Staff Report

of

Exceptions and Recommendations

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of The Cincinnati Gas & Electric Company for Approval of Its Transition Plan and for Authorization to Collect Transition Revenues.	)	Case No. 99-1658-EL-ETP
In the Matter of the Application of The Cincinnati Gas & Electric Company for Approval of Tariff Changes Required to Implement Retail Electric Competition	)	Case No. 99-1659-EL-ATA
In the Matter of the Application of The Cincinnati Gas & Electric Company for Approval of Its New Tariffs.	)	Case No. 99-1660-EL-ATA
In the Matter of the Application of The Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures to Defer Costs Incurred Arising From the Implementation of its Transition Plan.	)	Case No. 99-1661-EL-AAM
In the Matter of the Application of The Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures to Defer Transition Costs and Continue to Defer the Unrecovered Balance Of Regulatory Assets.	)	Case No. 99-1662-EL-AAM
In the Matter of the Application of The Cincinnati Gas & Electric Company for Approval to Transfer Its Generating Assets To an Exempt Wholesale Generator.	)	Case No. 99-1663-EL-UNC

PUCO

The Public Utilities Commission of Ohio

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Alan R. Schriber, Chairman
Ronda Hartman Fergus, Commissioner
Craig A. Glazer, Commissioner
Judith A. Jones, Commissioner
Donald M. Mason, Commissioner

To The Honorable Commission:

In accordance with the Section 4928.32(B), Revised Code, the Commission's Staff has conducted its investigation in the above matter and hereby submits its report of recommendations.

This Report has been prepared under the overall supervision of Christine Pirik, Chief of Staff, Scott Potter, Director of the Utilities Department, Deborah Gnann, Director of the Consumers Service Department, Douglas R. Maag, Deputy Director of the Utilities Department, David R. Hodgden, Deputy Director of the Utilities Department, and J. Edward Hess, Chief of the Electric Division of the Utilities Department.

The Unbundling portion of the report was prepared under the supervision of Robert Fortney, the Corporate Separation portion was prepared under the supervision of Joseph Buckley, the Operational Support System Planning portion was prepared under the supervision of Carl Evans, the Employee Assistance portion was prepared under the supervision of Raquel Dowdy-Cornute, the Educational portion was prepared under the supervision of Lee Ruh, the Transition Charges portion was prepared under the supervision of Christopher Kotting, the Transmission portion was prepared under the supervision of Patrick Sarver, and the Shopping Incentives portion was prepared under the supervision of Daniel Johnson.

Copies of the Staff Report have been filed with the Docketing Division of the Commission and served by certified mail upon the utility or its authorized representative and all parties of record. The Commission has set this matter for public hearing for May 22, 2000.

This report is intended to present the Staff's exceptions to the Applicant's transition plan filing for the Commission's consideration and to recommend solutions for those exceptions. Not every proposed provision, item, or process will be discussed. Only provisions, items or processes with which the Staff takes exception are presented in this report. Exceptions presented include those that appear to be:

- In conflict with public policy including, but not limited to, public health, welfare, and safety.

- In conflict with current and proposed Commission Rules.

- In conflict with acceptable utility regulatory or disciplinary practices.

This Report does not purport to reflect the views of the Commission nor should any party to said proceeding consider the Commission as bound in any manner by the statements or recommendations set forth herein. The Staff Report, however, is legally cognizable evidence upon which the Commission may rely in reaching its decision in this matter. (See Lindsey, et. al. v. PUC, 111 O.S. 6)

Respectfully submitted,

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Background

The Cincinnati Gas & Electric Company (CG&E or Applicant) was incorporated in Ohio on April 3, 1837, as Cincinnati Gas, Light and Coke company, and its present name was adopted in 1901. Growth, acquisitions and mergers throughout the years have resulted in the present operation in which the utility renders electric and gas service in ten counties in Ohio. CG&E is a public utility engaged in the business of production, transmission, distribution, and sale of electricity to over 600,000 customers in the southwestern section of Ohio. CG&E is an operating subsidiary of Cinergy Corporation which is a registered public utility holding company created in 1994 by the merger of CG&E and PSI Resources, Inc.

