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PENGAD 800-631-6989 EXHIBIT 33 Duke

## Spiller, Amy B

**From:** Mark S. Yurick [myurick@cwslaw.com]
**Sent:** Monday, November 14, 2011 10:33 AM
**To:** Spiller, Amy B
**Subject:** Re: Prompt Review Requested - Duke Energy Ohio ESP, Case No. 11-3549

Amy; This is fine with me. Thanks.

CHESTER WILLCOX & SAXBE ATTORNEYS & COUNSELORS AT LAW


Mark S. Yurick

DIRECT: 614.334.7197
myurick@cwslaw.com
Chester Willcox & Saxbe, LLP
65 East State Street, Suite 1000
Columbus, OH 43215
MAIN: 614.221.4000
FAX: 614.221.4012
V-Card
Bio Page


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**From:** Spiller, Amy B [mailto:Amy.Spiller@duke-energy.com]
**Sent:** Monday, November 14, 2011 10:12 AM
**To:** Allison Haedt <aehaedt@jonesday.com>; Spiller, Amy B <Amy.Spiller@duke-energy.com>; Anastasia O'Brien <anastasia.obrien@exeloncorp.com>; Andrew Sonderman <asonderman@keglerbrown.com>; Anne Vogel <amvogel@aep.com>; Arin Aragona <aaragona@eimerstahl.com>; Barth Royer <barthroyer@aol.com>; Christopher Allwein <callwein@williamsandmoser.com>; Colleen Mooney <cmooney2@columbus.rr.com>; Cynthia Fonner Brady <cynthia.brady@constellation.com>; Dane Stinson <dane.stinson@baileycavalieri.com>; David Boehm <dboehm@bkllawfirm.com>; David Fein <david.fein@constellation.com>; David Kutik <dakutik@jonesday.com>; David Stahl <dstahl@eimerstahl.com>; Doug Hart <dhart@douglasehart.com>; Erin C. Miller <ecmiller@aep.com>; Frank Darr <fdarr@mwncmh.com>; Gary Jeffries <gary.a.jeffries@dom.com>; Glen Thomas <gthomas@gtpowergroup.com>; Greg Poulos <gpoulos@enernoc.com>; Howard Petricoff <mhpetricoff@vorys.com>; Jeffrey L. Small <small@occ.state.oh.us>; Jesse Rodriguez <jesse.rodriguez@exeloncorp.com>; Jim Lang <jlang@calfee.com>; Jody Kyler <jkyler@bkllawfirm.com>; Joe Clark <jmclark@vectren.com>; Joe Oliker <joliker@mwncmh.com>; Joel Brenzel <jouett.brenzel@cinbell.com>; Joel Malina <malina@wexlerwalker.com>; John W. Bentine; John Jones <john.jones@puc.state.oh.us>; Joseph Serio <serio@occ.state.oh.us>; Kevin Osterkamp <kosterkamp@ralaw.com>; Kurt Boehm <kboehm@bkllawfirm.com>; Laura Chappelle <laurac@chappelleconsulting.net>; Laura McBride <lmcbride@calfee.com>; Lija Kaleps Clark <lkalepsclark@vorys.com>; Lisa McAlister <lmcalister@bricker.com>; Margeaux Kimbrough <mkimbrough@keglerbrown.com>; Mark Hayden <haydenm@firstenergycorp.com>; Mark S. Yurick; Mary Christensen <mchristensen@columbuslaw.org>; Matt Warnock <mwarnock@bricker.com>; Matt White

<mswhite@igsenergy.com>; Matthew Cox <mcox@mcdonaldhopkins.com>; Matthew Satterwhite <mjsatterwhite@aep.com>; Melissa Yost <yost@occ.state.oh.us>; Michael Kurtz <mkurtz@bkllawfirm.com>; Michael Settineri <mjsettineri@vorys.com>; Nolan Moser <nolan@theoec.org>; Rick Chamberlain <rdc_law@swbell.net>; D'Ascenzo, Rocco O <Rocco.D'Ascenzo@duke-energy.com>; Sam Randazzo <sam@mwncmh.com>; Sandy I-ru Grace <sandy.grace@exeloncorp.com>; Scott Solberg <ssolberg@eimerstahl.com>; Sharon Hillman <sharonhillman@mc2energyservices.com>; Steve Howard <smhoward@vorys.com>; Steven Beeler <steven.beeler@puc.state.oh.us>; Tammy Turkenton <tammy.turkenton@puc.state.oh.us>; Tara Santarelli <tsantarelli@elpc.org>; Teresa Ringenbach <teresa.ringenbach@directenergy.com>; Tom O'Brien <tobrien@bricker.com>; Trent Dougherty <trent@theoec.org>; Trevor Alexander <talexander@calfee.com>; Vince Parisi <vparisi@igsenergy.com>; William Massey <wmassey@cov.com>; Zachary D. Kravitz
**Cc**: D'Ascenzo, Rocco O <Rocco.D'Ascenzo@duke-energy.com>; Kingery, Jeanne W <Jeanne.Kingery@duke-energy.com>; Watts, Elizabeth H <Elizabeth.Watts@duke-energy.com>
**Subject**: Prompt Review Requested - Duke Energy Ohio ESP, Case No. 11-3549

Dear Counsel and Parties of Record:

In reviewing the Stipulation and Recommendation in our ESP proceeding, we have discovered a small error. We would like to get this corrected before the Commission issues an order.

The error appears on page 12, section IV.A., relating to "Capacity for Shopping Customers.�□ It reads as follows, redlined to show the proposed correction:

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

Duke Energy Ohio proposes to file a motion, asking that the single page of the stipulation on which this change appears be admitted to the record as Joint Exhibit 1.1. In order to ensure that the Commission can consider this minor change on a timely basis, we would appreciate hearing back from you, **no later than 10:00 a.m. tomorrow, November 15**, indicating both:

- Your agreement with the change to Section IV.A., and
- Your consent to expedited treatment by the Commission.

Following the receipt of each signatory party's consent, Duke Energy Ohio will file the necessary motion with the Commission.

Thank you for your anticipated assistance in this matter.

**Amy B. Spiller**
Deputy General Counsel
Duke Energy Business Services
139 E. Fourth Street, 1303-Main
Cincinnati, Ohio 45202
(513) 287-4359 (telephone)
(513) 287-4385 (facsimile)

**NOTE: My contact information changed effective November 29, 2010. My new telephone number is (513) 287-4359.**

*OCC EXHIBIT* 25

**BEFORE**
**THE PUBLIC UTILITIES COMMISSION OF OHIO**

| | | |
|---|---|---|
| In the Matter of the Application of Duke Energy Ohio, Inc. for the Establishment of a Charge Pursuant to Revised Code Section 4909.18. | ) | Case No. 12-2400-EL-UNC |
| In the Matter of the Application of Duke Energy Ohio, Inc. for Approval to Change Accounting Methods. | ) | Case No. 12-2401-EL-AAM |
| In the Matter of the Application of Duke Energy Ohio, Inc. for Approval of a Tariff for a New Service. | ) | Case No. 12-2402-EL-ATA |

**DIRECT TESTIMONY**
**of**
**DAVID J. EFFRON**

(PUBLIC VERSION)

On Behalf of the
**OFFICE OF THE OHIO CONSUMERS' COUNSEL**
10 West Broad St., Suite 1800
Columbus, OH 43215

***MARCH 26, 2013***

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**SCHEDULES**

## I. QUALIFICATIONS AND PURPOSE OF TESTIMONY

***Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.***

***A1.*** My name is David J. Effron. My address is 12 Pond Path, North Hampton, New Hampshire, 03862.

***Q2. WHAT IS YOUR PRESENT OCCUPATION?***

***A2.*** I am a consultant specializing in utility regulation.

***Q3. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.***

***A3.*** My professional career includes over thirty years as a regulatory consultant, two years as a supervisor of capital investment analysis and controls at Gulf & Western Industries and two years at Touche Ross & Co. as a consultant and staff auditor. I am a Certified Public Accountant and I have served as an instructor in the business program at Western Connecticut State College.

***Q4. WHAT EXPERIENCE DO YOU HAVE IN THE AREA OF UTILITY RATE SETTING PROCEEDINGS AND OTHER UTILITY MATTERS?***

***A4.*** I have analyzed numerous electric, gas, telephone, and water filings in different jurisdictions. Pursuant to those analyses, I have prepared testimony, assisted attorneys in case preparation, and provided assistance during settlement negotiations with various utility companies.

I have testified in over three hundred cases before regulatory commissions in Alabama, Colorado, Connecticut, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Missouri, Nevada, New Jersey, New York, North Dakota, Ohio, Pennsylvania, Rhode Island, South Carolina, Texas, Vermont, Virginia, and Washington.

***Q5. PLEASE DESCRIBE YOUR OTHER WORK EXPERIENCE.***

*A5.* As a supervisor of capital investment analysis at Gulf & Western Industries, I was responsible for reports and analyses concerning capital spending programs, including project analysis, formulation of capital budgets, establishment of accounting procedures, monitoring capital spending, and administration of the leasing program. At Touche Ross & Co., I was an associate consultant in management services for one year, and a staff auditor for one year.

***Q6. HAVE YOU EARNED ANY DISTINCTIONS AS A CERTIFIED PUBLIC ACCOUNTANT?***

*A6.* Yes. I received the Gold Charles Waldo Haskins Memorial Award for the highest scores in the May 1974 certified public accounting examination in New York State.

***Q7. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.***

*A7.* I have a Bachelor's degree in Economics (with distinction) from Dartmouth College and a Masters of Business Administration Degree from Columbia University.

***Q8. ON WHOSE BEHALF ARE YOU TESTIFYING?***

***A8.*** I am testifying on behalf of the Office of the Ohio Consumers' Counsel ("OCC").

***Q9. WHAT IS THE PURPOSE OF YOUR TESTIMONY?***

***A9.*** Duke Energy Ohio, Inc. ("Duke" or "Company") has requested approval of a cost-based charge as compensation for providing capacity service in connection with its obligations as a fixed resource requirement (FRR) entity. I address certain issues related to the revenue requirement presented by the Company in support of its proposed cost-based capacity rate, and I have also quantified the effect of the Dr. Woolridge's return on equity recommendations on the Company's revenue requirement. I also explain why the cost-based charge as compensation for providing capacity service proposed by the Company in this case is tantamount to a request to recover generation costs in excess of market value and, as such, is inconsistent with the agreements on which the Company's restructuring transition plan was based.

***Q10. WHAT DOCUMENTS DID YOU REVIEW IN PREPARING YOUR TESTIMONY?***

***A10.*** I reviewed the Company's testimony, exhibits, workpapers and the Company's responses to discovery and data requests propounded by the OCC, motions and comments submitted by the OCC, and certain relevant stipulations and Commission Opinions and Orders in other cases.

## II. REVENUE REQUIREMENT ISSUES

### A. INTRODUCTION

***Q11. BY ADDRESSING REVENUE REQUIREMENT ISSUES IN THIS CASE, ARE YOU IMPLICITLY AGREEING THAT THE COMPANY'S REQUEST TO ESTABLISH A COST-BASED CAPACITY CHARGE FOR IT LEGACY GENERATION IS APPROPRIATE?***

***A11.*** Absolutely not. As I stated above, the approval of a cost-based capacity charge would be inconsistent with the agreements (as described later in this testimony) on which the Company's restructuring transition plan was based. In addition, on October 4, 2012, the OCC and several signatories to the Duke ESP[1] filed a Joint Motion to Dismiss. The Joint Motion to Dismiss set out the primary reasons why the Company's proposal to establish a cost-based capacity charge should be rejected. In particular, the Commission should enforce the Stipulation it approved in the Duke Electric Security Plan proceeding (Case No. 11-3549-EL-SSO, et al.). There, Duke agreed to provide capacity for all load (both shopping and Standard Service Offer ("SSO")) at market-based Reliability Pricing Model ("RPM") rates, supplemented by a non-bypassable Electric Service Stability Charge ("ESSC") of

[1] *In the Matter of the Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service*, Case No. 11-3549-EL-SSO, et al., ("Duke ESP"), Stipulation and Recommendation (Oct. 24, 2011) (approved, Opinion and Order (Nov. 22, 2011)).

$330 million over three years.[2] Duke, OCC, and multiple intervenors agreed to the terms of this Stipulation, which the Commission approved. Customers have paid and are continuing to pay the ESSC, thereby upholding their end of the agreement. Duke should be required to, in turn, fulfill its commitments under that agreement, especially its commitment to be compensated at market-based RPM capacity rates - not fully embedded capacity rates. Duke's application seeking to unilaterally improve upon the Stipulation (after seeing the outcome of the Ohio Power capacity proceeding) should be rejected. The integrity of the agreement in the ESP case should be upheld.[3]

Duke cites the "newly adopted state compensation mechanism" (referring to the mechanism adopted for Ohio Power in Case No. 10-2929-EL-UNC) as authority for its request in this proceeding. But it is the position of the OCC that the Ohio Power Capacity Case decision was not a generic PUCO decision that applies to all electric distribution utilities, but that rather. Rather, the Commission limited its decision for a cost-based state compensation mechanism in the Ohio Power Capacity Case to Ohio Power.[4] Therefore, Duke cannot rely on decision by the Commission in the Ohio Power Capacity Case as justification for its request in this case.

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[2] ("Duke ESP"), Stipulation and Recommendation (Oct. 24, 2011). (approved, Opinion and Order (Nov. 22, 2011).

[3] See Case Nos. 12-2400-EL-UNC, et al., Joint Motion to Dismiss at 13-17 (October 4, 2012), and Comments of OCC and OEG at 2-4 (January 2, 2013).

[4] See Case Nos. 12-2400-EL-UNC, et al., Comments of OCC and OEG at 2-4 (January 2, 2013).

***Q12. IF THE COMMISSION DOES NOT GRANT THE JOINT MOTION TO DISMISS DUKE'S APPLICATION, SHOULD THERE BE CERTAIN LIMITATIONS ON THE IMPOSITION OF ANY COST-BASED CAPACITY CHARGES ON CUSTOMERS?***

*A12.* Yes. First, Duke is seeking to establish a deferral as of the month of its Application in the present case, August 2012, to account for the difference between the amounts being recovered for the provision of capacity service and the cost of providing such capacity. By this request, the Company is asking to be compensated prospectively for losses incurred in the past. The approval of such a request would constitute retroactive ratemaking, and the Commission should not authorize the Company to defer any costs incurred prior to the completion of this case.

To illustrate by example, in Case No. 12-1682-EL-AIR, Duke has requested an increase in its electric distribution rates based on a 2012 test year. If the Commission finds that the Company has a revenue deficiency in that case, any increase in rates will not go into effect until the conclusion of the case. If Duke had argued there that the finding of a revenue deficiency implied that distribution revenues had fallen short of full cost recovery in 2012 and that the Company should be authorized to defer that shortfall for future recovery, such a request would be summarily rejected as retroactive ratemaking. Duke's request to create a deferral dating back to August 29, 2012 in the present case should similarly be denied as retroactive ratemaking.

Second, in Case No. 11-3549-EL-SSO, et al., the Company agreed to transfer all of its generation assets out of Duke Energy Ohio by December 31, 2014. It is the position of the OCC that the cost-based capacity charge should cease at the time of such transfer.

***Q13. HAVE YOU SUMMARIZED THE REVENUE REQUIREMENT EFFECTS OF THE ISSUES THAT YOU ARE ADDRESSING IN THIS TESTIMONY?***

***A13.*** Yes. I have summarized the revenue requirement effect of the issues that I am addressing in this testimony on my Schedule DJE-1. The adjustments to the Company's revenue requirement presented in this testimony are based on my own review and analysis, and I am not taking a position on any other adjustments that may be presented by Staff or other intervenors.

***Q14. HAVE YOU ALSO QUANTIFIED THE EFFECTS OF DR. WOOLRIDGE'S RETURN ON EQUITY RECOMMENDATIONS?***

***A14.*** Yes. I also show the revenue requirement effects of Mr. Woolridge's return on equity recommendations on my Schedule DJE-1. Again, the adjustments to the Company's revenue requirement position that I address, as well as the adjustments related to the appropriate return on equity, are relevant only if the Commission does not grant the OCC Motion to Dismiss Duke's Application.

**B. ELECTRIC SECURITY STABILITY CHARGE REVENUES**

***Q15. DID THE STIPULATION IN CASE NO. 11-3549-EL-SSO COMPENSATE THE COMPANY FOR PROVIDING RETAIL ELECTRIC SERVICE AS A FIXED RESOURCE REQUIREMENT ENTITY?***

*A15.* Yes.[5] Section VII.A of the Stipulation and Recommendation in Case No. 11-3549-EL-SSO established a non-bypassable generation charge designated as the Electric Service Stability Charge Rider ("Rider ESSC"), which was "intended to provide stability and certainty regarding Duke Energy Ohio's provision of retail electric service as an FRR [Fixed Resource Requirement] entity while continuing to operate under an ESP."[6] Pursuant to Rider ESSC, the Company was "permitted to collect $110 million per year for a period of three years commencing January 1, 2012, with the collection to be trued-up annually and the total equal to $330 million."[7] This section of the Stipulation and Recommendation also explicitly stated that "(t)he revenue collected under Rider ESSC shall stay with Duke Energy Ohio and shall not be transferred to any subsidiary or affiliate."[8]

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[5] It is the position of the OCC that the Stipulation and Recommendation in Case No. 11-3549-EL-SSO addressed wholesale capacity commitments as well as retail electric service (Case No. 12-2400-EL-AIR, Joint Reply to Duke Energy's Memorandum Contra by Signatory Parties, page 6).

[6] Case No, 11-3549-EL-SSO, et al., Stipulation and Recommendation, pages 15-16.

[7] Id.

[8] Id.

***Q16. DID THE COMPANY INCLUDE THE REVENUES FROM RIDER ESSC AS A CREDIT TO THE ANNUAL PRODUCTION FIXED COST IN ITS DETERMINATION OF THE NET REVENUE REQUIREMENT IN THE PRESENT CASE?***

***A16.*** *No.*

***Q17. DID THE COMPANY EXPLAIN WHY IT DID NOT RECOGNIZE THE ESSC RIDER REVENUES AS A CREDIT TO THE ANNUAL PRODUCTION FIXED COST?***

***A17.*** Yes. In response to OCC Interrogatory 04-043, Duke stated that "Rider ESSC is intended to provide certainty and stability in the provision of competitive retail electric service." However, Duke went on to say, "the capacity charge at issue in these proceedings is intended to compensate Duke Energy Ohio for its provision of noncompetitive capacity service as an FRR entity." Therefore, the Company concludes, the compensation for these services should be separate. In other words, for the purposes of determining the revenue requirement for the Company's generating capacity in the present case, it is, in effect, the Company's position that revenues produced by Rider ESSC may as well not exist.

***Q18. IS THE COMPANY'S EXPLANATION A VALID REASON FOR IGNORING THE ESSC REVENUES IN THE DETERMINATION OF THE GENERATION REVENUE REQUIREMENT IN THE PRESENT CASE?***

***A18.*** No. As stated above, the Stipulation and Recommendation in Case No. 11-3549-EL-SSO stated that Rider ESSC was "intended to provide stability and certainty regarding Duke Energy Ohio's provision of retail electric service as an FRR entity." No distinction was drawn between "competitive retail electric service" and "noncompetitive capacity service," as Duke now claims. Conversely, this Stipulation and Recommendation explicitly states that the ESSC Rider was related to "Duke Energy Ohio's provision of retail electric service as an FRR entity," which the Company now claims is separate and distinct from "non-competitive" capacity service provided as an FRR entity.

More substantively, although Duke claims that the provision of competitive and non-competitive capacity services are distinct, the Company does not assign or allocate its legacy generation between competitive retail electric service and noncompetitive capacity service (response to OCC Interrogatory 07-061). Thus, in the framework being advocated by the Company, it is collecting $110 million annually pursuant to Rider ESSC for providing a service that has no assets and incurs no expenses. In other words, according to Duke, the $110 million is "money for nothing."

***Q19. WHAT DO YOU RECOMMEND?***

***A19.*** As stated above, the Commission should deny the Company's request for a cost-based capacity charge. However, if a cost-based capacity charge is authorized, then the charge must take into account the existence of Rider ESSC revenues. If the $110 million being recovered annually pursuant to Rider ESSC is ignored, then whatever the Company ultimately collects from customers as a result of the cost-based capacity charge will be a pure windfall to the Company. Therefore, the ESSC revenues should be credited to Annual Production Fixed Cost, and the revenue requirement on which the Company's proposed capacity charge is based should be reduced accordingly (Schedule DJE-1). Alternatively, the ESSC revenues being recovered by the Company could be credited directly to the charges that Duke is seeking to defer for future collection, which should ultimately have the same end result.

## C. GENERAL PLANT

***Q20. DOES THE PRODUCTION-RELATED PLANT IN THE COMPANY'S RATE BASE INCLUDE AN ALLOCATION OF GENERAL PLANT?***

***A20.*** Yes. As can be seen on Attachment WDW-1, page 5, the production related plant includes $86,794,000 of general and intangible plant. The allocation of the general and intangible plant to the production function is shown on Attachment WDW-1, page 13.

***Q21. SHOULD THE GENERAL PLANT INCLUDED IN THE PRODUCTION RELATED RATE BASE BE ADJUSTED?***

***A21.*** Yes. First, the general plant accounts include assets related to the Company's Smart Grid initiative. The Smart Grid assets should be eliminated before any allocation of plant to the production function. Second, the allocation factor used to allocate the general and intangible function should be modified.

***Q22. WHY SHOULD THE SMART GRID ASSETS BE ELIMINATED FROM THE GENERAL ASSETS BEFORE ANY ALLOCATION TO PRODUCTION?***

***A22.*** The costs related to Smart Grid are recovered by means of a separate rider. None of these costs should be allocated to the production related rate base. Smart Grid assets are included in Account 391 – Office Furniture and Equipment and Account 397 – Communications Equipment. Theses accounts should be adjusted to eliminate $36,089,000 of Smart Grid assets before they are allocated to production (Schedule DJE-2).

***Q23. WHY SHOULD THE ALLOCATION FACTOR USED TO ALLOCATE GENERAL PLANT TO THE PRODUCTION FUNCTION BE MODIFIED?***

***A23.*** The Company begins with the total general plant as of December 31, 2011 and then uses an allocation factor of 51.42% to allocate the general and intangible plant to production. However, in the Company's pending distribution rate case, Case No. 12-1682-EL-AIR, the Company began with the total general plant as of March 31, 2012 and used an allocation factor of 92.257% to allocate the general plant to the distribution function.[9] Obviously, use of allocation factors that add to greater than 100% creates an overlap and will lead to Duke obtaining a double recovery if not corrected.

The Company is proposing to recover 92.257% of the general plant in its distribution revenue requirement in Case No. 12-1682-EL-AIR. Accordingly, only 7.743% of general plant remains to be recovered. On Schedule DJE-2, I show the allocation of the remaining 7.743% of general plant between transmission and production. This modification is necessary to prevent the double recovery of a portion of the general plant.

***Q24. WHAT IS THE EFFECT OF YOUR PROPOSED ADJUSTMENTS TO GENERAL PLANT?***

***A24.*** My adjustments reduce the general plant included in the demand related production rate base by $26,575,000. Consistent this adjustment to plant, the depreciation reserve on the general plant in the production rate base should be reduced by $6,282,000, and the depreciation expense on the general plant in the production rate base should be reduced by $1,192,000 (Schedule DJE-2).

[9] Case No. 12-1682-EL-AIR, Application, Volume 9, Schedule B-2.1, page 3. The 92.257% allocation factor was based on 2011 salaries and wages.

**D. COMMON PLANT**

***Q25. DOES THE PRODUCTION- RELATED PLANT INCLUDED IN THE COMPANY'S RATE BASE ALSO INCLUDE AN ALLOCATION OF COMMON PLANT?***

*A25.* Yes. As can be seen on Attachment WDW-1, Page 5, the production-related plant includes $141,933,000 of common plant. Common plant is intangible and general plant that serves both electric and gas operations. The allocation of the common plant to electric operations and then to the production function is shown on Attachment WDW-1, page 14.

***Q26. SHOULD THE GENERAL AND INTANGIBLE PLANT INCLUDED IN THE PRODUCTION RELATED RATE BASE BE ADJUSTED?***

*A26.* Yes. Common plant accounts also include assets related to the Company's Smart Grid initiative. Again, the Smart Grid assets should be eliminated before any allocation of plant to the electric production function, because costs related to Smart grid are recovered from customers by means of a separate rider. Smart Grid assets are included in Account 191 – Office Furniture and Equipment, and Account 197 – Communications Equipment. Theses accounts should be adjusted to eliminate the Smart Grid assets before they are allocated to electric production (Schedule DJE-3).

***Q27. WHAT IS THE EFFECT OF ELIMINATING SMART GRID ASSETS FROM COMMON PLANT?***

***A27.*** The elimination of Smart Grid assets reduces the common plant included in the demand related production rate base by $6,036,000. Consistent with this adjustment to plant, the depreciation reserve on demand related production plant should be reduced by $916,000, and the depreciation expense on demand related production plant should be reduced by $176,000 (Schedule DJE-3).

**E. ACCUMULATED AMORTIZATION – INTANGIBLE PLANT**

***Q28. DOES THE COMPANY INCLUDE INTANGIBLE PLANT IN ITS PRODUCTION RATE BASE?***

***A28.*** Yes. Intangible plant is shown on Attachment WDW-1, page 13, along with general plant.

***Q29. DID THE COMPANY INCLUDE THE ACCUMULATED AMORTIZATION OF INTANGIBLE PLANT WITH THE ACCUMULATED DEPRECIATION THAT IS DEDUCTED FROM PLANT IN SERVICE IN THE DETERMINATION OF RATE BASE?***

***A29.*** No. The depreciation reserve on Attachment WDW-1, page 5 reflects the accumulated depreciation on general plant, but not the accumulated amortization of intangible plant.

***Q30. SHOULD THE ACCUMULATED AMORTIZATION OF INTANGIBLE PLANT BE INCLUDED WITH THE ACCUMULATED DEPRECIATION THAT IS DEDUCTED FROM PLANT IN SERVICE?***

***A30.*** Yes. Obviously, if intangible plant is included in rate base, the accumulated amortization of that plant should be reflected as a rate base deduction

***Q31. WHAT DO YOU RECOMMEND?***

***A31.*** Bases on information presented in Case No. 12-1682-EL-AIR, the ratio of accumulated amortization of intangible plant to intangible plant in service is 81.62% (Schedule DJE-4). Applying that ratio to the intangible plant included in the demand related production rate base, the balance of accumulated amortization is $20,606,000. This balance should be deducted from plant in service, and the Company's demand related production rate base should be reduced accordingly.

**F. ACCUMULATED DEFERRED INCOME TAXES**

***Q32. HAVE YOU ANALYZED THE BALANCE OF ACCUMULATED DEFERRED INCOME TAXES ("ADIT") REFLECTED BY THE COMPANY IN ITS DETERMINATION OF THE PRODUCTION RATE BASE?***

***A32.*** Yes. The details of the balance of ADIT are shown on Attachment WDW-1, pages 6-9. The ADIT balances consist of both credit balances that reduce the rate base and debit balances that increase rate base. The net ADIT balance is deducted from plant in service in the determination of rate base on Attachment WDW-1, page 4.

***Q33. ARE YOU PROPOSING ADJUSTMENTS TO THE ADIT BALANCE THAT THE COMPANY REFLECTS IN THE DETERMINATION OF ITS PRODUCTION RATE BASE?***

*A33.* Yes. First, Account 190 includes certain deferred tax debit balances that are related to accrued liabilities or reserves. One of these items is a debit balance of $14,451,000 related to "Property Tax Reserve." This item represents property taxes accrued as expenses that are in excess of cash payments for property taxes that can be deducted for income taxes. However, the accrued reserve for property taxes is not deducted from rate base, nor is the lag in payment for accrued property taxes recognized in the cash working capital allowance, as the Company has not proposed to include a cash working capital allowance in its production rate base. To be consistent, the deferred tax debit balance related to that accrued property tax reserve should not be included in rate base. Elimination of this item reduces the Company's production rate base by $14,451,000 (Schedule DJE-1).

Second, on Attachment WDW-1, page 8, there is an item described as "Retirement Plan Funding – Overfunded" on line 153 with a credit balance of $28,566,000. The Company did not allocate any of this balance to the generation rate base. In the response to OCC Interrogatory 04-048, the Company acknowledged that $8,400,000 of this item should be allocated to generation, of which $5,300,000 is demand-related. The demand related production rate base should be adjusted accordingly.

***Q34. PLEASE SUMMARIZE YOUR PROPOSED ADJUSTMENTS TO THE BALANCE OF ADIT.***

***A34.*** The deferred tax debit balance related to the property tax reserves should be eliminated from the balance of ADIT, and the credit balance related to Retirement Plan Funding – Overfunded should be added to the balance of ADIT. Together, these items increase the balance of production ADIT related to demand by $19,751,000 and reduce the demand related production rate base accordingly (Schedule DJE-1).

## G. OPERATION AND MAINTENANCE EXPENSE

***Q35. ARE YOU PROPOSING AN ADJUSTMENT TO THE OPERATION AND MAINTENANCE EXPENSE INCLUDED BY THE COMPANY IN THE PRODUCTION REVENUE REQUIREMENT?***

***A35.*** Yes. At his deposition, Company Witness Savoy made reference to improvements in the projected results of operations for its generating plants. Regarding these improvements, he stated that "a lot of it was driven by significant cost reduction effort at all of our plants as they've continued to deal with the economics in Ohio and the market changes on our projected generating fleet on the power prices and the fuel prices."[10] It is factors such as economics in Ohio and market conditions that underlie the Company's request to establish a cost-based capacity charge. If these same factors are driving cost reduction efforts, then those cost reduction

[10] Savoy deposition, March 15, 2013, page 79.

efforts should be reflected in the determination of the Company's revenue requirement. Therefore, the actual 2011 production operation and maintenance expense should be adjusted to reflect the improvements to operations and the cost reduction efforts at the Company's plants.

***Q36. HAVE YOU QUANTIFIED AN ADJUSTMENT TO PRODUCTION OPERATION AND MAINTENANCE EXPENSE TO REFLECT THE COMPANY'S COST REDUCTION EFFORTS?***

***A36.*** Yes. Attachment BDS-1 (Confidential) shows the forecasted operation and maintenance expense for 2013. The expenses on that schedule are [redacted] than the production operation and maintenance expenses on Attachment WDW-1, page 19. Based on this difference, I have quantified a reduction to 2011 demand related production operation and maintenance expense of [redacted] (Schedule DJE-5). The OCC has discovery outstanding on this matter, and I reserve the right to modify my testimony on this issue based on the responses to that discovery.

## H. PROPERTY TAXES

***Q37. HOW DID THE COMPANY ALLOCATE PROPERTY TAX EXPENSE TO THE LEGACY GENERATION COST OF SERVICE?***

*A37.* The Company began with the total 2011 property tax expense and then allocated that expense to production based on the ratio of production plant to total company plant (Attachment WDW-1, page 22). This method allocates 56.02% of the property taxes to the demand related production function.

***Q38. IS THIS THE APPROPRIATE METHOD TO ALLOCATE PROPERTY TAX EXPENSE TO THE PRODUCTION FUNCTION?***

*A38.* No. This method of allocation implicitly assumes that all of the Company's plant in service is assessed and taxed at the same rate. However, this is clearly not the case. Based on the 2011 property tax Valuation Notice, the ratio of the assessed "True Value" of Production Plant, to the book value of production plant is substantially less than that ratio is for Transmission & Distribution Plant.[11] Furthermore, the ratio of "Taxable Value" to "True Value" is 24% for Production Plant as compared to 85% for Transmission & Distribution Plant. The end result is that the 2011 Taxable Value for Production Plant is $161,862,000, as compared to a Taxable Value for Transmission & Distribution Plant of $890,691,000. Obviously, any method that allocates 56.02% of property taxes to the production function substantially overstates the level of property taxes properly attributable to the production function and must be corrected.

[11] The True Value of production plant was $674 million vs. a book value of $3.379 billion. The True Value of T&D plant was $1.048 billion vs. a book value of $2.535 billion.

***Q39. WHAT DO YOU RECOMMEND?***

***A39.*** The 2011 Valuation Notice should be used as the basis for the allocation of property taxes to the demand related production function. On Schedule DJE-6, I have calculated that based on the Taxable Value of production plant in 2011, the actual 2011 property tax expense allocable to production is $14,697,000. After elimination of property taxes on assets transferred to Duke Energy Commercial Asset Management ("DECAM"), this expense is $13,710,000. I have also calculated that $2,049,000 of property taxes on general and common plant should be allocated to the demand related production function. The resulting total property tax expense of $15,759,000 is $40,533,000 less than the property tax expense calculated by the Company. The demand related production revenue requirement should be adjusted accordingly.

