA were at prices no greater than market, and also believes that the purchase of reserve capacity from DENA could discourage other suppliers from making competitive offers to DE-Ohio. (Audit Report, at page 1-9).

These concerns led the auditor to recommend that "purchases of reserve capacity from DENA assets should not be eligible for inclusion in the SRT, as is currently the case." (Audit Report, pages 1-10)

Q84. ARE THERE CONTINUING CONCERNS REGARDING THE NON-AVOIDABILITY OF THE SRT?

A84. Yes. The Company says that "in Case No. 06-986-EL-UNC, DE-Ohio has proposed to make reserve capacity purchases, currently included in Rider SRT, unavoidable. This proposal is consistent with DE-Ohio's past proposals. All MBSSO consumers benefit from the reserve capacity purchases and should pay the price."[16] I repeat my concern that the charge, like the IMF, involves overcharging customers who switch to competitive retailers.

Q85. THE COMPANY HAS ARGUED THAT IT HAS A GREATER COMMITMENT TO RELIABILITY THAN COMPETITIVE RETAILERS DO. DO YOU AGREE?

A85. Competitive retailers are designated "Load Serving Entities" ("LSEs") and "Transmission Customers" by the Midwest ISO, and have *some* commitment to their customers and to the ISO with regard to reliability. They are required to line up transmission and take responsibility for providing ancillary services, including spinning and other reserves that add up to about 4 percent of demand. To this

[16] DE-Ohio's Response to OCC-INT-04-RI77, NHT Attachment 11.

extent at least there is currently an overlap. Furthermore, to the extent that retailers' current commitments fall short of those of utility LSEs, it is not clear why they should not be enhanced. It would be preferable for the Commission to create equal responsibilities for non-utility and utility LSEs, rather than having the Company volunteer to take on this obligation at considerable cost to consumers. I am concerned that this feature of the regional power market is being used as the basis for making large portions of Duke's generation charges unavoidable, thereby creating barriers to competitive entry into the market by CRESs.

Q86. ARE THE COST ELEMENTS BEING CLAIMED BY THE COMPANY UNDER THE SRT CONSISTENT WITH ITS JUSTIFICATION FOR MAKING THE TRACKER UNAVOIDABLE?

A86. No. The specific details of DE-Ohio's request for SRT undermine the view that its concern about reliability is totally different than that of competitive retailers. I say this because, in the SRT, the Company is not asking only for recovery of the cost of acquiring "real" resources like shares in generation plants. It is also requesting compensation for the costs of such financial instruments as purchased power and forward reliability contracts, options, etc. (See Application for Rehearing, Attachment 2, page 2) These financial instruments do not directly add to reliability in the regional power grid. And to the extent that contracts such as these are actually entered into – or could feasibly be entered into -- by competitive retailers, the scope of competitive services is reduced and there is a likelihood of overlapping services and costs.

Q87. IS THE SRT AVOIDABLE BY ANY RETAIL CUSTOMERS?

A87. The SRT is unavoidable by residential customers. It is, however, avoidable to non-residential customers that agree to stay with a competitive retailer until December 31, 2008. If these customers return to DE-Ohio prior to this date their generation rates will consist of the MISO hourly locational marginal price.

G. Rate Stabilization Charge

Q88. WHAT IS THE RSC?

A88. In the Stipulation of May 19, 2004, the Rate Stabilization Charge was included as one of the two components of the non-bypassable Provider of Last Resort charge. This would apply to all customers – to non-residential customers effective January 1, 2006 and to residential customers effective January 1, 2006 – except that the first 25 percent of load in any consumer class could avoid paying this charge, subject to certain conditions relating to return to CG&E service, in the case of non-residential customers. Residential customers could return to standard service offer. There were, however, monetary limits on the Company's lost revenues resulting from switching by residential customers. Subject to FERC and MISO regulations, while load-serving entities would provide ancillary services and daily operating reserves, they "may rely upon CG&E's reserve capacity to meet their reserve capacity (but not energy) requirements for loads served within CG&E's certified territory." (Stipulation, page 11) Thus, Competitive Retail Electric Suppliers could apparently not compete to supply capacity as well as energy, ancillary services and operating reserves, as the Company retained the sole right to provide capacity.

Q89. WHAT IS THE RATIONALE OR BASIS FOR THE RSC?

A89. The basis for the charge is quite unclear. "The RSC is the Company charge for providing a stable market price over a prolonged period of time."[17] Is this, then, the provision of a hedge against market price changes? To what degree have prices actually been hedged, and what was the cost or measure of any such hedges? The Company's response and its testimony do not provide a clear basis for the RSC.

Q90. DOES THE RSC APPARENTLY DUPLICATE COSTS ALSO RECOVERED BY THE IMF AND POSSIBLY LITTLE G?

A90. Yes. I have discussed this issue in connection with the IMF.

Q91. AGAIN, HAS THE COMPANY TAKEN A BALANCED VIEW OF THE ISSUE OF RISK AND RISK-AVOIDANCE BY HEDGING?

A91. No, as I said in connection with the IMF, it has taken a completely one-sided view. A "stable market price over a prolonged period of time" cuts both ways. For a utility like Duke Energy Ohio with generation resources, there is a benefit to price stability, which is a hedge against volatility of sales prices and profits. An

[17] DE-Ohio's Response to OCC-INT-04-RI62(a), NHT Attachment 12.

open or unhedged position would be a "long" position in which the Company has the assets but no assured market for them. It would be at the mercy of market fluctuations.

Q92. WITHOUT A BALANCED RISK ASSESSMENT, IS THERE ANY JUSTIFICATION FOR THE RSC?

A92. No. There is no showing that the Company is taking on risk, let alone providing a quantitative risk analysis to justify any specific risk charge.

Q93. IS THE RSC A NEW CHARGE?

A93. Yes and no. It was a component of little g, and in that sense was not new. But it was new in the sense that 15 percent of little g was now recovered through a different rider. The significance of the new rider is that, unlike the remaining 85 percent of little g, it is non-bypassable by shopping customers. Why this component should be set at the level it is set, and why it should not be bypassable, is not clear. The Company has recently broadened the rationale for the charge and in the process made it even less clear. "The Company determined that this level for the RSC would be sufficient compensation to satisfy the Commission's Rate Stabilization Plan goal of price certainty for consumers and revenue stability for utilities. The 15% was determined to be a reasonable market price to help achieve all three of the Commission's goals for the plan." [18]

[18] DE-Ohio's Response to OCC-INT-06-RI134, NHT Attachment 13.