On July 6, 1999, Ohio Governor Bob Taft signed into law legislation providing residents of Ohio with a choice of generation suppliers. The new law provides customer the choice of electric generation suppliers starting January 1, 2001. The new legislation also required an electric utility supplying retail electric service in the state of Ohio to file a plan for the utility's provision of electric service in this state during the market development period (2001-2005). The plan is to include a rate unbundling plan, a corporate separation plan, a plan to address operational support systems and any other technical implementation issues pertaining to competitive retail electric service, an employee assistance plan, and a consumer education plan. The electric utility could also include in its plan changes to tariff terms and conditions to address reasonable requirements of changing suppliers, length of commitment by a customer for service, and such other matters as are necessary to accommodate electric restructuring. The plan could also include an application for the opportunity to receive transition revenues and a plan for the independent operation of the utility's transmission facilities.

On November 30, 1999, the Public Utilities Commission of Ohio (PUCO) issued its Promulgation of Rules for Electric Transition Plans and of a Consumer Education Plan in Case No. 99-1141-EL-ORD. The Commission issued an Entry on Rehearing on January 4, 2000, a Second Entry on Rehearing on January 27, 2000, and a Third Entry on Rehearing on February 17, 2000. Those rules identified the form of the transition plan filing, a PUCO policy on consumer education, and rules on corporate separation and independent operation of transmission facilities.

The PUCO and its Staff are currently working on numerous other rules that were required by the new legislation. These rules include Certification of Providers of Competitive Retail Electric Services (99-1609-EL-ORD), Nuclear Decommissioning (99-1610-EL-ORD), Minimum Competitive Retail Electric Service Standards (99-1611-EL-ORD), Market Monitoring (99-1612-EL-ORD), Electric Service and Safety Standards (99-1613-EL-ORD), Long-Term Forecast Reporting (99-1614-EL-ORD), and Alternative Dispute Resolution (ADR) (99-1615-EL-ORD). A complete list of the Staff's proposed rules is listed at the PUCO's Electric Restructuring Web site (http://www.puc.ohio.gov/CONSUMER/ restructuring/proposed_rules.html).

On December 28, 1999, CG&E filed its transition plan for its electric utility operations. Pursuant to Commission entry, CG&E held a technical conference on January 7, 2000 to explain the structure of its filing, the work papers, the data sources, and the manner in which calculations were made. Thereafter, the Applicant held a series of eight technical conferences on each component of its transition plan to expedite discovery and to provide more details about its plan. On February 11, 2000, parties to the case filed preliminary objections to the Applicant's plan. A second procedural technical conference pursuant to Commission entry was conducted on February 24, 2000.

Scope of the Staff's Investigation

The scope of the Staff's investigation was designed to determine if the Transition Plan filed by CG&E meets the applicable requirements of Chapter 4928, Revised Code. The scope of the investigation was also designed to determine compliance with PUCO's consumer education policy, PUCO proposed corporate separation rules, PUCO proposed rules for the independent operation of transmission facilities, and any applicable Staff proposed rules required to be implemented by the new legislation. This report identifies the Staff's exceptions to the electric utility's transition plan, generally explains the basis or bases for each exception, and provides recommendations to correct those exceptions. The recommendations reported herein are only for those items for which Staff identified an issue or for which Staff objects. This Report will not recount, describe, discuss, or evaluate every item or topic or process proposed in the Application for which there is no alternative Staff recommendation.

The Staff reviewed all of the documentation originally filed by Applicant and all of the revisions and updates that were subsequently filed. The Staff issued data requests, conducted investigative interviews, and performed independent analyses when necessary. The Staff also reviewed all of the objections and documentation filed by the intervening parties. The Staff hired an independent consultant, Resource Data International, Inc., to determine a market valuation of each utility's generation plant. The results of that investigation are generally discussed in this report. The Staff also requested the assistance of the Ohio Department of Development (ODOD) to perform the audit required by Section 4928.51(D), Revised Code to establish a baseline for Percentage of Income Payment Plan Program that will be used as a rate for the Universal Service Rider. The results of that audit will be included in the ODOD consultant's report.