## III. STRANDED GENERATION COSTS

***Q40. IS THE COMPANY'S APPLICATION TO ESTABLISH A CHARGE BASED ON THE REVENUE REQUIREMENT OF ITS LEGACY GENERATION ASSETS, IN EFFECT, A REQUEST TO RECOVER STRANDED GENERATION COSTS?***

***A40.*** Yes. Stranded generation costs are generally defined as generation costs that are not recoverable in a competitive market for generation services or as the book value of generation assets in excess of the market value of those assets. The cost-based charge being requested by the Company reflects the cost of owning and operating its generation assets in excess of the market value of the capacity of those assets and the energy produced by those assets. In other words, the Company is seeking to recover the costs of the generation assets not recoverable in a competitive market for generation services.

***Q41. IS THE COMPANY'S REQUEST TO RECOVER THE ABOVE MARKET COSTS OF ITS GENERATION ASSETS CONSISTENT WITH THE AGREEMENTS BY WHICH THE COMPANY IMPLEMENTED ITS RESTRUCTURING TRANSITION PLAN?***

***A41.*** No. The Company's transition plan was based on the Stipulation and Recommendation of May 8, 2000 (or "Transition Plan Stipulation") as approved by the Commission in Case No. 99-1658-EL-ETP et al. In its consideration of the Transition Plan Stipulation, the Commission noted that in its transition plan as filed, the Company (at the time Cincinnati Gas and Electric Company, or "CG&E") had originally requested the recovery of $563 million of generation transition costs[12] (or "GTC" representing the above market cost of its generating units). However, as the Commission stated, in contrast to the Company's original claim for recovery of generation transition costs, "The transition plan stipulation provides CG&E with no GTC recovery and places the electricity market price risk entirely on CG&E."[13]

[12] Case No. 99-1658-EL-ETP et al., Opinion and Order, at 23.

[13] Id.

In finding that the transition plan stipulation provided an equitable resolution of the recovery of transition costs, the Commission further noted that "The Company has agreed to forego asserting a claim for stranded generation costs that they calculate on brief to be approximately $470 million on a netted basis."[14] This finding was based on the representation by the Company in its reply brief that "Further, CG&E respectfully requests that the Commission expressly find, as a matter of fact, that in order to resolve this case through stipulation, CG&E agreed to forego its claim to approximately $470 million in generation-related stranded costs."[15]

***Q42. WAS THERE ANY QUID PRO QUO FOR THE COMPANY'S FOREGOING THE RECOVERY OF GENERATION TRANSITION COSTS IN CASE NO. 99-1658-EL-ETP ET AL.?***

***A42.*** Yes. In its reply brief, the Company responded to an objection by certain intervenors that the transition plan stipulation would provide it with open-ended recovery of stranded costs. The Company dismissed such criticism as "simply wrong," and further noted, without qualification, that "As part of the stipulation, of course, CG&E has agreed to forego recovery of its generation related stranded costs in return for authority to recover regulatory assets, the approval of additional regulatory assets, and certain deferrals."[16] Evidently, now that the Company has

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[14] Id., at 28.

[15] Case No. 99-1658-EL-ETP et al., CG&E Reply Brief, at 22.

[16] Id., at 11, Footnote 10.

safely completed the recovery of its generation related regulatory assets from customers in 2010, as provided in the transition plan stipulation, it believes that it can come back and get the generation-related stranded costs which it had agreed to forego in return for authority to recover those regulatory assets.

***Q43. HAS THE COMPANY CITED FINANCIAL INTEGRITY CONCERNS, RATHER THAN RECOVERY OF STRANDED GENERATION COSTS, AS A JUSTIFICATION FOR ITS REQUEST FOR A COST-BASED CAPACITY CHARGE?***

*A43.* Yes. Company Witness Trent states that if the Company's application is not approved, it "will be forced into operating at a significant financial loss," which he believes would not be "just and reasonable" (Direct Testimony, pages 24-25). Company Witness DeMay also addresses Company's present financial condition and the effect of a rejection of the Company's proposal on its financial integrity and credit metrics.

***Q44. ASSUMING THAT THEIR CHARACTERIZATION OF THE CONDITION OF THE COMPANY'S FINANCES IS ACCURATE, WERE THESE CIRCUMSTANCES AVOIDABLE?***

***A44.*** Yes. First, to be clear, I am not endorsing the Company's position on the effect that a rejection of its proposal would have on its financial integrity.[17] However, assuming for the sake of argument that a rejection of its proposed cost-based capacity charge would have the consequences that the Company describes, this outcome is entirely the result of its own decisions.

***Q45. PLEASE EXPLAIN.***

***A45.*** The Company could have either sold its generation assets to an unaffiliated entity or transferred those generation assets to a non-utility affiliate over the course of its transition plan, which was approved in 2012. Then, to the extent that the market price of electricity was less than its cost, it would have no effect on the regulated electric utility or its financial condition.

***Q46. WOULD SUCH A SALE OR TRANSFER OF GENERATION ASSETS BE AN UNUSUAL OR UNORTHODOX COURSE OF ACTION IN THE CONTEXT OF MAKING THE TRANSITION TO A COMPETITIVE MARKET FOR POWER PRODUCTION?***

***A46.*** No. I have participated in electric restructuring matters in Illinois, Maryland, Massachusetts, Rhode Island, and Texas. For the most part, the electric utilities in those jurisdictions either divested substantially all of their generation assets to unaffiliated entities or transferred those assets to non-utility affiliates.

[17] Just as one example, both Mr. Trent and Mr. DeMay cite the negative returns calculated by Mr. Savoy as evidence of the Company's dire financial straits. However, those negative returns omit the $110 million of revenues provided annually by Rider ESSC (response to OCC Interrogatory 11-081).

In fact, it had originally been the intention of CG&E to implement such a transfer. In Case No. 99-1658-EL-ETP et al., the Commission noted that "CG&E's CSP [corporate separation plan] provides for the transfer of its generating assets to an EWG [exempt wholesale generator] and, according to the plan, CG&E will complete the transfer by no later than December 31, 2004."[18] Thus, it was expected at the time the transition plan commenced that just such a transfer would take place.

However, the contemplated transfer of the generating assets did not happen within the specified time frame. The Stipulation and Recommendation in Case No. 03-93-EL-ATA, et al. provided that CG&E would not be required to transfer generating assets to an exempt wholesale generator by the end of 2004.[19] Certain intervenors (including the OCC) in that case submitted that CG&E should be required to comply with the corporate separation plan and not be permitted to retain ownership of its generating assets, and that any delay in such compliance should not be unlimited.[20] The Commission found that "CG&E's corporate separation shall be amended to allow it to retain its generating assets through 2008, after which time the stabilized prices under the stipulation will terminate and corporate separation should be reconsidered."[21]

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[18] Case No. 99-1658-EL-ETP et al., Opinion and Order, at 45.

[19] Case No. 03-93-EL-ATA, et al., Opinion and Order, at 33.

[20] Id.

[21] Id., at 34.

However, 2008 came and went with CG&E (now Duke Energy Ohio) retaining ownership of the generating assets. It is those generating assets that are now the subject of the Company's request to establish a cost-based capacity charge. But it must be emphasized that the Company's retention of its generating assets was not at the behest of the Commission or customer representatives. It was the Company's decision in those years not to sell or transfer its generating assets.[22] Had its decision been different, I believe that we would not be here today.

## IV. CONCLUSION

***Q47. PLEASE SUMMARIZE THE RECOMMENDATIONS MADE IN YOUR TESTIMONY.***

*A47.* The Commission should reject the Company's application to establish a cost-based capacity charge. If the Commission does not grant the Joint Motion to dismiss the Company's Application, then the revenue requirement presented by the Company in support of its cost-based capacity charged should be adjusted. I have quantified adjustments that reduce the Company's revenue requirement by $259,253,000 with Dr. Woolridge's 4.11% return on equity or by $197,942,000 with Dr. Woolridge's 8.75% return on equity.

[22] In Case No. 03-93-EL-ATA, CG&E asserted that in order to provide service at stable rates, it had to retain its generating assets. In fact, the same rate stability could have been achieved by divesting the generating assets with an obligation on the part of the buyer to sell back the output from the generating units at a specified stream of prices during the period of stabilized prices to customers, just as other utilities did in conjunction with electric restructuring transition plans.

***Q48. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?***

***A48.*** Yes. However, I reserve the right to incorporate new information that may subsequently become available.

## CERTIFICATE OF SERVICE

It is hereby certified that a true copy of the foregoing *Direct Testimony of David J. Effron (Public Version) on Behalf of The Ohio Consumers' Counsel* was served via electronic transmission this 26th day of March, 2013.

*/s/ Maureen R. Grady*
Maureen R. Grady
Assistant Consumers' Counsel

## PARTIES OF RECORD

John.jones@puc.state.oh.us
Steven.beeler@puc.state.oh.us
sam@mwncmh.com
fdarr@mwncmh.com
joliker@mwncmh.com
mpritchard@mwncmh.com
cmooney2@columbus.rr.com
dhart@douglasehart.com
haydenm@firstenergycorp.com
jlang@calfee.com
lmcbride@calfee.com
talexander@calfee.com
bojko@carpenterlipps.com
mohler@carpenterlipps.com
joseph.strines@DPLINC.com
judi.sobecki@DPLINC.com
randall.griffin@DPLINC.com

Devin.parram@puc.state.oh.us
dakutik@jonesday.com
aehaedt@jonesday.com
jbentine@amppartners.org
jouett.brenzel@cinbell.com
mjsatterwhite@aep.com
kosterkamp@ralaw.com
asonderman@keglerbrown.com
mkimbrough@keglerbrown.com
wmassey@cov.com
asonderman@keglerbrown.com
mkimbrough@keglerbrown.com

Amy.spiller@duke-energy.com
Jeanne.kingery@duke-energy.com
Elizabeth.watts@duke-energy.com
Rocco.DAscenzo@duke-energy.com
dboehm@BKLlawfirm.com
mkurtz@BKLlawfirm.com
jkylercohn@BKLlawfirm.com
tobrien@bricker.com
tsiwo@bricker.com
mwarnock@bricker.com
jejadwin@aep.com
yalami@aep.com
mhpetricoff@vorys.com
smhoward@vorys.com
stnourse@aep.com
Rdc_law@swbell.net
dakutik@jonesday.com
lfloyd@jonesday.com

Gary.A.Jeffries@dom.com
aaragona@eimerstahl.com
dstahl@eimerstahl.com
ssolberg@eimerstahl.com
BarthRoyer@aol.com

Christine.pirik@puc.state.oh.us
Katie.stenman@puc.state.oh.us

Schedule DJE-1

DUKE ENERGY OHIO, INC.
CASE NO. 12-2400-EL-UNC
SUMMARY OF REVENUE REQUIREMENT ISSUES
($000)

| | | Rate Base | Revenues/ Expenses | Revenue Req. |
|---|---|---|---|---|
| Company Revenue Deficiency | (A) | | | 257,337 |
| Adjustments: | | | | |
| ESSC Revenues | (B) | | [redacted] | [redacted] |
| General Plant | (C) | [redacted] | [redacted] | [redacted] |
| Common Plant | (D) | [redacted] | [redacted] | [redacted] |
| Accum. Amort. - Intangible Plant | (E) | [redacted] | | [redacted] |
| Accum. Deferred Income Taxes | (F) | [redacted] | | [redacted] |
| Operation and Maintenance | (G) | | [redacted] | [redacted] |
| Property Taxes | (H) | | [redacted] | [redacted] |
| Return on Equity - 4.11% | (I) | | | (93,025) |
| Total Adjustments | | | | (259,253) |
| Adjusted Revenue Deficiency 4.11% ROE | | | | (1,916) |
| Sum of Adjustments other than ROE | | | | [redacted] |
| Return on Equity - 8.75% | (H) | | | (31,713) |
| Total Adjustments | | | | (197,942) |
| Adjusted Revenue Deficiency 8.75% ROE | | | | 59,395 |

Sources:

(A) Attachment WDW-1, Page 3

(B) Case No, 11-3549-EL-SSO, Stipulation and Recommendation, Page16

(C) Schedule DJE-2

(D) Schedule DJE-3

(E) Schedule DJE-4

| | | | |
|---|---|---|---|
| (F) | ADIT - Property Taxes | 14,451 | Att. WDW-1, Page 6 |
| | ADIT - Ret. Plan Overfunded | 5,300 | OCC-INT-04-048 |
| | Total Adjustment | 19,751 | |

(G) Schedule DJE-5

(H) Schedule DJE-6

(I) Schedule DJE-7

Schedule DJE-1A

DUKE ENERGY OHIO, INC.
CASE NO. 12-2400-EL-UNC
FACTORS USED IN REVENUE REQUIREMENT EFFECT CALCULATIONS

Rate of Return, per Company (Attachment WDW-1, page 17)

| | Ratio | Cost | Wtd. Cost | Pre-tax Cost |
|---|---|---|---|---|
| Debt | 46.84% | 4.11% | 1.93% | 1.93% |
| Equity | 53.16% | 11.15% | 5.93% | 9.16% |
| Total Capital | 100.00% | | 7.85% | 11.08% |

| | | |
|---|---|---|
| Effective Income Tax Rate | 35.2796% | Attachment WDW-1, page 23 |
| Complement | 64.7204% | |

DUKE ENERGY OHIO, INC.
CASE NO. 12-2400-EL-UNC
GENERAL PLANT
($000)

| | | | |
|---|---|---|---|
| Total General Plant | (1) | (A) | 90,270 |
| Smart Grid | | (B) | 36,089 |
| Total General Plant Excluding Smart Grid | | | 54,181 |
| Adjusted Allocation Factor | | (C) | 4.511% |
| General Plant Allocated to Production - Demand | (2) | | 2,444 |
| General Plant Allocated to Production - Demand by Company | | (A) | 29,019 |
| Adjustment to General Plant | | | (26,575) |
| | | | |
| Depreciation Reserve - General Plant | | (D) | 21,341 |
| Ratio of Allocated General Plant to Total | | (E) | 2.708% |
| Depreciation Reserve Allocated to Production - Demand | | | 578 |
| General Plant Allocated to Production - Demand by Company | | (D) | 6,860 |
| Adjustment to Depreciation Reserve - General Plant | | | (6,282) |
| | | | |
| Net Adjustment to General Plant in Rate Base | | | (20,293) |
| | | | |
| Depreciation on General Plant | | (F) | 4,050 |
| Ratio of Allocated General Plant to Total | | (E) | 2.708% |
| Depreciation Expense Allocated to Production - Demand | | | 110 |
| Depreciation Expense Allocated by Company | | (G) | 1,302 |
| Adjustment to Depreciation Expense - General Plant | | | (1,192) |

Sources:

| | | | | |
|---|---|---|---|---|
| (A) | Attachment WDW-1, Page 13 | | | |
| (B) | Response to OCC INT 13-105 | | 1036+35053 | |
| (C) | Allocation to Distribution | | 92.257% | 12-1682, Sch. B-2.1 |
| | Allocation to G&T | | 7.743% | |
| | Allocation to Generation | 93.182% | 7.215% | 12-1682, WPB-7a |
| | Allocation to Demand | | 62.52% | WDW-1, Page 6 |
| | Allocation Factor | | 4.511% | |
| (D) | Attachment WDW-1, Page 5 | | | |
| (E) | (2)/(1) | | | |
| (F) | FERC Form 1, page 336, line 10 | | | |
| (G) | Attachment WDW-1, Page 13 | 32.147% | * | 4,050 |

Schedule DJE-3

DUKE ENERGY OHIO, INC.
CASE NO. 12-2400-EL-UNC
COMMON PLANT
($000)

| | | |
|---|---|---|
| Smart Grid Assets in Common Plant as of 12/31/2011 | (A) | 12,847 |
| Allocation to Electric | (B) | 83.50% |
| Smart Grid Allocation to Electric | | 10,727 |
| Allocation to Production Demand | (B) | 56.458% |
| Adjustment to Common Plant in Production Rate Base | | (6,056) |
| | | |
| Common Smart Grid Depreciation Reserve | (C) | 1,943 |
| Allocation to Electric | (B) | 83.50% |
| Smart Grid Allocation to Electric | | 1,622 |
| Allocation to Production Demand | (B) | 56.458% |
| Adjustment to Common Plant Depreciation Reserve | | (916) |
| | | |
| Net Adjustment to Rate Base | | (5,140) |
| | | |
| Depreciation on Common Plant - Production Demand | (D) | 2,426 |
| Ratio of Plant Adjustment to Common Plant (Excl. Intangible) | (E) | 7.27% |
| Adjustment to Depreciation Expense | | (176) |

Sources:

| | | |
|---|---|---|
| (A) | Response to OCC INT 13-106 | 61.4+12785.3 |
| (B) | Attachment WDW-1, Page 14 | |
| (C) | Case No. 12-1682-EL-AIR, Schedule B-2.5b, Page 3 | |
| (D) | Attachment WDW-1, Page 21 | |
| (E) | Line 1/(298250-121525) | Attachment WDW-1, Page 14 |

Schedule DJE-4

DUKE ENERGY OHIO, INC.
CASE NO. 12-2400-EL-UNC
ACCUMULATED AMORTIZATION - INTANGIBLE PLANT
($000)

| | |
|---|---|
| Intangible Plant in Production - Demand Rate Base | 25,246 |
| Ratio of Accumulated Amortization to Plant | 81.62% |
| Accumulated Amortization - Intangible Plant | 20,606 |

Sources:

(A) Attachment WDW-1, Page 13

(B) Case No. 12-1682-EL-AIR, Schedule B-3, Page 3

| | |
|---|---|
| Accumulated Amortization | 28,384 |
| Intangible Plant | 34,776 |
| Ratio | 81.62% |

Schedule DJE-5

DUKE ENERGY OHIO, INC.
CASE NO. 12-2400-EL-UNC
OPERATION AND MAINTENANCE EXPENSE
($000)

| | | |
|---|---|---|
| Forecasted 2013 Operation and Maintenance Expense | | |
| 2011 Production O&M Expense | (A) | [redacted] |
| Adjustment to O&M Expenses | (B) | 225,711 |
| | | [redacted] |
| Allocation to Demand | | [redacted] |
| Adjustment to Demand Related Production Expenses | (B) | [redacted] |
| | | [redacted] |

Sources:
(A) Attachment BDS-1, Confidential
(B) Attachment WDW-1, Page 19

Schedule DJE-6

# DUKE ENERGY OHIO, INC.
## CASE NO. 12-2400-EL-UNC
## ADJUSTMENT TO PROPERTY TAX EXPENSE
## ($000)

| | | |
|---|---|---|
| Taxable Value of Production Property | (A) | 161,862 |
| Total Taxable Value of Property | (A) | 1,106,637 |
| Ratio | | 14.626% |
| Total 2011 Property Taxes | (B) | 100,482 |
| Property Taxes on Production Plant | | 14,697 |
| Taxes on Assets Transferred to DECAM | (C) | 987 |
| Adjusted Property Taxes on Production Plant | | 13,710 |
| | | |
| Taxable Value of General Plant | (A) | 54,083 |
| Total Taxable Value Property | (A) | 1,106,637 |
| Ratio | | 4.887% |
| Total 2011 Property Taxes | (B) | 100,482 |
| Property Taxes on General Plant | | 4,911 |
| Ratio of General and Common Plant Allocated to Production - Demand | (D) | 41.72% |
| Allocation to Production-Demand | | 2,049 |
| | | |
| Total Property Taxes Allocated to Production - Demand | | 15,759 |
| Property Taxes Allocated to Production - Demand per Company | (B) | 56,292 |
| Adjustment to Property Tax Expense | | (40,533) |

Sources:

(A) 2011 Valuation Notice
(B) Attachment WDW-1, Page 22
(C) Rate Schedule 101, Page 14 Workpaper
(D) Attachment WDW-1, Page 5

Schedule DJE-7

DUKE ENERGY OHIO, INC.
CASE NO. 12-2400-EL-UNC
RATE OF RETURN EFFECT
($000)

| | | |
|---|---|---|
| Company Rate Base | (A) | 1,674,513 |
| Proposed Adjustments to Rate Base | (B) | (65,790) |
| Adjusted Rate Base | | 1,608,723 |
| | | |
| Pre-Tax Rate of Return - Duke | (C) | 11.08% |
| Pre-Tax Rate of Return - OCC - 4.11% ROE | (D) | 5.30% |
| Difference | | -5.78% |
| | | |
| Effect on Return Requirement | | (93,025) |
| | | |
| Pre-Tax Rate of Return - Duke | (C) | 11.08% |
| Pre-Tax Rate of Return - OCC - 8.75% ROE | (D) | 9.11% |
| Difference | | -1.97% |
| | | |
| Effect on Return Requirement | | (31,713) |

Sources:

(A) Attachment WDW-1, Page 4
(B) Schedule DJE-1
(C) Attachment WDW-1, Page 17
(D) Testimony of Dr. Woolridge

| | Ratio | Cost | Wtd. Cost | Pre-tax Cost |
|---|---|---|---|---|
| Debt | 46.84% | 4.11% | 1.93% | 1.93% |
| Equity | 53.16% | 4.11% | 2.18% | 3.38% |
| Total Capital | 100.00% | | 4.11% | 5.30% |

| | Ratio | Cost | Wtd. Cost | Pre-tax Cost |
|---|---|---|---|---|
| Debt | 46.84% | 4.11% | 1.93% | 1.93% |
| Equity | 53.16% | 8.75% | 4.65% | 7.19% |
| Total Capital | 100.00% | | 6.58% | 9.11% |

*OCC EXHIBIT* 25A

**BEFORE**
**THE PUBLIC UTILITIES COMMISSION OF OHIO**

| | | |
|---|---|---|
| In the Matter of the Application of Duke Energy Ohio, Inc. for the Establishment of a Charge Pursuant to Revised Code Section 4909.18. | ) ) ) ) | Case No. 12-2400-EL-UNC |
| In the Matter of the Application of Duke Energy Ohio, Inc. for Approval to Change Accounting Methods. | ) ) | Case No. 12-2401-EL-AAM |
| In the Matter of the Application of Duke Energy Ohio, Inc. for Approval of a Tariff for a New Service. | ) ) ) | Case No. 12-2402-EL-ATA |

**DIRECT TESTIMONY**
**of**
**DAVID J. EFFRON**

(CONFIDENTIAL VERSION)

On Behalf of the
**OFFICE OF THE OHIO CONSUMERS' COUNSEL**
10 West Broad St., Suite 1800
Columbus, OH 43215

*MARCH 26, 2013*

# TABLE OF CONTENTS

## I. QUALIFICATIONS AND PURPOSE OF TESTIMONY

***Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.***

***A1.*** My name is David J. Effron. My address is 12 Pond Path, North Hampton, New Hampshire, 03862.

***Q2. WHAT IS YOUR PRESENT OCCUPATION?***

***A2.*** I am a consultant specializing in utility regulation.

***Q3. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.***

***A3.*** My professional career includes over thirty years as a regulatory consultant, two years as a supervisor of capital investment analysis and controls at Gulf & Western Industries and two years at Touche Ross & Co. as a consultant and staff auditor. I am a Certified Public Accountant and I have served as an instructor in the business program at Western Connecticut State College.

***Q4. WHAT EXPERIENCE DO YOU HAVE IN THE AREA OF UTILITY RATE SETTING PROCEEDINGS AND OTHER UTILITY MATTERS?***

***A4.*** I have analyzed numerous electric, gas, telephone, and water filings in different jurisdictions. Pursuant to those analyses, I have prepared testimony, assisted attorneys in case preparation, and provided assistance during settlement negotiations with various utility companies.

I have testified in over three hundred cases before regulatory commissions in Alabama, Colorado, Connecticut, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Missouri, Nevada, New Jersey, New York, North Dakota, Ohio, Pennsylvania, Rhode Island, South Carolina, Texas, Vermont, Virginia, and Washington.

***Q5. PLEASE DESCRIBE YOUR OTHER WORK EXPERIENCE.***

***A5.*** As a supervisor of capital investment analysis at Gulf & Western Industries, I was responsible for reports and analyses concerning capital spending programs, including project analysis, formulation of capital budgets, establishment of accounting procedures, monitoring capital spending, and administration of the leasing program. At Touche Ross & Co., I was an associate consultant in management services for one year, and a staff auditor for one year.

***Q6. HAVE YOU EARNED ANY DISTINCTIONS AS A CERTIFIED PUBLIC ACCOUNTANT?***

***A6.*** Yes. I received the Gold Charles Waldo Haskins Memorial Award for the highest scores in the May 1974 certified public accounting examination in New York State.

***Q7. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.***

***A7.*** I have a Bachelor's degree in Economics (with distinction) from Dartmouth College and a Masters of Business Administration Degree from Columbia University.

***Q8. ON WHOSE BEHALF ARE YOU TESTIFYING?***

***A8.*** I am testifying on behalf of the Office of the Ohio Consumers' Counsel ("OCC").

***Q9. WHAT IS THE PURPOSE OF YOUR TESTIMONY?***

***A9.*** Duke Energy Ohio, Inc. ("Duke" or "Company") has requested approval of a cost-based charge as compensation for providing capacity service in connection with its obligations as a fixed resource requirement (FRR) entity. I address certain issues related to the revenue requirement presented by the Company in support of its proposed cost-based capacity rate, and I have also quantified the effect of the Dr. Woolridge's return on equity recommendations on the Company's revenue requirement. I also explain why the cost-based charge as compensation for providing capacity service proposed by the Company in this case is tantamount to a request to recover generation costs in excess of market value and, as such, is inconsistent with the agreements on which the Company's restructuring transition plan was based.

***Q10. WHAT DOCUMENTS DID YOU REVIEW IN PREPARING YOUR TESTIMONY?***

***A10.*** I reviewed the Company's testimony, exhibits, workpapers and the Company's responses to discovery and data requests propounded by the OCC, motions and comments submitted by the OCC, and certain relevant stipulations and Commission Opinions and Orders in other cases.

## II. REVENUE REQUIREMENT ISSUES

### A. INTRODUCTION

***Q11. BY ADDRESSING REVENUE REQUIREMENT ISSUES IN THIS CASE, ARE YOU IMPLICITLY AGREEING THAT THE COMPANY'S REQUEST TO ESTABLISH A COST-BASED CAPACITY CHARGE FOR IT LEGACY GENERATION IS APPROPRIATE?***

***A11.*** Absolutely not. As I stated above, the approval of a cost-based capacity charge would be inconsistent with the agreements (as described later in this testimony) on which the Company's restructuring transition plan was based. In addition, on October 4, 2012, the OCC and several signatories to the Duke ESP[1] filed a Joint Motion to Dismiss. The Joint Motion to Dismiss set out the primary reasons why the Company's proposal to establish a cost-based capacity charge should be rejected. In particular, the Commission should enforce the Stipulation it approved in the Duke Electric Security Plan proceeding (Case No. 11-3549-EL-SSO, et al.). There, Duke agreed to provide capacity for all load (both shopping and Standard Service Offer ("SSO")) at market-based Reliability Pricing Model ("RPM") rates, supplemented by a non-bypassable Electric Service Stability Charge ("ESSC") of

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[1] *In the Matter of the Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service*, Case No. 11-3549-EL-SSO, et al., ("Duke ESP"), Stipulation and Recommendation (Oct. 24, 2011) (approved, Opinion and Order (Nov. 22, 2011)).

\$330 million over three years.[2] Duke, OCC, and multiple intervenors agreed to the terms of this Stipulation, which the Commission approved. Customers have paid and are continuing to pay the ESSC, thereby upholding their end of the agreement. Duke should be required to, in turn, fulfill its commitments under that agreement, especially its commitment to be compensated at market-based RPM capacity rates - not fully embedded capacity rates. Duke's application seeking to unilaterally improve upon the Stipulation (after seeing the outcome of the Ohio Power capacity proceeding) should be rejected. The integrity of the agreement in the ESP case should be upheld.[3]

Duke cites the "newly adopted state compensation mechanism" (referring to the mechanism adopted for Ohio Power in Case No. 10-2929-EL-UNC) as authority for its request in this proceeding. But it is the position of the OCC that the Ohio Power Capacity Case decision was not a generic PUCO decision that applies to all electric distribution utilities, but that rather. Rather, the Commission limited its decision for a cost-based state compensation mechanism in the Ohio Power Capacity Case to Ohio Power.[4] Therefore, Duke cannot rely on decision by the Commission in the Ohio Power Capacity Case as justification for its request in this case.

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[2] ("Duke ESP"), Stipulation and Recommendation (Oct. 24, 2011). (approved, Opinion and Order (Nov. 22, 2011).

[3] See Case Nos. 12-2400-EL-UNC, et al., Joint Motion to Dismiss at 13-17 (October 4, 2012), and Comments of OCC and OEG at 2-4 (January 2, 2013).

[4] See Case Nos. 12-2400-EL-UNC, et al., Comments of OCC and OEG at 2-4 (January 2, 2013).

***Q12. IF THE COMMISSION DOES NOT GRANT THE JOINT MOTION TO DISMISS DUKE'S APPLICATION, SHOULD THERE BE CERTAIN LIMITATIONS ON THE IMPOSITION OF ANY COST-BASED CAPACITY CHARGES ON CUSTOMERS?***

***A12.*** Yes. First, Duke is seeking to establish a deferral as of the month of its Application in the present case, August 2012, to account for the difference between the amounts being recovered for the provision of capacity service and the cost of providing such capacity. By this request, the Company is asking to be compensated prospectively for losses incurred in the past. The approval of such a request would constitute retroactive ratemaking, and the Commission should not authorize the Company to defer any costs incurred prior to the completion of this case.

To illustrate by example, in Case No. 12-1682-EL-AIR, Duke has requested an increase in its electric distribution rates based on a 2012 test year. If the Commission finds that the Company has a revenue deficiency in that case, any increase in rates will not go into effect until the conclusion of the case. If Duke had argued there that the finding of a revenue deficiency implied that distribution revenues had fallen short of full cost recovery in 2012 and that the Company should be authorized to defer that shortfall for future recovery, such a request would be summarily rejected as retroactive ratemaking. Duke's request to create a deferral dating back to August 29, 2012 in the present case should similarly be denied as retroactive ratemaking.

Second, in Case No. 11-3549-EL-SSO, et al., the Company agreed to transfer all of its generation assets out of Duke Energy Ohio by December 31, 2014. It is the position of the OCC that the cost-based capacity charge should cease at the time of such transfer.

***Q13. HAVE YOU SUMMARIZED THE REVENUE REQUIREMENT EFFECTS OF THE ISSUES THAT YOU ARE ADDRESSING IN THIS TESTIMONY?***

***A13.*** Yes. I have summarized the revenue requirement effect of the issues that I am addressing in this testimony on my Schedule DJE-1. The adjustments to the Company's revenue requirement presented in this testimony are based on my own review and analysis, and I am not taking a position on any other adjustments that may be presented by Staff or other intervenors.

***Q14. HAVE YOU ALSO QUANTIFIED THE EFFECTS OF DR. WOOLRIDGE'S RETURN ON EQUITY RECOMMENDATIONS?***

***A14.*** Yes. I also show the revenue requirement effects of Mr. Woolridge's return on equity recommendations on my Schedule DJE-1. Again, the adjustments to the Company's revenue requirement position that I address, as well as the adjustments related to the appropriate return on equity, are relevant only if the Commission does not grant the OCC Motion to Dismiss Duke's Application.

**B. ELECTRIC SECURITY STABILITY CHARGE REVENUES**

***Q15. DID THE STIPULATION IN CASE NO. 11-3549-EL-SSO COMPENSATE THE COMPANY FOR PROVIDING RETAIL ELECTRIC SERVICE AS A FIXED RESOURCE REQUIREMENT ENTITY?***

***A15.*** Yes.[5] Section VII.A of the Stipulation and Recommendation in Case No. 11-3549-EL-SSO established a non-bypassable generation charge designated as the Electric Service Stability Charge Rider ("Rider ESSC"), which was "intended to provide stability and certainty regarding Duke Energy Ohio's provision of retail electric service as an FRR [Fixed Resource Requirement] entity while continuing to operate under an ESP."[6] Pursuant to Rider ESSC, the Company was "permitted to collect $110 million per year for a period of three years commencing January 1, 2012, with the collection to be trued-up annually and the total equal to $330 million."[7] This section of the Stipulation and Recommendation also explicitly stated that "(t)he revenue collected under Rider ESSC shall stay with Duke Energy Ohio and shall not be transferred to any subsidiary or affiliate."[8]

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[5] It is the position of the OCC that the Stipulation and Recommendation in Case No. 11-3549-EL-SSO addressed wholesale capacity commitments as well as retail electric service (Case No. 12-2400-EL-AIR, Joint Reply to Duke Energy's Memorandum Contra by Signatory Parties, page 6).

[6] Case No, 11-3549-EL-SSO, et al., Stipulation and Recommendation, pages 15-16.

[7] Id.

[8] Id.