Q94. IS THERE A COST BASIS FOR THE RATE STABILIZATION CHARGE?

A94. Yes and no. The tendency has been for other riders to become cost-based in terms of current costs, but the RSC is resolutely founded on historical costs as reflected in little g. "As with a number of the components of the MBSSO, the RSC is not cost-based. The Company used its judgment to determine that 15% of little g represented a reasonable market price for the RSC component of its MBSSO as compensation for providing a stable price over a prolonged period of time."[19]

Q95. IS THIS A SOUND BASIS FOR A RATE COMPONENT IN ORDER TO PROVIDE REASONABLY PRICE SERVICE?

A95. No. In this instance, as in others, there is confusion over whether the standard service offer rate components are cost-based or market-based. This confusion allows the Company's proposals to avoid thorough scrutiny. To the extent that there is an accounting cost basis of rate components like the FPP, they can be audited. But to the extent components like the RSC are merely there in order to build up the total standard service offer price to a level that the Company regards as a "market price," there is no sound basis for these charges, nor is it clear why they should not be bypassable.

[19] DE-Ohio's (Response to OCC-INT-04-RI62(e), NHT Attachment 12.

Q96. HOW DID THE COMMISSION TREAT THE RSC IN ITS OPINION AND ORDER OF SEPTEMBER 29, 2004?

A96. In its Order, the Commission said that it was "very concerned about the impact that the stipulation may have on competition." (Order at page 19) The initial relatively high levels of switching by non-residential customers had subsided, and the Commission realized that the avoidability of the RSC charge by only 25 percent of load in each customer class might be an inhibiting factor. The Commission still accepted a limit for avoidability, but increased it to 50 percent of non-residential load. For residential customers, who had switched in much smaller numbers, there was still scope for substantial switching without bumping into the 25 percent ceiling, and the Commission left that ceiling in place.

Q97. DO YOU AGREE WITH THE COMMISSION'S LOGIC REGARDING THE LIMIT ON CUSTOMER SWITCHING BEYOND WHICH CUSTOMERS WOULD BE CHARGED THE RSC CHARGE?

A97. With respect, I disagree with the Commission. The RSC, when looked at from the standpoint of a competitive retailer, is a penalty on switching, period. It has the effect of inhibiting competitive entry, even if it only takes effect over and above a certain level, whether that level is 25 percent of load or 50 percent. Before making the necessary investment in marketing, administration, contracting, other overhead, etc., competitive retailers would surely like to know that they have the chance of being rewarded for their success in attracting large numbers of customers, not penalized for doing so. It should be borne in mind that the individual retailer is not looking at a potential market of 25 percent or 50 percent of load, but at some smaller market share, since it will not be the only competitor in the market. Of course, with a 25 percent limit on avoiding the RSC charge, the deterrent effect is even greater.

Q98. WHAT WERE THE PROVISIONS REGARDING THE RATE STABILIZATION CHARGE IN THE COMPANY'S APPLICATION FOR REHEARING OF OCTOBER 29, 2004?

98. Reflecting the Commission's order, the RSC was made effective January 1, 2005 for non-residential customers and January 1, 2006 for residential customers. Like the AAC, It would be an unavoidable charge related to the Company's POLR responsibilities, but it would be avoidable for the first 25 percent of residential load to switch and the first 50 percent of non-residential load to switch. In order to avoid paying this charge (and the AAC), non-residential customers must be within the first 50 percent of load to switch, and they must have a contract for firm generation service with a competitive retailer. Moreover, if they return to the Company's generation service, they will have to pay the highest applicable marginal rate for generation. Residential customers may avoid paying this charge (and the AAC) if they are within the first 25 percent of load to switch and they must comply with "any applicable tariffed minimum stay or exit fee provisions." They may, however, return to standard service offer at standard rates if their competitive supplier defaults.

Q99. DID THE SUPREME COURT OF OHIO ADDRESS THE RSC IN ITS ORDER OF NOVEMBER 26, 2006?

A99. Yes. It did so, however, in passing and without going into it. "Neither CG&E nor the commission identified the purpose of the rate stabilization charge. Nevertheless, the charge is self-defining, and the signatory parties agreed to it." (Decision at Paragraph 25, page 9) This is not exactly a thorough analysis of the RSC, let alone a ringing endorsement of it. This cursory reference does not seem to shut the door on a review of the RSC in the context of the reasonableness of non-bypassable charges and their impact on competition. The combined magnitude and complementary nature (or lack thereof) of the various rate components in standard service offer -- including the RSC, little g, the SRT, the IMF, the AAC and the FPP – surely also remains a valid concern for the Commission.

Q100. IS THE COMPANY CURRENTLY PROPOSING CHANGES TO THE RSC?

A100. Yes. "In Case No. 06-986-EL-UNC DE-Ohio is proposing to combine the AAC and the RSC in order to simplify the MBSSO."[20] The Company is also seeking to increase the level of the RSC to 16 percent of little g for 2009 and 17 percent of little g for 2010. "In order to extend stable prices for two more years the Company is willing to accept a slight increase to its RSC component of its MBSSO."[21]

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[20] DE-Ohio's Response to OCC-INT-04-RI63, NHT Attachment 14.

[21] DE-Ohio's (Response to OCC-INT-04-RI64, NHT Attachment 15.

Q101. IF THE COMMISSION DECIDES TO RETAIN THE RSC, WOULD THIS PROPOSAL PROVIDE AN OPPORTUNITY TO TIGHTEN UP THE BASIS OF THE RSC?

A101. Yes. I would note, firstly, that since the RSC is, or has been, a component of little g, an increase in the RSC percentage of little g, if permitted by the Commission, should presumably be matched by a reduction in the remaining little g charge. Even if it is now completely detached from historical little g, however, the RSC needs to be justified on its own terms. The increase would still have the unfavorable effect of increasing the Company's unavoidable generation charges. Bearing these considerations in mind, this could be a good opportunity for the Commission to make the RSC completely bypassable and to clarify which parts of generation resources and costs are covered by the RSC. A sound general position would be that all generation-related services should be competitively provided and all generation-related charges, including the RSC, should be avoidable by shopping customers. If the RSC is retained for customers who do not shop, it should be tightened up by basing it on verifiable and measurable generation costs.

H. Regulatory Transition Charge

Q102. FOR COMPLETENESS, PLEASE DESCRIBE THE REGULATORY TRANSITION CHARGE

A102. The Regulatory Transition Charge (RTC) is a component of generation charges ("g") that was separated out to reflect stranded costs and other transitional or restructuring charges. It is also a reminder that customers are still paying for the Company's costs of restructuring.