The Staff's exceptions and recommendations to the Applicant's proposed restructuring plans are generally discussed below. The exceptions and recommendations are organized by Parts A through H similar to the application. In Part I the Staff discusses Potential Structural Impediments to Retail Competition.

Part A – The Applicant's Unbundling Proposal

Introduction

Section 4928.31(A)(1), Revised Code mandates that transition plans include a rate unbundling plan consistent with Sections 4928.34 (A)(1) through (A)(7). The PUCO established a set of filing requirements for the unbundling plan by its Order and Entries on Rehearing issued in Case No. 99-1141-EL-ORD.

Summary Description of the Applicant's Unbundling Proposal

In its filing the Applicant has unbundled the rates that were in effect on October 5, 1999. The base rates that were in effect on October 5, 1999 were approved in Case No. 92-1464-EL-AIR. The Electric Fuel Component Rate (EFC) was approved in Case No. 98-103-EL-EFC. The Percentage of Income Payment Plan rate (PIPP) was approved in Case No. 96-1120-GE-PIP. The Emission Fee Allowance Rider was approved in Case No. 93-1001-EL-EFR on March 11, 1999.

The current bundled rates of the Applicant were unbundled into the following components: Distribution Charge, Transmission Charge, Ancillary Service Charges, Regulatory Transition Charge Rider, Customer Transition Charge Rider, Universal Service Rider, Energy Efficiency Charge, Emission Fee Rider and a Generation Charge. In addition, the Applicant has proposed changes to its standard terms and conditions of electric service.

To unbundle its current rates the Applicant utilized the Cost of Service Study (COSS) from its last rate case. Based on that COSS, the Applicant generated an unbundled COSS. Finally, the Applicant incorporated the tax-related adjustments to create an adjusted COSS used to unbundle its rates.

Following the application of functionalizing into generation, transmission and distribution, the Applicant unbundled rates into the components previously mentioned. As required by Section 4928, Revised Code, the Applicant developed its transmission rates based on its Federal Energy Regulatory Commission Open Access Transmission Tariff (FERC OATT). The distribution revenue requirement was derived by subtracting the FERC OATT revenue requirement from the transmission and distribution revenue requirement as determined from the Applicant's COSS.

The ancillary charges were unbundled from generation. From generation, the companies unbundled a Regulatory Asset Transition Charge revenue requirement that was to be developed based on the regulatory assets that are currently contained in base rates. The derivation of the total Customer Transition Charge revenue requirement will be discussed in a later section of this report, however, the allocation of such revenue requirement to the various classes and the rate design associated with the revenue requirements will be discussed in this section of the report.

The unbundled Universal Service Charge is based on the portion of the PIPP rider that is related only to the on-going costs of the program. The remaining generation-related portion of the Rider has been included in the Applicant's regulatory asset calculation. The Applicant will update this charge when additional information is available concerning the administration costs associated with program.

The Applicant has included a placeholder in its tariff for the Energy Efficiency Fund Charge, however, since the exact charge cannot be determined at this time, the charge that has been included is zero. The Applicant will update this charge when the appropriate amount is determined.

Finally, the unbundled generation component is determined by taking the total bundled rate component and subtracting the items discussed above.

Staff's Exceptions and Recommendations

The order of the exceptions in Part A will be provided in the same manner as the UNB (Unbundled) schedules that were required in Section 4901:1-20-03, Appendix A, Section (F), followed by a discussion of those exceptions that may not fall under the UNB Schedule categories.

UNB-1 Proposed Tariff Language

In accordance with Section 4901:1-20-03, Appendix A, Section (F), the Applicant filed UNB-1 schedules that provide a copy of the proposed tariffs. This section identifies Staff's exceptions to the proposed language for the General Service Rules and Regulations, proposed language changes to existing schedules and the proposed language in the new schedules.