***Q16. DID THE COMPANY INCLUDE THE REVENUES FROM RIDER ESSC AS A CREDIT TO THE ANNUAL PRODUCTION FIXED COST IN ITS DETERMINATION OF THE NET REVENUE REQUIREMENT IN THE PRESENT CASE?***

*A16. No.*

***Q17. DID THE COMPANY EXPLAIN WHY IT DID NOT RECOGNIZE THE ESSC RIDER REVENUES AS A CREDIT TO THE ANNUAL PRODUCTION FIXED COST?***

*A17.* Yes. In response to OCC Interrogatory 04-043, Duke stated that "Rider ESSC is intended to provide certainty and stability in the provision of competitive retail electric service." However, Duke went on to say, "the capacity charge at issue in these proceedings is intended to compensate Duke Energy Ohio for its provision of noncompetitive capacity service as an FRR entity." Therefore, the Company concludes, the compensation for these services should be separate. In other words, for the purposes of determining the revenue requirement for the Company's generating capacity in the present case, it is, in effect, the Company's position that revenues produced by Rider ESSC may as well not exist.

***Q18. IS THE COMPANY'S EXPLANATION A VALID REASON FOR IGNORING THE ESSC REVENUES IN THE DETERMINATION OF THE GENERATION REVENUE REQUIREMENT IN THE PRESENT CASE?***

***A18.*** No. As stated above, the Stipulation and Recommendation in Case No. 11-3549-EL-SSO stated that Rider ESSC was "intended to provide stability and certainty regarding Duke Energy Ohio's provision of retail electric service as an FRR entity." No distinction was drawn between "competitive retail electric service" and "noncompetitive capacity service," as Duke now claims. Conversely, this Stipulation and Recommendation explicitly states that the ESSC Rider was related to "Duke Energy Ohio's provision of retail electric service as an FRR entity," which the Company now claims is separate and distinct from "non-competitive" capacity service provided as an FRR entity.

More substantively, although Duke claims that the provision of competitive and non-competitive capacity services are distinct, the Company does not assign or allocate its legacy generation between competitive retail electric service and noncompetitive capacity service (response to OCC Interrogatory 07-061). Thus, in the framework being advocated by the Company, it is collecting $110 million annually pursuant to Rider ESSC for providing a service that has no assets and incurs no expenses. In other words, according to Duke, the $110 million is "money for nothing."

***Q19. WHAT DO YOU RECOMMEND?***

***A19.*** As stated above, the Commission should deny the Company's request for a cost-based capacity charge. However, if a cost-based capacity charge is authorized, then the charge must take into account the existence of Rider ESSC revenues. If the $110 million being recovered annually pursuant to Rider ESSC is ignored, then whatever the Company ultimately collects from customers as a result of the cost-based capacity charge will be a pure windfall to the Company. Therefore, the ESSC revenues should be credited to Annual Production Fixed Cost, and the revenue requirement on which the Company's proposed capacity charge is based should be reduced accordingly (Schedule DJE-1). Alternatively, the ESSC revenues being recovered by the Company could be credited directly to the charges that Duke is seeking to defer for future collection, which should ultimately have the same end result.

## C. GENERAL PLANT

***Q20. DOES THE PRODUCTION-RELATED PLANT IN THE COMPANY'S RATE BASE INCLUDE AN ALLOCATION OF GENERAL PLANT?***

***A20.*** Yes. As can be seen on Attachment WDW-1, page 5, the production related plant includes $86,794,000 of general and intangible plant. The allocation of the general and intangible plant to the production function is shown on Attachment WDW-1, page 13.

***Q21. SHOULD THE GENERAL PLANT INCLUDED IN THE PRODUCTION RELATED RATE BASE BE ADJUSTED?***

***A21.*** Yes. First, the general plant accounts include assets related to the Company's Smart Grid initiative. The Smart Grid assets should be eliminated before any allocation of plant to the production function. Second, the allocation factor used to allocate the general and intangible function should be modified.

***Q22. WHY SHOULD THE SMART GRID ASSETS BE ELIMINATED FROM THE GENERAL ASSETS BEFORE ANY ALLOCATION TO PRODUCTION?***

***A22.*** The costs related to Smart Grid are recovered by means of a separate rider. None of these costs should be allocated to the production related rate base. Smart Grid assets are included in Account 391 – Office Furniture and Equipment and Account 397 – Communications Equipment. Theses accounts should be adjusted to eliminate $36,089,000 of Smart Grid assets before they are allocated to production (Schedule DJE-2).

***Q23. WHY SHOULD THE ALLOCATION FACTOR USED TO ALLOCATE GENERAL PLANT TO THE PRODUCTION FUNCTION BE MODIFIED?***

***A23.*** The Company begins with the total general plant as of December 31, 2011 and then uses an allocation factor of 51.42% to allocate the general and intangible plant to production. However, in the Company's pending distribution rate case, Case No. 12-1682-EL-AIR, the Company began with the total general plant as of March 31, 2012 and used an allocation factor of 92.257% to allocate the general plant to the distribution function.[9] Obviously, use of allocation factors that add to greater than 100% creates an overlap and will lead to Duke obtaining a double recovery if not corrected.

The Company is proposing to recover 92.257% of the general plant in its distribution revenue requirement in Case No. 12-1682-EL-AIR. Accordingly, only 7.743% of general plant remains to be recovered. On Schedule DJE-2, I show the allocation of the remaining 7.743% of general plant between transmission and production. This modification is necessary to prevent the double recovery of a portion of the general plant.

***Q24. WHAT IS THE EFFECT OF YOUR PROPOSED ADJUSTMENTS TO GENERAL PLANT?***

***A24.*** My adjustments reduce the general plant included in the demand related production rate base by $26,575,000. Consistent this adjustment to plant, the depreciation reserve on the general plant in the production rate base should be reduced by $6,282,000, and the depreciation expense on the general plant in the production rate base should be reduced by $1,192,000 (Schedule DJE-2).

[9] Case No. 12-1682-EL-AIR, Application, Volume 9, Schedule B-2.1, page 3. The 92.257% allocation factor was based on 2011 salaries and wages.

**D. COMMON PLANT**

***Q25. DOES THE PRODUCTION- RELATED PLANT INCLUDED IN THE COMPANY'S RATE BASE ALSO INCLUDE AN ALLOCATION OF COMMON PLANT?***

***A25.*** Yes. As can be seen on Attachment WDW-1, Page 5, the production-related plant includes $141,933,000 of common plant. Common plant is intangible and general plant that serves both electric and gas operations. The allocation of the common plant to electric operations and then to the production function is shown on Attachment WDW-1, page 14.

***Q26. SHOULD THE GENERAL AND INTANGIBLE PLANT INCLUDED IN THE PRODUCTION RELATED RATE BASE BE ADJUSTED?***

***A26.*** Yes. Common plant accounts also include assets related to the Company's Smart Grid initiative. Again, the Smart Grid assets should be eliminated before any allocation of plant to the electric production function, because costs related to Smart grid are recovered from customers by means of a separate rider. Smart Grid assets are included in Account 191 – Office Furniture and Equipment, and Account 197 – Communications Equipment. Theses accounts should be adjusted to eliminate the Smart Grid assets before they are allocated to electric production (Schedule DJE-3).

***Q27. WHAT IS THE EFFECT OF ELIMINATING SMART GRID ASSETS FROM COMMON PLANT?***

***A27.*** The elimination of Smart Grid assets reduces the common plant included in the demand related production rate base by $6,036,000. Consistent with this adjustment to plant, the depreciation reserve on demand related production plant should be reduced by $916,000, and the depreciation expense on demand related production plant should be reduced by $176,000 (Schedule DJE-3).

**E. ACCUMULATED AMORTIZATION – INTANGIBLE PLANT**

***Q28. DOES THE COMPANY INCLUDE INTANGIBLE PLANT IN ITS PRODUCTION RATE BASE?***

***A28.*** Yes. Intangible plant is shown on Attachment WDW-1, page 13, along with general plant.

***Q29. DID THE COMPANY INCLUDE THE ACCUMULATED AMORTIZATION OF INTANGIBLE PLANT WITH THE ACCUMULATED DEPRECIATION THAT IS DEDUCTED FROM PLANT IN SERVICE IN THE DETERMINATION OF RATE BASE?***

***A29.*** No. The depreciation reserve on Attachment WDW-1, page 5 reflects the accumulated depreciation on general plant, but not the accumulated amortization of intangible plant.

***Q30. SHOULD THE ACCUMULATED AMORTIZATION OF INTANGIBLE PLANT BE INCLUDED WITH THE ACCUMULATED DEPRECIATION THAT IS DEDUCTED FROM PLANT IN SERVICE?***

***A30.*** Yes. Obviously, if intangible plant is included in rate base, the accumulated amortization of that plant should be reflected as a rate base deduction

***Q31. WHAT DO YOU RECOMMEND?***

***A31.*** Bases on information presented in Case No. 12-1682-EL-AIR, the ratio of accumulated amortization of intangible plant to intangible plant in service is 81.62% (Schedule DJE-4). Applying that ratio to the intangible plant included in the demand related production rate base, the balance of accumulated amortization is $20,606,000. This balance should be deducted from plant in service, and the Company's demand related production rate base should be reduced accordingly.

## F. ACCUMULATED DEFERRED INCOME TAXES

***Q32. HAVE YOU ANALYZED THE BALANCE OF ACCUMULATED DEFERRED INCOME TAXES ("ADIT") REFLECTED BY THE COMPANY IN ITS DETERMINATION OF THE PRODUCTION RATE BASE?***

***A32.*** Yes. The details of the balance of ADIT are shown on Attachment WDW-1, pages 6-9. The ADIT balances consist of both credit balances that reduce the rate base and debit balances that increase rate base. The net ADIT balance is deducted from plant in service in the determination of rate base on Attachment WDW-1, page 4.

***Q33. ARE YOU PROPOSING ADJUSTMENTS TO THE ADIT BALANCE THAT THE COMPANY REFLECTS IN THE DETERMINATION OF ITS PRODUCTION RATE BASE?***

***A33.*** Yes. First, Account 190 includes certain deferred tax debit balances that are related to accrued liabilities or reserves. One of these items is a debit balance of $14,451,000 related to "Property Tax Reserve." This item represents property taxes accrued as expenses that are in excess of cash payments for property taxes that can be deducted for income taxes. However, the accrued reserve for property taxes is not deducted from rate base, nor is the lag in payment for accrued property taxes recognized in the cash working capital allowance, as the Company has not proposed to include a cash working capital allowance in its production rate base. To be consistent, the deferred tax debit balance related to that accrued property tax reserve should not be included in rate base. Elimination of this item reduces the Company's production rate base by $14,451,000 (Schedule DJE-1).

Second, on Attachment WDW-1, page 8, there is an item described as "Retirement Plan Funding – Overfunded" on line 153 with a credit balance of $28,566,000. The Company did not allocate any of this balance to the generation rate base. In the response to OCC Interrogatory 04-048, the Company acknowledged that $8,400,000 of this item should be allocated to generation, of which $5,300,000 is demand-related. The demand related production rate base should be adjusted accordingly.

***Q34. PLEASE SUMMARIZE YOUR PROPOSED ADJUSTMENTS TO THE BALANCE OF ADIT.***

***A34.*** The deferred tax debit balance related to the property tax reserves should be eliminated from the balance of ADIT, and the credit balance related to Retirement Plan Funding – Overfunded should be added to the balance of ADIT. Together, these items increase the balance of production ADIT related to demand by $19,751,000 and reduce the demand related production rate base accordingly (Schedule DJE-1).

## G. OPERATION AND MAINTENANCE EXPENSE

***Q35. ARE YOU PROPOSING AN ADJUSTMENT TO THE OPERATION AND MAINTENANCE EXPENSE INCLUDED BY THE COMPANY IN THE PRODUCTION REVENUE REQUIREMENT?***

***A35.*** Yes. At his deposition, Company Witness Savoy made reference to improvements in the projected results of operations for its generating plants. Regarding these improvements, he stated that "a lot of it was driven by significant cost reduction effort at all of our plants as they've continued to deal with the economics in Ohio and the market changes on our projected generating fleet on the power prices and the fuel prices."[10] It is factors such as economics in Ohio and market conditions that underlie the Company's request to establish a cost-based capacity charge. If these same factors are driving cost reduction efforts, then those cost reduction

[10] Savoy deposition, March 15, 2013, page 79.

efforts should be reflected in the determination of the Company's revenue requirement. Therefore, the actual 2011 production operation and maintenance expense should be adjusted to reflect the improvements to operations and the cost reduction efforts at the Company's plants.

***Q36. HAVE YOU QUANTIFIED AN ADJUSTMENT TO PRODUCTION OPERATION AND MAINTENANCE EXPENSE TO REFLECT THE COMPANY'S COST REDUCTION EFFORTS?***

*A36.* Yes. Attachment BDS-1 (Confidential) shows the forecasted operation and maintenance expense for 2013. The expenses on that schedule are $13,411,000 lower than the production operation and maintenance expenses on Attachment WDW-1, page 19. Based on this difference, I have quantified a reduction to 2011 demand related production operation and maintenance expense of $7,035,000 (Schedule DJE-5). The OCC has discovery outstanding on this matter, and I reserve the right to modify my testimony on this issue based on the responses to that discovery.

**H. PROPERTY TAXES**

***Q37. HOW DID THE COMPANY ALLOCATE PROPERTY TAX EXPENSE TO THE LEGACY GENERATION COST OF SERVICE?***

***A37.*** The Company began with the total 2011 property tax expense and then allocated that expense to production based on the ratio of production plant to total company plant (Attachment WDW-1, page 22). This method allocates 56.02% of the property taxes to the demand related production function.

***Q38. IS THIS THE APPROPRIATE METHOD TO ALLOCATE PROPERTY TAX EXPENSE TO THE PRODUCTION FUNCTION?***

***A38.*** No. This method of allocation implicitly assumes that all of the Company's plant in service is assessed and taxed at the same rate. However, this is clearly not the case. Based on the 2011 property tax Valuation Notice, the ratio of the assessed "True Value" of Production Plant, to the book value of production plant is substantially less than that ratio is for Transmission & Distribution Plant.[11] Furthermore, the ratio of "Taxable Value" to "True Value" is 24% for Production Plant as compared to 85% for Transmission & Distribution Plant. The end result is that the 2011 Taxable Value for Production Plant is $161,862,000, as compared to a Taxable Value for Transmission & Distribution Plant of $890,691,000. Obviously, any method that allocates 56.02% of property taxes to the production function substantially overstates the level of property taxes properly attributable to the production function and must be corrected.

[11] The True Value of production plant was $674 million vs. a book value of $3.379 billion. The True Value of T&D plant was $1.048 billion vs. a book value of $2.535 billion.

***Q39. WHAT DO YOU RECOMMEND?***

***A39.*** The 2011 Valuation Notice should be used as the basis for the allocation of property taxes to the demand related production function. On Schedule DJE-6, I have calculated that based on the Taxable Value of production plant in 2011, the actual 2011 property tax expense allocable to production is $14,697,000. After elimination of property taxes on assets transferred to Duke Energy Commercial Asset Management ("DECAM"), this expense is $13,710,000. I have also calculated that $2,049,000 of property taxes on general and common plant should be allocated to the demand related production function. The resulting total property tax expense of $15,759,000 is $40,533,000 less than the property tax expense calculated by the Company. The demand related production revenue requirement should be adjusted accordingly.

## III. STRANDED GENERATION COSTS

***Q40. IS THE COMPANY'S APPLICATION TO ESTABLISH A CHARGE BASED ON THE REVENUE REQUIREMENT OF ITS LEGACY GENERATION ASSETS, IN EFFECT, A REQUEST TO RECOVER STRANDED GENERATION COSTS?***

***A40.*** Yes. Stranded generation costs are generally defined as generation costs that are not recoverable in a competitive market for generation services or as the book value of generation assets in excess of the market value of those assets. The cost-based charge being requested by the Company reflects the cost of owning and operating its generation assets in excess of the market value of the capacity of those assets and the energy produced by those assets. In other words, the Company is seeking to recover the costs of the generation assets not recoverable in a competitive market for generation services.

***Q41. IS THE COMPANY'S REQUEST TO RECOVER THE ABOVE MARKET COSTS OF ITS GENERATION ASSETS CONSISTENT WITH THE AGREEMENTS BY WHICH THE COMPANY IMPLEMENTED ITS RESTRUCTURING TRANSITION PLAN?***

***A41.*** No. The Company's transition plan was based on the Stipulation and Recommendation of May 8, 2000 (or "Transition Plan Stipulation") as approved by the Commission in Case No. 99-1658-EL-ETP et al. In its consideration of the Transition Plan Stipulation, the Commission noted that in its transition plan as filed, the Company (at the time Cincinnati Gas and Electric Company, or "CG&E") had originally requested the recovery of $563 million of generation transition costs[12] (or "GTC" representing the above market cost of its generating units). However, as the Commission stated, in contrast to the Company's original claim for recovery of generation transition costs, "The transition plan stipulation provides CG&E with no GTC recovery and places the electricity market price risk entirely on CG&E."[13]

[12] Case No. 99-1658-EL-ETP et al., Opinion and Order, at 23.

[13] Id.

In finding that the transition plan stipulation provided an equitable resolution of the recovery of transition costs, the Commission further noted that "The Company has agreed to forego asserting a claim for stranded generation costs that they calculate on brief to be approximately $470 million on a netted basis."[14] This finding was based on the representation by the Company in its reply brief that "Further, CG&E respectfully requests that the Commission expressly find, as a matter of fact, that in order to resolve this case through stipulation, CG&E agreed to forego its claim to approximately $470 million in generation-related stranded costs."[15]

***Q42. WAS THERE ANY QUID PRO QUO FOR THE COMPANY'S FOREGOING THE RECOVERY OF GENERATION TRANSITION COSTS IN CASE NO. 99-1658-EL-ETP ET AL.?***

***A42.*** Yes. In its reply brief, the Company responded to an objection by certain intervenors that the transition plan stipulation would provide it with open-ended recovery of stranded costs. The Company dismissed such criticism as "simply wrong," and further noted, without qualification, that "As part of the stipulation, of course, CG&E has agreed to forego recovery of its generation related stranded costs in return for authority to recover regulatory assets, the approval of additional regulatory assets, and certain deferrals."[16] Evidently, now that the Company has

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[14] Id., at 28.

[15] Case No. 99-1658-EL-ETP et al., CG&E Reply Brief, at 22.

[16] Id., at *11, Footnote 10.*

safely completed the recovery of its generation related regulatory assets from customers in 2010, as provided in the transition plan stipulation, it believes that it can come back and get the generation-related stranded costs which it had agreed to forego in return for authority to recover those regulatory assets.

***Q43. HAS THE COMPANY CITED FINANCIAL INTEGRITY CONCERNS, RATHER THAN RECOVERY OF STRANDED GENERATION COSTS, AS A JUSTIFICATION FOR ITS REQUEST FOR A COST-BASED CAPACITY CHARGE?***

*A43.* Yes. Company Witness Trent states that if the Company's application is not approved, it "will be forced into operating at a significant financial loss," which he believes would not be "just and reasonable" (Direct Testimony, pages 24-25). Company Witness DeMay also addresses Company's present financial condition and the effect of a rejection of the Company's proposal on its financial integrity and credit metrics.

***Q44. ASSUMING THAT THEIR CHARACTERIZATION OF THE CONDITION OF THE COMPANY'S FINANCES IS ACCURATE, WERE THESE CIRCUMSTANCES AVOIDABLE?***

***A44.*** Yes. First, to be clear, I am not endorsing the Company's position on the effect that a rejection of its proposal would have on its financial integrity.[17] However, assuming for the sake of argument that a rejection of its proposed cost-based capacity charge would have the consequences that the Company describes, this outcome is entirely the result of its own decisions.

***Q45. PLEASE EXPLAIN.***

***A45.*** The Company could have either sold its generation assets to an unaffiliated entity or transferred those generation assets to a non-utility affiliate over the course of its transition plan, which was approved in 2012. Then, to the extent that the market price of electricity was less than its cost, it would have no effect on the regulated electric utility or its financial condition.

***Q46. WOULD SUCH A SALE OR TRANSFER OF GENERATION ASSETS BE AN UNUSUAL OR UNORTHODOX COURSE OF ACTION IN THE CONTEXT OF MAKING THE TRANSITION TO A COMPETITIVE MARKET FOR POWER PRODUCTION?***

***A46.*** No. I have participated in electric restructuring matters in Illinois, Maryland, Massachusetts, Rhode Island, and Texas. For the most part, the electric utilities in those jurisdictions either divested substantially all of their generation assets to unaffiliated entities or transferred those assets to non-utility affiliates.

[17] Just as one example, both Mr. Trent and Mr. DeMay cite the negative returns calculated by Mr. Savoy as evidence of the Company's dire financial straits. However, those negative returns omit the $110 million of revenues provided annually by Rider ESSC (response to OCC Interrogatory 11-081).

In fact, it had originally been the intention of CG&E to implement such a transfer. In Case No. 99-1658-EL-ETP et al., the Commission noted that "CG&E's CSP [corporate separation plan] provides for the transfer of its generating assets to an EWG [exempt wholesale generator] and, according to the plan, CG&E will complete the transfer by no later than December 31, 2004."[18] Thus, it was expected at the time the transition plan commenced that just such a transfer would take place.

However, the contemplated transfer of the generating assets did not happen within the specified time frame. The Stipulation and Recommendation in Case No. 03-93-EL-ATA, et al. provided that CG&E would not be required to transfer generating assets to an exempt wholesale generator by the end of 2004.[19] Certain intervenors (including the OCC) in that case submitted that CG&E should be required to comply with the corporate separation plan and not be permitted to retain ownership of its generating assets, and that any delay in such compliance should not be unlimited.[20] The Commission found that "CG&E's corporate separation shall be amended to allow it to retain its generating assets through 2008, after which time the stabilized prices under the stipulation will terminate and corporate separation should be reconsidered."[21]

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[18] Case No. 99-1658-EL-ETP et al., Opinion and Order, at 45.

[19] Case No. 03-93-EL-ATA, et al., Opinion and Order, at 33.

[20] Id.

[21] Id., at 34.

However, 2008 came and went with CG&E (now Duke Energy Ohio) retaining ownership of the generating assets. It is those generating assets that are now the subject of the Company's request to establish a cost-based capacity charge. But it must be emphasized that the Company's retention of its generating assets was not at the behest of the Commission or customer representatives. It was the Company's decision in those years not to sell or transfer its generating assets.[22] Had its decision been different, I believe that we would not be here today.

## IV. CONCLUSION

***Q47. PLEASE SUMMARIZE THE RECOMMENDATIONS MADE IN YOUR TESTIMONY.***

***A47.*** The Commission should reject the Company's application to establish a cost-based capacity charge. If the Commission does not grant the Joint Motion to dismiss the Company's Application, then the revenue requirement presented by the Company in support of its cost-based capacity charged should be adjusted. I have quantified adjustments that reduce the Company's revenue requirement by $259,253,000 with Dr. Woolridge's 4.11% return on equity or by $197,942,000 with Dr. Woolridge's 8.75% return on equity.

[22] In Case No. 03-93-EL-ATA, CG&E asserted that in order to provide service at stable rates, it had to retain its generating assets. In fact, the same rate stability could have been achieved by divesting the generating assets with an obligation on the part of the buyer to sell back the output from the generating units at a specified stream of prices during the period of stabilized prices to customers, just as other utilities did in conjunction with electric restructuring transition plans.

***Q48. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?***

***A48.*** Yes. However, I reserve the right to incorporate new information that may subsequently become available.

## CERTIFICATE OF SERVICE

It is hereby certified that a true copy of the foregoing *Direct Testimony of David J. Effron (Confidential Version) on Behalf of The Ohio Consumers' Counsel* was served via electronic transmission this 26th day of March, 2013.

Maureen R. Grady
Assistant Consumers' Counsel

## PARTIES OF RECORD

Amy.spiller@duke-energy.com
Jeanne.kingery@duke-energy.com
Elizabeth.watts@duke-energy.com
Rocco.DAscenzo@duke-energy.com

DUKE ENERGY OHIO, INC.
CASE NO. 12-2400-EL-UNC
SUMMARY OF REVENUE REQUIREMENT ISSUES
($000)

| | | Rate Base | Revenues/ Expenses | Revenue Req. |
|---|---|---|---|---|
| Company Revenue Deficiency | (A) | | | 257,337 |
| Adjustments: | | | | |
| ESSC Revenues | (B) | | 110,000 | (110,000) |
| General Plant | (C) | (20,293) | (1,192) | (3,441) |
| Common Plant | (D) | (5,140) | (176) | (746) |
| Accum. Amort. - Intangible Plant | (E) | (20,606) | | (2,284) |
| Accum. Deferred Income Taxes | (F) | (19,751) | | (2,189) |
| Operation and Maintenance | (G) | | (7,035) | (7,035) |
| Property Taxes | (H) | | (40,533) | (40,533) |
| Return on Equity - 4.11% | (I) | | | (93,025) |
| Total Adjustments | | | | (259,253) |
| Adjusted Revenue Deficiency 4.11% ROE | | | | (1,916) |
| Sum of Adjustments other than ROE | | | | (166,229) |
| Return on Equity - 8.75% | (H) | | | (31,713) |
| Total Adjustments | | | | (197,942) |
| Adjusted Revenue Deficiency 8.75% ROE | | | | 59,395 |

Sources:

| | | | |
|---|---|---|---|
| (A) | Attachment WDW-1, Page 3 | | |
| (B) | Case No, 11-3549-EL-SSO, Stipulation and Recommendation, Page16 | | |
| (C) | Schedule DJE-2 | | |
| (D) | Schedule DJE-3 | | |
| (E) | Schedule DJE-4 | | |
| (F) | ADIT - Property Taxes | 14,451 | Att. WDW-1, Page 6 |
| | ADIT - Ret. Plan Overfunded | 5,300 | OCC-INT-04-048 |
| | Total Adjustment | 19,751 | |
| (G) | Schedule DJE-5 | | |
| (H) | Schedule DJE-6 | | |
| (I) | Schedule DJE-7 | | |

DUKE ENERGY OHIO, INC.
CASE NO. 12-2400-EL-UNC
FACTORS USED IN REVENUE REQUIREMENT EFFECT CALCULATIONS

Rate of Return, per Company (Attachment WDW-1, page 17)

| | Ratio | Cost | Wtd. Cost | Pre-tax Cost |
|---|---|---|---|---|
| Debt | 46.84% | 4.11% | 1.93% | 1.93% |
| Equity | 53.16% | 11.15% | 5.93% | 9.16% |
| Total Capital | 100.00% | | 7.85% | 11.08% |

| | | |
|---|---|---|
| Effective Income Tax Rate | 35.2796% | Attachment WDW-1, page 23 |
| Complement | 64.7204% | |

DUKE ENERGY OHIO, INC.
CASE NO. 12-2400-EL-UNC
GENERAL PLANT
($000)

| | | | |
|---|---|---|---|
| Total General Plant | (1) | (A) | 90,270 |
| Smart Grid | | (B) | 36,089 |
| Total General Plant Excluding Smart Grid | | | 54,181 |
| Adjusted Allocation Factor | | (C) | 4.511% |
| General Plant Allocated to Production - Demand | (2) | | 2,444 |
| General Plant Allocated to Production - Demand by Company | | (A) | 29,019 |
| Adjustment to General Plant | | | (26,575) |
| | | | |
| Depreciation Reserve - General Plant | | (D) | 21,341 |
| Ratio of Allocated General Plant to Total | | (E) | 2.708% |
| Depreciation Reserve Allocated to Production - Demand | | | 578 |
| General Plant Allocated to Production - Demand by Company | | (D) | 6,860 |
| Adjustment to Depreciation Reserve - General Plant | | | (6,282) |
| | | | |
| Net Adjustment to General Plant in Rate Base | | | (20,293) |
| | | | |
| Depreciation on General Plant | | (F) | 4,050 |
| Ratio of Allocated General Plant to Total | | (E) | 2.708% |
| Depreciation Expense Allocated to Production - Demand | | | 110 |
| Depreciation Expense Allocated by Company | | (G) | 1,302 |
| Adjustment to Depreciation Expense - General Plant | | | (1,192) |

Sources:

| | | | | |
|---|---|---|---|---|
| (A) | Attachment WDW-1, Page 13 | | | |
| (B) | Response to OCC INT 13-105 | | 1036+35053 | |
| (C) | Allocation to Distribution | | 92.257% | 12-1682, Sch. B-2.1 |
| | Allocation to G&T | | 7.743% | |
| | Allocation to Generation | 93.182% | 7.215% | 12-1682, WPB-7a |
| | Allocation to Demand | | 62.52% | WDW-1, Page 6 |
| | Allocation Factor | | 4.511% | |
| (D) | Attachment WDW-1, Page 5 | | | |
| (E) | (2)/(1) | | | |
| (F) | FERC Form 1, page 336, line 10 | | | |
| (G) | Attachment WDW-1, Page 13 | 32.147% | * | 4,050 |

DUKE ENERGY OHIO, INC.
CASE NO. 12-2400-EL-UNC
COMMON PLANT
($000)

| | | |
|---|---|---|
| Smart Grid Assets in Common Plant as of 12/31/2011 | (A) | 12,847 |
| Allocation to Electric | (B) | 83.50% |
| Smart Grid Allocation to Electric | | 10,727 |
| Allocation to Production Demand | (B) | 56.458% |
| Adjustment to Common Plant in Production Rate Base | | (6,056) |
| | | |
| Common Smart Grid Depreciation Reserve | (C) | 1,943 |
| Allocation to Electric | (B) | 83.50% |
| Smart Grid Allocation to Electric | | 1,622 |
| Allocation to Production Demand | (B) | 56.458% |
| Adjustment to Common Plant Depreciation Reserve | | (916) |
| | | |
| Net Adjustment to Rate Base | | (5,140) |
| | | |
| Depreciation on Common Plant - Production Demand | (D) | 2,426 |
| Ratio of Plant Adjustment to Common Plant (Excl. Intangible) | (E) | 7.27% |
| Adjustment to Depreciation Expense | | (176) |

Sources:

| | | |
|---|---|---|
| (A) | Response to OCC INT 13-106 | 61.4+12785.3 |
| (B) | Attachment WDW-1, Page 14 | |
| (C) | Case No. 12-1682-EL-AIR, Schedule B-2.5b, Page 3 | |
| (D) | Attachment WDW-1, Page 21 | |
| (E) | Line 1/(298250-121525) | Attachment WDW-1, Page 14 |

Schedule DJE-4

DUKE ENERGY OHIO, INC.
CASE NO. 12-2400-EL-UNC
ACCUMULATED AMORTIZATION - INTANGIBLE PLANT
($000)

| | |
|---|---|
| Intangible Plant in Production - Demand Rate Base | 25,246 |
| Ratio of Accumulated Amortization to Plant | 81.62% |
| Accumulated Amortization - Intangible Plant | 20,606 |

Sources:

(A) Attachment WDW-1, Page 13

(B) Case No. 12-1682-EL-AIR, Schedule B-3, Page 3

| | |
|---|---|
| Accumulated Amortization | 28,384 |
| Intangible Plant | 34,776 |
| Ratio | 81.62% |

Schedule DJE-5

DUKE ENERGY OHIO, INC.
CASE NO. 12-2400-EL-UNC
OPERATION AND MAINTENANCE EXPENSE
($000)

| | | |
|---|---|---|
| Forecasted 2013 Operation and Maintenance Expense | (A) | 212,270 |
| 2011 Production O&M Expense | (B) | 225,711 |
| Adjustment to O&M Expenses | | (13,441) |
| Allocation to Demand | (B) | 52.341% |
| Adjustment to Demand Related Production Expenses | | (7,035) |

Sources:

(A) Attachment BDS-1, Confidential

(B) Attachment WDW-1, Page 19

DUKE ENERGY OHIO, INC.
CASE NO. 12-2400-EL-UNC
ADJUSTMENT TO PROPERTY TAX EXPENSE
($000)

| | | |
|---|---|---|
| Taxable Value of Production Property | (A) | 161,862 |
| Total Taxable Value of Property | (A) | 1,106,637 |
| Ratio | | 14.626% |
| Total 2011 Property Taxes | (B) | 100,482 |
| Property Taxes on Production Plant | | 14,697 |
| Taxes on Assets Transferred to DECAM | (C) | 987 |
| Adjusted Property Taxes on Production Plant | | 13,710 |
| | | |
| Taxable Value of General Plant | (A) | 54,083 |
| Total Taxable Value Property | (A) | 1,106,637 |
| Ratio | | 4.887% |
| Total 2011 Property Taxes | (B) | 100,482 |
| Property Taxes on General Plant | | 4,911 |
| Ratio of General and Common Plant Allocated to Production - Demand | (D) | 41.72% |
| Allocation to Production-Demand | | 2,049 |
| | | |
| Total Property Taxes Allocated to Production - Demand | | 15,759 |
| Property Taxes Allocated to Production - Demand per Company | (B) | 56,292 |
| Adjustment to Property Tax Expense | | (40,533) |

Sources:
(A) 2011 Valuation Notice
(B) Attachment WDW-1, Page 22
(C) Rate Schedule 101, Page 14 Workpaper
(D) Attachment WDW-1, Page 5