V. OVERALL ASSESSMENT OF DUKE ENERGY OHIO'S STANDARD SERVICE OFFER PRICING

Q103. WHAT IS YOUR OVERALL ASSESSMENT OF THE COMPANY'S STANDARD SERVICE OFFER?

A103. I assess Duke's standard service offer against the criteria established by the Commission in its implementation of Senate Bill 3. These are "rate certainty, financial stability for the electric distribution utilities and further competitive market development."[22] In the last several years, however, problems with deregulation and competitive electricity markets have led to a partial return to traditional thinking about rates. The Company's standard service offer is caught in a kind of time warp. Within an apparent framework of market pricing created three years ago, its riders and trackers increasingly look like traditional rate components based on accounting costs. This issue needs to be addressed head-on by the Commission, and in that spirit I also ask the fundamental question whether Duke's standard service offer rates provide reasonably priced generation service. I will deal in some detail with a number of specific problems of the standard service offer rate components separately and with their consistency and complementary nature (or lack thereof).

[22] In FirstEnergy Case No. 03-1461-EL-UNC, Entry on Rehearing, October 22, 2003.

Q104. DID THE STIPULATION OF MAY 19, 2004 OSTENSIBLY ESTABLISH A REASONABLE PRICING SYSTEM?

A104. The Stipulation of May 19, 2004 contains the following "finding of fact." "The market-based standard service offer price, and individually the price to compare and the Provider of Last Resort components, represent the price of competitive retail electric generation service from a willing seller to willing buyers." (Stipulation, page 21) One only has to look at the statistics on switching, or the lack thereof, to see that this assertion cannot be correct. As of September 30, 2006, Duke Energy Ohio retained 96.76 percent of sales. This figure can be compared to the data for December 31, 2004 in which Duke Energy Ohio retained only 83.47 percent of total sales. Breaking down its market monopoly, as of September 31, 2006, Duke Energy Ohio retained 98.25 percent of residential kWh sales, 91.77% of commercial sales, and an amazing 99.65% of industrial sales. (The data are from the Commission's website, Summary of Switch Rates from EDUs to CRES Providers in Terms of Sales For the Months Ending December 31, 2004 and September 30, 2006 respectively.) It seems more accurate to conclude that, as a result of a combination of several factors, standard service offer pricing and the conditions placed on customer switching have created a playing field that is far from level and strongly favors Duke Energy Ohio as an incumbent monopolist.

Q105. DOES THIS IMPLY THAT STANDARD OFFER SERVICE IS PRICED BELOW COST?

A105. No. The lack of switching does not suggest that the Company is pricing service below the level of its accounting costs. Recall that the Company has a number of legacy generating plants that burn coal that is relatively cheap when compared with recent and current prices of natural gas, which tends to be the marginal fuel during peak periods. (The Stipulation of May 19, 2004 contained a provision that the Company would "have no obligation to transfer ownership of its generating assets." (Stipulation, page 23)) Likewise, compared with potential retail competitors, the Company has a long-established customer service network, and this benefit of incumbency enables it to avoid the heavy marketing and administrative costs that a new entrant would have to incur.

Q106. ARE THERE BARRIERS TO ENTRY CONTAINED IN THE PRICING OF STANDARD SERVICE OFFER?

A106. Yes. The Company's standard service offer is made up of six generation-related components – little g, FPP, AAC, IMF, SRT and RSC. A striking feature of the offer is that no fewer than four of these six generation-related price components – the AAC, IMF, SRT and RSC -- are not fully bypassable by consumers who switch to competitive retailers. There are only two components that are fully avoidable, namely the legacy generation rate known as "little g" and the fuel and economy purchased power (FPP) tracker.

Q107. ARE THERE NOT PROVISIONS UNDER WHICH CERTAIN PERCENTAGES OF SWITCHING CUSTOMERS CAN AVOID PAYING SOME OF THESE CHARGES?

A107. Yes. However, these provisions do not remove the barriers to entry, they only lower them. In regard to the previous CMO MBSSO, I objected to what was called the "flex down" provision, which allowed the Company to reduce its standard service offer rates if it began to encounter significant competition from competitive retail electric suppliers. The partial bypassability provisions in the current standard service offer have a similar effect. After the first 25 percent or 50 percent of each customer class's load has switched, other retail customers cannot avoid paying these charges when they switch to competitive retailers. Like the earlier flex-down provision, it is a warning to market entrants that if they are successful, they or their customers will be penalized. It is important to understand that unlike an incumbent monopolist such as a distribution utility, competitive retailers have to incur significant marketing and other overhead and indirect costs if they are to enter a market. They are unlikely to do this unless there is the chance of establishing a large customer base in competition with not only the incumbent utility but also other competitors who are likely to be pursuing the same limited opportunity. These switching provisions are yellow lights for competitors and constitute barriers to entry even when actual switching percentages are below the limits.

Q108. ARE THERE OTHER BARRIERS TO COMPETITIVE ENTRY?

A108. I note as a barrier the Company's retention of the role of providing capacity to back up energy provided by competitors, and charging all customers POLR charges for this service, including customers who switch. As the incumbent generation service provider, the Company is positioned (in the absence of tight regulatory oversight) to use affiliates to discriminate in favor of customers whom it fears are most likely to switch to competitive suppliers. The Company's current service plan does not seem conducive to the development of the competitive market. The Company has retained a 99.65 percent market share of industrial sales, as of September 30, 2006, closer to a complete monopoly than it was on December 31, 2004, when its market share was 91.04 percent.

Q109. PLEASE TURN TO OTHER ASPECTS OF THE PRICING OF DUKE ENERGY OHIO'S STANDARD SERVICE OFFER.

A109. It is difficult to summarize all of the Company's rate components, which I discussed in the previous section of my testimony. Here I will deal with major concerns and general features. There are several themes that I would like to develop, apart from the problem of unavoidable charges discussed above. These include the difficulty of finding a reasonable basis for some of the charges; the problem of differing and possibly conflicting pricing methodologies; and the difficulty of figuring out how the various rate components fit together.

Q110. HOW WOULD YOU COMPARE THE COMPANY'S STANDARD SERVICE OFFER RATE REQUESTS WITH TRADITIONAL RATE CASES?

A110. As noted earlier, the Company seems caught between what is supposedly a market pricing framework and what in detail looks increasingly like accounting cost-based justifications for specific rate components. Take for example the AAC, which was initially expressed as a percentage of little g and was not based on the recovery of actual costs incurred. The AAC now looks quite like a traditional rate component, a tracker to recover actual costs incurred for certain items such as environmental investments and costs of homeland security, including reconciliation of past over- or under-recovery.