<u>Service Regulations</u>

A-1. In Section III of the Electric Service Regulations for installations of meters, the applicant has deleted language which gives the customer or customer's agent the option to own and install meters. The rationale provided does not adequately justify the proposed change. Staff defers its recommendations on this issues pending the outcome of the Operational Support Plan (OSP) Workgroup meetings and reserves the right to offer comments and testimony on this subject in the hearing for this case or other appropriate form.

A-2. Section III.1 would require Competitive Retail Electric Service (CRES) providers to obtain customer-signed documents indicating choice of supplier and authorizing the Applicant to release customer-specific information to that supplier. To the extent this requirement applies to telephone and internet enrollment, it is contrary to Staff's proposed CRES Rule 6, which requires the customer's signature only enrollment obtained via mail and through direct (face-to-face) solicitation. Staff recommends this provision be revised to be consistent with proposed final CRES Rule 6.

A-3. Section III.1 would also require CRES providers to include in customer contracts the customer's authorization to release "standard historical usage information." Such a requirement would be contrary to Section 4928.10 (G), Revised Code and staff's proposed Electric Service and Safety Standards (ESSS) Rule 22 (D)(5), which require customer-specific load pattern information to be made available unless the customer objects. Staff recommends this tariff section be modified to eliminate this requirement.

A-4. Finally, Section III.1 would require the CRES provider to supply both the customer(s) and the Company 90 days written notice prior to discontinuing service. Staff agrees that an Electric Distribution Utility (EDU) may need considerable advance notice if the CRES provider were to release entire customer classes or large groups of customers. In fact, the proposed Certification Rules require CRES providers that are abandoning service to provide customers and EDUs 90 days notice. However, requiring that individual customers receive such notice would be contrary to Staff's proposed CRES Rule 12 (B)(5), would only require 14 days notice. The purpose of this requirement is to allow CRES providers to terminate the contract for non-payment of CRES charges and thus avoid accumulating bad debt expenses. Staff recommends this provision be modified to be consistent with the final CRES Rules.

A-5. Section III.2 would require customers with billing demand of 100 kW or more to have an interval meter installed before they could switch to a competitive supplier. The incremental cost of such meter and its installation would be borne by the supplier; but the meter would then become the property of the Company. The 100 kW interval-metering requirement would not apply to the Company's standard offer customers. The Interval-metering issue is being discussed by some parties at the Operational Support Plan Workgroup (OSP Workgroup) meetings. Staff defers its recommendations on this issue pending the outcome of the OSP Workgroup meetings and reserves the right to offer comments and testimony on this subject in the hearing for this case or other appropriate form.

A-6. Section III.3 would require that once enrolled, a customer could return to standard offer service only during the month of October, and after such return, would have to remain on standard offer service for at least 24 consecutive months. Staff believes that confining customer returns to a 1-month window constitutes an unfair restriction on a customer's right to choose. "Return to standard offer" issues are being discussed by some parties at the OSP Workgroup meetings. Staff defers its recommendations on these issues pending the outcome of the OSP Workgroup meetings and reserves the right to offer comments and testimony on this subject in the hearing for this case or other appropriate form.

A-7. Section III.5 would require a CRES provider to pay extra charges if it discontinued service to a customer at any time other than the Company's designated October notice period (unless the customer switched to another CRES provider during the ensuing 3 billing cycles). Staff believes such a requirement unfairly penalizes a supplier for, in many cases, merely trying to control bad debt expense by releasing a non-paying customer. Staff also notes that the CRES provider has no power to force the customer to switch from standard-offer service to another CRES provider (in order to avoid the proposed penalty fee). There is no such penalty in the gas choice programs and Staff sees no reason for one with electric choice either. Staff recommends this requirement be dropped from the tariff.