DUKE ENERGY OHIO, INC.
CASE NO. 12-2400-EL-UNC
RATE OF RETURN EFFECT
($000)

| | | |
|---|---|---|
| Company Rate Base | (A) | 1,674,513 |
| Proposed Adjustments to Rate Base | (B) | (65,790) |
| Adjusted Rate Base | | 1,608,723 |
| | | |
| Pre-Tax Rate of Return - Duke | (C) | 11.08% |
| Pre-Tax Rate of Return - OCC - 4.11% ROE | (D) | 5.30% |
| Difference | | -5.78% |
| | | |
| Effect on Return Requirement | | (93,025) |
| | | |
| Pre-Tax Rate of Return - Duke | (C) | 11.08% |
| Pre-Tax Rate of Return - OCC - 8.75% ROE | (D) | 9.11% |
| Difference | | -1.97% |
| | | |
| Effect on Return Requirement | | (31,713) |

Sources:

(A) Attachment WDW-1, Page 4
(B) Schedule DJE-1
(C) Attachment WDW-1, Page 17
(D) Testimony of Dr. Woolridge

| | Ratio | Cost | Wtd. Cost | Pre-tax Cost |
|---|---|---|---|---|
| Debt | 46.84% | 4.11% | 1.93% | 1.93% |
| Equity | 53.16% | 4.11% | 2.18% | 3.38% |
| Total Capital | 100.00% | | 4.11% | 5.30% |

| | Ratio | Cost | Wtd. Cost | Pre-tax Cost |
|---|---|---|---|---|
| Debt | 46.84% | 4.11% | 1.93% | 1.93% |
| Equity | 53.16% | 8.75% | 4.65% | 7.19% |
| Total Capital | 100.00% | | 6.58% | 9.11% |

Schedule DJE-1R

DUKE ENERGY OHIO, INC.
CASE NO. 12-2400-EL-UNC
SUMMARY OF REVENUE REQUIREMENT ISSUES
($000)

| | | Rate Base | Revenues/ Expenses | Revenue Req. |
|---|---|---|---|---|
| Company Revenue Deficiency | (A) | | | 257,337 |
| Adjustments: | | | | |
| ESSC Revenues | (B) | | 110,000 | (110,000) |
| General Plant | (C) | (20,293) | (1,192) | (3,441) |
| Common Plant | (D) | (5,140) | (176) | (746) |
| Accum. Amort. - Intangible Plant | (E) | (20,606) | | (2,284) |
| Accum. Deferred Income Taxes | (F) | (19,751) | | (2,189) |
| Operation and Maintenance | (G) | | [redacted] | [redacted] |
| Property Taxes | (H) | | (40,209) | (40,209) |
| Return on Equity - 4.11% | (I) | | | (93,025) |
| Total Adjustments | | | | (271,287) |
| Adjusted Revenue Deficiency 4.11% ROE | | | | (13,950) |
| Sum of Adjustments other than ROE | | | | (178,263) |
| Return on Equity - 8.75% | (H) | | | (31,713) |
| Total Adjustments | | | | (209,976) |
| Adjusted Revenue Deficiency 8.75% ROE | | | | 47,361 |

Sources:

| | | | |
|---|---|---|---|
| (A) | Attachment WDW-1, Page 3 | | |
| (B) | Case No, 11-3549-EL-SSO, Stipulation and Recommendation, Page16 | | |
| (C) | Schedule DJE-2 | | |
| (D) | Schedule DJE-3 | | |
| (E) | Schedule DJE-4 | | |
| (F) | ADIT - Property Taxes | 14,451 | Att. WDW-1, Page 6 |
| | ADIT - Ret. Plan Overfunded | 5,300 | OCC-INT-04-048 |
| | Total Adjustment | 19,751 | |
| (G) | Schedule DJE-5R | | |
| (H) | Schedule DJE-6R | | |
| (I) | Schedule DJE-7 | | |

DUKE ENERGY OHIO, INC.
CASE NO. 12-2400-EL-UNC
OPERATION AND MAINTENANCE EXPENSE
($000)

| | | |
|---|---|---|
| Forecasted 2013 Operation and Maintenance Expense | (A) | [redacted] |
| 2011 Production O&M Expense | (B) | 225,711 |
| Adjustment to O&M Expenses | | [redacted] |
| Allocation to Demand | (C) | 52.341% |
| Adjustment to Demand Related Production Expenses | | [redacted] |

Sources:

| | | |
|---|---|---|
| (A) | Response to OCC POD-18-119 (Confidential) | |
| (B) | Attachment WDW-1, Page 19 | 509+25320+199882 |
| (C) | Attachment WDW-1, Page 19 | 118139 / 225,711 |

DUKE ENERGY OHIO, INC.
CASE NO. 12-2400-EL-UNC
ADJUSTMENT TO PROPERTY TAX EXPENSE
($000)

| | | |
|---|---|---|
| Taxable Value of Production Property | (A) | 194,139 |
| Total Taxable Value of Property | (A) | 1,106,191 |
| Ratio | | 17.550% |
| Total 2011 Property Taxes | (B) | 101,469 |
| Property Taxes on Production Plant | | 17,808 |
| Allocation to Demand | (C) | 91.263% |
| Property Taxes on Demand Related Production Plant | | 16,252 |
| Taxes on Assets Transferred to DECAM | (D) | 987 |
| Adjusted Property Taxes on Production Plant | | 15,265 |

| | | |
|---|---|---|
| Taxable Value of General Plant | (A) | 21,361 |
| Total Taxable Value Property | (A) | 1,106,191 |
| Ratio | | 1.931% |
| Total 2011 Property Taxes | (B) | 101,469 |
| Property Taxes on General Plant | | 1,959 |
| Ratio of General and Common Plant Allocated to Production - Demand | (E) | 41.72% |
| Allocation to Production-Demand | | 818 |
| Total Property Taxes Allocated to Production - Demand | | 16,083 |
| Property Taxes Allocated to Production - Demand per Company | (B) | 56,292 |
| Adjustment to Property Tax Expense | | (40,209) |

Sources:

(A) Case No. 12-1682-EL-AIR, WPC-3.8b
(B) Attachment WDW-1, Page 22 100481.972+987
(C) Case No. 12-1682-EL-AIR, WPC-3.8b (161862+15316)/194139
(D) Rate Schedule 101, Page 14 Workpaper
(E) Attachment WDW-1, Page 5

OCC-27

**Demand Related O&M for 2011**
Source: FES-INT-04-004 for O&M by Unit

| | Beckjord | Beckjord 6 | Beckjord CT | Conesville | Dick's Creek CT | Killen | Miami Fort 7-8 | Miami Fort CT | MW Gas Other | Stuart | Zimmer |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 500 | 822,037 | 299,669 | 27,134 | 670,411 | 14,705 | 326,345 | 1,045,278 | 6,097 | | 1,746,647 | 1,078,704 |
| 501 | 46,854,245 | 21,820,334 | 779 | 42,687,080 | 567 | 36,366,278 | 109,035,342 | 236 | | 154,464,867 | 86,933,185 |
| 502 | 680,980 | 179,972 | 5,616 | 3,066,633 | | 2,444,283 | 6,533,755 | | | 9,253,353 | 9,421,956 |
| 505 | 6,476 | 4,275 | | 54,101 | | 147,452 | 175,418 | | | 619,595 | 249,604 |
| 506 | 3,526,328 | 1,274,908 | 178,841 | 1,922,743 | 128,142 | 1,316,867 | 3,163,841 | 53,384 | | 7,843,826 | 3,503,520 |
| 507 | | | | 311,664 | | | 197,328 | | | 248 | |
| 509 | | | | | | | | | | | |
| 510 | 1,032,973 | 355,308 | 9,186 | 80,080 | 6,682 | 224,061 | 1,506,249 | 2,785 | | 625,354 | 1,400,497 |
| 511 | 1,026,588 | 346,619 | 104 | 185,675 | 76 | 585,047 | 2,656,256 | 32 | | 853,089 | 2,514,153 |
| 512 | 20,525,903 | 2,760,716 | | 4,273,375 | | 3,504,904 | 12,623,256 | | | 20,984,223 | 7,483,831 |
| 513 | 1,064,772 | 302,991 | 405 | 664,676 | 262 | 575,586 | 2,961,783 | 109 | | 6,388,812 | 830,733 |
| 514 | 4,155,068 | 839,772 | (4,973) | 482,437 | 290 | 314,881 | 6,245,505 | (36) | | 138,674 | 6,382,109 |
| 546 | | | 69,838 | | 20,154 | | | 200,513 | | | |
| 547 | | | 432,214 | | 171,603 | | | 121,731 | | | |
| 548 | 23 | 30 | 83,942 | | 85,907 | | 65 | 14,869 | | | 71 |
| 549 | 642 | 685 | (19,236) | | 2,850 | | 1,687 | 68 | | | 2,149 |
| 551 | 308 | 329 | 42,166 | | 30,578 | | 810 | 12,543 | | | 1,032 |
| 552 | | | (10) | | 878 | | | 25,004 | | | |
| 553 | | | 28,909 | | 66,471 | | | 17,446 | | | |
| 554 | | | 350,158 | | 116,083 | | | 85,449 | | | 1,327 |
| 555 | | | | | | | | | 462,609 | | |
| 557 | 276 | 295 | | | | | 726 | | | | 925 |
| | 79,696,618 | 28,185,901 | 1,205,073 | 54,398,877 | 645,246 | 45,805,704 | 146,147,298 | 540,232 | 462,609 | 202,918,687 | 119,803,797 |

| | Demand Related | Energy Related |
|---|---|---|
| 500 | xx | - |
| 501 | - | xx |
| 502 | xx | - |
| 505 | xx | - |
| 506 | xx | - |
| 507 | xx | - |
| 509 | - | xx |
| 510 | - | xx |
| 511 | xx | - |
| 512 | - | xx |
| 513 | - | xx |
| 514 | xx | - |
| 546 | xx | - |
| 547 | - | xx |
| 548 | xx | - |
| 549 | xx | - |
| 551 | xx | - |
| 552 | xx | - |
| 553 | xx | - |
| 554 | xx | - |
| 555 | - | xx |
| 557 | xx | - |

Demand Related

| | Beckjord | Beckjord 6 | Beckjord CT | Conesville | Dick's Creek CT | Killen | Miami Fort 7-8 | Miami Fort CT | MW Gas Other | Stuart | Zimmer | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 500 | 822,037 | 299,669 | 27,134 | 670,411 | 14,705 | 326,345 | 1,045,278 | 6,097 | 0 | 1,746,647 | 1,078,704 | |
| 501 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 502 | 680,980 | 179,972 | 5,616 | 3,066,633 | 0 | 2,444,283 | 6,533,755 | 0 | 0 | 9,253,353 | 9,421,956 | |
| 505 | 6,476 | 4,275 | 0 | 54,101 | 0 | 147,452 | 175,418 | 0 | 0 | 619,595 | 249,604 | |
| 506 | 3,526,328 | 1,274,908 | 178,841 | 1,922,743 | 128,142 | 1,316,867 | 3,163,841 | 53,384 | 0 | 7,843,826 | 3,503,520 | |
| 507 | 0 | 0 | 0 | 311,664 | 0 | 0 | 197,328 | 0 | 0 | 248 | 0 | |
| 509 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 510 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 511 | 1,026,588 | 346,619 | 104 | 185,675 | 76 | 585,047 | 2,656,256 | 32 | 0 | 853,089 | 2,514,153 | |
| 512 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 513 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 514 | 4,155,068 | 839,772 | -4,973 | 482,437 | 290 | 314,881 | 6,245,505 | -36 | 0 | 138,674 | 6,382,109 | |
| 546 | 0 | 0 | 69,838 | 0 | 20,154 | 0 | 0 | 200,513 | 0 | 0 | 0 | |
| 547 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 548 | 23 | 30 | 83,942 | 0 | 85,907 | 0 | 65 | 14,869 | 0 | 0 | 71 | |
| 549 | 642 | 685 | -19,236 | 0 | 2,850 | 0 | 1,687 | 68 | 0 | 0 | 2,149 | |
| 551 | 308 | 329 | 42,166 | 0 | 30,578 | 0 | 810 | 12,543 | 0 | 0 | 1,032 | |
| 552 | 0 | 0 | -10 | 0 | 878 | 0 | 0 | 25,004 | 0 | 0 | 0 | |
| 553 | 0 | 0 | 28,909 | 0 | 66,471 | 0 | 0 | 17,446 | 0 | 0 | 0 | |
| 554 | 0 | 0 | 350,158 | 0 | 116,083 | 0 | 0 | 85,449 | 0 | 0 | 1,327 | |
| 555 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 557 | 276 | 295 | 0 | 0 | 0 | 0 | 726 | 0 | 0 | 0 | 925 | |
| | 10,218,725 | 2,946,552 | 762,488 | 6,693,666 | 466,132 | 5,134,875 | 20,020,668 | 415,369 | - | 20,455,431 | 23,155,550 | 90,269,457 |
| | | | | | | | | | | | excl. Beck 1-5 | 80,050,731 |

**Demand Related O&M for 2012**
Source: FES-INT-04-004 for O&M by Unit

| | Beckjord | Beckjord 6 | Beckjord CT | Conesville | Dick's Creek CT | Killen | Miami Fort 7-8 | Miami Fort CT | MW Gas Other | Stuart | Zimmer | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 500 | 468,463 | 247,446 | 38,201 | 671,512 | 29,211 | 366,997 | 1,129,175 | 15,575 | | 1,712,323 | 1,013,950 | |
| 501 | 40,120,429 | 20,695,718 | 517 | 41,772,875 | 373 | 35,829,431 | 128,048,754 | 154 | | 126,993,020 | 69,566,877 | |
| 502 | 103,232 | 48,247 | | 2,619,999 | | 3,580,451 | 7,532,821 | | | 11,026,429 | 7,428,672 | |
| 505 | 121 | 49 | | 66,282 | | 169,780 | 6,637 | | | 628,767 | 2,593 | |
| 506 | 3,006,260 | 858,361 | 213,631 | 3,924,946 | 157,783 | 1,154,309 | 2,958,098 | 59,868 | | 7,308,064 | 3,441,437 | |
| 507 | | | | 591,324 | | 522 | 185,664 | | | 11,048 | | |
| 509 | 1,390,030 | 970,353 | | 53,820 | | 119,045 | 412,876 | | | 218,246 | 336,555 | |
| 510 | 387,954 | 229,576 | 7,266 | 77,013 | 5,240 | 169,770 | 1,330,458 | 2,164 | | 745,795 | 1,817,549 | |
| 511 | 601,475 | 257,599 | 148 | 176,727 | 107 | 1,243,460 | 2,903,138 | 44 | | 1,468,676 | 3,362,318 | |
| 512 | 2,670,609 | 611,366 | | 4,550,669 | | 3,882,013 | 4,644,765 | | | 18,279,854 | 11,102,047 | |
| 513 | 887,311 | 283,039 | 293 | 588,978 | 211 | 993,086 | 901,737 | 87 | | 6,928,576 | 3,074,411 | |
| 514 | 839,702 | 626,436 | 262 | 404,065 | 189 | 175,778 | 3,168,273 | 78 | | 614,877 | 8,160,000 | |
| 546 | | | 32,474 | | 31,964 | | | 153,052 | | | | |
| 547 | | | 341,856 | | 144,202 | | | 136,548 | | | | |
| 548 | 12 | 30 | 93,917 | | 68,692 | | 72 | 19,266 | | | 109 | |
| 549 | | | 223 | | 13,446 | | | 350 | | | 5,375 | |
| 551 | | 4 | 42,532 | | 30,324 | | 11 | 12,468 | | | 14 | |
| 552 | | | 9,922 | | 41,096 | | | 13,831 | | | | |
| 553 | | | 17,922 | | 110,394 | | | 17,348 | | | | |
| 554 | | | 71,864 | | 74,852 | | 764 | 5,140 | | | | |
| 555 | | | | | | | | | | | | |
| 557 | | | | | | | | | | | | |
| | 50,475,600 | 24,828,223 | 871,028 | 55,498,208 | 708,082 | 47,684,643 | 153,223,244 | 435,973 | - | 175,935,675 | 109,311,908 | 618,972,584 |

| | Demand Related | Energy Related |
|---|---|---|
| 500 | xx | - |
| 501 | - | xx |
| 502 | xx | - |
| 505 | xx | - |
| 506 | xx | - |
| 507 | xx | - |
| 509 | - | xx |
| 510 | - | xx |
| 511 | xx | - |
| 512 | - | xx |
| 513 | - | xx |
| 514 | xx | - |
| 546 | xx | - |
| 547 | - | xx |
| 548 | xx | - |
| 549 | xx | - |
| 551 | xx | - |
| 552 | xx | - |
| 553 | xx | - |
| 554 | xx | - |
| 555 | - | xx |
| 557 | xx | - |

Demand Related

| | Beckjord | Beckjord 6 | Beckjord CT | Conesville | Dick's Creek CT | Killen | Miami Fort 7-8 | Miami Fort CT | MW Gas Other | Stuart | Zimmer | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 500 | 468,463 | 247,446 | 38,201 | 671,512 | 29,211 | 366,997 | 1,129,175 | 15,575 | 0 | 1,712,323 | 1,013,950 | |
| 501 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 502 | 103,232 | 48,247 | 0 | 2,619,999 | 0 | 3,580,451 | 7,532,821 | 0 | 0 | 11,026,429 | 7,428,672 | |
| 505 | 121 | 49 | 0 | 66,282 | 0 | 169,780 | 6,637 | 0 | 0 | 628,767 | 2,593 | |
| 506 | 3,006,260 | 858,361 | 213,631 | 3,924,946 | 157,783 | 1,154,309 | 2,958,098 | 59,868 | 0 | 7,308,064 | 3,441,437 | |
| 507 | 0 | 0 | 0 | 591,324 | 0 | 522 | 185,664 | 0 | 0 | 11,048 | 0 | |
| 509 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 510 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 511 | 601,475 | 257,599 | 148 | 176,727 | 107 | 1,243,460 | 2,903,138 | 44 | 0 | 1,468,676 | 3,362,318 | |
| 512 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 513 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 514 | 839,702 | 626,436 | 262 | 404,065 | 189 | 175,778 | 3,168,273 | 78 | 0 | 614,877 | 8,160,000 | |
| 546 | 0 | 0 | 32,474 | 0 | 31,964 | 0 | 0 | 153,052 | 0 | 0 | 0 | |
| 547 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 548 | 12 | 30 | 93,917 | 0 | 68,692 | 0 | 72 | 19,266 | 0 | 0 | 109 | |
| 549 | 0 | 0 | 223 | 0 | 13,446 | 0 | 0 | 350 | 0 | 0 | 5,375 | |
| 551 | 0 | 4 | 42,532 | 0 | 30,324 | 0 | 11 | 12,468 | 0 | 0 | 14 | |
| 552 | 0 | 0 | 9,922 | 0 | 41,096 | 0 | 0 | 13,831 | 0 | 0 | 0 | |
| 553 | 0 | 0 | 17,922 | 0 | 110,394 | 0 | 0 | 17,348 | 0 | 0 | 0 | |
| 554 | 0 | 0 | 71,864 | 0 | 74,852 | 0 | 764 | 5,140 | 0 | 0 | 0 | |
| 555 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 557 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | 5,019,267 | 2,038,172 | 521,096 | 8,454,853 | 558,057 | 6,691,298 | 17,884,653 | 297,020 | - | 22,770,184 | 23,414,469 | 87,649,068 |
| | | | | | | | | | | | Excl Beck 1-5 | 82,629,802 |

| | |
|---|---|
| Increase from 2011 | (2,620,388) |
| w/o Beck 1-5 | 2,579,070 |

## Margin on Sale -- Summary

| | | | Energy Revenue (2011 $000) | | | Total Expenses (2011 $000) | | | Energy Margin (2011 $000) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Unit Name | Duke Share | 2013 | 2014 | 2015 | 2013 | 2014 | 2015 | 2013 | 2014 | 2015 |
| ST COAL UNITS | Walter C Beckjord ST6 | 37.5% | $ 27,067 | $ 28,590 | $ - | $ 22,431 | $ 23,701 | $ - | $ 4,636 | $ 4,888 | $ - |
| | Conesville 4 | 40% | $ 66,068 | $ 72,017 | $ 33,889 | $ 49,539 | $ 53,588 | $ 25,716 | $ 16,529 | $ 18,429 | $ 8,173 |
| | Killen Station 2 | 33% | $ 40,441 | $ 43,797 | $ 20,767 | $ 32,933 | $ 35,888 | $ 17,101 | $ 7,508 | $ 7,910 | $ 3,665 |
| | J M Stuart 1 | 39% | $ 46,745 | $ 50,288 | $ 23,631 | $ 36,743 | $ 40,114 | $ 18,861 | $ 10,002 | $ 10,173 | $ 4,770 |
| | J M Stuart 2 | 39% | $ 47,121 | $ 50,518 | $ 18,228 | $ 36,027 | $ 39,144 | $ 14,271 | $ 11,094 | $ 11,373 | $ 3,957 |
| | J M Stuart 3 | 39% | $ 46,407 | $ 50,367 | $ 23,589 | $ 37,247 | $ 40,803 | $ 19,264 | $ 9,160 | $ 9,564 | $ 4,326 |
| | J M Stuart 4 | 39% | $ 46,942 | $ 50,581 | $ 17,960 | $ 37,040 | $ 40,399 | $ 14,348 | $ 9,901 | $ 10,182 | $ 3,611 |
| | Miami Fort ST7 | 64% | $ 60,618 | $ 65,141 | $ 24,854 | $ 45,880 | $ 49,312 | $ 19,202 | $ 14,738 | $ 15,829 | $ 5,652 |
| | Miami Fort ST8 | 64% | $ 59,331 | $ 64,083 | $ 30,990 | $ 45,628 | $ 49,328 | $ 24,197 | $ 13,703 | $ 14,755 | $ 6,793 |
| | W H Zimmer | 46.5% | $ 116,337 | $ 128,253 | $ 61,137 | $ 93,399 | $ 102,462 | $ 49,109 | $ 22,938 | $ 25,790 | $ 12,028 |
| CT GAS UNITS | Dicks Creek 1 | 100% | $ 32 | $ 35 | $ 32 | $ 31 | $ 31 | $ 30 | $ 1 | $ 4 | $ 2 |
| | Dicks Creek 3 | 100% | $ 6 | $ - | $ 15 | $ 5 | $ - | $ 15 | $ 0 | $ - | $ 0 |
| CT OIL UNITS | Walter C Beckjord CT1 | 100% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Walter C Beckjord CT2 | 100% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Walter C Beckjord CT3 | 100% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Walter C Beckjord CT4 | 100% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Dicks Creek 4 | 100% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Dicks Creek 5 | 100% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Killen Station CT | 33% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Miami Fort CT3 | 100% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Miami Fort CT4 | 100% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Miami Fort CT5 | 100% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Miami Fort CT6 | 100% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | | TOTAL | $ 557,114 | $ 603,668 | $ 255,090 | $ 436,903 | $ 474,770 | $ 202,114 | $ 120,210 | $ 128,898 | $ 52,977 |

| Inflation Factors | |
|---|---|
| 2012 | 1.020 |
| 2013 | 1.040 |
| 2014 | 1.061 |
| 2015 | 1.082 |

## Margin on Sale of Legacy Generation

| | 2013 | 2014 | Jan-May 2015 |
|---|---|---|---|
| Total Energy Revenue ($000) | $ 579,621 | $ 640,618 | $ 276,118 |
| Total Expenses ($000) | $ 454,554 | $ 503,830 | $ 218,774 |
| Total Energy Margin ($000) | $ 125,067 | $ 136,788 | $ 57,344 |

Real 2011$ **Plant: Walter C Beckjord ST6**

**Total Annual Proforma Summary**

| **Unit Name** | **Output Data** | | | |
|---|---|---|---|---|
| Beckjrd6 | | **2013** | **2014** | **2015** |
| | **Generation Details** | | | |
| | Max Capacity (MW) | 421 | 421 | 421 |
| | Average Capacity (MW) | 418 | 418 | 420 |
| | Possible Generation (GWh) | 3,662 | 3,662 | 1,523 |
| | Total Generation (GWh) | 2,394 | 2,323 | 850 |
| | Capacity Factor (%) | 65.4% | 63.4% | 55.8% |
| | Realized Heat Rate (Btu/KWh) | 10,487 | 10,487 | 10,487 |
| | Number of Starts | 3 | 2 | 1 |
| | Hours of Operation | 7,872 | 7,857 | 2,777 |
| | **Revenue and Costs Details** | | | |
| | Average LMP ($/MWh) | $28.37 | $30.81 | $31.05 |
| | Average LMP Received ($/MWh) | $30.15 | $32.82 | $32.45 |
| | Fuel Used (MMBtu) | 25,102,351 | 24,355,914 | 8,914,152 |
| | Average Fuel Price ($/MMBtu) | $2.22 | $2.44 | $2.48 |
| | Average Fuel Cost ($/MWh) | $23.33 | $25.58 | $26.00 |
| | Average Variable O&M ($/MWh) | $1.44 | $1.44 | $1.44 |
| | **Emissions Details** | | | |
| | NOx Emission (ton) | 4,831 | 4,686 | 1,715 |
| | CO2 Emission (ton) | 2,576,611 | 2,499,657 | 914,962 |
| | SO2 Emission (ton) | 49,487 | 48,009 | 17,573 |
| | NOx Emission Cost ($/ton) | $47.10 | $50.65 | $51.15 |
| | CO2 Emission Cost ($/ton) | $0.00 | $0.00 | $0.00 |
| | SO2 Emission Cost ($/ton) | $0.79 | $0.84 | $0.00 |
| | **Revenue** | | | |
| | Energy Revenues ($000) | $72,178 | $76,239 | $27,584 |
| | **Total Revenue ($000)** | $72,178 | $76,239 | $27,584 |
| | **Expenses** | | | |
| | Fuel ($000) | $55,853 | $59,421 | $22,098 |
| | Start Up (Fixed plus Fuel $000) | $248 | $157 | $77 |
| | Variable O&M ($000) | $3,447 | $3,345 | $1,224 |
| | Total Emission Cost ($000) | $269 | $280 | $89 |
| | **Total Expenses ($000)** | $59,816 | $63,203 | $23,489 |
| | **Energy Market Margin - Total ($000)** | $12,362 | $13,035 | $4,096 |

Real 2011$ **Plant: Conesville 4**

**Total Annual Proforma Summary**

| Unit Name | Output Data | | | |
|---|---|---|---|---|
| CONESVIL | | 2013 | 2014 | 2015 |
| | **Generation Details** | | | |
| | Max Capacity (MW) | 780 | 780 | 780 |
| | Average Capacity (MW) | 764 | 764 | 774 |
| | Possible Generation (GWh) | 6,692 | 6,692 | 2,803 |
| | Total Generation (GWh) | 5,604 | 5,610 | 2,630 |
| | Capacity Factor (%) | 83.7% | 83.8% | 93.8% |
| | Realized Heat Rate (Btu/KWh) | 9,856 | 9,856 | 9,846 |
| | Number of Starts | 4 | 3 | 1 |
| | Hours of Operation | 7,850 | 7,833 | 3,591 |
| | **Revenue and Costs Details** | | | |
| | Average LMP ($/MWh) | $29.60 | $31.89 | $32.21 |
| | Average LMP Received ($/MWh) | $29.48 | $32.10 | $32.21 |
| | Fuel Used (MMBtu) | 55,228,484 | 55,286,303 | 25,896,035 |
| | Average Fuel Price ($/MMBtu) | $1.98 | $2.17 | $2.23 |
| | Average Fuel Cost ($/MWh) | $19.50 | $21.34 | $21.94 |
| | Average Variable O&M ($/MWh) | $2.40 | $2.40 | $2.40 |
| | **Emissions Details** | | | |
| | NOx Emission (ton) | 1,821 | 1,823 | 854 |
| | CO2 Emission (ton) | 5,797,135 | 5,802,006 | 2,717,169 |
| | SO2 Emission (ton) | 3,966 | 3,969 | 1,859 |
| | NOx Emission Cost ($/ton) | $47.10 | $50.65 | $51.15 |
| | CO2 Emission Cost ($/ton) | $0.00 | $0.00 | $0.00 |
| | SO2 Emission Cost ($/ton) | $0.79 | $0.84 | $0.00 |
| | **Revenue** | | | |
| | Energy Revenues ($000) | $165,170 | $180,042 | $84,722 |
| | **Total Revenue ($000)** | $165,170 | $180,042 | $84,722 |
| | **Expenses** | | | |
| | Fuel ($000) | $109,297 | $119,695 | $57,696 |
| | Start Up (Fixed plus Fuel $000) | $1,012 | $715 | $238 |
| | Variable O&M ($000) | $13,449 | $13,463 | $6,312 |
| | Total Emission Cost ($000) | $90 | $97 | $44 |
| | **Total Expenses ($000)** | $123,847 | $133,969 | $64,290 |
| | **Energy Market Margin - Total ($000)** | $41,322 | $46,073 | $20,432 |

Real 2011$ **Plant: Killen Station 2**

**Total Annual Proforma Summary**

| Unit Name | Output Data | | | |
|---|---|---|---|---|
| Killen2 | | 2013 | 2014 | 2015 |
| | **Generation Details** | | | |
| | Max Capacity (MW) | 600 | 600 | 600 |
| | Average Capacity (MW) | 588 | 588 | 595 |
| | Possible Generation (GWh) | 5,148 | 5,148 | 2,156 |
| | Total Generation (GWh) | 4,173 | 4,161 | 1,973 |
| | Capacity Factor (%) | 81.1% | 80.8% | 91.5% |
| | Realized Heat Rate (Btu/KWh) | 10,224 | 10,235 | 10,200 |
| | Number of Starts | 4 | 3 | 1 |
| | Hours of Operation | 7,852 | 7,853 | 3,595 |
| | **Revenue and Costs Details** | | | |
| | Average LMP ($/MWh) | $29.39 | $31.66 | $31.88 |
| | Average LMP Received ($/MWh) | $29.37 | $31.90 | $31.89 |
| | Fuel Used (MMBtu) | 42,664,733 | 42,589,536 | 20,126,235 |
| | Average Fuel Price ($/MMBtu) | $2.23 | $2.45 | $2.47 |
| | Average Fuel Cost ($/MWh) | $22.80 | $25.06 | $25.21 |
| | Average Variable O&M ($/MWh) | $0.93 | $0.93 | $0.93 |
| | **Emissions Details** | | | |
| | NOx Emission (ton) | 4,109 | 4,101 | 1,938 |
| | CO2 Emission (ton) | 4,378,536 | 4,370,167 | 2,064,904 |
| | SO2 Emission (ton) | 6,021 | 6,010 | 2,840 |
| | NOx Emission Cost ($/ton) | $47.10 | $50.65 | $51.15 |
| | CO2 Emission Cost ($/ton) | $0.00 | $0.00 | $0.00 |
| | SO2 Emission Cost ($/ton) | $0.79 | $0.84 | $0.00 |
| | **Revenue** | | | |
| | Energy Revenues ($000) | $122,549 | $132,719 | $62,929 |
| | **Total Revenue ($000)** | $122,549 | $132,719 | $62,929 |
| | **Expenses** | | | |
| | Fuel ($000) | $95,142 | $104,259 | $49,752 |
| | Start Up (Fixed plus Fuel $000) | $575 | $407 | $136 |
| | Variable O&M ($000) | $3,881 | $3,870 | $1,835 |
| | Total Emission Cost ($000) | $200 | $214 | $99 |
| | **Total Expenses ($000)** | $99,798 | $108,750 | $51,822 |
| | **Energy Market Margin - Total ($000)** | $22,751 | $23,968 | $11,107 |