Q111. DOES THIS MEAN THAT THERE IS NO PROBLEM WITH THESE COST-BASED RATE COMPONENTS?

A111. No. One difficulty is that, when pressed on the details of the accounting costs underlying these supposedly cost-based items, the Company sometimes switches to a broader justification, namely that they are part of market-based pricing. According to the Company, cost-based items do not need to be specifically justified in detail if the overall total price is reasonable.

Q112. CAN YOU GIVE AN EXAMPLE?

A112. Yes. The calculation of the accounting costs of environmental investments in the AAC rate component is a good example of how the Company uses a "revenue requirements" type calculation, but balks at implementing it in a precise manner that accords with traditional rate-making standards. As noted earlier, in the calculation of the accounting cost basis of AAC charges for environmental investments, construction work in progress ("CWIP") is included in investment. The Commission only permits CWIP in rate base in certain circumstances. Is its inclusion here appropriate? The Company side steps this issue. Mr. Wathen says: "The applicability of traditional ratemaking regulations, such as the limit on CWIP at issue here, must be set aside because we are not dealing with traditional cost based regulation – instead, we have a "new" formula to determine a market price, just as the Commission wrote on page 19 of its Entry on Rehearing." (Wathen Supplemental Testimony at page 5) This reference to what the Commission said does not resolve the issue. In accepting or requiring the use of an accounting cost procedure to build up the components of a market price, I doubt that the Commission meant to say those procedures could be loosely applied. The only argument for preferring a cost-based procedure for estimating a market price is surely that it is hopefully more precise than unreliable guesses at what the market price would be. It is not enough to say that the procedures are vaguely or approximately reasonable, it would be better for them to be precisely applied and precisely reasonable. Taking the Company's approach, the whole costing exercise hardly seems to be relevant, so long as the net result is a reasonable market price. But, apart from prices paid for goods and services like fuel and capacity in the marketplace, there is no clear evidence as to what exactly the market price is, which leaves an accounting cost basis as a proxy, and a precisely estimated proxy is better than an approximate one.

Q113. HOW WERE YOU CONCERNED ABOUT THE REASONABLENESS OF THE COMPANY'S EARLIER PROPOSALS?

A113. In my previous testimony in 2004 in this matter, I critiqued the Company's attempt to build up a market price for generation services. The Company tried to justify its MBSSO pricing structure as an attempt to replicate the kind of price that a Competitive Retail Electric Supplier (CRES) would build up from a number of cost and risk components. To the base component, which was a market price index, the Company added several components reflecting the kinds of costs and risks that it argued a CRES would seek to recover in its retail prices. The problem was that the components were based upon estimates by the Company's very imprecise measures of the costs and risks faced by CRES providers (let alone those actually faced by the Company itself as the MBSSO provider). Some of the cost or risk items appeared to be over-estimated, and there also appeared to be double-counting of costs. Company witness Rose acknowledged that the pricing methodology was novel, untested, and based upon a large number of judgments and estimates for which there was no firm basis. When I testified in 2004, my concern was that the prices constructed according to the CMO MBSSO methodology were unlikely to correctly measure the actual costs and risks of providing competitive retail service. The prices seemed likely to be higher than justified by either the Company's underlying cost of providing the service, or prices likely to be determined in the competitive market. In my testimony, I addressed this concern in relation to various specific price components. The general problem with the way the Company developed its proposed MBSSO rates was that it was complex, artificial and imprecise. I argued that it was next to impossible to accurately simulate prices that would prevail in the competitive retail market, as opposed to letting the market itself determine what those prices would be. Perhaps also fearing that the estimated price was too high, or at least being uncertain about the accuracy of its methods, the Company also included a flex-down provision under which it could lower its price if it started to lose market share to competitors.

Q114. DID SUBSEQUENT DEVELOPMENTS VALIDATE YOUR CONCERNS?

A114. Yes. The essentially subjective nature of the CMO MBSSO pricing methodology was dramatically borne out by a subsequent development. When the Company filed its Alternate Plan, pursuant to the Stipulation of May 19, 2004, it was concerned that its new proposed rates might be *lower than* its costs and might therefore constitute predatory pricing. It therefore filed testimony by Mr. Rose in which much lower revised "market prices" were developed by simply changing a few input assumptions of the pricing methodology. Probably, the lower estimates were more reasonable than the earlier ones, and the Company's proposed prices were therefore higher than market prices.

Q115. WHY DO YOU RAISE THESE ISSUES AGAIN?

A115. It is not my intention to try to settle this old argument. I provide this example of the difficulty inherent in trying to artificially construct market prices using risk models, etc. The range of Mr. Rose's "market" prices was so large that the pricing exercise lost all credibility.

Q116. HAS MR. ROSE RETURNED TO THIS ISSUE IN HIS SECOND SUPPLEMENTAL TESTIMONY?

A116. Yes. He has the following to say.

> "Attachment JLR-37-Supplemental to my first supplemental testimony shows CMO MBSSO prices based on four hypothetical adjustments: (1) lower power prices (*i.e.*, at 2003 levels instead of 2004), (2) with greater load shape information and non-block pricing, (3) lower margins *i.e.*, 7% operating risk versus 13.4%), and (4) lower supply management fees (*i.e.*, 4% instead of 7%). Lower costs, lower risks or greater competition could also lower margins and fees...The results showed that depending on market conditions, the CMO MBSSO might either be above, below, or close to the RSP MBSSO price to compare." (Second Supplemental Testimony at page 9.)

This boils down to saying that market prices depend on a variety of factors and when a risk model is used in an attempt to estimate market prices, it all depends on how you assess those factors in the particular circumstances. This was not a sound basis for determining electricity market prices in 2004 and it is not a sound basis today.

Q117. SHOULD THE COMMISSION SWITCH TO MARKET PRICES AS DETERMINED BY THE MARKET ITSELF?

A117. The market itself is in principle the best source of market prices. I would like to express two reservations about observed market prices. One is that, after several years of electricity market pricing around the country, we now know that market prices can be volatile in the short-run. Price volatility can make short-run prices depart significantly from long-run equilibrium prices. Complete reliance on short-term pricing can have adverse effects on consumers, and can give consumers the wrong price signals. The other potential problem with pricing in newly restructured markets is that incumbent utilities or their affiliates may have large shares of the regional generation market and may be able to exercise market power.

Q118. IS THERE AN ALTERNATE METHOD FOR DETERMINING MARKET PRICES, OR A PROXY FOR MARKET PRICES, IN THE NEAR TERM?