A-8. Section VI.6 proposes conditions applicable to customer-generators electing to be served under a net metering arrangement. Among other things, the tariff requires the customer-generator to provide a voltage wave shape that is a "clean" 60-Hertz sine wave. Staff considers the word "clean" to be too subjective and, as such, may allow the Applicant to establish unreasonably strict sine-wave requirements. Staff recommends the word "clean" be dropped from this provision. Staff also notes that the same paragraph appears twice (on pages 3 and 4 of this section), and recommends this duplication be corrected. Finally, Staff considers the last sentence of subsection 6 (regarding high speed automatic re-closing) to be redundant, since it is implied by the preceding paragraph. Staff therefore recommends the last sentence be deleted.

A-9. Section VII.2, relating to non-payment disconnection of non-residential customers, states: "Failure to pay the Certified Supplier portion of customer's bill is not a cause for disconnection by the Company." Although Staff agrees with this provision, which is consistent with proposed CRES Rule 2 (B), Staff is concerned that the Company may intend to exclude residential customers from such protection. Staff recommends the provision be repeated in Section VII.1, which applies to residential customers.

Rate DS

A-10. The Applicant is proposing a minimum monthly load factor of not less than 71 kWh per kW be instituted. The current tariff states that the maximum monthly rate, excluding the customer charge and the electric fuel component charges, shall not exceed 19.0 cents per kilowatt-hour. The Applicant's rationale states that the load factor calculation will more fairly distribute the 19 cents maximum over the functional components. However, the Applicant did not provide any analysis supporting this conclusion. Data request No. 9 was submitted asking for all workpapers that were not provided in the Applicant's filing that would support the company's conclusion.

Rate EH

A-11. The Applicant added language qualifying that primary source is defined as at least 90%. The O.A.C states that "Primary source of heat" means that energy which is the heat source for the control heating system of the residence or, if the residence is not centrally heated, that energy which makes up the bulk of the energy used for space heating. The definition provided in O.A.C. does not quantify primary source of heat. Data request No. 9 was submitted asking if current customers who are currently served under the tariff could be affected negatively by the proposed change. A data request is pending.

Rider RGR

A-12. The Applicant does not indicate that the customer's bills will be reduced by the .2047 cents per kilowatt-hour rate. The company should revise the proposed language so those customers understand that the rate as provided in the schedule is a reduction to the customer's bill.

Curtailable Power Provision

A-13. For rate schedules DS, DP, and TS, the Applicant's current tariffs include an interruptible credit of $4.38 for curtailable power. The Applicant is proposing to eliminate this provision. The Applicant failed to state how the proposed will affect any customers currently served under this provision. Data request No. 9 is pending.

Rider APS

A-14. The Staff takes exception to the addition of the language added to the applicability section of Rider APS (proposed sheet No. 70). The meaning and necessity of the phrase "and receive energy supply from the Company" is unclear. If a customer which has generation equipment capable of supplying all or a portion of its power requirements for other than emergency purposes, but which requires supplemental, maintenance or backup power contracts with a Certified Supplier for those services, why would it need the "Company" to supply those same services? The Staff recommends that the Applicant provide a response to this exception within thirty days of the issuance of this report.

Rider X – Line Extension Policy

A-15. Staff takes exception to the changes proposed in the Applicant's Rider X, Line Extension Policy (proposed sheet No. 73). (a) One change lowers the amount applied to the guaranteed minimum amount to only the customer's unbundled transmission and distribution charges. While this may be reasonable for customers which choose a competitive supplier, it appears to be a potential increase in rates for customers who do not shop. (b) Another proposed change alters the policy that the company's expenditure for a requested residential line extension be no more than three times the customer's projected annual revenue. Applicant proposes to eliminate the revenue test and to simply provide up to 100 feet of line extension at no cost. While this solves the problem as to "which revenue" the "three times" is applied, it appears to be a potential increase in rates for residential customers. (c) The final change alters the policy that the company's expenditure for a requested non-residential line extension be no more than two-and-one-half times the customer's projected annual revenue. In this instance, Applicant proposes that the projected annual revenue be based only on the unbundled transmission and distribution charges of the company. Once again, while this appears to be reasonable for customers that choose a competitive supplier, it appears to be an increase in rates for customers who do not shop.