Real 2011$ **Plant: J M Stuart 1**

**Total Annual Proforma Summary**

| Unit Name | Output Data | | | |
|---|---|---|---|---|
| Stuart1 | | 2013 | 2014 | 2015 |
| | **Generation Details** | | | |
| | Max Capacity (MW) | 577 | 577 | 577 |
| | Average Capacity (MW) | 565 | 565 | 572 |
| | Possible Generation (GWh) | 4,951 | 4,951 | 2,074 |
| | Total Generation (GWh) | 4,072 | 4,082 | 1,901 |
| | Capacity Factor (%) | 82.3% | 82.5% | 91.7% |
| | Realized Heat Rate (Btu/KWh) | 9,818 | 9,818 | 9,818 |
| | Number of Starts | 4 | 2 | 1 |
| | Hours of Operation | 7,841 | 7,835 | 3,595 |
| | **Revenue and Costs Details** | | | |
| | Average LMP ($/MWh) | $29.39 | $31.66 | $31.88 |
| | Average LMP Received ($/MWh) | $29.43 | $31.59 | $31.88 |
| | Fuel Used (MMBtu) | 39,982,295 | 40,080,472 | 18,660,337 |
| | Average Fuel Price ($/MMBtu) | $2.22 | $2.44 | $2.46 |
| | Average Fuel Cost ($/MWh) | $21.80 | $23.93 | $24.17 |
| | Average Variable O&M ($/MWh) | $1.18 | $1.18 | $1.18 |
| | **Emissions Details** | | | |
| | NOx Emission (ton) | 1,942 | 1,947 | 906 |
| | CO2 Emission (ton) | 4,104,701 | 4,113,515 | 1,915,180 |
| | SO2 Emission (ton) | 3,537 | 3,544 | 1,650 |
| | NOx Emission Cost ($/ton) | $47.10 | $50.65 | $51.15 |
| | CO2 Emission Cost ($/ton) | $0.00 | $0.00 | $0.00 |
| | SO2 Emission Cost ($/ton) | $0.79 | $0.84 | $0.00 |
| | **Revenue** | | | |
| | Energy Revenues ($000) | $119,859 | $128,942 | $60,591 |
| | **Total Revenue ($000)** | $119,859 | $128,942 | $60,591 |
| | **Expenses** | | | |
| | Fuel ($000) | $88,761 | $97,676 | $45,942 |
| | Start Up (Fixed plus Fuel $000) | $551 | $261 | $130 |
| | Variable O&M ($000) | $4,805 | $4,817 | $2,243 |
| | Total Emission Cost ($000) | $95 | $103 | $46 |
| | **Total Expenses ($000)** | $94,212 | $102,857 | $48,361 |
| | **Energy Market Margin - Total ($000)** | $25,646 | $26,086 | $12,230 |

Real 2011$ **Plant: J M Stuart 2**

**Total Annual Proforma Summary**

| Unit Name | Output Data | | | |
|---|---|---|---|---|
| Stuart2 | | 2013 | 2014 | 2015 |
| | **Generation Details** | | | |
| | Max Capacity (MW) | 577 | 577 | 577 |
| | Average Capacity (MW) | 565 | 565 | 572 |
| | Possible Generation (GWh) | 4,951 | 4,951 | 2,074 |
| | Total Generation (GWh) | 4,095 | 4,080 | 1,472 |
| | Capacity Factor (%) | 82.7% | 82.4% | 71.0% |
| | Realized Heat Rate (Btu/KWh) | 9,572 | 9,572 | 9,572 |
| | Number of Starts | 3 | 2 | 1 |
| | Hours of Operation | 7,881 | 7,879 | 2,775 |
| | **Revenue and Costs Details** | | | |
| | Average LMP ($/MWh) | $29.39 | $31.66 | $31.88 |
| | Average LMP Received ($/MWh) | $29.50 | $31.75 | $31.76 |
| | Fuel Used (MMBtu) | 39,198,345 | 39,053,330 | 14,087,305 |
| | Average Fuel Price ($/MMBtu) | $2.22 | $2.44 | $2.46 |
| | Average Fuel Cost ($/MWh) | $21.25 | $23.33 | $23.57 |
| | Average Variable O&M ($/MWh) | $1.18 | $1.18 | $1.18 |
| | **Emissions Details** | | | |
| | NOx Emission (ton) | 2,253 | 2,244 | 810 |
| | CO2 Emission (ton) | 4,023,642 | 4,008,133 | 1,445,988 |
| | SO2 Emission (ton) | 3,218 | 3,205 | 1,156 |
| | NOx Emission Cost ($/ton) | $47.10 | $50.65 | $51.15 |
| | CO2 Emission Cost ($/ton) | $0.00 | $0.00 | $0.00 |
| | SO2 Emission Cost ($/ton) | $0.79 | $0.84 | $0.00 |
| | **Revenue** | | | |
| | Energy Revenues ($000) | $120,823 | $129,533 | $46,739 |
| | **Total Revenue ($000)** | $120,823 | $129,533 | $46,739 |
| | **Expenses** | | | |
| | Fuel ($000) | $87,020 | $95,173 | $34,683 |
| | Start Up (Fixed plus Fuel $000) | $417 | $265 | $130 |
| | Variable O&M ($000) | $4,832 | $4,815 | $1,737 |
| | Total Emission Cost ($000) | $107 | $118 | $42 |
| | **Total Expenses ($000)** | $92,376 | $100,370 | $36,592 |
| | **Energy Market Margin - Total ($000)** | $28,447 | $29,163 | $10,147 |

Real 2011$ **Plant: J M Stuart 3**

**Total Annual Proforma Summary**

| **Unit Name** | **Output Data** | | | |
|---|---|---|---|---|
| Stuart3 | | **2013** | **2014** | **2015** |
| | **Generation Details** | | | |
| | Max Capacity (MW) | 577 | 577 | 577 |
| | Average Capacity (MW) | 565 | 565 | 572 |
| | Possible Generation (GWh) | 4,951 | 4,951 | 2,074 |
| | Total Generation (GWh) | 4,026 | 4,048 | 1,896 |
| | Capacity Factor (%) | 81.3% | 81.8% | 91.4% |
| | Realized Heat Rate (Btu/KWh) | 10,080 | 10,084 | 10,061 |
| | Number of Starts | 4 | 2 | 1 |
| | Hours of Operation | 7,853 | 7,883 | 3,593 |
| | **Revenue and Costs Details** | | | |
| | Average LMP ($/MWh) | $29.39 | $31.66 | $31.88 |
| | Average LMP Received ($/MWh) | $29.56 | $31.90 | $31.90 |
| | Fuel Used (MMBtu) | 40,585,174 | 40,818,130 | 19,079,761 |
| | Average Fuel Price ($/MMBtu) | $2.22 | $2.44 | $2.46 |
| | Average Fuel Cost ($/MWh) | $22.38 | $24.57 | $24.77 |
| | Average Variable O&M ($/MWh) | $1.18 | $1.18 | $1.18 |
| | **Emissions Details** | | | |
| | NOx Emission (ton) | 2,189 | 2,201 | 1,029 |
| | CO2 Emission (ton) | 4,166,552 | 4,189,197 | 1,958,212 |
| | SO2 Emission (ton) | 1,533 | 1,541 | 720 |
| | NOx Emission Cost ($/ton) | $47.10 | $50.65 | $51.15 |
| | CO2 Emission Cost ($/ton) | $0.00 | $0.00 | $0.00 |
| | SO2 Emission Cost ($/ton) | $0.79 | $0.84 | $0.00 |
| | **Revenue** | | | |
| | Energy Revenues ($000) | $118,993 | $129,147 | $60,486 |
| | **Total Revenue ($000)** | $118,993 | $129,147 | $60,486 |
| | **Expenses** | | | |
| | Fuel ($000) | $90,099 | $99,474 | $46,974 |
| | Start Up (Fixed plus Fuel $000) | $551 | $260 | $130 |
| | Variable O&M ($000) | $4,751 | $4,777 | $2,238 |
| | Total Emission Cost ($000) | $104 | $112 | $53 |
| | **Total Expenses ($000)** | $95,505 | $104,622 | $49,394 |
| | **Energy Market Margin - Total ($000)** | $23,488 | $24,524 | $11,091 |

Real 2011$ **Plant: J M Stuart 4**

**Total Annual Proforma Summary**

| Unit Name | Output Data | | | |
|---|---|---|---|---|
| Stuart4 | | **2013** | **2014** | **2015** |
| | **Generation Details** | | | |
| | Max Capacity (MW) | 577 | 577 | 577 |
| | Average Capacity (MW) | 565 | 565 | 572 |
| | Possible Generation (GWh) | 4,951 | 4,951 | 2,074 |
| | Total Generation (GWh) | 4,082 | 4,087 | 1,435 |
| | Capacity Factor (%) | 82.5% | 82.6% | 69.2% |
| | Realized Heat Rate (Btu/KWh) | 9,891 | 9,892 | 9,884 |
| | Number of Starts | 3 | 1 | 1 |
| | Hours of Operation | 7,882 | 7,911 | 2,705 |
| | **Revenue and Costs Details** | | | |
| | Average LMP ($/MWh) | $29.39 | $31.66 | $31.88 |
| | Average LMP Received ($/MWh) | $29.49 | $31.74 | $32.08 |
| | Fuel Used (MMBtu) | 40,376,931 | 40,426,237 | 14,187,268 |
| | Average Fuel Price ($/MMBtu) | $2.22 | $2.44 | $2.46 |
| | Average Fuel Cost ($/MWh) | $21.96 | $24.11 | $24.33 |
| | Average Variable O&M ($/MWh) | $1.18 | $1.18 | $1.18 |
| | **Emissions Details** | | | |
| | NOx Emission (ton) | 2,296 | 2,299 | 807 |
| | CO2 Emission (ton) | 4,144,550 | 4,148,358 | 1,456,239 |
| | SO2 Emission (ton) | 2,747 | 2,749 | 965 |
| | NOx Emission Cost ($/ton) | $47.10 | $50.65 | $51.15 |
| | CO2 Emission Cost ($/ton) | $0.00 | $0.00 | $0.00 |
| | SO2 Emission Cost ($/ton) | $0.79 | $0.84 | $0.00 |
| | **Revenue** | | | |
| | Energy Revenues ($000) | $120,363 | $129,695 | $46,051 |
| | **Total Revenue ($000)** | $120,363 | $129,695 | $46,051 |
| | **Expenses** | | | |
| | Fuel ($000) | $89,637 | $98,519 | $34,929 |
| | Start Up (Fixed plus Fuel $000) | $413 | $129 | $129 |
| | Variable O&M ($000) | $4,817 | $4,822 | $1,694 |
| | Total Emission Cost ($000) | $108 | $116 | $39 |
| | **Total Expenses ($000)** | $94,975 | $103,587 | $36,791 |
| | **Energy Market Margin - Total ($000)** | $25,388 | $26,108 | $9,260 |

Real 2011$ **Plant: Miami Fort 7**

**Total Annual Proforma Summary**

| Unit Name | Output Data | | | |
|---|---|---|---|---|
| MiamiFt7 | | 2013 | 2014 | 2015 |
| | **Generation Details** | | | |
| | Max Capacity (MW) | 500 | 500 | 500 |
| | Average Capacity (MW) | 490 | 490 | 496 |
| | Possible Generation (GWh) | 4,290 | 4,290 | 1,797 |
| | Total Generation (GWh) | 3,264 | 3,228 | 1,242 |
| | Capacity Factor (%) | 76.1% | 75.2% | 69.1% |
| | Realized Heat Rate (Btu/KWh) | 9,493 | 9,496 | 9,478 |
| | Number of Starts | 4 | 2 | 1 |
| | Hours of Operation | 7,857 | 7,884 | 2,782 |
| | **Revenue and Costs Details** | | | |
| | Average LMP ($/MWh) | $28.37 | $30.81 | $31.05 |
| | Average LMP Received ($/MWh) | $29.01 | $31.53 | $31.26 |
| | Fuel Used (MMBtu) | 30,989,032 | 30,651,175 | 11,773,874 |
| | Average Fuel Price ($/MMBtu) | $2.18 | $2.39 | $2.42 |
| | Average Fuel Cost ($/MWh) | $20.73 | $22.70 | $22.96 |
| | Average Variable O&M ($/MWh) | $1.09 | $1.09 | $1.09 |
| | **Emissions Details** | | | |
| | NOx Emission (ton) | 2,135 | 2,111 | 811 |
| | CO2 Emission (ton) | 3,181,031 | 3,145,589 | 1,208,388 |
| | SO2 Emission (ton) | 2,676 | 2,646 | 1,016 |
| | NOx Emission Cost ($/ton) | $47.10 | $50.65 | $51.15 |
| | CO2 Emission Cost ($/ton) | $0.00 | $0.00 | $0.00 |
| | SO2 Emission Cost ($/ton) | $0.79 | $0.84 | $0.00 |
| | **Revenue** | | | |
| | Energy Revenues ($000) | $94,716 | $101,784 | $38,834 |
| | **Total Revenue ($000)** | $94,716 | $101,784 | $38,834 |
| | **Expenses** | | | |
| | Fuel ($000) | $67,680 | $73,256 | $28,528 |
| | Start Up (Fixed plus Fuel $000) | $349 | $166 | $82 |
| | Variable O&M ($000) | $3,558 | $3,518 | $1,354 |
| | Total Emission Cost ($000) | $100 | $110 | $39 |
| | **Total Expenses ($000)** | $71,687 | $77,050 | $30,003 |
| | **Energy Market Margin - Total ($000)** | $23,028 | $24,733 | $8,831 |

Real 2011$ **Plant: Miami Fort ST8**

**Total Annual Proforma Summary**

| **Unit Name** | **Output Data** | | | |
|---|---|---|---|---|
| MiamiFt8 | | **2013** | **2014** | **2015** |
| | **Generation Details** | | | |
| | Max Capacity (MW) | 500 | 500 | 500 |
| | Average Capacity (MW) | 490 | 490 | 496 |
| | Possible Generation (GWh) | 4,290 | 4,290 | 1,797 |
| | Total Generation (GWh) | 3,191 | 3,170 | 1,539 |
| | Capacity Factor (%) | 74.4% | 73.9% | 85.6% |
| | Realized Heat Rate (Btu/KWh) | 9,666 | 9,669 | 9,656 |
| | Number of Starts | 4 | 3 | 1 |
| | Hours of Operation | 7,858 | 7,866 | 3,599 |
| | **Revenue and Costs Details** | | | |
| | Average LMP ($/MWh) | $28.37 | $30.81 | $31.05 |
| | Average LMP Received ($/MWh) | $29.05 | $31.58 | $31.47 |
| | Fuel Used (MMBtu) | 30,846,377 | 30,655,143 | 14,856,656 |
| | Average Fuel Price ($/MMBtu) | $2.18 | $2.39 | $2.42 |
| | Average Fuel Cost ($/MWh) | $21.11 | $23.11 | $23.40 |
| | Average Variable O&M ($/MWh) | $1.09 | $1.09 | $1.09 |
| | **Emissions Details** | | | |
| | NOx Emission (ton) | 2,123 | 2,110 | 1,022 |
| | CO2 Emission (ton) | 3,166,379 | 3,146,373 | 1,524,678 |
| | SO2 Emission (ton) | 3,108 | 3,088 | 1,496 |
| | NOx Emission Cost ($/ton) | $47.10 | $50.65 | $51.15 |
| | CO2 Emission Cost ($/ton) | $0.00 | $0.00 | $0.00 |
| | SO2 Emission Cost ($/ton) | $0.79 | $0.84 | $0.00 |
| | **Revenue** | | | |
| | Energy Revenues ($000) | $92,704 | $100,129 | $48,422 |
| | **Total Revenue ($000)** | $92,704 | $100,129 | $48,422 |
| | **Expenses** | | | |
| | Fuel ($000) | $67,368 | $73,266 | $35,998 |
| | Start Up (Fixed plus Fuel $000) | $344 | $243 | $81 |
| | Variable O&M ($000) | $3,479 | $3,456 | $1,677 |
| | Total Emission Cost ($000) | $103 | $110 | $52 |
| | **Total Expenses ($000)** | $71,294 | $77,075 | $37,808 |
| | **Energy Market Margin - Total ($000)** | $21,410 | $23,054 | $10,614 |

Real 2011$ **Plant: W H Zimmer**

**Total Annual Proforma Summary**

| Unit Name | Output Data | | | |
|---|---|---|---|---|
| Zimmer | | 2013 | 2014 | 2015 |
| | **Generation Details** | | | |
| | Max Capacity (MW) | 1,300 | 1,300 | 1,300 |
| | Average Capacity (MW) | 1,273 | 1,273 | 1,289 |
| | Possible Generation (GWh) | 11,154 | 11,154 | 4,672 |
| | Total Generation (GWh) | 8,798 | 8,942 | 4,234 |
| | Capacity Factor (%) | 78.9% | 80.2% | 90.6% |
| | Realized Heat Rate (Btu/KWh) | 9,534 | 9,534 | 9,523 |
| | Number of Starts | 4 | 2 | 0 |
| | Hours of Operation | 7,714 | 7,817 | 3,624 |
| | **Revenue and Costs Details** | | | |
| | Average LMP ($/MWh) | $28.37 | $30.81 | $31.05 |
| | Average LMP Received ($/MWh) | $28.44 | $30.84 | $31.05 |
| | Fuel Used (MMBtu) | 83,879,751 | 85,250,227 | 40,317,955 |
| | Average Fuel Price ($/MMBtu) | $2.20 | $2.40 | $2.45 |
| | Average Fuel Cost ($/MWh) | $20.96 | $22.91 | $23.33 |
| | Average Variable O&M ($/MWh) | $1.57 | $1.57 | $1.57 |
| | **Emissions Details** | | | |
| | NOx Emission (ton) | 7,520 | 7,639 | 3,610 |
| | CO2 Emission (ton) | 8,598,764 | 8,733,929 | 4,128,155 |
| | SO2 Emission (ton) | 18,379 | 18,668 | 8,824 |
| | NOx Emission Cost ($/ton) | $47.10 | $50.65 | $51.15 |
| | CO2 Emission Cost ($/ton) | $0.00 | $0.00 | $0.00 |
| | SO2 Emission Cost ($/ton) | $0.79 | $0.84 | $0.00 |
| | **Revenue** | | | |
| | Energy Revenues ($000) | $250,186 | $275,812 | $131,477 |
| | **Total Revenue ($000)** | $250,186 | $275,812 | $131,477 |
| | **Expenses** | | | |
| | Fuel ($000) | $184,452 | $204,856 | $98,779 |
| | Start Up (Fixed plus Fuel $000) | $2,223 | $1,048 | $0 |
| | Variable O&M ($000) | $13,813 | $14,039 | $6,647 |
| | Total Emission Cost ($000) | $370 | $406 | $185 |
| | **Total Expenses ($000)** | $200,858 | $220,349 | $105,611 |
| | **Energy Market Margin - Total ($000)** | $49,328 | $55,463 | $25,866 |

Real 2011$ **Plant: Walter C Beckjord CT1**

**Total Annual Proforma Summary**

| **Unit Name** | **Output Data** | | | |
|---|---|---|---|---|
| BkjrdCT1 | | **2013** | **2014** | **2015** |
| | **Generation Details** | | | |
| | Max Capacity (MW) | 61 | 61 | 61 |
| | Average Capacity (MW) | 55 | 55 | 60 |
| | Possible Generation (GWh) | 483 | 483 | 216 |
| | Total Generation (GWh) | 0 | 0 | 0 |
| | Capacity Factor (%) | 0.0% | 0.0% | 0.0% |
| | Realized Heat Rate (Btu/KWh) | | | |
| | Number of Starts | 0 | 0 | 0 |
| | Hours of Operation | 0 | 0 | 0 |
| | **Revenue and Costs Details** | | | |
| | Average LMP ($/MWh) | $28.37 | $30.81 | $31.05 |
| | Average LMP Received ($/MWh) | | | |
| | Fuel Used (MMBtu) | 0 | 0 | 0 |
| | Average Fuel Price ($/MMBtu) | | | |
| | Average Fuel Cost ($/MWh) | | | |
| | Average Variable O&M ($/MWh) | | | |
| | **Emissions Details** | | | |
| | NOx Emission (ton) | 0 | 0 | 0 |
| | CO2 Emission (ton) | 0 | 0 | 0 |
| | SO2 Emission (ton) | 0 | 0 | 0 |
| | NOx Emission Cost ($/ton) | $47.10 | $50.65 | $51.15 |
| | CO2 Emission Cost ($/ton) | $0.00 | $0.00 | $0.00 |
| | SO2 Emission Cost ($/ton) | $0.79 | $0.84 | $0.00 |
| | **Revenue** | | | |
| | Energy Revenues ($000) | $0 | $0 | $0 |
| | **Total Revenue ($000)** | $0 | $0 | $0 |
| | **Expenses** | | | |
| | Fuel ($000) | $0 | $0 | $0 |
| | Start Up (Fixed plus Fuel $000) | $0 | $0 | $0 |
| | Variable O&M ($000) | $0 | $0 | $0 |
| | Total Emission Cost ($000) | $0 | $0 | $0 |
| | **Total Expenses ($000)** | $0 | $0 | $0 |
| | **Energy Market Margin - Total ($000)** | $0 | $0 | $0 |

Real 2011$ **Plant: Walter C Beckjord CT2**

**Total Annual Proforma Summary**

| **Unit Name** | **Output Data** | | | |
|---|---|---|---|---|
| BkjrdCT2 | | **2013** | **2014** | **2015** |
| | **Generation Details** | | | |
| | Max Capacity (MW) | 61 | 61 | 61 |
| | Average Capacity (MW) | 55 | 55 | 60 |
| | Possible Generation (GWh) | 483 | 483 | 216 |
| | Total Generation (GWh) | 0 | 0 | 0 |
| | Capacity Factor (%) | 0.0% | 0.0% | 0.0% |
| | Realized Heat Rate (Btu/KWh) | | | |
| | Number of Starts | 0 | 0 | 0 |
| | Hours of Operation | 0 | 0 | 0 |
| | **Revenue and Costs Details** | | | |
| | Average LMP ($/MWh) | $28.37 | $30.81 | $31.05 |
| | Average LMP Received ($/MWh) | | | |
| | Fuel Used (MMBtu) | 0 | 0 | 0 |
| | Average Fuel Price ($/MMBtu) | | | |
| | Average Fuel Cost ($/MWh) | | | |
| | Average Variable O&M ($/MWh) | | | |
| | **Emissions Details** | | | |
| | NOx Emission (ton) | 0 | 0 | 0 |
| | CO2 Emission (ton) | 0 | 0 | 0 |
| | SO2 Emission (ton) | 0 | 0 | 0 |
| | NOx Emission Cost ($/ton) | $47.10 | $50.65 | $51.15 |
| | CO2 Emission Cost ($/ton) | $0.00 | $0.00 | $0.00 |
| | SO2 Emission Cost ($/ton) | $0.79 | $0.84 | $0.00 |
| | **Revenue** | | | |
| | Energy Revenues ($000) | $0 | $0 | $0 |
| | **Total Revenue ($000)** | $0 | $0 | $0 |
| | **Expenses** | | | |
| | Fuel ($000) | $0 | $0 | $0 |
| | Start Up (Fixed plus Fuel $000) | $0 | $0 | $0 |
| | Variable O&M ($000) | $0 | $0 | $0 |
| | Total Emission Cost ($000) | $0 | $0 | $0 |
| | **Total Expenses ($000)** | $0 | $0 | $0 |
| | **Energy Market Margin - Total ($000)** | $0 | $0 | $0 |

Real 2011$ **Plant: Walter C Beckjord CT3**

**Total Annual Proforma Summary**

| **Unit Name** | **Output Data** | | | |
|---|---|---|---|---|
| BkjrdCT3 | | **2013** | **2014** | **2015** |
| | **Generation Details** | | | |
| | Max Capacity (MW) | 61 | 61 | 61 |
| | Average Capacity (MW) | 55 | 55 | 60 |
| | Possible Generation (GWh) | 483 | 483 | 216 |
| | Total Generation (GWh) | 0 | 0 | 0 |
| | Capacity Factor (%) | 0.0% | 0.0% | 0.0% |
| | Realized Heat Rate (Btu/KWh) | | | |
| | Number of Starts | 0 | 0 | 0 |
| | Hours of Operation | 0 | 0 | 0 |
| | **Revenue and Costs Details** | | | |
| | Average LMP ($/MWh) | $28.37 | $30.81 | $31.05 |
| | Average LMP Received ($/MWh) | | | |
| | Fuel Used (MMBtu) | 0 | 0 | 0 |
| | Average Fuel Price ($/MMBtu) | | | |
| | Average Fuel Cost ($/MWh) | | | |
| | Average Variable O&M ($/MWh) | | | |
| | **Emissions Details** | | | |
| | NOx Emission (ton) | 0 | 0 | 0 |
| | CO2 Emission (ton) | 0 | 0 | 0 |
| | SO2 Emission (ton) | 0 | 0 | 0 |
| | NOx Emission Cost ($/ton) | $47.10 | $50.65 | $51.15 |
| | CO2 Emission Cost ($/ton) | $0.00 | $0.00 | $0.00 |
| | SO2 Emission Cost ($/ton) | $0.79 | $0.84 | $0.00 |
| | **Revenue** | | | |
| | Energy Revenues ($000) | $0 | $0 | $0 |
| | **Total Revenue ($000)** | $0 | $0 | $0 |
| | **Expenses** | | | |
| | Fuel ($000) | $0 | $0 | $0 |
| | Start Up (Fixed plus Fuel $000) | $0 | $0 | $0 |
| | Variable O&M ($000) | $0 | $0 | $0 |
| | Total Emission Cost ($000) | $0 | $0 | $0 |
| | **Total Expenses ($000)** | $0 | $0 | $0 |
| | **Energy Market Margin - Total ($000)** | $0 | $0 | $0 |

Real 2011$ **Plant: Walter C Beckjord CT4**

**Total Annual Proforma Summary**

| Unit Name | Output Data | | | |
|---|---|---|---|---|
| BkjrdCT4 | | 2013 | 2014 | 2015 |
| | **Generation Details** | | | |
| | Max Capacity (MW) | 61 | 61 | 61 |
| | Average Capacity (MW) | 55 | 55 | 60 |
| | Possible Generation (GWh) | 483 | 483 | 216 |
| | Total Generation (GWh) | 0 | 0 | 0 |
| | Capacity Factor (%) | 0.0% | 0.0% | 0.0% |
| | Realized Heat Rate (Btu/KWh) | | | |
| | Number of Starts | 0 | 0 | 0 |
| | Hours of Operation | 0 | 0 | 0 |
| | **Revenue and Costs Details** | | | |
| | Average LMP ($/MWh) | $28.37 | $30.81 | $31.05 |
| | Average LMP Received ($/MWh) | | | |
| | Fuel Used (MMBtu) | 0 | 0 | 0 |
| | Average Fuel Price ($/MMBtu) | | | |
| | Average Fuel Cost ($/MWh) | | | |
| | Average Variable O&M ($/MWh) | | | |
| | **Emissions Details** | | | |
| | NOx Emission (ton) | 0 | 0 | 0 |
| | CO2 Emission (ton) | 0 | 0 | 0 |
| | SO2 Emission (ton) | 0 | 0 | 0 |
| | NOx Emission Cost ($/ton) | $47.10 | $50.65 | $51.15 |
| | CO2 Emission Cost ($/ton) | $0.00 | $0.00 | $0.00 |
| | SO2 Emission Cost ($/ton) | $0.79 | $0.84 | $0.00 |
| | **Revenue** | | | |
| | Energy Revenues ($000) | $0 | $0 | $0 |
| | **Total Revenue ($000)** | $0 | $0 | $0 |
| | **Expenses** | | | |
| | Fuel ($000) | $0 | $0 | $0 |
| | Start Up (Fixed plus Fuel $000) | $0 | $0 | $0 |
| | Variable O&M ($000) | $0 | $0 | $0 |
| | Total Emission Cost ($000) | $0 | $0 | $0 |
| | **Total Expenses ($000)** | $0 | $0 | $0 |
| | **Energy Market Margin - Total ($000)** | $0 | $0 | $0 |

Real 2011$ **Plant: Dicks Creek 1**

**Total Annual Proforma Summary**

| **Unit Name** | **Output Data** | | | |
|---|---|---|---|---|
| DkCrk1 | | **2013** | **2014** | **2015** |
| | **Generation Details** | | | |
| | Max Capacity (MW) | 110 | 110 | 110 |
| | Average Capacity (MW) | 102 | 102 | 108 |
| | Possible Generation (GWh) | 898 | 898 | 392 |
| | Total Generation (GWh) | 0.32 | 0.30 | 0.30 |
| | Capacity Factor (%) | 0.0% | 0.0% | 0.1% |
| | Realized Heat Rate (Btu/KWh) | 14,544 | 14,544 | 14,544 |
| | Number of Starts | 1 | 1 | 1 |
| | Hours of Operation | 3 | 3 | 3 |
| | **Revenue and Costs Details** | | | |
| | Average LMP ($/MWh) | $28.37 | $30.81 | $31.05 |
| | Average LMP Received ($/MWh) | $102.19 | $113.61 | $104.63 |
| | Fuel Used (MMBtu) | 4,609 | 4,421 | 4,421 |
| | Average Fuel Price ($/MMBtu) | $3.96 | $4.14 | $3.87 |
| | Average Fuel Cost ($/MWh) | $57.62 | $60.14 | $56.30 |
| | Average Variable O&M ($/MWh) | $4.25 | $4.25 | $4.25 |
| | **Emissions Details** | | | |
| | NOx Emission (ton) | 1 | 1 | 1 |
| | CO2 Emission (ton) | 290 | 279 | 279 |
| | SO2 Emission (ton) | 0 | 0 | 0 |
| | NOx Emission Cost ($/ton) | $47.10 | $50.65 | $51.15 |
| | CO2 Emission Cost ($/ton) | $0.00 | $0.00 | $0.00 |
| | SO2 Emission Cost ($/ton) | $0.79 | $0.84 | $0.00 |
| | **Revenue** | | | |
| | Energy Revenues ($000) | $32 | $35 | $32 |
| | **Total Revenue ($000)** | $32 | $35 | $32 |
| | **Expenses** | | | |
| | Fuel ($000) | $18 | $18 | $17 |
| | Start Up (Fixed plus Fuel $000) | $11 | $11 | $11 |
| | Variable O&M ($000) | $1 | $1 | $1 |
| | Total Emission Cost ($000) | $0 | $0 | $0 |
| | **Total Expenses ($000)** | $31 | $31 | $30 |
| | **Energy Market Margin - Total ($000)** | $1 | $4 | $2 |

Real 2011$ **Plant: Dicks Creek 3**

**Total Annual Proforma Summary**

| **Unit Name** | **Output Data** | | | |
|---|---|---|---|---|
| DkCrk3 | | **2013** | **2014** | **2015** |
| | **Generation Details** | | | |
| | Max Capacity (MW) | 20 | 20 | 20 |
| | Average Capacity (MW) | 17 | 17 | 19 |
| | Possible Generation (GWh) | 151 | 151 | 69 |
| | Total Generation (GWh) | 0.05 | 0.00 | 0.18 |
| | Capacity Factor (%) | 0.0% | 0.0% | 0.3% |
| | Realized Heat Rate (Btu/KWh) | 13,328 | | 13,328 |
| | Number of Starts | 1 | 0 | 2 |
| | Hours of Operation | 3 | 0 | 10 |
| | **Revenue and Costs Details** | | | |
| | Average LMP ($/MWh) | $28.37 | $30.81 | $31.05 |
| | Average LMP Received ($/MWh) | $102.19 | | $84.38 |
| | Fuel Used (MMBtu) | 721 | 0 | 2,353 |
| | Average Fuel Price ($/MMBtu) | $3.96 | | $4.04 |
| | Average Fuel Cost ($/MWh) | $52.81 | | $53.86 |
| | Average Variable O&M ($/MWh) | $4.25 | | $4.25 |
| | **Emissions Details** | | | |
| | NOx Emission (ton) | 0 | 0 | 1 |
| | CO2 Emission (ton) | 45 | 0 | 143 |
| | SO2 Emission (ton) | 0 | 0 | 0 |
| | NOx Emission Cost ($/ton) | $47.10 | $50.65 | $51.15 |
| | CO2 Emission Cost ($/ton) | $0.00 | $0.00 | $0.00 |
| | SO2 Emission Cost ($/ton) | $0.79 | $0.84 | $0.00 |
| | **Revenue** | | | |
| | Energy Revenues ($000) | $6 | $0 | $15 |
| | **Total Revenue ($000)** | $6 | $0 | $15 |
| | **Expenses** | | | |
| | Fuel ($000) | $3 | $0 | $10 |
| | Start Up (Fixed plus Fuel $000) | $2 | $0 | $4 |
| | Variable O&M ($000) | $0 | $0 | $1 |
| | Total Emission Cost ($000) | $0 | $0 | $0 |
| | **Total Expenses ($000)** | $5 | $0 | $15 |
| | **Energy Market Margin - Total ($000)** | $0 | $0 | $0 |

Real 2011$ **Plant: Dicks Creek 4**

**Total Annual Proforma Summary**

| ***Unit Name*** | ***Output Data*** | | | |
|---|---|---|---|---|
| DkCrk4 | | **2013** | **2014** | **2015** |
| | **Generation Details** | | | |
| | Max Capacity (MW) | 21 | 21 | 21 |
| | Average Capacity (MW) | 19 | 19 | 21 |
| | Possible Generation (GWh) | 164 | 164 | 75 |
| | Total Generation (GWh) | 0 | 0 | 0 |
| | Capacity Factor (%) | 0.0% | 0.0% | 0.0% |
| | Realized Heat Rate (Btu/KWh) | | | |
| | Number of Starts | 0 | 0 | 0 |
| | Hours of Operation | 0 | 0 | 0 |
| | **Revenue and Costs Details** | | | |
| | Average LMP ($/MWh) | $28.37 | $30.81 | $31.05 |
| | Average LMP Received ($/MWh) | | | |
| | Fuel Used (MMBtu) | 0 | 0 | 0 |
| | Average Fuel Price ($/MMBtu) | | | |
| | Average Fuel Cost ($/MWh) | | | |
| | Average Variable O&M ($/MWh) | | | |
| | **Emissions Details** | | | |
| | NOx Emission (ton) | 0 | 0 | 0 |
| | CO2 Emission (ton) | 0 | 0 | 0 |
| | SO2 Emission (ton) | 0 | 0 | 0 |
| | NOx Emission Cost ($/ton) | $47.10 | $50.65 | $51.15 |
| | CO2 Emission Cost ($/ton) | $0.00 | $0.00 | $0.00 |
| | SO2 Emission Cost ($/ton) | $0.79 | $0.84 | $0.00 |
| | **Revenue** | | | |
| | Energy Revenues ($000) | $0 | $0 | $0 |
| | **Total Revenue ($000)** | $0 | $0 | $0 |
| | **Expenses** | | | |
| | Fuel ($000) | $0 | $0 | $0 |
| | Start Up (Fixed plus Fuel $000) | $0 | $0 | $0 |
| | Variable O&M ($000) | $0 | $0 | $0 |
| | Total Emission Cost ($000) | $0 | $0 | $0 |
| | **Total Expenses ($000)** | $0 | $0 | $0 |
| | **Energy Market Margin - Total ($000)** | $0 | $0 | $0 |