A118. Yes. Greater reliance on actual accounting costs -- rather than costs estimated from pricing theories and models -- can provide a relatively stable proxy for market prices. As I look at the trend or tendency of the Commission's regulation of Duke's standard service offer during the past two or three years, it seems that this is the direction in which the Commission has been heading.

Q119. CAN YOU PROVIDE EXAMPLES OF THIS TREND?

A119. Of the six generation-related rate components, three are now (either in principle or in practice) based primarily on accounting cost – the FPP, the AAC and the SRT. The FPP, which is one of the bypassable rate components, is functioning for the most part as a traditional fuel adjustment clause tracker. And the AAC and SRT – two of the four non-bypassable components– are also based on accounting costs. While not agreeing with all the features of these charges, I believe that, if correctly designed, they can be components of reasonably priced service that meet the Commission's objectives of rate stability for consumers and financial stability for the Company. The third objective – the fostering of competition – is turning out to be less easily attainable than had been previously hoped. What is clear at this point is that competition will be enhanced to the extent the Commission transfers cost recovery from non-bypassable POLR charges to bypassable Price to Compare charges. For example, the SRT should be completely bypassable.

Q120. DO YOU HAVE ANY COMMENTS ON THE BASIS OF THE OTHER THREE RATE COMPONENTS?

A120. Little g and the RSC, which is a component of little g, are currently neither market-based nor based on recently-audited costs. The fact is that little g, and by extension the RSC which is a component of little g, are legacy items that go back many years. It should be possible, however, to update the cost basis of legacy generation.

Q121. THE COMPANY REGARDS THE ASSETS COVERED BY LITTLE G AS DEREGULATED. CAN THE COMMISSION CONTINUE TO MAINTAIN REGULATORY PRICING OF THESE ASSETS?

A121. I don't know the answer to this question from a legal standpoint. However, I note that the Company has resisted attempts to be required to transfer its generation assets to a separate deregulated affiliate and is still committing these assets ("at 1st call") to standard service offer customers. It is also currently recovering transitional charges under the Regulatory Transition Cost (RTC) rider, and will continue to do so through 2008 or 2010. It seems appropriate for customers who are paying for the transition costs of restructuring to get the benefit of reasonably-priced electricity from partially restructured assets.

Q122. WHAT ABOUT THE BASIS OF THE IMF?

A122. From a consistent cost basis, this is an anomalous charge that should be dropped. Again, if generation charges are to be cost based, the cost of generating capacity should be recovered by means of some combination of an updated little g and the SRT, which is already based on current costs incurred.

Q123. IS CONTINUATION OF THE MOVEMENT TOWARD COST-BASED PRICING THE PREFERABLE WAY FOR THE COMMISSION TO GO?

A123. I am not stating a preference for cost-based pricing over market-based pricing. What I am saying is that tightening up the cost basis of the Company's charges is a reasonable response to the challenge of developing a consistent and reasonable framework for standard service offer pricing that provides reasonable prices.

Q124. WOULD A CONTINUATION OF THE STATUS QUO, WITH THE COMMISSION SIMPLY AFFIRMING THE PRESENT STRUCTURE, BE DESIRABLE?

A124. No. I have presented a number of criticisms of the Company's current standard service offer. In my opinion, it is impossible to find a reasonable and consistent basis for all of its pricing components, separately or in combination, as they are currently designed.

Q125. THE COMPANY HAS, AMONG OTHER ALTERNATIVES, GIVEN THE COMMISSION THE CHOICE OF RETURNING TO THE STIPULATED MBSSO OF MAY 19, 2004 OR THE ORIGINAL CMO MBSSO. IN YOUR OPINION, ARE THESE GOOD ALTERNATIVES?

A125. No. A return to the Stipulated RSP MBSSO would reverse a number of beneficial changes that the Commission has made, for example the increase in avoidability of some of the rate components. Regarding the CMO MBSSO, I refer to my testimony of May 6, 2004, which contained a number of very sharp criticisms of that proposal. I referred earlier to the issue of using a risk model to estimate market prices, and showed that the estimates depend on so many assumptions that they are too approximate and unreliable to be used for rate-making purposes.

Q126. WHAT THEN IS YOUR OVERALL CONCLUSION?

A126. Taken together, the components of the current standard service offer pricing are poorly defined and do not have a reasonable basis. Generation charges should be completely bypassable by shopping customers. Unless the Company's standard service offer rates are based on either market prices actually determined in the market place, or on the proxy of consistently-calculated embedded and current costs, the service will not be reasonably priced for consumers.

Q127. DOES THAT CONCLUDE YOUR TESTIMONY?

A127. Yes it does. However, I reserve the right to incorporate new information that may subsequently become available.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the Testimony of Neil Talbot was served electronically on the persons listed on the electronic service list shown below (as supplemented for this pleading), provided by the Attorney Examiner, this 9th day of March 2007.

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NHT Attachment 1

Ohio Consumers' Counsel
Sixth Set Interrogatories
Duke Energy Ohio, Inc.
Case No. 03-93-EL-ATA
Following Remand
Date Received: February 15, 2007
Response Due: February 26, 2007

OCC-INT-06-RI148

REQUEST:

Regarding the Companies' meeting of the standard service offer peak loads and capabilities, what was a breakdown of the amounts and cost recovery of that megawatt generating capacity and capacity products covered by each standard service offer component or rider (e.g. *Little g, IMF, RSC, and SRT) as of Summer 2006* and Winter 2006/2007?

RESPONSE:

The only components of the MBSSO that are market prices based upon direct "cost recovery" are the Riders FPP and SRT. For 2006, the billed revenue for each component of the Company's MBSSO are shown in the table below:

MBSSO Revenue for 2006	
Components of MBSSO	Amount
Generation (G)	$654,280,074
RSC	114,747,660
Little g (G + RSC)	$769,027,734
FPP	$194,302,151
AAC	55,008,125
SRT	(6,031,653)
IMF	31,549,495
Total MBSSO Revenue	$1,043,855,852

WITNESS RESPONSIBLE: N/A

NHT Attachment 2

Ohio Consumers' Counsel
Fourth Set Interrogatories
Duke Energy Ohio, Inc.
Case No. 03-93-EL-ATA
Following Remand
Date Received: January 26, 2007
Response Due: February 5, 2007

OCC-INT-04-RI78

REQUEST:

In regards to DE-Ohio's FPP for 2005, 2006, and as proposed for 2007:

a. What is the rationale for this component?

b. What are its sub-components?

c. What are the underlying costs associated with each sub-component?

d. Which of the sub-components are accounting cost based and which are market-based, and what were the actual costs for those sub-components that are based upon costs?

e. Of the cost based sub-components in response to Interrogatory No. 78d, what are the actual costs for 2005 and 2006?

f. How is the FPP calculated and allocated to the residential class (including an explanation of the use of actual per kWh costs and estimated amounts)?

g. How is each sub-component of the FPP calculated and allocated to the residential class (including an explanation of the use of actual per kWh costs and estimated amounts)?

h. What risks are covered by the FPP in the current standard service offer?

i. How does DE-Ohio allocate the type of costs upon which the FPP is based between customers who receive the Company's standard service offer and those customers who do not receive the Company's standard service offer?