Other UNB-1 Exceptions

A-16. In the Applicant's UNB-1 schedule Staff has identified inconsistencies between the rates that appear in either the workpapers or the UNB-7 schedules with those rates that ultimately end up in the proposed tariffs in the UNB-1 schedule. For example, the rates that appear in the UNB-1 schedule for Rate TL, Reactive & Voltage Control, shows 0.1048 cents/kWh, and according to the workpapers it should be 0.0148 cents/kWh. The same is true for Rate OL, Scheduling/System/Dispatch, where the rate in the UNB-1 shows 0.0112 cents/kWh, and the workpapers indicate that the rate should be 0.0012 cents/kWh. Staff recommends that the Applicant ensure that the final rates and rate structures that are carried over to the UNB-1 schedule are accurate.

A-17. It is Staff's understanding that when a customer chooses an electric supplier other than the Applicant that the customer will be served under the rates, terms and conditions of the Applicant's FERC OATT. The proposed tariffs are not clear on this issue and; therefore, the Staff recommends that additional language be added in the individual tariff schedules to indicate that a shopping customer will be served under the FERC OATT.

A-18. Within the Applicant's proposed rate schedules, the Applicant has provided separate charges for distribution, transmission, generation, and various riders. However, the generation charges that are contained within the schedules include the regulatory asset charge (RTC) and the generation transition charge (GTC), that are also part of the riders that are listed in each of the rate schedules. Therefore, Staff takes exception to the fact that the schedules are not clear that the Generation Charge is inclusive of RTC and GTC, and that both should be removed from Generation when calculating a bill, since the RTC and GTC are already included as part of the applicable riders as contained in each schedule. The Staff recommends that language be added to the schedules to clarify that since the RTC and GTC are included as riders that they must be removed from the generation when determining a bill.

UNB-4 Cost of Service Study

In accordance with Section 4901:1-20-03, Appendix A, Section (F), the Applicant filed its UNB-4 schedules as part of its transition plan filing. The Applicant filed a bundled and unbundled COSS in UNB-4 and UNB-4.1 as allowed in the last rate case; and UNB-4.2 and UNB-4.3 as adjusted for net changes in taxation. The purpose of the studies was to utilize the COSS that was used in the company's last rate case as a basis to unbundle its current rates in a revenue neutral manner. The Applicant's starting point for the development of the unbundled rates was the bundled rate-schedule-by-rate-schedule COSS, Schedule UNB-4 that incorporates the revenues, expenses and investments in the Commission's decision for the Applicant's last rate case. The unbundled COSS, Schedule UNB-4.1 is then prepared by analyzing the schedule results from the bundled COSS on a functional basis, while maintaining the schedule-by-schedule relationships.

The Applicant utilized the FERC Uniform System of Accounts (USOA) as a basis for unbundling most of the plant and expense accounts. The Applicant developed allocation factors where the FERC USOA and / or the last rate case cost of service study did not provide the detail necessary to functionalize certain types of costs. For example, the Administrative and General expenses, and General and Common plant are functionalized based on the functionalization of salaries and wages. The impact of the property tax reduction is determined by function. The step up transformer investment is assigned to the generation function.

A-19. To the extent possible the Applicant should also provide an unbundled COSS that is unadjusted from the last rate case. However, to the extent that the Commission finds the Applicant's methods of functionalizing to be reasonable, the Staff has identified other accounts to be reviewed for functionalization purposes. These accounts include the following:

- Account 447 – Sale for Resale
- Account 282 – Accumulated Deferred Income Tax Depreciation, and Tax Adjustment – Timing Differences

<u>Seven-Factor Test</u>

A-20. According to the transition rules as found in Section 4901:1-20-03 Appendix A, Unbundling Plan (F)(2)(g) Cost of Service Study, each of the electric utilities are required to "demonstrate that the facilities included for cost recovery in the transmission component are consistent with the FERC seven-factor test." The Applicant did not conduct the seven-factor test analysis and identify specific transmission assets as part of it's transition plan filing. Cincinnati Gas and Electric also did not report the cost of service requirements reflecting the refunctionalization.