Real 2011$ **Plant: Dicks Creek 5**

**Total Annual Proforma Summary**

| Unit Name | Output Data | | | |
|---|---|---|---|---|
| DkCrk5 | | 2013 | 2014 | 2015 |
| | **Generation Details** | | | |
| | Max Capacity (MW) | 21 | 21 | 21 |
| | Average Capacity (MW) | 19 | 19 | 21 |
| | Possible Generation (GWh) | 164 | 164 | 75 |
| | Total Generation (GWh) | 0 | 0 | 0 |
| | Capacity Factor (%) | 0.0% | 0.0% | 0.0% |
| | Realized Heat Rate (Btu/KWh) | | | |
| | Number of Starts | 0 | 0 | 0 |
| | Hours of Operation | 0 | 0 | 0 |
| | **Revenue and Costs Details** | | | |
| | Average LMP ($/MWh) | $28.37 | $30.81 | $31.05 |
| | Average LMP Received ($/MWh) | | | |
| | Fuel Used (MMBtu) | 0 | 0 | 0 |
| | Average Fuel Price ($/MMBtu) | | | |
| | Average Fuel Cost ($/MWh) | | | |
| | Average Variable O&M ($/MWh) | | | |
| | **Emissions Details** | | | |
| | NOx Emission (ton) | 0 | 0 | 0 |
| | CO2 Emission (ton) | 0 | 0 | 0 |
| | SO2 Emission (ton) | 0 | 0 | 0 |
| | NOx Emission Cost ($/ton) | $47.10 | $50.65 | $51.15 |
| | CO2 Emission Cost ($/ton) | $0.00 | $0.00 | $0.00 |
| | SO2 Emission Cost ($/ton) | $0.79 | $0.84 | $0.00 |
| | **Revenue** | | | |
| | Energy Revenues ($000) | $0 | $0 | $0 |
| | **Total Revenue ($000)** | $0 | $0 | $0 |
| | **Expenses** | | | |
| | Fuel ($000) | $0 | $0 | $0 |
| | Start Up (Fixed plus Fuel $000) | $0 | $0 | $0 |
| | Variable O&M ($000) | $0 | $0 | $0 |
| | Total Emission Cost ($000) | $0 | $0 | $0 |
| | **Total Expenses ($000)** | $0 | $0 | $0 |
| | **Energy Market Margin - Total ($000)** | $0 | $0 | $0 |

Real 2011$ **Plant: Killen Station CT**

**Total Annual Proforma Summary**

| **Unit Name** | **Output Data** | | | |
|---|---|---|---|---|
| *Killen1* | | **2013** | **2014** | **2015** |
| | **Generation Details** | | | |
| | Max Capacity (MW) | 24 | 24 | 24 |
| | Average Capacity (MW) | 21 | 21 | 23 |
| | Possible Generation (GWh) | 188 | 188 | 85 |
| | Total Generation (GWh) | 0 | 0 | 0 |
| | Capacity Factor (%) | 0.0% | 0.0% | 0.0% |
| | Realized Heat Rate (Btu/KWh) | | | |
| | Number of Starts | 0 | 0 | 0 |
| | Hours of Operation | 0 | 0 | 0 |
| | **Revenue and Costs Details** | | | |
| | Average LMP ($/MWh) | $29.39 | $31.66 | $31.88 |
| | Average LMP Received ($/MWh) | | | |
| | Fuel Used (MMBtu) | 0 | 0 | 0 |
| | Average Fuel Price ($/MMBtu) | | | |
| | Average Fuel Cost ($/MWh) | | | |
| | Average Variable O&M ($/MWh) | | | |
| | **Emissions Details** | | | |
| | NOx Emission (ton) | 0 | 0 | 0 |
| | CO2 Emission (ton) | 0 | 0 | 0 |
| | SO2 Emission (ton) | 0 | 0 | 0 |
| | NOx Emission Cost ($/ton) | $47.10 | $50.65 | $51.15 |
| | CO2 Emission Cost ($/ton) | $0.00 | $0.00 | $0.00 |
| | SO2 Emission Cost ($/ton) | $0.79 | $0.84 | $0.00 |
| | **Revenue** | | | |
| | Energy Revenues ($000) | $0 | $0 | $0 |
| | **Total Revenue ($000)** | $0 | $0 | $0 |
| | **Expenses** | | | |
| | Fuel ($000) | $0 | $0 | $0 |
| | Start Up (Fixed plus Fuel $000) | $0 | $0 | $0 |
| | Variable O&M ($000) | $0 | $0 | $0 |
| | Total Emission Cost ($000) | $0 | $0 | $0 |
| | **Total Expenses ($000)** | $0 | $0 | $0 |
| | **Energy Market Margin - Total ($000)** | $0 | $0 | $0 |

Real 2011$ **Plant: Miami Fort CT3**

**Total Annual Proforma Summary**

| Unit Name | Output Data | | | |
|---|---|---|---|---|
| MmiFtCT3 | | 2013 | 2014 | 2015 |
| | **Generation Details** | | | |
| | Max Capacity (MW) | 20 | 20 | 20 |
| | Average Capacity (MW) | 17 | 17 | 19 |
| | Possible Generation (GWh) | 151 | 151 | 69 |
| | Total Generation (GWh) | 0 | 0 | 0 |
| | Capacity Factor (%) | 0.0% | 0.0% | 0.0% |
| | Realized Heat Rate (Btu/KWh) | | | |
| | Number of Starts | 0 | 0 | 0 |
| | Hours of Operation | 0 | 0 | 0 |
| | **Revenue and Costs Details** | | | |
| | Average LMP ($/MWh) | $28.37 | $30.81 | $31.05 |
| | Average LMP Received ($/MWh) | | | |
| | Fuel Used (MMBtu) | 0 | 0 | 0 |
| | Average Fuel Price ($/MMBtu) | | | |
| | Average Fuel Cost ($/MWh) | | | |
| | Average Variable O&M ($/MWh) | | | |
| | **Emissions Details** | | | |
| | NOx Emission (ton) | 0 | 0 | 0 |
| | CO2 Emission (ton) | 0 | 0 | 0 |
| | SO2 Emission (ton) | 0 | 0 | 0 |
| | NOx Emission Cost ($/ton) | $47.10 | $50.65 | $51.15 |
| | CO2 Emission Cost ($/ton) | $0.00 | $0.00 | $0.00 |
| | SO2 Emission Cost ($/ton) | $0.79 | $0.84 | $0.00 |
| | **Revenue** | | | |
| | Energy Revenues ($000) | $0 | $0 | $0 |
| | **Total Revenue ($000)** | $0 | $0 | $0 |
| | **Expenses** | | | |
| | Fuel ($000) | $0 | $0 | $0 |
| | Start Up (Fixed plus Fuel $000) | $0 | $0 | $0 |
| | Variable O&M ($000) | $0 | $0 | $0 |
| | Total Emission Cost ($000) | $0 | $0 | $0 |
| | **Total Expenses ($000)** | $0 | $0 | $0 |
| | **Energy Market Margin - Total ($000)** | $0 | $0 | $0 |

Real 2011$ **Plant: Miami Fort CT4**

**Total Annual Proforma Summary**

| Unit Name | Output Data | | | |
|---|---|---|---|---|
| MmiFtCT4 | | 2013 | 2014 | 2015 |
| | **Generation Details** | | | |
| | Max Capacity (MW) | 20 | 20 | 20 |
| | Average Capacity (MW) | 17 | 17 | 19 |
| | Possible Generation (GWh) | 151 | 151 | 69 |
| | Total Generation (GWh) | 0 | 0 | 0 |
| | Capacity Factor (%) | 0.0% | 0.0% | 0.0% |
| | Realized Heat Rate (Btu/KWh) | | | |
| | Number of Starts | 0 | 0 | 0 |
| | Hours of Operation | 0 | 0 | 0 |
| | **Revenue and Costs Details** | | | |
| | Average LMP ($/MWh) | $28.37 | $30.81 | $31.05 |
| | Average LMP Received ($/MWh) | | | |
| | Fuel Used (MMBtu) | 0 | 0 | 0 |
| | Average Fuel Price ($/MMBtu) | | | |
| | Average Fuel Cost ($/MWh) | | | |
| | Average Variable O&M ($/MWh) | | | |
| | **Emissions Details** | | | |
| | NOx Emission (ton) | 0 | 0 | 0 |
| | CO2 Emission (ton) | 0 | 0 | 0 |
| | SO2 Emission (ton) | 0 | 0 | 0 |
| | NOx Emission Cost ($/ton) | $47.10 | $50.65 | $51.15 |
| | CO2 Emission Cost ($/ton) | $0.00 | $0.00 | $0.00 |
| | SO2 Emission Cost ($/ton) | $0.79 | $0.84 | $0.00 |
| | **Revenue** | | | |
| | Energy Revenues ($000) | $0 | $0 | $0 |
| | **Total Revenue ($000)** | $0 | $0 | $0 |
| | **Expenses** | | | |
| | Fuel ($000) | $0 | $0 | $0 |
| | Start Up (Fixed plus Fuel $000) | $0 | $0 | $0 |
| | Variable O&M ($000) | $0 | $0 | $0 |
| | Total Emission Cost ($000) | $0 | $0 | $0 |
| | **Total Expenses ($000)** | $0 | $0 | $0 |
| | **Energy Market Margin - Total ($000)** | $0 | $0 | $0 |

Real 2011$ **Plant: Miami Fort CT5**

**Total Annual Proforma Summary**

| Unit Name | Output Data | | | |
|---|---|---|---|---|
| *MmiFtCT5* | | 2013 | 2014 | 2015 |
| | **Generation Details** | | | |
| | Max Capacity (MW) | 20 | 20 | 20 |
| | Average Capacity (MW) | 17 | 17 | 19 |
| | Possible Generation (GWh) | 151 | 151 | 69 |
| | Total Generation (GWh) | 0 | 0 | 0 |
| | Capacity Factor (%) | 0.0% | 0.0% | 0.0% |
| | Realized Heat Rate (Btu/KWh) | | | |
| | Number of Starts | 0 | 0 | 0 |
| | Hours of Operation | 0 | 0 | 0 |
| | **Revenue and Costs Details** | | | |
| | Average LMP ($/MWh) | $28.37 | $30.81 | $31.05 |
| | Average LMP Received ($/MWh) | | | |
| | Fuel Used (MMBtu) | 0 | 0 | 0 |
| | Average Fuel Price ($/MMBtu) | | | |
| | Average Fuel Cost ($/MWh) | | | |
| | Average Variable O&M ($/MWh) | | | |
| | **Emissions Details** | | | |
| | NOx Emission (ton) | 0 | 0 | 0 |
| | CO2 Emission (ton) | 0 | 0 | 0 |
| | SO2 Emission (ton) | 0 | 0 | 0 |
| | NOx Emission Cost ($/ton) | $47.10 | $50.65 | $51.15 |
| | CO2 Emission Cost ($/ton) | $0.00 | $0.00 | $0.00 |
| | SO2 Emission Cost ($/ton) | $0.79 | $0.84 | $0.00 |
| | **Revenue** | | | |
| | Energy Revenues ($000) | $0 | $0 | $0 |
| | **Total Revenue ($000)** | $0 | $0 | $0 |
| | **Expenses** | | | |
| | Fuel ($000) | $0 | $0 | $0 |
| | Start Up (Fixed plus Fuel $000) | $0 | $0 | $0 |
| | Variable O&M ($000) | $0 | $0 | $0 |
| | Total Emission Cost ($000) | $0 | $0 | $0 |
| | **Total Expenses ($000)** | $0 | $0 | $0 |
| | **Energy Market Margin - Total ($000)** | $0 | $0 | $0 |

Real 2011$ **Plant: Miami Fort CT6**

**Total Annual Proforma Summary**

| **Unit Name** | **Output Data** | | | |
|---|---|---|---|---|
| MmiFtCT6 | | **2013** | **2014** | **2015** |
| | **Generation Details** | | | |
| | Max Capacity (MW) | 20 | 20 | 20 |
| | Average Capacity (MW) | 17 | 17 | 19 |
| | Possible Generation (GWh) | 151 | 151 | 69 |
| | Total Generation (GWh) | 0 | 0 | 0 |
| | Capacity Factor (%) | 0.0% | 0.0% | 0.0% |
| | Realized Heat Rate (Btu/KWh) | | | |
| | Number of Starts | 0 | 0 | 0 |
| | Hours of Operation | 0 | 0 | 0 |
| | **Revenue and Costs Details** | | | |
| | Average LMP ($/MWh) | $28.37 | $30.81 | $31.05 |
| | Average LMP Received ($/MWh) | | | |
| | Fuel Used (MMBtu) | 0 | 0 | 0 |
| | Average Fuel Price ($/MMBtu) | | | |
| | Average Fuel Cost ($/MWh) | | | |
| | Average Variable O&M ($/MWh) | | | |
| | **Emissions Details** | | | |
| | NOx Emission (ton) | 0 | 0 | 0 |
| | CO2 Emission (ton) | 0 | 0 | 0 |
| | SO2 Emission (ton) | 0 | 0 | 0 |
| | NOx Emission Cost ($/ton) | $47.10 | $50.65 | $51.15 |
| | CO2 Emission Cost ($/ton) | $0.00 | $0.00 | $0.00 |
| | SO2 Emission Cost ($/ton) | $0.79 | $0.84 | $0.00 |
| | **Revenue** | | | |
| | Energy Revenues ($000) | $0 | $0 | $0 |
| | **Total Revenue ($000)** | $0 | $0 | $0 |
| | **Expenses** | | | |
| | Fuel ($000) | $0 | $0 | $0 |
| | Start Up (Fixed plus Fuel $000) | $0 | $0 | $0 |
| | Variable O&M ($000) | $0 | $0 | $0 |
| | Total Emission Cost ($000) | $0 | $0 | $0 |
| | **Total Expenses ($000)** | $0 | $0 | $0 |
| | **Energy Market Margin - Total ($000)** | $0 | $0 | $0 |

| Category | LMP Location | Fuel Location | Summer Capacity | Winter Capacity | Average Heat Rate at Minimum Load | Average Heat Rate at Maximum Load | Forced Outage Rate | Maintenance Days/Year | Fixed Startup Cost | Startup Fuel Use | VOM | Minimum Up Time | Minimum Down Time | Ramp Rate |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Units | | | MW | MW | MMBtu/MWh | MMBtu/MWh | % | Days | $ | MMBtu | $/MWh | Hours | Hours | MW/Hour |
| Walter C Beckjord:6 | Duke Energy Ohio | Walter C Beckjord | 414 | 421 | 10.473 | 10.494 | 9.01 | 35 | 4,317.38 | 3,605.67 | 1.44 | 12 | 8 | 82 |
| Conesville:4 | Columbus Southern Power Company (AEP) | Conesville | 748 | 780 | 11.668 | 9.845 | 5.24 | 35 | 7,403.00 | 11,374.11 | 2.40 | 16 | 16 | 211.5 |
| Killen Station:2 | Dayton Power & Light Co. | Killen Station | 575 | 600 | 12.603 | 10.197 | 7.59 | 35 | 5,782.00 | 6,405.06 | 0.93 | 8 | 14 | 114 |
| Miami Fort:ST7 | Duke Energy Ohio | Miami Fort | 479 | 500 | 9.932 | 9.474 | 9.01 | 35 | 4,990.00 | 3,791.62 | 1.09 | 8 | 12 | 103.5 |
| Miami Fort:ST8 | Duke Energy Ohio | Miami Fort | 479 | 500 | 10.052 | 9.643 | 9.01 | 35 | 4,963.00 | 3,754.84 | 1.09 | 8 | 12 | 102 |
| J M Stuart:1 | Dayton Power & Light Co. | J M Stuart | 553 | 577 | 13.156 | 9.817 | 7.59 | 35 | 5,754.00 | 6,135.05 | 1.18 | 8 | 14 | 177 |
| J M Stuart:2 | Dayton Power & Light Co. | J M Stuart | 553 | 577 | 13.085 | 9.571 | 7.59 | 35 | 5,763.00 | 6,147.31 | 1.18 | 8 | 14 | 172 |
| J M Stuart:3 | Dayton Power & Light Co. | J M Stuart | 553 | 577 | 12.384 | 10.058 | 7.59 | 35 | 5,745.00 | 6,122.79 | 1.18 | 8 | 14 | 140 |
| J M Stuart:4 | Dayton Power & Light Co. | J M Stuart | 553 | 577 | 12.375 | 9.883 | 7.59 | 35 | 5,727.00 | 6,098.27 | 1.18 | 8 | 14 | 138.5 |
| W H Zimmer:1 | Duke Energy Ohio | W H Zimmer | 1,247 | 1,300 | 11.909 | 9.522 | 9.34 | 35 | 11,687.00 | 25,189.61 | 1.57 | 48 | 48 | 165.5 |
| Walter C Beckjord:GT1 | Duke Energy Ohio | MISO Distillate Fuel Oil | 47 | 61 | 12.619 | 12.619 | 3.96 | 21 | 6,342.00 | 197.60 | 0.43 | 3 | 2 | |
| Walter C Beckjord:GT2 | Duke Energy Ohio | MISO Distillate Fuel Oil | 47 | 61 | 12.619 | 12.619 | 3.96 | 21 | 6,342.00 | 197.60 | 0.43 | 3 | 2 | |
| Walter C Beckjord:GT3 | Duke Energy Ohio | MISO Distillate Fuel Oil | 47 | 61 | 12.619 | 12.619 | 3.96 | 21 | 6,342.00 | 197.60 | 0.43 | 3 | 2 | |
| Walter C Beckjord:GT4 | Duke Energy Ohio | MISO Distillate Fuel Oil | 47 | 61 | 12.619 | 12.619 | 3.96 | 21 | 6,342.00 | 197.60 | 0.43 | 3 | 2 | |
| Dicks Creek:1 | Duke Energy Ohio | Dominion South Point Gas | 92 | 110 | 14.544 | 14.544 | 3.96 | 21 | 9,933.00 | 352.24 | 4.25 | 1 | 1 | |
| Dicks Creek:3 | Duke Energy Ohio | Dominion South Point Gas | 14 | 20 | 13.328 | 13.328 | 7.58 | 14 | 2,060.00 | 45.25 | 4.25 | 1 | 1 | |
| Dicks Creek:4 | Duke Energy Ohio | MISO Distillate Fuel Oil | 15 | 21 | 14.083 | 14.083 | 6.46 | 14 | 2,123.00 | 51.92 | 4.25 | 1 | 1 | |
| Dicks Creek:5 | Duke Energy Ohio | MISO Distillate Fuel Oil | 15 | 21 | 14.083 | 14.083 | 6.46 | 14 | 2,123.00 | 51.92 | 4.25 | 1 | 1 | |
| Killen Station:1 | Dayton Power & Light Co. | PJM West Distillate Fuel Oil | 18 | 24 | 12.500 | 12.500 | 6.46 | 14 | 2,370.00 | 56.02 | 4.25 | 1 | 1 | |
| Miami Fort:GT3 | Duke Energy Ohio | MISO Distillate Fuel Oil | 14 | 20 | 13.516 | 13.516 | 6.46 | 14 | 2,370.00 | 56.02 | 4.25 | 1 | 1 | |
| Miami Fort:GT4 | Duke Energy Ohio | MISO Distillate Fuel Oil | 14 | 20 | 13.516 | 13.516 | 6.46 | 14 | 2,370.00 | 56.02 | 4.25 | 1 | 1 | |
| Miami Fort:GT5 | Duke Energy Ohio | MISO Distillate Fuel Oil | 14 | 20 | 13.516 | 13.516 | 6.46 | 14 | 2,370.00 | 56.02 | 4.25 | 1 | 1 | |
| Miami Fort:GT6 | Duke Energy Ohio | MISO Distillate Fuel Oil | 14 | 20 | 13.516 | 13.516 | 6.46 | 14 | 2,370.00 | 56.02 | 4.25 | 1 | 1 | |

**Gas Price Comparison ($/mmBtu)**

| | Duke Model Henry Hub | Navigant Model Henry Hub |
|---|---|---|
| Jan-13 | [redacted] | 3.49 |
| Feb-13 | [redacted] | 3.51 |
| Mar-13 | [redacted] | 3.49 |
| Apr-13 | [redacted] | 3.47 |
| May-13 | [redacted] | 3.51 |
| Jun-13 | [redacted] | 3.56 |
| Jul-13 | [redacted] | 3.54 |
| Aug-13 | [redacted] | 3.63 |
| Sep-13 | [redacted] | 3.62 |
| Oct-13 | [redacted] | 3.63 |
| Nov-13 | [redacted] | 3.72 |
| Dec-13 | [redacted] | 3.92 |
| Jan-14 | [redacted] | 4.11 |
| Feb-14 | [redacted] | 4.11 |
| Mar-14 | [redacted] | 4.05 |
| Apr-14 | [redacted] | 3.91 |
| May-14 | [redacted] | 3.92 |
| Jun-14 | [redacted] | 3.94 |
| Jul-14 | [redacted] | 3.99 |
| Aug-14 | [redacted] | 4.01 |
| Sep-14 | [redacted] | 4.01 |
| Oct-14 | [redacted] | 4.04 |
| Nov-14 | [redacted] | 4.23 |
| Dec-14 | [redacted] | 4.33 |
| Jan-15 | [redacted] | 4.46 |
| Feb-15 | [redacted] | 4.34 |
| Mar-15 | [redacted] | 4.19 |
| Apr-15 | [redacted] | 4.07 |
| May-15 | [redacted] | 4.10 |
| Average | [redacted] | 3.89 |
| Percent Difference | | 2.9% |

**Heat Rate Comparison for Coal Units**

| | Navigant Full Load Heat Rate | Navigant Realized Average Heat Rate | DEO Model Average Heat Rate | Percent Difference |
|---|---|---|---|---|
| Walter C Beckjord:6 | 10,494 | 10,487 | [redacted] | -2% |
| Miami Fort:ST7 | 9,474 | 9,492 | | 7% |
| Miami Fort:ST8 | 9,643 | 9,665 | | 4% |
| W H Zimmer:1 | 9,522 | 9,532 | | 1% |
| J M Stuart:1 | 9,817 | 9,818 | | 0% |
| J M Stuart:2 | 9,571 | 9,572 | | 4% |
| J M Stuart:3 | 10,058 | 10,078 | | -2% |
| J M Stuart:4 | 9,883 | 9,891 | | 0% |
| Killen Station:2 | 10,197 | 10,224 | | -1% |
| Conesville:4 | 9,845 | 9,854 | | 3% |
| | | | | |
| Average | | 9,861 | 10,014 | 2% |

**AD (AEP-Dayton) Hub Price Comparison**

| | Navigant | | Duke Model | |
|---|---|---|---|---|
| Month | On Peak | Off Peak | On Peak | Off Peak |
| Jan-13 | 33.20 | 26.08 | [redacted] | |
| Feb-13 | 33.67 | 26.59 | | |
| Mar-13 | 33.01 | 25.18 | | |
| Apr-13 | 35.73 | 26.61 | | |
| May-13 | 34.37 | 24.86 | | |
| Jun-13 | 37.03 | 24.76 | | |
| Jul-13 | 39.64 | 24.85 | | |
| Aug-13 | 38.82 | 24.97 | | |
| Sep-13 | 36.42 | 24.07 | | |
| Oct-13 | 36.43 | 26.82 | | |
| Nov-13 | 37.37 | 28.61 | | |
| Dec-13 | 33.19 | 27.10 | | |
| Jan-14 | 37.29 | 29.30 | | |
| Feb-14 | 36.47 | 29.17 | | |
| Mar-14 | 36.97 | 28.35 | | |
| Apr-14 | 38.28 | 28.40 | | |
| May-14 | 37.76 | 27.73 | | |
| Jun-14 | 40.92 | 26.84 | | |
| Jul-14 | 45.14 | 27.51 | | |
| Aug-14 | 45.78 | 27.77 | | |
| Sep-14 | 39.78 | 26.00 | | |
| Oct-14 | 39.86 | 29.37 | | |
| Nov-14 | 39.85 | 29.54 | | |
| Dec-14 | 36.09 | 28.57 | | |
| Jan-15 | 39.28 | 30.84 | | |
| Feb-15 | 38.70 | 30.75 | | |
| Mar-15 | 38.75 | 29.95 | | |
| Apr-15 | 40.65 | 30.25 | | |
| May-15 | 39.54 | 28.99 | | |
| Simple Avg | 37.93 | 27.58 | 40.30 | 29.44 |
| | -6% | -6% | | |

**Variable O&M Comparison for Coal Units**

| Unit | Navigant VOM $/MWh | Duke VOM $/MWh |
|---|---|---|
| Walter C Beckjord ST6 | 1.44 | [redacted] |
| Conesville 4 | 2.40 | [redacted] |
| Killen Station 2 | 0.93 | [redacted] |
| J M Stuart 1 | 1.18 | [redacted] |
| J M Stuart 2 | 1.18 | [redacted] |
| J M Stuart 3 | 1.18 | [redacted] |
| J M Stuart 4 | 1.18 | [redacted] |
| Miami Fort ST7 | 1.09 | [redacted] |
| Miami Fort ST8 | 1.09 | [redacted] |
| W H Zimmer | 1.57 | [redacted] |
| ***Total*** | | |
| | | |
| Average [redacted] | 1.31 | 0.41 |
| Difference | | 0.90 |

**Coal Price Comparison**

| | Duke Energy Ohio Model ($/mmBtu) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Beckj | MiamiFt | MiamiFt | Zimmer | Stuart | Stuart | Stuart | Stuart | Killen | Conesv |
| | 6 | 7 | 8 | | 1 | 2 | 3 | 4 | 2 | 4 |
| Jan-13 | [redacted] | | | | | | | | | |
| Feb-13 | | | | | | | | | | |
| Mar-13 | | | | | | | | | | |
| Apr-13 | | | | | | | | | | |
| May-13 | | | | | | | | | | |
| Jun-13 | | | | | | | | | | |
| Jul-13 | | | | | | | | | | |
| Aug-13 | | | | | | | | | | |
| Sep-13 | | | | | | | | | | |
| Oct-13 | | | | | | | | | | |
| Nov-13 | | | | | | | | | | |
| Dec-13 | | | | | | | | | | |
| Jan-14 | | | | | | | | | | |
| Feb-14 | | | | | | | | | | |
| Mar-14 | | | | | | | | | | |
| Apr-14 | | | | | | | | | | |
| May-14 | | | | | | | | | | |
| Jun-14 | | | | | | | | | | |
| Jul-14 | | | | | | | | | | |
| Aug-14 | | | | | | | | | | |
| Sep-14 | | | | | | | | | | |
| Oct-14 | | | | | | | | | | |
| Nov-14 | | | | | | | | | | |
| Dec-14 | | | | | | | | | | |
| Jan-15 | | | | | | | | | | |
| Feb-15 | | | | | | | | | | |
| Mar-15 | | | | | | | | | | |
| Apr-15 | | | | | | | | | | |
| May-15 | | | | | | | | | | |
| Average | 2.31 | 2.22 | 2.22 | 2.24 | 2.33 | 2.33 | 2.33 | 2.95 | 2.33 | 2.16 |
| Overall Average | | | | | | | | | | 2.34 |
| Difference | | | | | | | | | | |

| | Navigant Model (nominal $/mmBtu) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Beckj | MiamiFt | MiamiFt | Zimmer | Stuart | Stuart | Stuart | Stuart | Killen | Conesv |
| | 6 | 7 | 8 | | 1 | 2 | 3 | 4 | 2 | 4 |
| Jan-13 | 2.31 | 2.27 | 2.27 | 2.29 | 2.31 | 2.31 | 2.31 | 2.31 | 2.32 | 2.06 |
| Feb-13 | 2.31 | 2.27 | 2.27 | 2.29 | 2.31 | 2.31 | 2.31 | 2.31 | 2.32 | 2.06 |
| Mar-13 | 2.31 | 2.27 | 2.27 | 2.29 | 2.31 | 2.31 | 2.31 | 2.31 | 2.32 | 2.06 |
| Apr-13 | 2.31 | 2.27 | 2.27 | 2.29 | 2.31 | 2.31 | 2.31 | 2.31 | 2.32 | 2.06 |
| May-13 | 2.31 | 2.27 | 2.27 | 2.29 | 2.31 | 2.31 | 2.31 | 2.31 | 2.32 | 2.06 |
| Jun-13 | 2.31 | 2.27 | 2.27 | 2.29 | 2.31 | 2.31 | 2.31 | 2.31 | 2.32 | 2.06 |
| Jul-13 | 2.31 | 2.27 | 2.27 | 2.29 | 2.31 | 2.31 | 2.31 | 2.31 | 2.32 | 2.06 |
| Aug-13 | 2.31 | 2.27 | 2.27 | 2.29 | 2.31 | 2.31 | 2.31 | 2.31 | 2.32 | 2.06 |
| Sep-13 | 2.31 | 2.27 | 2.27 | 2.29 | 2.31 | 2.31 | 2.31 | 2.31 | 2.32 | 2.06 |
| Oct-13 | 2.31 | 2.27 | 2.27 | 2.29 | 2.31 | 2.31 | 2.31 | 2.31 | 2.32 | 2.06 |
| Nov-13 | 2.31 | 2.27 | 2.27 | 2.29 | 2.31 | 2.31 | 2.31 | 2.31 | 2.32 | 2.06 |
| Dec-13 | 2.31 | 2.27 | 2.27 | 2.29 | 2.31 | 2.31 | 2.31 | 2.31 | 2.32 | 2.06 |
| Jan-14 | 2.59 | 2.54 | 2.54 | 2.55 | 2.59 | 2.59 | 2.59 | 2.59 | 2.60 | 2.30 |
| Feb-14 | 2.59 | 2.54 | 2.54 | 2.55 | 2.59 | 2.59 | 2.59 | 2.59 | 2.60 | 2.30 |
| Mar-14 | 2.59 | 2.54 | 2.54 | 2.55 | 2.59 | 2.59 | 2.59 | 2.59 | 2.60 | 2.30 |
| Apr-14 | 2.59 | 2.54 | 2.54 | 2.55 | 2.59 | 2.59 | 2.59 | 2.59 | 2.60 | 2.30 |
| May-14 | 2.59 | 2.54 | 2.54 | 2.55 | 2.59 | 2.59 | 2.59 | 2.59 | 2.60 | 2.30 |
| Jun-14 | 2.59 | 2.54 | 2.54 | 2.55 | 2.59 | 2.59 | 2.59 | 2.59 | 2.60 | 2.30 |
| Jul-14 | 2.59 | 2.54 | 2.54 | 2.55 | 2.59 | 2.59 | 2.59 | 2.59 | 2.60 | 2.30 |
| Aug-14 | 2.59 | 2.54 | 2.54 | 2.55 | 2.59 | 2.59 | 2.59 | 2.59 | 2.60 | 2.30 |
| Sep-14 | 2.59 | 2.54 | 2.54 | 2.55 | 2.59 | 2.59 | 2.59 | 2.59 | 2.60 | 2.30 |
| Oct-14 | 2.59 | 2.54 | 2.54 | 2.55 | 2.59 | 2.59 | 2.59 | 2.59 | 2.60 | 2.30 |
| Nov-14 | 2.59 | 2.54 | 2.54 | 2.55 | 2.59 | 2.59 | 2.59 | 2.59 | 2.60 | 2.30 |
| Dec-14 | 2.59 | 2.54 | 2.54 | 2.55 | 2.59 | 2.59 | 2.59 | 2.59 | 2.60 | 2.30 |
| Jan-15 | 2.68 | 2.62 | 2.62 | 2.65 | 2.66 | 2.66 | 2.66 | 2.66 | 2.68 | 2.41 |
| Feb-15 | 2.68 | 2.62 | 2.62 | 2.65 | 2.66 | 2.66 | 2.66 | 2.66 | 2.68 | 2.41 |
| Mar-15 | 2.68 | 2.62 | 2.62 | 2.65 | 2.66 | 2.66 | 2.66 | 2.66 | 2.68 | 2.41 |
| Apr-15 | 2.68 | 2.62 | 2.62 | 2.65 | 2.66 | 2.66 | 2.66 | 2.66 | 2.68 | 2.41 |
| May-15 | 2.68 | 2.62 | 2.62 | 2.65 | 2.66 | 2.66 | 2.66 | 2.66 | 2.68 | 2.41 |
| Average | 2.49 | 2.44 | 2.44 | 2.46 | 2.49 | 2.49 | 2.49 | 2.49 | 2.50 | 2.22 |
| Overall Average | | | | | | | | | | 2.45 |
| Difference | | | | | | | | | | 4% |