RESPONSE:

a. Rider FPP is a component of the Company's formula-based MBSSO. Rider FPP allows the Company to recover incremental fuel, purchased power, and emission allowance costs (EAs).

b. The Rider FPP market price includes the incremental costs of fuel, economy purchased power, and EAs over the amount of the EFC rate frozen as of October 1999. It also includes a reconciliation adjustment for prior period over- or under-collections. As of the first quarterly filing for 2007, Rider FPP also includes MISO charges for congestion and losses.

c. The fuel component includes the costs of fossil fuel used in the generation of power and the cost of economy purchases of power from the MISO. The congestion and losses are also included in the fuel component.

   Since the average cost for fuel and purchased power used in the calculation is at the busbar, there is also an adjustment (the System Loss Adjustment or "SLA") to convert the market price to an "at the meter" price.

   The EA component includes the incremental cost of emission allowances.

   The reconciliation adjustment includes all prior period differences between revenue and costs that will be recovered from or returned to consumers.

d. The FPP market price is calculated using accounting costs.

e. The FPP is a market price, not a cost-based rate. See Attachment OCC-INT-04-RI78.

f. All costs are allocated to the consumer classes based on kWh usage. For documentation of the FPP calculation, please see the company's quarterly filings.

g. See response to OCC-INT-04-RI78f.

h. The Rider FPP covers the price risk for fuel, economy purchased power, and EAs.

i. DE-Ohio allocates on a per/ kWh basis.

WITNESS RESPONSIBLE: N/A

NHT Attachment 3

Ohio Consumers' Counsel
Fourth Set Interrogatories
Duke Energy Ohio, Inc.
Case No. 03-93-EL-ATA
Following Remand
Date Received: January 26, 2007
Response Due: February 5, 2007

OCC-INT-04-RI61

REQUEST:

In regards to DE-Ohio's AAC for the years 2005, 2006, and as proposed for 2007 in Case No. 06-1085-EL-UNC:

a. What were the actual revenues received by DE-Ohio from the AAC in years 2005 and 2006?

b. What were the actual accounting costs incurred by the Company for each of the components of the AAC, e.g., environmental costs, Homeland Security costs and costs (or credits) for tax changes?

c. Will the Company be truing up any over- or under-recovery of AAC costs in 2005 and 2006 (as proposed by the Company for 2007)?

d. If the response to Interrogatory No. 61c is negative, why will there be no true-up ?

e. If the response to Interrogatory No. 61c is positive, when will the true-up occur?

f. Of the costs listed in response to Interrogatory No. 61b what amount was classified as generation expenses?

g. Of the costs listed in response to Interrogatory No. 61b what amount was classified as distribution expenses?

h. Of the costs listed in response to Interrogatory No. 61b what amount was classified as transmission expenses?

i. How did the Company allocate the AAC costs between SSO customers and other retail and wholesale customers?

j. In proposing a larger increase in the 2007 AAC charges for residential customers than for other customer classes does the Company apparently believe that the Commission should no longer be concerned about the rate impact on residential customers?

k. If the response to Interrogatory No.61j is negative, why is the Company requesting a larger increase for residential customers?

l. Why did the Company include CWIP in rate base for the purpose of calculating the AAC in 2007?

m. Does the Company agree that in a competitive market, costs incurred, including the return of and on generating facilities, generally can only be recovered from sales after the facilities are completed?

n. If the response to Interrogatory No. 61m is negative, explain how a generating facility could recover costs prior to completion of construction of the facility?

RESPONSE:

Please see the general objection.

a. For 2005, $15.8 million. For 2006, $55.0 million.

b. For 2005 and 2006, the Rider AAC was established at a fixed percentage of "little g." For those years, the Company did not track the costs referred to in the question. For 2007, the Rider AAC proposed in Case No. 06-1085-EL-UNC, is based on actual data for the twelve month period ending May 31, 2006. (One component of the Rider AAC revenue requirement, environmental reagents, is based on forecasted data for 2007 per a Stipulation Agreement approved by the Commission in Case No. 05-806-EL-UNC).

c. No.

d. The agreed upon price was a fixed percentage of little g with no true-up required.

e. Not applicable.

f. All costs eligible for recovery in Rider AAC are classified as generation.

g. None.

h. None.

i. Costs eligible for recovery in the Rider AAC are allocated to all MBSSO load.

j. The AAC component is DE-Ohio's market price for generation service. The factors the Commission uses to review and any market price application is set forth by statute.

k. De-Ohio is to treat all consumers at the same level and to have no cross-subsidization.

l. The AAC is not a regulated rate. It is a market price and has no "rate base." CWIP has been a component of DE-Ohio's AAC market price since its approval in Case No. 03-93-EL-ATA.

m. No.

n. In a truly competitive market any type of arrangement can be made between a willing buyer and a willing seller.ee response to OCC-INT-04-RI61(n).

WITNESS RESPONSIBLE: N/A

NHT Attachment 4

Ohio Consumers' Counsel
Sixth Set Interrogatories
Duke Energy Ohio, Inc.
Case No. 03-93-EL-ATA
Following Remand
Date Received: February 15, 2007
Response Due: February 26, 2007

OCC-INT-06-RI140

REQUEST:

In its response to OCC-INT-04-RI67(c), the Company states that "[t]he fixed percentage of little g that DE-Ohio receives for the IMF as a component of its MBSSO is compensation for its opportunity cost associated with committing its assets at first call to MBSSO load."

a. What are the assets to which the Company refers (i.e. identify the assets)?

b. What kind of assets are they?

c. Who owns these assets (i.e. identify the owner(s))?

d. To the extent these assets are generation plants, what are their megawatt capacities?

e. Which of these assets were previously included in little g?

f. What does "committing (such) assets at first call to MBSSO load" entail?

g. In what way(s) is the commitment referred to legally binding?

h. What is the "opportunity cost" (i.e. the cost foregone) and how has the opportunity cost been calculated?

i. What amount of the committed generation assets are committed to MBSSO load?

j. What amount of the committed generation assets are committed to other retail load?

k. What percentage of the generation from the committed generation assets is sold in the market to non-MBSSO customers?

l. How are the revenues from sales inquired into by RI141(k) passed on to MBSSO customers?