**Forced Outage Rates Comparison**

**Duke Model:**

| | Beckj 6 | MiamiFt 7 | MiamiFt 8 | Zimmer | Stuart 1 | Stuart 2 | Stuart 3 | Stuart 4 | Killen 2 | Conesvl 4 |
|---|---|---|---|---|---|---|---|---|---|---|
| Jan-13 | [redacted] | | | | | | | | | |
| Feb-13 | [redacted] | | | | | | | | | |
| Mar-13 | [redacted] | | | | | | | | | |
| Apr-13 | [redacted] | | | | | | | | | |
| May-13 | [redacted] | | | | | | | | | |
| Jun-13 | [redacted] | | | | | | | | | |
| Jul-13 | [redacted] | | | | | | | | | |
| Aug-13 | [redacted] | | | | | | | | | |
| Sep-13 | [redacted] | | | | | | | | | |
| Oct-13 | [redacted] | | | | | | | | | |
| Nov-13 | [redacted] | | | | | | | | | |
| Dec-13 | [redacted] | | | | | | | | | |
| Jan-14 | [redacted] | | | | | | | | | |
| Feb-14 | [redacted] | | | | | | | | | |
| Mar-14 | [redacted] | | | | | | | | | |
| Apr-14 | [redacted] | | | | | | | | | |
| May-14 | [redacted] | | | | | | | | | |
| Jun-14 | [redacted] | | | | | | | | | |
| Jul-14 | [redacted] | | | | | | | | | |
| Aug-14 | [redacted] | | | | | | | | | |
| Sep-14 | [redacted] | | | | | | | | | |
| Oct-14 | [redacted] | | | | | | | | | |
| Nov-14 | [redacted] | | | | | | | | | |
| Dec-14 | [redacted] | | | | | | | | | |
| Jan-15 | [redacted] | | | | | | | | | |
| Feb-15 | [redacted] | | | | | | | | | |
| Mar-15 | [redacted] | | | | | | | | | |
| Apr-15 | [redacted] | | | | | | | | | |
| May-15 | [redacted] | | | | | | | | | |
| **Average** | 21.49% | 8.80% | 9.52% | 9.50% | 10.80% | 9.72% | 9.80% | 13.80% | 6.55% | 20.10% |
| **Navigant** | 9.01% | 9.01% | 9.01% | 9.34% | 7.59% | 7.59% | 7.59% | 7.59% | 7.59% | 5.24% |
| **Difference** | 12.48% | -0.21% | 0.51% | 0.16% | 3.21% | 2.13% | 2.21% | 6.21% | -1.04% | 14.86% |
| **Average Difference excluding Beckjord and Conesville** | | | | | | 1.6% | | | | |

Percentage Navigant Model Coal Price Higher Than DEO Model
January 2013 - May 2015 ($/mmBtu)

| | DEO | Navigant | |
|---|---|---|---|
| Becкj 6 | 2.31 | 2.49 | 7.8 % |
| Miami Ft 7 | 2.22 | 2.44 | 9.9 % |
| Miami Ft 8 | 2.22 | 2.44 | 9.9 % |
| Zimmer | 2.24 | 2.46 | 9.8 % |
| Stuart 1 | 2.33 | 2.49 | 6.9 % |
| Stuart 2 | 2.33 | 2.49 | 6.9 % |
| Stuart 3 | 2.33 | 2.49 | 6.9 % |
| Stuart 4 | 2.33 ~~2.95~~ | 2.49 | 6.9 % |
| Killen | 2.95 ~~2.33~~ | 2.50 | (15.3%) |
| Conesv 4 | 2.16 | 2.22 | (2.8%) |

EXHIBIT
14
OEG
PENGAD 800-631-6989

Dollar Amount Navigant Model
Coal Price Different Than DEO Model
January 2013 - May 2015 ($000)

| | Navigant Fuel Cost DEO Share Total Plant | %Δ | $Δ |
|---|---|---|---|
| Beckj 6 | $51,514 | 7.8% | $4,018 |
| Miami Ft 7 | $108,456 | 9.9% | $10,737 |
| Miami Ft 8 | $113,044 | 9.9% | $11,191 |
| Zimmer | $226,960 | 9.8% | $22,242 |
| Stuart 1 | $90,627 | 6.9% | $6,253 |
| Stuart 2 | $84,581 | 6.9% | $5,836 |
| Stuart 3 | $92,253 | 6.9% | $6,365 |
| Stuart 4 | $87,003 | 6.9% | $6,003 |
| Killen | $82,220 | (15.3%) | ($12,579) |
| Connesv 4 | $114,675 | (2.8%) | ($3,210) |
| | | | $56,856,000 |

Revenue Produced Five Highest
Peak Demand Chared $158.08 MW-Day

4,460 mw X $158.08 MW-day X 30.4167 days x 34 months =

$729,126,356

Revenue Produced Retail Load Obligation
Charged $158.08 MW-Day

[redacted] mw X $158.08 MW-day X 30.4167 days X 34 months =

$ [redacted]

Navigant Increased VOM Expense
Compared To DEO Model ($000)
January 2013 - May 2015

| | O+M Δ $/MWH | Generation MWH | DEO Share | Total Dollars |
|---|---|---|---|---|
| Beckj 6 | [redacted] | 5,567,000 | 37.5% | $ [redacted] |
| Miami Ft 7 | [redacted] | 7,734,000 | 64% | $ [redacted] |
| Miami Ft 8 | [redacted] | 7,900,000 | 64% | $ [redacted] |
| Zimmer | [redacted] | 21,974,000 | 46.5% | $ [redacted] |
| Stuart 1 | [redacted] | 10,055,000 | 39% | $ [redacted] |
| Stuart 2 | [redacted] | 9,647,000 | 39% | $ [redacted] |
| Stuart 3 | [redacted] | 9,970,000 | 39% | $ [redacted] |
| Stuart 4 | [redacted] | 9,604,000 | 37% | $ [redacted] |
| Killen | [redacted] | 10,307,000 | 33% | $ [redacted] |
| ConnesV 4 | [redacted] | 13,844,000 | 40% | $ [redacted] |
| | | | | $34,943,000 |

**BEFORE**
**THE PUBLIC UTILITIES COMMISSION OF OHIO**

| | | |
|---|---|---|
| In the Matter of the Application of **Duke Energy Ohio, Inc.** for the Establishment of a Charge Pursuant to Revised Code Section 4909.18. | : | Case No. 12-2400-EL-UNC |
| In the Matter of the Application of **Duke Energy Ohio, Inc.** for Approval to Change Accounting Methods. | : | Case No. 12-2401-EL-AAM |
| In the Matter of the Application of **Duke Energy Ohio, Inc.** for Approval of a Tariff for a New Service. | : | Case No. 12-2402-EL-ATA |



**CONFIDENTIAL**
**DIRECT TESTIMONY**
**OF**
**RALPH L. LUCIANI**
**ON BEHALF OF**
**THE STAFF OF THE**
**PUBLIC UTILITIES COMMISSION OF OHIO**

**Staff Exhibit** 1

**April 9, 2013**

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## I. INTRODUCTION

1. Q. Please state your name and business address.

A. My name is Ralph L. Luciani. My business address is 1200 19th Street, NW, Suite 700, Washington, DC, 20036.

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

A. I am a Director with Navigant Consulting, Inc. ("Navigant").

3. Q. Please summarize your professional experience and educational background.

A. I have more than 20 years of consulting experience analyzing economic and financial issues affecting the electricity industry, including those related to costing, ratemaking, generation and transmission planning, environmental compliance, fuel supply, competitive restructuring, stranded cost, asset valuation, wholesale power solicitations, power marketing, and Regional Transmission Organization ("RTO") costs and benefits. From 2010 to 2012, I assisted the Eastern Interconnection Planning Collaborative ("EIPC") in its effort to analyze the transmission requirements for the Eastern Interconnection under a broad range of alternative futures. Prior to joining Navigant in 2012, I was a Vice President at Charles River Associates ("CRA"). Prior to joining CRA in 2001, I was a Senior Vice President at PHB Hagler Bailly, and a Director at Putnam, Hayes and Bartlett, Inc. I hold a B.S. in Electrical Engineering and Economics from Carnegie Mellon University. I also hold an M.S. from the Graduate School of Industrial Administration at Carnegie Mellon University. I have previously testified before the Arkansas, Kansas, Kentucky, Louisiana, Maryland, Mississippi, Missouri, Ohio, Pennsylvania and Texas state regulatory commissions, the Federal Energy Regulatory Commission ("FERC"), and the Ontario Energy Board. My resume is attached as Appendix RLL-1.

4. Q. On whose behalf are you appearing?

A. I am testifying on behalf of the Staff ("Staff") of the Public Utilities Commission of Ohio ("Commission" or "PUCO").

5. Q. Have you previously presented testimony before the Commission?

A. Yes. I have presented testimony before the Commission on behalf of Dayton Power and Light in Docket No. 99-1687-EL-ETP (*In the Matter of the Application of The Dayton Power & Light Company for Approval of Transition Plan, Pursuant to 4928.31, Revised Code and for the Opportunity to Receive Transition Revenues as Authorized under 4928.31 to 4928.40*).

6. Q. What is the purpose of your testimony?

A. Duke Energy Ohio has requested approval of a cost-based rate for providing capacity service in connection with its obligations as a fixed resource requirement ("FRR") entity over the August 1, 2012 to May 31, 2015 period. I was contracted by the PUCO on March 25, 2013 to provide an independent assessment of this cost-based capacity rate.

7. Q. Is it your understanding that Staff supports the approval of a cost-based capacity rate for Duke Energy Ohio?

A. No, my understanding is that Staff does not support the institution of a cost-based capacity rate for Duke Energy Ohio. My assessment is intended to provide guidance to the Commission if it were to choose to institute a cost-based capacity rate for Duke Energy Ohio.

8. Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring six Exhibits identified as follows:

- Exhibit RLL-1: Correction of Retirement Plan Overfunding Allocation;
- Exhibit RLL-2: Beckjord 1-5 and Beckjord 6 O&M Adjustments;
- Exhibit RLL-3: Projected FRR Capacity Purchases using FRR Plan;
- Exhibit RLL-4: Impact of Alternative ROEs;

- Exhibit RLL-5: Margin on Sale of Energy of Legacy Generating Units; and
- Exhibit RLL-6: Summary of Capacity Rate Changes

9. Q. What information did you review in preparing your testimony in this case?

A. Focusing on the derivation of the cost-based capacity rate, I reviewed Duke Energy Ohio's testimony and exhibits in this proceeding; Duke Energy Ohio's responses to the data requests of other parties; the testimony of intervenor witnesses in this proceeding; and information from Case No. 10-2929-EL-UNC related to the derivation of the cost-based state compensation method mechanism adopted for Ohio Power. I also reviewed the Commission's Opinion and Order in Case No. 11-346-EL-SSO with respect to return on equity ("ROE").

10. Q. What issues will you address in your testimony?

A. I will present certain modifications to the calculation of Duke Energy Ohio's cost-based capacity charge presented in Attachment WDW-1 to the testimony of William Don Wathan Jr., and the results of my independent analysis of the operating margins of Duke Energy Ohio's legacy generating units.

11. Q. How is the remainder of your testimony organized?

A. The remainder of my testimony is organized into the following sections:

II. Summary of Conclusions and Recommendations

III. Capacity Rate Modifications

IV. Analysis of Margins on Sales of Energy

## II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

12. Q. Please summarize your conclusions and recommendations.

A. My conclusions and recommendations are as follows:

- The proposed Duke Energy Ohio cost-based capacity rate of $224.15/MW-Day[1] should be adjusted as follows:
  - The retirement plan overfunding allocation error identified by Duke Energy Ohio in the response to OCC-INT-04-048 should be corrected resulting in a reduction in the capacity rate of $0.32/MW-Day.
  - The demand-related O&M associated with Beckjord 1-5 should be removed from the calculation of the capacity rate, resulting in a reduction of $[redacted]/MW-Day.

---

[1] Capacity Daily Rate after credits for margins from sales of energy and ancillary services, from page 1 of Attachment WDW-1.

- The demand-related O&M associated with Beckjord 6 should be removed from the calculation of the capacity rate beginning [redacted] resulting in a capacity rate reduction of $[redacted]/MW-Day starting at that time, or $[redacted]/MW-Day normalized over the August 2012 to June 2015 period.
- The amount of FRR capacity available from the legacy generating units[2] should be increased for the 2013-14 and 2014-15 planning years, resulting in a reduction in the capacity rate, normalized over the August 2012 to June 2015 period, of $[redacted]/MW-Day.

- For potential consideration by the Commission, I have calculated the impact of reducing Duke Energy Ohio's proposed ROE of 11.15% to be in the range from 7% to 11% cited in the Commission's Opinion and Order for AEP Ohio in Case No. 11-346-EL-SSO, calculated in half percentage point steps. At a 7.00% ROE, the capacity rate would be reduced by $32.40/MW-Day. At an 11.00% ROE, the capacity rate would be reduced by $1.18/MW-Day.
- My independent assessment of the margins on sales of energy from the legacy generating units over the 2013 to 2015 period yields margins that are lower than those estimated by Duke Energy Ohio. Using my inde-

[2] The legacy generating units are identified in Attachment A to the Application of Duke Energy Ohio, Inc.

pendent assessment of these margins increases the capacity rate by $21.58/MW-Day.

## III. CAPACITY RATE MODIFICATIONS

13. Q. Please explain how you developed your recommended adjustment to the Duke Energy Ohio capacity rate with respect to the allocation of retirement plan overfunding.

A. In its response to OCC-INT-04-048, Duke Energy Ohio noted that there was an error in the internal allocation of "Retirement Plan Expense –Overfunded" included in page 8 of 24 of Attachment WDW-1. Based on the corrected allocation provided in that interrogatory response, I calculated the impact to the capacity rate. With the corrected allocation, the rate is reduced by $523,577 on an annualized basis, or $0.32/MW-Day. See Exhibit RLL-1.

14. Q. Please explain how you developed your recommended adjustment to the Duke Energy Ohio capacity rate with respect to the removal of the demand-related O&M for Beckjord 1-5 and Beckjord 6.

A. Based on Duke Energy Ohio's confidential attachment to OCC-POD-01-005 and the confidential workpapers of Duke Energy Ohio witness Scott Niemann which contain the ICAP and UCAP capacity for Duke Energy Ohio units under its FRR in PJM planning years 2012-13, 2013-14 and

2014-15, the [redacted] units are not included as a FRR resource in any of these planning years. [redacted] is not included as a FRR resource in the 2014-2015 planning year. The operating costs of these units should not be included in a capacity rate intended to recover the costs of providing FRR service in any period in which they are not providing this service.

Using the confidential attachment provided by Duke Energy Ohio to FES-INT-04-004, I have identified the fixed O&M associated with the [redacted] units included in Attachment WDW-1. Removing this demand-related O&M over the August 2012 to May 2015 period reduces the capacity rate by $6.29/MW-Day. Removing the [redacted] demand-related O&M included in Attachment WDW-1 over the June 2014 to May 2015 period reduces the capacity rate by $1.81/MW-Day starting June 1, 2014, and by $0.64/MW-Day on a normalized basis over the August 2012 to May 2015 period.[3] See Exhibit RLL-2.

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[3] Attachment WDW-1 is based on data from the Duke Edison Ohio FERC Form 1 for 2011. In its supplemental response to FES-INT-04-004, Duke Energy Ohio supplied O&M data for 2012. Based on my review of this data, the total demand-related O&M for the legacy generating units is $[redacted] million lower in 2012 than in 2011. Excluding [redacted], the total demand-related O&M for the legacy generating units is $[redacted] million higher in 2012 than in 2011.

15. Q. Please explain how you developed your recommended adjustments to the Duke Energy Ohio capacity rate with respect to increasing the capacity available from the legacy generating units.

A. The confidential workpapers of Duke Energy Ohio witness Scott Niemann provide the current Unforced Capacity ("UCAP") values for the legacy generating unit in the Duke Energy Ohio FRR plan for PJM planning years 2012-13, 2013-14 and 2014-15.[4] The UCAP of the legacy generating units is used in Attachment WDW-1 to determine the amount of FRR purchases needed to be made by Duke Energy Ohio (line 7 on page 3 of Attachment WDW-1, "Cost of Capacity to Fulfill FRR Obligations"). The UCAP value in the FRR plan is identical to that used in Attachment WDW-1 for the 2012-13 planning year, but higher by 17 MW in 2013-14 and by 74 MW in 2015-16. Applying the UCAP values from the FRR plan decreases the "Cost of Capacity to Fulfill FRR Obligations" from $[redacted] million on an annualized basis to $[redacted] million, which decreases the capacity rate by $0.78/MW-Day. See Exhibit RLL-3.

16. Q. Please describe your calculation of the impact of varying the ROE used in Attachment WDW-1 from 7% to 11%.

---

4 Deposition of Scott Niemann, March 30, 2013, and the Duke Energy Ohio response to FES-POD-02-014.

A. In Case No. 10-2929-EL-UNC (July 2, 2012, page 34), the Commission ultimately approved the use of an ROE of 11.15% in setting the capacity rates for AEP Ohio, which is also applied by Duke Energy Ohio in Attachment WDW-1. In the Commission's Opinion and Order for AEP Ohio in Case No. 11-346-EL-SSO regarding the AEP Ohio ESP (August 8, 2012, page 33), the Commission identified a zone of reasonableness for the ROE to be applied of 7% to 11%. For potential consideration by the Commission, I have calculated the impact of applying an ROE in the range from 7% to 11% in the derivation of the capacity rate, calculated in half percentage point steps.[5] At a 7.00% ROE, the capacity rate would be reduced by \$32.40/MW-Day. At an 11.00% ROE, the capacity rate would be reduced by \$1.18/MW-Day. See Exhibit RLL-4.

## IV. ANALYSIS OF MARGINS ON SALES OF ENERGY

17. Q. Please describe the independent analysis of the margins on sales of energy of the legacy units that you performed.

A. Using Navigant's models and model input assumptions, I have assessed the margin on sales of energy from the legacy generating units over the January 2013 to May 2015 period. See Appendix RLL-2 for a description of the

[5] This calculation uses as a starting point the Attachment WDW-1 rate base after correction for the retirement overfunding error discussed above. The changes would be slightly higher using the as-filed uncorrected rate base.

Navigant models. The analysis used the results of Navigant's most recent PROMOD base case for the Eastern Interconnection, prepared under our semi-annual updating process. Using the projected locational marginal prices ("LMPs") at the nearest pricing hub to each legacy unit from this PROMOD case and the operating parameters for the legacy units from the PROMOD input dataset, each of the legacy generating units was then dispatched through Navigant's Extrinsic Value Model ("EVM") to calculate individual unit operating margins over the January 2013 to May 2015 period.[6] An analysis of the August to December 2012 period was not performed.

18. Q. Please describe the results of your independent analysis of the margins on energy sales of the legacy units.

A. The results are summarized in Exhibit RLL-5. The annualized margin on sale of legacy generation according to my analysis is $35.1 million lower than the $[redacted] million applied by Duke Energy Ohio in Attachment WDW-1.[7] Applying the results of my margin analysis in Attachment WDW-1 increases the capacity rate by $21.58/MW-Day. In essence, the

[6] Detailed results and inputs are provided in my workpapers. Consistent with the Duke Energy Ohio FRR plan, [redacted] was assumed to not be available in the 2013 to 2015 period. [redacted] was assumed to be not available in 2015.

[7] Navigant did not analyze the August 2012 to December 2012 period. No difference between the Navigant and Duke Energy Ohio estimate was applied for this period in obtaining the difference in annualized margin. See Exhibit RLL-5.

confidential Duke Energy Ohio margin analysis is more optimistic about the margins on energy sales that the legacy generating units will earn over the January 2013 to May 2015 period than the Navigant analysis. My margin analysis estimates both higher revenue and higher costs (fuel, variable O&M and emissions) from January 2013 to May 2015 for the legacy generating units than the Duke Energy Ohio analysis. The cost increase is higher than the revenue increase, leading to lower margins than those estimated by Duke Energy Ohio. I recommend that the cost-based capacity rate be increased by $21.58/MW-Day to reflect the results of my margin analysis.

19. Q. Have you done a comparison of the legacy generating unit parameters in the Duke Energy Ohio margin analysis and your analysis?

Yes. Navigant performed its margin analysis using the legacy generating unit input parameters contained in its standard PROMOD dataset. I reviewed the gas prices, heat rates, power prices, coal prices, forced outage rates and variable O&M from the Navigant modeling in comparison to those used in the Duke Energy Ohio modeling.[8] The projected gas prices used by Duke Energy Ohio in its analysis are within 3% on average of those used by Navigant. Heat rates are also roughly similar for the coal units between the Duke Energy Ohio and Navigant analyses, within about

[8] See my workpapers for details. A number of the Duke Energy Ohio margin analysis input assumptions were provided in the response OCC-POD-05-031.

2% on average. The projected power prices at the AEP-Dayton hub are somewhat lower in the Navigant analysis than those used in the Duke Energy Ohio analysis, on average about 6% lower on-peak and off-peak. All else equal, lower power prices would reduce margins. Delivered coal prices for the legacy generating units in the Navigant analysis are about 4% higher on average than those used in the Duke Energy Ohio analysis. All else equal, higher coal prices would reduce margins. Forced outage rates for the legacy coal units are somewhat higher in the Duke Energy Ohio modeling than in the Navigant modeling, with the rates for Beckjord 6 and Conesville 4 being considerably higher. Excluding those two coal units, the legacy coal unit forced outage rates are about 1.6% lower on average in the Navigant modeling than in the Duke Energy Ohio modeling. All else equal, lower forced outage rates would increase margins. The variable O&M costs used for the coal plants in the Navigant model are about $0.9/MWh higher on average than those used in the Duke Energy Ohio modeling. All else equal, higher variable O&M rates would reduce margins.

20. Q. Have you examined the Duke Energy Ohio estimate of Ancillary Services revenues?

A. Yes. I reviewed the Duke Energy Ohio revenue requirements for ancillary services as posted on the PJM website, and determined that the Duke

Energy Ohio estimate for these ancillary services revenue as applied in Attachment WDW-1 are in line with these revenue requirements.

21. Q. Have you prepared a summary of the impact of your recommended adjustments?

A. Yes. I have summarized the adjustments to the capacity rate discussed above in Exhibit RLL-6.

22. Q. Doe this conclude your testimony?

A. Yes, it does. However, I reserve the right to submit supplemental testimony as described herein, as new information subsequently becomes available or in response to positions taken by other parties.

## V. PROOF OF SERVICE

I hereby certify that a true copy of the foregoing **Confidential Direct Testimony of Ralph L. Luciani** submitted on behalf of the Staff of the Public Utilities Commission of Ohio, was served by electronic mail, upon the following Parties of Record, this 9th day of April, 2013.

/s/ Steven L. Beeler

**Steven L. Beeler**
Assistant Attorney General

Parties of Record:

Jeanne W. Kingery
Amy Spiller
Elizabeth H. Watts
Duke Energy Ohio
139 East Fourth Street
1303-Main
P.O. Box 961
Cincinnati, OH 45201-0960
jeanne.kingery@duke-energy.com
amy.spiller@duke-energy.com
elizabeth.watts@duke-energy.com

Laura C. McBride
Ulmer & Berne
Skylight Office Tower
1660 West 2nd Street, Suite 1100
Cleveland, OH 44113
lmcbride@ulmer.com

Mark A. Hayden
FirstEnergy Service Company
76 South Main Street
Akron, OH 44308
haydenm@firstenergycorp.com

Rick D. Chamberlain
Behrens Wheeler & Chamberlain
6 N.E. 63rd Street, Suite 400
Oklahoma City, OK 73105
rdc_law@swbell.net

Maureen Grady
Assistant Consumers' Counsel
Office of the Ohio Consumers' Counsel
10 West Broad Street, 18th Floor
Columbus, OH 43215
grady@occ.state.oh.us

James F. Lang
N. Trevor Alexander
Lindsey Sacher
Calfee, Halter & Griswold
The Calfee Building
1405 East Sixth Street
Cleveland, Oh 44114
jlang@calfee.com
talexander@calfee.com
lasacher@calfee.com

M. Howard Petricoff
Gretchen L. Petrucci
Vorys Sater Seymour & Pease
52 East Gay Street
P.O. Box 1008
Columbus, OH 43216-1008
mhpetricoff@vorys.com
glpetrucci@vorys.com

Colleen L. Mooney
Ohio Partners for Affordable Energy
231 West Lima Street
Findlay, OH 45840
cmooney@ohiopartners.org

David A. Kutick
Lydia M. Floyd
Jones Day
901 Lakeside Avenue
Cleveland, OH 44114
dakutik@jonesday.com
lfloyd@jonesday.com

Barth E. Royer
Bell & Royer
33 South Grant Avenue
Columbus, OH 43215-3927
barthroyer@aol.com

Michael L. Kurtz
Boehm, Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, OH 45202
mkurtz@bkllawfirm.com

Angela N. Hogan
The Dayton Power & Light Company
1065 Woodman Drive
Dayton, OH 45432
angela.hogan@dplinc.com

Douglas E. Hart
441 Vine Street
Suite 4192
Cincinnati, OH 45202
dhart@douglasehart.com

J. Thomas Siwo
Matthew W. Warnock
Thomas O'Brien
Bricker & Eckler
100 South Third Street
Columbus, OH 43215-4291
tsiwo@bricker.com
mwarnock@bricker.com
tobrien@bricker.com

Kimberly J. Bojko
Carpenter Lipps & Leland
280 North High Street
280 Plaza Suite 1300
Columbus, OH 43215
bojko@carpenterlipps.com

Samuel C. Randazzo
Frank P. Darr
Joseph E. Oliker
Matthew R. Pritchard
McNees Wallace & Nurick
21 East State Street, 17th Floor
Columbus, OH 43215
sam@mwncmh.com
fdarr@mwncmh.com
joliker@mwncmh.com
mpritchard@mwncmh.com

Yazem Alami
Steven T. Nourse
American Electric Power Company
1 Riverside Plaza, 29th Floor
Columbus, OH 43215
yalami@aep.com

Cynthia Fonner Brady
Constellation NewEnergy, Inc.
P.O. Box 1125
Chicago, IL 60690-1125
cynthia.brady@constellation.com

stnourse@aep.com
Kevin J. Osterkamp
Roetzel & Andress
155 East Broad Street, 12th Floor
Columbus, OH 43215
kosterkamp@ralaw.com

## Correction of Retirement Plan Overfunding Allocation

Correction per response to OCC-INT-04-048:

| **ADIT for Retirement Plan Funding - Overfunded** | **As-Filed** | **Corrected** | |
|---|---|---|---|
| - Total Company | (28,566,515) | (28,566,515) | |
| - Legacy Generation Share | 0 | (8,400,000) | a |
| Demand Allocation | NA | 62.52% | b |
| - Legacy Generation Demand Share | 0 | (5,251,904) | a*b |

| | | |
|---|---|---|
| Average of demand at time of five highest daily peaks (MW) | 4459.85 | <-- from Att. WDW-1, page 1 |
| Commercial Activities Tax Rate | 0.261% | <-- from Att. WDW-1, page 3 |

| | A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Cost of Capital | | | | | | | | | Increase/(Decrease) | | |
| | Debt Share | Equity Share | Debt Rate | ROE | Wghtd Cost | Demand Ratebase | Return on Ratebase | Effective Tax Rate | Return w/ Inc. Taxes | Annual $ | $/MW-Day | 8/12-5/15 |
| 1 DEO As Filed | 46.84% | 53.16% | 4.11% | 11.15% | 7.85% | 1,674,512,547 | 131,485,513 | 35.2796% | 166,502,797 | | | |
| Correction | | | | | | (5,251,904) | | | | | | |
| 2 With Correction | 46.84% | 53.16% | 4.11% | 11.15% | 7.85% | 1,669,260,643 | 131,073,125 | 35.2796% | 165,980,581 | (523,577) | (0.32) | (1,483,468) |

Sources:

| | |
|---|---|
| col.A - col.E | Att. WDW-1, page 10 |
| col.F | L.1: WDW-1, page 4, line 16; L.2: L.1 + Corrected Legacy Generation Demand Share |
| col.G | col(E)*col(F) |
| col.H | [0.3185/(1-0.3185)] * (1- (col.A*col.C/col.E)) |
| col.I | (col.G-col.F*col.C*col.A)*col.H+col.G |
| col.J | (col.I - col.I L.1) * (1 + Commercial Activities Tax Rate) |
| col.K. | col.K/Average of demand at time of five highest daily peaks/365 |
| col. L | col. J /12 * 34 months |

## [redacted] and [redacted] O&M Adjustments

| | 2011 O&M by FERC Account | | | Demand | Energy | Demand Related O&M | | |
|---|---|---|---|---|---|---|---|---|
| | [redacted] | [redacted] | | | | [redacted] | [redacted] | |
| | (a) | (a) | (b) | Related | Related | | | |
| 500 | [redacted] | [redacted] | 500 | xx | - | [redacted] | [redacted] | |
| 501 | | | 501 | - | xx | | | |
| 502 | | | 502 | xx | - | | | |
| 505 | | | 505 | xx | - | | | |
| 506 | | | 506 | xx | - | | | |
| 507 | | | | | | | | |
| 509 | | | | | | | | |
| 510 | | | 510 | - | xx | | | |
| 511 | | | 511 | xx | - | | | |
| 512 | | | 512 | - | xx | | | |
| 513 | | | 513 | - | xx | | | |
| 514 | | | 514 | xx | - | | | |
| 546 | | | | | | | | |
| 547 | | | | | | | | |
| 548 | | | 548 | xx | - | | | |
| 549 | | | 549 | xx | - | | | |
| 551 | | | 551 | xx | - | | | |
| 552 | | | | | | | | |
| 553 | | | | | | | | |
| 554 | | | | | | | | |
| 555 | | | | | | | | |
| 557 | | | 557 | xx | - | | | |
| Total | 79,696,618 | 28,185,901 | | | | 10,218,725 | 2,946,552 | A |

| | | | |
|---|---|---|---|
| **Average of demand at time of five highest daily peaks (MW) (c)** | 4459.85 | 4459.85 | B |
| **Commercial Activities Tax Rate (Att. WDW-1, p.3)** | 0.261% | 0.261% | C |
| **Days per Year** | 365 | 365 | D |
| **Capacity Daily Rate Increase/(Decrease)** | (6.29) | (1.81) | E=A/B/D * (1+C) |
| | | | |
| **Exclude Starting With:** | All Months | June 2014 | E |
| **Months in Period from August 2012 to May 2015** | 34 | 34 | F |
| **Months Included** | 34 | 12 | G |
| **Annualized Increase/(Decrease) to Capacity Daily Rate ($/MW-Day)** | (6.29) | (0.64) | H=E*G/F |
| **Annualized Increase/(Decrease) ($)** | (10,245,363) | (1,042,671) | I=B*H*D |
| **Increase/(Decrease) August 2012 to May 2015 ($)** | (29,028,529) | (2,954,233) | J=I/12*F |

(a) From Confidential Response to FES-INT-04-004
(b) From Attachment WDW-1, page 20 of 34
(c) From Attachment WDW-1, page 1 of 24

## Projected FRR Capacity Purchases Using FRR Plan

**1. Duke Energy Ohio as Filed** *Source: FES-POD-04-001-INT-04-002-INT-04-003 CONF Attach*

| FRR Capacity Purchases | | | | |
|---|---|---|---|---|
| | August 2012 - May 2013 | 2013-14 | 2014-15 | Average (Annualized) |
| Capacity Purchases | [redacted] | [redacted] | [redacted] | |
| Price ($/MW-Day) | 16.73 | 27.73 | 125.99 | |
| Days | 300 | 365 | 365 | |
| Total Capacity Purchase Costs | $[redacted] | $[redacted] | $[redacted] | $[redacted] |