RESPONSE:

a. See Attachment OCC-INT-06-RI140(a).

b. Electric generating plants.

c. DE-Ohio owns all or parts of all of the assets in question.

d. See response to OCC-INT-06-RI140(a).

e. All generating assets identified in response to OCC-INT-06-RI140(a).

f. It means that consumers in DE-Ohio's certified service territory have the right to receive generation capacity from these units before it can be sold to anyone else.

g. To the same extent the Commission's Orders in this case are legally binding.

h. The opportunity cost is the market price of incremental capacity and energy to non-MBSSO customers. The Company has not performed such calculation..

i. All.

j. None.

k. The percentage varies from hour to hour. For 2006, the percentage of the energy not needed by DE-Ohio's FPP consumers was approximately 11%.

l. Assuming the question is referring to OCC-INT-06-RI140(k): None. DE-Ohio's market price does not include a credit for revenue from the sale of power to non-MBSSO consumers.

WITNESS RESPONSIBLE: N/A

NHT Attachment 5

Ohio Consumers' Counsel
Fourth Set Interrogatories
Duke Energy Ohio, Inc.
Case No. 03-93-EL-ATA
Following Remand
Date Received: January 26, 2007
Response Due: February 5, 2007

OCC-INT-04-RI67

REQUEST:

In regards to DE-Ohio's IMF for 2005, 2006, and as proposed for 2007:

a. What is the rationale for this component?

b. What are the actual revenues received by DE-Ohio from the IMF for 2005 and 2006?

c. What are the underlying costs associated with each of the sub-components?

d. Of the sub-components, which are based upon accounting costs and which are market-based?

e. What is the rationale for using 4 percent of little g in 2005 and 2006 and 6 percent of little g in 2007 and 2008 as the estimate for the IMF?

f. How is each sub-component calculated and allocated to the residential class (including an explanation of the use of actual per kWh costs and estimated amounts)?

RESPONSE:

a. The Infrastructure Maintenance Fund (IMF) was created to compensate DE-Ohio for committing its generating assets to its retail consumers on a first call basis.

b. $19.8 million for 2005. $31.5 million for 2006.

c. The fixed percentage of little g that DE-Ohio receives for the IMF as a componenet of its MBSSO is compensation for its opportunity cost associated with committing its assets at first call to MBSSO load.

d. Rider IMF is a market price component of the formula for calculating the Market-Base Standard Service Offer. There are no sub-components of the IMF.

e. See the response to OCC-INT—04-RI67(d).

f. Rider IMF is calculated as a fixed percentage of "little g" for each rate class.

WITNESS RESPONSIBLE: N/A

NHT Attachment 6

Ohio Consumers' Counsel
Sixth Set Interrogatories
Duke Energy Ohio, Inc.
Case No. 03-93-EL-ATA
Following Remand
Date Received: February 15, 2007
Response Due: February 26, 2007

OCC-INT-06-RI142

REQUEST:

In its response to OCC-INT-04-RI68(a), the Company states that, "[t]he SRT is DE-Ohio's *market price for the cost of purchasing* capacity to maintain a 15% reserve margin under its provider of last resort obligation." How is the capacity covered by this rider different from other capacity owned or acquired by the Company for which compensation is covered by other riders or components of the MBSSO, such as little g and the IMF?

RESPONSE:

The SRT represents the direct costs for incremental capacity to maintain a 15% reserve margin.

Little g and the IMF represent compensation for the Company's existing capacity.

WITNESS RESPONSIBLE: N/A

NHT Attachment 7

Ohio Consumers' Counsel
Sixth Set Interrogatories
Duke Energy Ohio, Inc.
Case No. 03-93-EL-ATA
Following Remand
Date Received: February 15, 2007
Response Due: February 26, 2007

OCC-INT-06-RI149

REQUEST:

Regarding the Company's response to OCC-INT-04-RI70:

a. Why is the Company requesting an increase in its IMF component of its standard service offer "in order to commit its generation at 1st call to MBSSO consumers"?

b. What is the definition of "a slight increase" as used in response to OCC-INT-04-RI70?

RESPONSE:

Objection. Irrelevant. Assumes facts not in evidence in the consolidated remand cases as ordered by the Commission on or about December 14, 2006. However, without waiving said objection:

a. The Company is willing to commit its generation at 1st call to MBSSO consumers for an additional two years. In exchange for such commitment, the Company believes the proposed increase in the IMF component is appropriate.

b. The American Heritage College dictionary defines "slight" as, 1. small in size, degree, or amount.

WITNESS RESPONSIBLE: N/A

NHT Attachment 8

Ohio Consumers' Counsel
Sixth Set Interrogatories
Duke Energy Ohio, Inc.
Case No. 03-93-EL-ATA
Following Remand
Date Received: February 15, 2007
Response Due: February 26, 2007

OCC-INT-06-RI150

REQUEST:

If costs or risks covered by the IMF component have increased:

a. In what way have they increased?

b. Why have they increased?

RESPONSE:

Since 2004, various costs and risks have increased. Additionally, opportunities and prices in the electric power market have increased.

WITNESS RESPONSIBLE: N/A

NHT Attachment 9

Ohio Consumers' Counsel
Fourth Set Interrogatories
Duke Energy Ohio, Inc.
Case No. 03-93-EL-ATA
Following Remand
Date Received: January 26, 2007
Response Due: February 5, 2007

OCC-INT-04-RI68

REQUEST:

In regards to DE-Ohio's SRT for 2005, 2006, and as proposed for 2007:

a. What is the rationale for this component?

b. What are the actual revenues received by DE-Ohio in SRT charges for 2005 and 2006?

c. Which of the sub-components are based upon accounting costs and which are market-based, and what were the actual costs for those sub-components that are based upon costs?

d. How is the SRT calculated and allocated to the residential class (including an explanation of the use of actual per kWh costs and estimated amounts)?

e. How is each component calculated and allocated to the residential class (including an explanation of the use of actual per kWh costs and estimated amounts)?

RESPONSE:

a. The SRT is DE-Ohio's market price for the cost of purchasing capacity to maintain a 15% reserve margin under it's provider of last resort obligation.

b. 2005: $14.8 million 2006: ($6.0 million)

c. The Company calculates its market price for Rider SRT based upon the price to purchase various capacity products in the market. The products and their cost are included in the quarterly SRT update filings.

d. The calculation of the SRT and the allocation among classes and to demand and energy charges is included in the quarterly SRT filing.

e. The SRT cost is allocated 42.382% to the residential class as provided in the Stipulation and Agreement approved by the Commission in Case No. 05-724-EL-UNC and signed by OCC. The cost is allocated per kWh using estimated and/or actual kWh volumes. The final annual cost is reconciled and any over-collection is returned to customers and any under-collection is recovered from customers.

WITNESS RESPONSIBLE: N/A

NHT Attachment 10

Ohio Consumers' Counsel
Fourth Set Interrogatories
Duke Energy Ohio, Inc.
Case No. 03-93-EL-ATA
Following Remand
Date Received: January 26, 2007
Response Due: February 5, 2007

OCC-INT-04-RI73

REQUEST:

Which risks are covered by the IMF under the current standard service offer?

RESPONSE:

The IMF is a DE-Ohio market price component of the Company's provider of last resort charge. See the response to OCC-INT-04-RI67(a).

WITNESS RESPONSIBLE: N/A

NHT Attachment 11

Ohio Consumers' Counsel
Fourth Set Interrogatories
Duke Energy Ohio, Inc.
Case No. 03-93-EL-ATA
Following Remand
Date Received: January 26, 2007
Response Due: February 5, 2007

OCC-INT-04-RI77

REQUEST:

Why does DE-Ohio propose the SRT to be unavoidable starting in 2009?

RESPONSE:

Objection. Irrelevant. Assumes facts not in evidence in the consolidated remand cases as ordered by the Commission on or about December 14, 2006. Without waiving said objection:

Case No. 03-93-EL-ATA, *et al.*, does not include such a proposal. However, in Case No. 06-986-EL-UNC, DE-Ohio has proposed to make reserve capacity purchases, currently included in Rider SRT, unavoidable. This proposal is consistent with DE-Ohio's past proposals. All MBSSO consumers benefit from the reserve capacity purchases and should pay the price.

WITNESS RESPONSIBLE: N/A

NHT Attachment 12

Ohio Consumers' Counsel
Fourth Set Interrogatories
Duke Energy Ohio, Inc.
Case No. 03-93-EL-ATA
Following Remand
Date Received: January 26, 2007
Response Due: February 5, 2007

OCC-INT-04-RI62

REQUEST:

In regards to DE-Ohio's RSC for 2005, 2006, and as tariffed for 2007:

a. What is the rationale for this component?

b. What are its sub-components?

c. What are the underlying costs associated with each sub-component?

d. Which of the sub-components are based upon accounting costs and which are market-based?

e. Why did DE-Ohio use 15 percent of little g to project the estimated cost of the RSC?

f. How is the RSC calculated and allocated to the residential class (including an explanation of the use of actual per kWh costs and estimated amounts)?

g. How is each component or sub-component of the RSC calculated and allocated to the residential class (including an explanation of the use of actual per kWh costs and estimated amounts)?

h. What risks are covered by the RSC in the current standard service offer?

RESPONSE:

a. The RSC is the Company charge for providing a stable market price over a prolonged period of time.

b. There are no sub-components for the Rider RSC.

c. See response to OCC-INT-04-RI62(b)

d. See response to OCC-INT-04-RI62(b).

e. As with a number of the components of the MBSSO, the RSC is not cost-based. The Company used its judgment to determine that 15% of Little g represented a reasonable market price for the RSC component of its MBSSO as compensation for providing a stable price over a prolonged period of time.

f. Rider RSC was set at the same fixed percentage of Little g for all consumers. Thus, Rider RSC is allocated on exactly the same basis that Little g was allocated in the unbundling case, Case No. 99-1658-EL-ETP. Actual cost/kWh and estimated cost are irrelevant to the Rider RSC calculation.

g. See OCC-INT-04-RI62(a) and (e).

h. See OCC-INT-04-RI62(e).

WITNESS RESPONSIBLE: N/A

NHT Attachment 13

Ohio Consumers' Counsel
Sixth Set Interrogatories
Duke Energy Ohio, Inc.
Case No. 03-93-EL-ATA
Following Remand
Date Received: February 15, 2007
Response Due: February 26, 2007

OCC-INT-06-RI134

REQUEST:

Regarding the Company's response to OCC-INT-04-RI62(e), what considerations were taken into account by the Company when it "use[d] its judgment to determine that 15% of Little g represented a reasonable market price for the RSC component of its MBSSO as compensation for providing a stable price over a prolonged period of time"?

RESPONSE:

The Company determined that this level for the RSC would be sufficient compensation to satisfy the Commission's Rate Stabilization Plan goal of price certainty for consumers and revenue stability for utilities. The 15% was determined to be a reasonable market price to help achieve all three of the Commission's goals for the plan.

WITNESS RESPONSIBLE: N/A

NHT Attachment 14

Ohio Consumers' Counsel
Fourth Set Interrogatories
Duke Energy Ohio, Inc.
Case No. 03-93-EL-ATA
Following Remand
Date Received: January 26, 2007
Response Due: February 5, 2007

OCC-INT-04-RI63

REQUEST:

Why does DE-Ohio propose to combine the AAC and RSC?

RESPONSE:

See the general objection.
Objection. Irrelevant. Assumes facts not in evidence in the consolidated remand cases as ordered by the Commission on or about December 14, 2006. Without waiving said objection:
Case No. 03-93-EL-ATA, *et al.*, does not include such a proposal. However, in Case No. 06-986-EL-UNC DE-Ohio is proposing to combine the AAC and the RSC in order to simplify the MBSSO.

WITNESS RESPONSIBLE: N/A

NHT Attachment 15

Ohio Consumers' Counsel
Fourth Set Interrogatories
Duke Energy Ohio, Inc.
Case No. 03-93-EL-ATA
Following Remand
Date Received: January 26, 2007
Response Due: February 5, 2007

OCC-INT-04-RI64

REQUEST:

What is the rationale for increasing the RSC to 16 of little g for 2009 and 17 percent of little g for 2010?

RESPONSE:

See the general objection.

Objection. Irrelevant. Assumes facts not in evidence in the consolidated remand cases as ordered by the Commission on or about December 14, 2006. However, without waiving said objection:
Case No. 03-93-EL-ATA, *et al.*, does not include such a proposal. In order to extend stable prices for two more years the Company is willing to accept a slight increase to its RSC component of its MBSSO.

WITNESS RESPONSIBLE: N/A