**2. Using UCAP per Duke Energy Ohio FRR Plan**

| FRR Capacity Purchases | | | | |
|---|---|---|---|---|
| | August 2012 - May 2013 | 2013-14 | 2014-15 | Average (Annualized) |
| Capacity Purchases (a) | [redacted] | [redacted] | [redacted] | |
| Price ($/MW-Day) | 16.73 | 27.73 | 125.99 | |
| Days | 300 | 365 | 365 | |
| Total Capacity Purchase Costs | $[redacted] | $[redacted] | $[redacted] | $[redacted] |

| | | |
|---|---|---|
| Annualized Increase/(Decrease) | A | ($1,266,973) |
| Avg of demand at time of five highest daily peaks (MW) (Att. WDW-1, p.1) | B | 4459.85 |
| Commercial Activities Tax Rate (Att. WDW-1, p.3) | C | 0.261% |
| **Capacity Rate Increase/(Decrease) $/MW-Day** | D=A/B/365*(1+C) | (0.78) |
| **Capacity Rate Annualized Reduction ($)** | E=D*365*B | ($1,270,276) |
| **Capacity Rate Reduction August 2012 to May 2015 ($)** | F=E/12*34 | ($3,599,114) |

Note: Annual Average calculation is sum of three periods divided by 34 months x 12 to match WDW-1
(a) - Exhibit RLL-3, page 2

## FRR Position

**1. Duke Energy Ohio as Filed** Source: OCC-INT-12-092 CONF Attachment

| Beckjord Situation | Beckjord 6 Planning Year 12-13 | Beckjord 6 Planning Year 13-14 | No Beckjords Planning Year 14-15 |
|---|---|---|---|
| Load (Estimate) | [redacted] | | |
| Threshold | | | |
| Load Requirement (Actual) | | | |
| Expected ESP Generation | | | |
| Expected DE-OHIO DR | | | |
| Total Position | | | |

**2. Using UCAP from Exhibit RLL-3, page 3 of 3 for Expected ESP Generation**

| Beckjord Situation | Beckjord 6 Planning Year 12-13 | Beckjord 6 Planning Year 13-14 | No Beckjords Planning Year 14-15 |
|---|---|---|---|
| Load (Estimate) | [redacted] | | |
| Threshold | | | |
| Load Requirement (Actual) | | | |
| Expected ESP Generation (b) | | | |
| Expected DE-OHIO DR | | | |
| Total Position | | | |
| Increase in Expected ESP Generation | 0.00 | 16.72 | 74.14 |

(b) From Exhibit RLL-3, page 3

**UCAP of DEO Units per FRR Plan** *Source: Niemann Workpapers, Confidential*

| 2012-13 | ResourceName | StartDay | StopDay | EFORd | FRR Committed MW | UCAP Committed MW |
|---|---|---|---|---|---|---|
| | BECKJORD 6 | 6/1/2012 | 5/31/2013 | [redacted] | | |
| | BECKJORD GT1 | 6/1/2012 | 5/31/2013 | [redacted] | | |
| | BECKJORD GT2 | 6/1/2012 | 5/31/2013 | [redacted] | | |
| | BECKJORD GT3 | 6/1/2012 | 5/31/2013 | [redacted] | | |
| | BECKJORD GT4 | 6/1/2012 | 5/31/2013 | [redacted] | | |
| | CONESVILLE 4 | 6/1/2012 | 5/31/2013 | [redacted] | | |
| | DICKS CREEK 1 | 6/1/2012 | 5/31/2013 | [redacted] | | |
| | DICKS CREEK 3 | 6/1/2012 | 5/31/2013 | [redacted] | | |
| | DICKS CREEK 4 | 6/1/2012 | 5/31/2013 | [redacted] | | |
| | DICKS CREEK 5 | 6/1/2012 | 5/31/2013 | [redacted] | | |
| | KILLEN | 6/1/2012 | 5/31/2013 | [redacted] | | |
| | MIAMI FORT 7 | 6/1/2012 | 5/31/2013 | [redacted] | | |
| | MIAMI FORT 8 | 6/1/2012 | 5/31/2013 | [redacted] | | |
| | MIAMI FORT GT3 | 6/1/2012 | 5/31/2013 | [redacted] | | |
| | MIAMI FORT GT4 | 6/1/2012 | 5/31/2013 | [redacted] | | |
| | MIAMI FORT GT5 | 6/1/2012 | 5/31/2013 | [redacted] | | |
| | MIAMI FORT GT6 | 6/1/2012 | 5/31/2013 | [redacted] | | |
| | STUART 1 | 6/1/2012 | 5/31/2013 | [redacted] | | |
| | STUART 2 | 6/1/2012 | 5/31/2013 | [redacted] | | |
| | STUART 3 | 6/1/2012 | 5/31/2013 | [redacted] | | |
| | STUART 4 | 6/1/2012 | 5/31/2013 | [redacted] | | |
| | STUART DIESEL 1-4 | 6/1/2012 | 5/31/2013 | [redacted] | | |
| | ZIMMER 1 | 6/1/2012 | 5/31/2013 | [redacted] | | |

**UCAP of DEO Units per FRR Plan** *Source: Niemann Workpapers, Confidential*

| 2013-14 | ResourceName | StartDay | StopDay | EFORd | FRR Committed MW | UCAP Committed MW | MW Incr. from 2012-13 |
|---|---|---|---|---|---|---|---|
| | BECKJORD 6 | 6/1/2013 | 5/31/2014 | [redacted] | | | |
| | BECKJORD GT1 | 6/1/2013 | 5/31/2014 | | | | |
| | BECKJORD GT2 | 6/1/2013 | 5/31/2014 | | | | |
| | BECKJORD GT3 | 6/1/2013 | 5/31/2014 | | | | |
| | BECKJORD GT4 | 6/1/2013 | 5/31/2014 | | | | |
| | CONESVILLE 4 | 6/1/2013 | 5/31/2014 | | | | |
| | DICKS CREEK 1 | 6/1/2013 | 5/31/2014 | | | | |
| | DICKS CREEK 3 | 6/1/2013 | 5/31/2014 | | | | |
| | DICKS CREEK 4 | 6/1/2013 | 5/31/2014 | | | | |
| | DICKS CREEK 5 | 6/1/2013 | 5/31/2014 | | | | |
| | KILLEN | 6/1/2013 | 5/31/2014 | | | | |
| | MIAMI FORT 7 | 6/1/2013 | 5/31/2014 | | | | |
| | MIAMI FORT 8 | 6/1/2013 | 5/31/2014 | | | | |
| | MIAMI FORT GT3 | 6/1/2013 | 5/31/2014 | | | | |
| | MIAMI FORT GT4 | 6/1/2013 | 5/31/2014 | | | | |
| | MIAMI FORT GT5 | 6/1/2013 | 5/31/2014 | | | | |
| | MIAMI FORT GT6 | 6/1/2013 | 5/31/2014 | | | | |
| | STUART 1 | 6/1/2013 | 5/31/2014 | | | | |
| | STUART 2 | 6/1/2013 | 5/31/2014 | | | | |
| | STUART 3 | 6/1/2013 | 5/31/2014 | | | | |
| | STUART 4 | 6/1/2013 | 5/31/2014 | | | | |
| | STUART DIESEL 1-4 | 6/1/2013 | 5/31/2014 | | | | |
| | ZIMMER 1 | 6/1/2013 | 5/31/2014 | | | | |

| 2014-15 | ResourceName | StartDay | StopDay | EFORd | FRR Committed MW | UCAP Committed MW | MW Incr. from 2012-13 |
|---|---|---|---|---|---|---|---|
| | BECKJORD 6 | 6/1/2014 | 5/31/2015 | [redacted] | | | |
| | BECKJORD GT1 | 6/1/2014 | 5/31/2015 | | | | |
| | BECKJORD GT2 | 6/1/2014 | 5/31/2015 | | | | |
| | BECKJORD GT3 | 6/1/2014 | 5/31/2015 | | | | |
| | BECKJORD GT4 | 6/1/2014 | 5/31/2015 | | | | |
| | CONESVILLE 4 (a) | 6/1/2014 | 5/31/2015 | | | | |
| | DICKS CREEK 1 | 6/1/2014 | 5/31/2015 | | | | |
| | DICKS CREEK 3 | 6/1/2014 | 5/31/2015 | | | | |
| | DICKS CREEK 4 | 6/1/2014 | 5/31/2015 | | | | |
| | DICKS CREEK 5 | 6/1/2014 | 5/31/2015 | | | | |
| | KILLEN | 6/1/2014 | 5/31/2015 | | | | |
| | MIAMI FORT 7 | 6/1/2014 | 5/31/2015 | | | | |
| | MIAMI FORT 8 | 6/1/2014 | 5/31/2015 | | | | |
| | MIAMI FORT GT3 | 6/1/2014 | 5/31/2015 | | | | |
| | MIAMI FORT GT4 | 6/1/2014 | 5/31/2015 | | | | |
| | MIAMI FORT GT5 | 6/1/2014 | 5/31/2015 | | | | |
| | MIAMI FORT GT6 | 6/1/2014 | 5/31/2015 | | | | |
| | STUART 1 | 6/1/2014 | 5/31/2015 | | | | |
| | STUART 2 | 6/1/2014 | 5/31/2015 | | | | |
| | STUART 3 | 6/1/2014 | 5/31/2015 | | | | |
| | STUART 4 | 6/1/2014 | 5/31/2015 | | | | |
| | STUART DIESEL 1-4 | | | | | | |
| | ZIMMER 1 | 6/1/2014 | 5/31/2015 | | | | |
| | *(a) Sum of two entries below:* | | | | | | |
| | *CONESVILLE 4* | *6/1/2014* | *5/31/2015* | | | | |
| | *CONESVILLE 4* | *6/1/2014* | *5/31/2015* | | | | |

**Impact of Alternative ROEs**

Average of demand at time of five highest daily p 4459.85 <-- from Att. WDW-1, page 1
Commercial Activities Tax Rate 0.261% <-- from Att. WDW-1, page 3

| | A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Cost of Capital | | | | | | | | | | | |
| | Debt Share | Equity Share | Debt Rate | ROE | Wgtd Cost | Demand Ratebase | Return on Ratebase | Effective Tax Rate | Return w/ Inc. Taxes | Increase/(Decrease) Annual $ | $/MW-Day | 8/12-5/15 |
| 1 DEO As Filed | 46.84% | 53.16% | 4.11% | 11.15% | 7.85% | 1,674,512,547 | 131,485,513 | 35.2796% | 166,502,797 | | | |
| 2 Exhibit RLL-1 (a) | 46.84% | 53.16% | 4.11% | 11.15% | 7.85% | 1,669,260,643 | 131,073,125 | 35.2796% | 165,980,581 | (523,577) | (0.32) | (1,483,468) |
| | | | | | | | | | | Increase/(Decrease) | | |
| 3 ROE @7.00% | 46.84% | 53.16% | 4.11% | 7.00% | 5.65% | 1,669,260,643 | 94,246,038 | 30.8033% | 113,380,449 | (52,737,249) | (32.40) | (149,422,206) |
| 4 ROE @7.50% | 46.84% | 53.16% | 4.11% | 7.50% | 5.91% | 1,669,260,643 | 98,683,036 | 31.5197% | 119,660,943 | (46,440,384) | (28.53) | (131,581,087) |
| 5 ROE @8.00% | 46.84% | 53.16% | 4.11% | 8.00% | 6.18% | 1,669,260,643 | 103,120,035 | 32.1744% | 125,961,242 | (40,123,661) | (24.65) | (113,683,707) |
| 6 ROE @8.50% | 46.84% | 53.16% | 4.11% | 8.50% | 6.44% | 1,669,260,643 | 107,557,033 | 32.7750% | 132,278,894 | (33,789,540) | (20.76) | (95,737,030) |
| 7 ROE @9.00% | 46.84% | 53.16% | 4.11% | 9.00% | 6.71% | 1,669,260,643 | 111,994,032 | 33.3281% | 138,611,838 | (27,440,088) | (16.86) | (77,746,915) |
| 8 ROE @9.50% | 46.84% | 53.16% | 4.11% | 9.50% | 6.98% | 1,669,260,643 | 116,431,030 | 33.8390% | 144,958,325 | (21,077,057) | (12.95) | (59,718,327) |
| 9 ROE @10.00% | 46.84% | 53.16% | 4.11% | 10.00% | 7.24% | 1,669,260,643 | 120,868,029 | 34.3124% | 151,316,864 | (14,701,943) | (9.03) | (41,655,504) |
| 10 ROE @10.50% | 46.84% | 53.16% | 4.11% | 10.50% | 7.51% | 1,669,260,643 | 125,305,027 | 34.7523% | 157,686,174 | (8,316,029) | (5.11) | (23,562,083) |
| 11 ROE @11.00% | 46.84% | 53.16% | 4.11% | 11.00% | 7.77% | 1,669,260,643 | 129,742,025 | 35.1621% | 164,065,150 | (1,920,424) | (1.18) | (5,441,202) |

(a) Correction for error with respect to the allocation of "Retirement Plant Expense - Overfunded" per response to OCC-INT-04-048
Note: ROE $/MW-Day increases/(decreases) are calculated using ratebase with Exhibit RLL-1 correction

Sources:

| | |
|---|---|
| col.A - col.C | Att. WDW-1, page 10 |
| col. D | L1 and L2: WDW-1, page 10; L3 through L11: 7% to 11% increasing at 0.5% steps |
| col.E | col.A* col.C + col. B* col.D |
| col.F | L 1: WDW-1, page 4, line 16; L 2 through L 11: Exhibit RLL-1 |
| col.G | col(E)*col(F) |
| col.H | [0.3185/(1-0.3185)] * (1- (col.A*col.C/col.E)) |
| col.I | (col.G-col.F*col.C*col.A)*col.H+col.G |
| col.J | Line 2: (col.I - col.I L.1)*(1+ commercial activities tax rate) ; L.3 through L.11. (col.I - col.I L.2)*(1+commerical activities tax rate) |
| col.K. | col.K/Average of demand at time of five highest daily peaks/365 |
| col. L | col. J /12 * 34 months |

## Margin on Sale of Energy of Legacy Generating Units

**Duke Energy Ohio (as used in Attachment WDW-1)**

| | Aug-Dec 2012 | 2013 | 2014 | Jan-May 2015 | Average (annualized) |
|---|---|---|---|---|---|
| **Energy Revenue ($000)** | $ [redacted] | $ [redacted] | $ [redacted] | $ [redacted] | |
| **Cost of Good Sold ($000)** | $ [redacted] | $ [redacted] | $ [redacted] | $ [redacted] | |
| **Generation Margin ($000)** | $ [redacted] | $ [redacted] | $ [redacted] | $ [redacted] | $ [redacted] |

*Source: FES-POD-04-001-INT-04-002-INT-04-003 CONF Attach*

**Navigant Analysis**

| | 2013 | 2014 | Jan-May 2015 |
|---|---|---|---|
| **Energy Revenue ($000)** | $579,621 | $640,618 | $276,118 |
| **Energy Expenses ($000) (a)** | $454,554 | $503,830 | $218,774 |
| **Generation Margin ($000)** | $125,067 | $136,788 | $57,344 |

| | Aug-Dec 2012(b) | 2013 | 2014 | Jan-May 2015 | Average (annualized) | |
|---|---|---|---|---|---|---|
| **Increase in Generation Margin ($000)** | 0 | ($32,819) | ($44,634) | ($22,102) | ($35,137) | A |

| | | |
|---|---|---|
| Avg of demand at time of five highest daily peaks (MW) (Att. WDW-1, p.1) | B | 4459.85 |
| **Capacity Rate Increase/(Decrease) $/MW-Day** | D=-A/B/365*1000 | 21.58 |
| **Capacity Rate Annualized Reduction ($)** | E=D*365*B | $35,137,029 |
| **Capacity Rate Reduction August 2012 to May 2015 ($)** | F=E/12*34 | $99,554,915 |

*A: Sum of Aug. 2012 through May 2015 / 34 * 12*
*(a) Fuel, variable O&M, emissions costs*
*(b) Navigant did not analyze Aug. to Dec. 2012, increase set to zero*

## Summary of Capacity Rate Changes

**Duke Energy Ohio Proposed Capacity Rate (after credit for margins from sales and anc. services):** 224.15

| **Applying an ROE of:** | **7.0%** | **7.5%** | **8.0%** | **8.5%** | **9.0%** | **9.5%** | **10.0%** | **10.5%** | **11.0%** | **11.15%** |
|---|---|---|---|---|---|---|---|---|---|---|
| **Capacity Rate Increase/(Decrease):** | | | | | | | | | | |
| Exhibit RLL-1, Error Correction | (0.32) | (0.32) | (0.32) | (0.32) | (0.32) | (0.32) | (0.32) | (0.32) | (0.32) | (0.32) |
| Exhibit RLL-2, [redacted] | (6.29) | (6.29) | (6.29) | (6.29) | (6.29) | (6.29) | (6.29) | (6.29) | (6.29) | (6.29) |
| Exhibit RLL-2, [redacted] | (0.64) | (0.64) | (0.64) | (0.64) | (0.64) | (0.64) | (0.64) | (0.64) | (0.64) | (0.64) |
| Exhibit RLL-3, FRR Capacity Purchases | (0.78) | (0.78) | (0.78) | (0.78) | (0.78) | (0.78) | (0.78) | (0.78) | (0.78) | (0.78) |
| Exhibit RLL-4, Alternate ROEs | (32.40) | (28.53) | (24.65) | (20.76) | (16.86) | (12.95) | (9.03) | (5.11) | (1.18) | 0.00 |
| Exhibit RLL-5, Margin on Sales | 21.58 | 21.58 | 21.58 | 21.58 | 21.58 | 21.58 | 21.58 | 21.58 | 21.58 | 21.58 |
| Total | (18.85) | (14.98) | (11.10) | (7.21) | (3.31) | 0.60 | 4.52 | 8.44 | 12.37 | 13.55 |
| | | | | | | | | | | |
| **Adjusted Capacity Rate** | 205.30 | 209.17 | 213.05 | 216.94 | 220.84 | 224.75 | 228.67 | 232.59 | 236.52 | 237.70 |

# Ralph Luciani

**Ralph Luciani**
Director

**Navigant Consulting, Inc.**
1200 19th Street NW
Suite 700
Washington, DC 20036

Tel 202.973.4537
Fax 202.973.2401

ralph.luciani@navigant.com

**Professional History**

- Director, Navigant Consulting
- Vice President, Charles River Associates
- Senior Vice President, PHB Hagler Bailly
- Director, Putnam, Hayes & Bartlett, Inc.
- Edison Engineer, General Electric Company
- Financial Analyst, IBM Corporation

**Education**

- M.S. Industrial Administration, Carnegie Mellon University
- B.S. Electrical Engineering and Economics, Carnegie Mellon University

Ralph Luciani is a Director in the Power Systems, Markets & Pricing Group of the Energy practice of Navigant. He has more than 20 years of consulting experience analyzing economic and financial issues affecting regulated industries.

Mr. Luciani has had a special focus on the electricity industry, where he has assisted electric utilities and generating companies with business planning and restructuring, merger and acquisition analysis, resource planning, power solicitations, ratemaking, transmission cost-benefit studies, fuel and power supply contract negotiations, and environmental compliance strategy.

He recently led the economic evaluation performed by the Eastern Interconnection Planning Collaborative (EIPC) in a two-year study of the expansion of the transmission system in the eastern U.S. needed to support future generation under uncertainty with respect to climate change, renewable portfolio standards, and fuel prices. Mr. Luciani has also recently performed cost-benefit studies for four different electric utilities considering joining a Regional Transmission Organization (RTO).

Mr. Luciani has assisted clients and their legal counsel in the management of numerous complex litigation matters, including electric utility prudence and rate cases, and assessments of economic damages in commercial disputes. He has assisted many clients in reaching agreements in settlement processes administered by the Federal Energy Regulatory Commission (FERC). He has appeared as an expert witness in a number of regulatory proceedings.

## Professional Experience

RTOs and Transmission

» *RTO Cost-Benefit Studies* — Performed a number of major cost-benefit studies of Regional Transmission Organizations (RTOs) over the last 10 years, and provided related testimony in state regulatory proceedings.

» *Transmission Planning* — On behalf of the Eastern Interconnection Planning Collaborative (EIPC), led the economic evaluation in a two-year study of the potential build-out of the transmission system in the eastern U.S. needed through 2030.

» *RTO Administrative Costs and Rates* — Served as the lead consultant on behalf of the PJM Finance Committee in a FERC settlement process in which PJM proposed the establishment of a stated rate for the recovery of its administrative costs in place of the existing formula rate.

» *Transmission Ratemaking* — On a number of occasions, filed testimony which developed OATT transmission, ancillary service, and reactive power rates and also has presented testimony before the FERC regarding calculations of earned returns for transmission operations.

» *Transmission Costing* — Provided testimony and negotiated settlement agreements in a FERC settlement process regarding the assignment of costs for through and out transmission charges.

Generation and Power Marketing

» *Wind/Transmission Studies* — Performed a number of wind/transmission cost-benefit studies, including analyzing the economics of installing 765 kV transmission lines to support new wind power in the Southwest Power Pool.

» *Power Solicitations* — Assisted electric utilities in a number of solicitations for power, including formulating the RFP, conducting bidder's conferences, negotiating term sheets and definitive agreements, and obtaining regulatory approval for the final agreements.

» *Generation Valuation Lecturer* — Over a five-year period, served as the lead lecturer and instructor of an advanced training course on generation valuation under cost-of-service rates and under market-based pricing offered annually at a large U.S. investor-owned utility.

» *Power Marketing* — Prepared several affidavits at FERC analyzing wholesale trading activities of power marketers, developed utility cost-based rates for wholesale sales of capacity and energy, and assisted counsel in reaching an arbitration settlement regarding standby power charges.

» *Stranded Cost Derivation* — Presented testimony before four state utility commissions on the quantification of the stranded cost associated with the deregulation of generation.

» *Nuclear Power* — Assisted a utility in negotiating the sale of a nuclear plant, developed the financial model used in a utility's application for DOE-supported financing of a new nuclear facility, and provided testimony on CWIP financing in rates to support new nuclear plants.

Financial Evaluation

» *Cost of Capital* — Testified before the U.S. Bankruptcy Court and assisted counsel in arbitration proceedings regarding the proper discount rate to apply in assessing termination payments for wholesale power contracts, and assessed capital structure and rates for use in FERC proceedings.

» *Municipalization* — Assisted an electric utility in deriving the exit charges to be assessed for a proposed municipalization of a portion of the electric utility's service territory.

» *Mergers and Acquisitions* — Analyzed the potential acquisition of electric utilities and formulated transmission and distribution pro forma financials.

» *Organizational Restructuring* — Lead facilitator in a 12-month project that functionally unbundled the operation of an integrated electric utility into stand-alone profit centers.

Distribution and Retail

» *Distribution Performance-Based Rates* —Formulated a performance-based ratemaking (PBR) plan, for an electric utility, and presented the plan to the state public utility commission.

» *Distribution Benchmarking* —Formulated a benchmarking analysis to compare the costs and rates for the distribution system of an electric utility to the systems of neighboring utilities.

» *Efficiency Programs* — Developed a financial and rate incentive model for an electric utility to evaluate the impact on rates and earnings of adopting energy efficiency programs.

» *Distribution Cost Allocation* — Filed an affidavit in Ontario regarding allocation of distribution costs and derivation of stand-by rates for load displacement generation.

» *Retail Market Strategy* — Formulated models to assess the profitability of new retail loads in a competitive market and a product to reduce on-peak demand in residences.

Environmental and Fuel

» *Environmental Regulations* — Assisted electric utilities in formulating strategies for meeting provisions of the Clean Air Act regarding $SO_2$, $NO_x$ and mercury emissions, and in assessing potential climate change regulations.

» *Fuel Supply* — Assisted an electric utility in negotiating the terms of a buyout and replacement of a long-term coal supply contract, and in obtaining approval for the rate treatment.

» *Nuclear Spent Fuel*—Assisted counsel in a litigation involving the responsibility for costs incurred in the management of nuclear spent fuel storage and disposal.

» *Natural Gas*—Assisted counsel in obtaining state and federal approval for the merger of natural gas distribution companies, and in evaluating natural gas market manipulation in California.

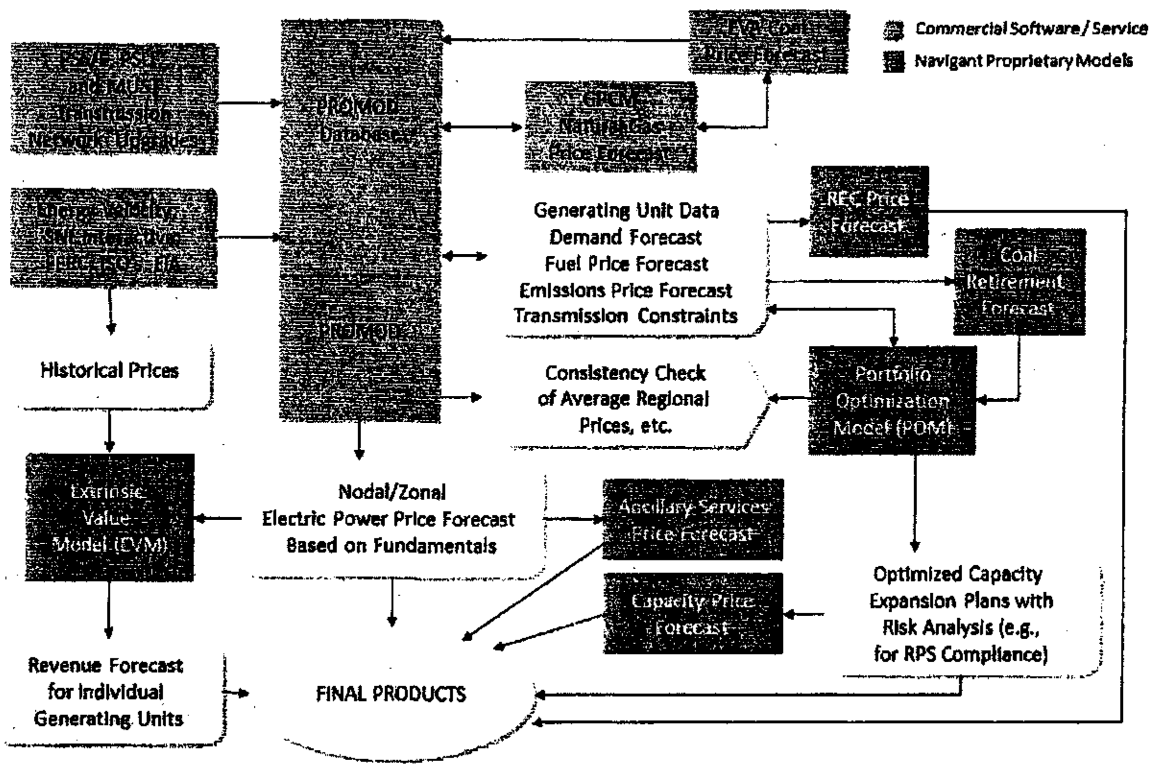
## Expert Testimony Experience

» Testified before the Arkansas, Kansas, Kentucky, Louisiana, Maryland, Mississippi, Missouri, Ohio, Pennsylvania, and Texas public utility commissions, the Ontario Energy Board, the U.S. Bankruptcy Court, and the Federal Energy Regulatory Commission (FERC).

» On a number of occasions, provided expert testimony on behalf of United Parcel Service (UPS) before the U.S. Postal Rate Commission.

## NAVIGANT MARKET ANALYSIS TOOLS

Navigant employs a variety of commercial and proprietary energy market modeling tools to project generating capacity retirements and additions, generating unit dispatch, fuel consumption, gas pipeline flows, and commodity prices in organized (e.g., ISO-NE, NYISO, PJM, ERCOT, MISO, SPP, CA-ISO) and traditional markets (e.g., Southeast, Pacific Northwest). A schematic of these tools is shown below, followed by a brief description of each tool.




**Navigant Energy Market Modeling Toolset**

### Ventyx's PROMOD Electric System Simulation Model

PROMOD IV is a detailed hourly chronological market model that simulates the dispatch and operation of the wholesale electricity market. This model replicates the least cost optimization decision criteria used by system operators and utilities in the market while observing generating operational limitations and transmission constraints. PROMOD can be run as a zonal or nodal model; although Navigant normally runs it in the full nodal model with full transmission representation.

**Transmission Planning – PSS/E, PSLF, and MUST**
Both PSS/E and PSLF are transmission planning software licensed from Siemens PTI and GE, respectively. Both programs include power flow, optimal power flow, balanced and unbalanced fault analysis, dynamic simulations, extended term dynamic simulations, open access and pricing, transfer limit analysis, and network reduction. Siemens PTI's MUST is used to determine transmission transfer capability (FCITC, ATC, TTC) by simulating network conditions with equipment outages under different loading conditions.

**Gas Price Competition Model (GPCM)**
GPCM is a commercial linear-programming model of the North American gas marketplace and infrastructure. Navigant applies its own analysis to provide macroeconomic outlook and natural gas supply and demand data for the model, including infrastructure additions and configurations, and its own supply and demand elasticity assumptions. Forecasts are based upon the breadth of Navigant's view, insight, and detailed knowledge of the U.S. and Canadian natural gas markets. Adjustments are made to the model to reflect accurate infrastructure operating capability as well as the rapidly changing market environment regarding economic growth rates, energy prices, gas production growth levels, sectoral demand and natural gas pipeline, storage and LNG terminal system additions and expansions. To capture current expectations for the gas market, this long term monthly forecast is combined with near term NYMEX average forward prices for the first two years of the forecast.

**EVA's Coal Price Forecast**
Navigant currently obtains the delivered coal price forecast from Energy Ventures Analysis, Inc. (EVA).

**Navigant's Portfolio Optimization Model (POM)**
Navigant's proprietary Portfolio Optimization Model (POM) is a capacity expansion model that emphasizes impacts of environmental policies and focus on renewable generation, while being suitable for risk analysis. It simultaneously performs least-cost optimization of the electric power system expansion and dispatch in multi-decade time horizons. Optionally POM can perform multivariate optimization, which considers other value propositions than just cost minimization, such as sustainability, technological innovation, or spurring economic development. This makes it especially suitable for modeling future renewable generation expansion.

**Navigant's Coal Plant Retirement Model**

Navigant's proprietary Coal Retirement Forecast model rapidly estimates the total coal fired capacity in danger of retirement due to EPA regulations, determines which states require the greatest emissions reductions to be compliant with the Cross-State Air Pollution Rule (CSAPR), and identifies the specific units and plants most at risk of retirement. The tool reviews the historical emissions of all existing coal units, the existing emissions equipment, and unit allocations for NOx and SOx emissions in order to determine which units are economic to retrofit with pollution control technology and which should be retired. The retirement or retrofit decision is based on the opportunity cost of replacing the coal units with natural gas generation. The Coal Retirement Forecast model summarizes the coal retirements and retrofits by state, ISO, and NERC region, and reports the retirements and retrofits as announced or economically driven. The tool will also estimate how far in or out of the money each unit is to retrofit and the emissions equipment required to be compliant with EPA regulations.

**Navigant's REC Price Forecast (RECPET)**

RECPET© a linear optimization forecasting model used to estimate future prices for RECs and SRECs. RECPET© integrates a diverse set of NCI proprietary models and datasets as well as public data sources to estimate the variables affecting REC/SREC values either within a state (e.g., New Jersey) or across a regional trading area (e.g., PJM RTO). What sets RECPET© apart from traditional REC/SREC forecasting models is its macro-level forecasting approach: starts with a notional value of the incremental revenue required by renewable resources to provide targeted returns over the life of the project then adjusts the notional value based on projections of supply and demand characteristics in the market as they are traded and contracted for by various entities. Using this approach, we help our clients understand the market dynamics that can cause such fluctuations in the prices of RECs/SRECs.

**Navigant's Extrinsic Value Model (EVM)**

Navigant uses our proprietary model EVM to evaluate bidding behavior, volatility, and arbitrage opportunities. It generates a single unit's dispatch based on input forecast prices. Using an hourly price stream from PROMOD, EVM models the plant as a price-taker, dispatching the unit over a horizon of expected prices. By repeatedly solving a weekly (or longer) problem to optimality, EVM replicates bidding patterns that reflect the plant operator's profit maximizing strategy. EVM also explicitly accounts for the additional volatility in market prices that is generally absent from simulated prices, including the effect of intra-month volatility in fuel and emissions prices, stochastic variations in demand, and deviations of market bidding away from marginal cost bidding. Navigant includes these adjustments in EVM as the forecasted hourly prices generated within PROMOD represent expected day-ahead market clearing prices under conditions of perfect foresight.

**Navigant's Ancillary Services Price Forecast Model**

Navigant's Ancillary Services Price Forecast model estimates prices in the regulation and reserve markets. The model is based on regression analysis of historical hourly market prices and is tailored to individual pool and RTO areas. Forecasts of individual generators' prospective ancillary service revenues are modeled as the product of the predicted market price and the power plant's ability to provide regulation or reserve services, given its availability and operating characteristics, and market rules.

**Navigant's Capacity Price Forecast Model**

Navigant's proprietary Capacity Price Forecast model estimates clearing prices in the PJM, ISO-NE and NYISO capacity markets. The model is tailored to the different market rules in each of these ISOs including resource eligibility, locational prices, and auction structure. It can be used to both forecast expected revenue from entering the capacity markets as well as for scenario analysis of uncertainties that may impact the revenue forecasts.