Section 4901:1-20-03 (F)(2)(g) was written so that the physical separation of transmission and distribution assets would be made for ratemaking purposes. Because of the way Chapter 4928, Revised Code is written, the transmission and distribution rates are somewhat fixed during the market development period. The law states in Section 4928.34(A)(1) that the unbundled transmission component for the utilities' unbundling plan shall equal the tariff rates determined by the FERC. The physical separation is however essential for post-market development rate implications and can be argued necessary during the market development period for the sake of determining charges for the use of specific facilities when specific power transactions take place by third party suppliers when using the Applicant's facilities.

The identification of separate transmission and distribution assets in Ohio, and the appropriate associated costs, should be identified now so that a more accurate unbundling of rates can occur and to comply with the rule requirements as found in Section 4901:1-20-03 (F)(2)(g). Recognizing the time requirements for such an endeavor, the Applicant should be required to begin the process and file with the Commission in this transition plan docket the necessary data and justification to separate transmission from distribution facilities. The justification should include the seven-factor test and appropriate load-flow studies to support the seven-factor test analysis and the associated cost of service requirements for what is identified as transmission and distribution.

UNB-5 Unbundled and Unadjusted Rates

In accordance with Section 4901:1-20-03, Appendix A, Section (F), the Applicant provided UNB-5 schedules. In its UNB-5 schedules, the Applicant did not provide unbundled rates but did provide unbundled revenues for Generation, Transmission and Distribution based on its UNB-4 schedule. The Applicant did not provide unbundled rates that were not adjusted by the tax law changes since the only unbundled rates that were provided were those that are contained in the UNB-7 schedules that reflect the final rates adjusted for all tax changes. Therefore, all rate design issues will be addressed in the UNB-7 section of the report.

UNB-6 Adjustments to Current Rates

In accordance with Section 4901:1-20-03, Appendix A, Section (F), the Applicant provided UNB-6 schedules in its transition plan filing. The UNB-6 schedules provide details of the adjustments that were made to the rates in accordance with the new tax laws and the mandated 5% residential reduction as prescribed in Chapter 4928, Revised Code. Following are the exceptions that Staff has identified with the Applicant's treatment of the tax-related changes and other changes the Applicant is proposing.

<u>Ohio Franchise Tax</u>

As a result of the Electric Restructuring Bill, electric utilities became subject to Ohio franchise tax. The utility is required to compute taxes based on both net worth and net income basis. The utility is required to pay tax on the basis that results in the higher tax. If the franchise tax is computed based on net worth, a two-factor formula must be used to determine the net worth that is attributable to Ohio. If the tax is computed based on net income, net income must be apportioned under a three-factor formula consisting of sales, property and payroll. A double weighted sales factor is used to determine the net income that is attributable to Ohio.

The Applicant calculated the current franchise tax liability of $13,107,000 based on the federal taxable income from the last rate case and the effective franchise tax rate of

7.8341%. The Applicant also calculated a deferred franchise tax of $5,415,000 and added to the current tax liability. The Applicant's total franchise tax is $18,522,000.

A-21. The Staff verified the Applicant's calculation and found it to be reasonable. However, the Staff is continuing to review the Applicant's deferred franchise tax adjustment of $5,415,000 and will make a recommendation during the hearing.

<u>Municipal Income Tax</u>

As a result of the Electric Restructuring Bill, electric utilities became subject to municipal income tax. The Applicant calculated the current municipal income tax liability of $1,861,000 based on the federal taxable income from the last rate case, adjusted for Ohio franchise tax, and the effective municipal tax rate of .71%. The Applicant also calculated a deferred municipal income tax of $505,000 and added to the current tax liability. The Applicant's total municipal income tax is $1,861,000.

A-22. The Staff verified the Applicant's calculation and found it to be reasonable. However, the Staff is still reviewing the Applicant's deferred municipal income tax adjustment of $505,000 and will make a recommendation during the hearing.

<u>Other Tax issues</u>

The change in Ohio franchise tax is effective January 1, 2002, at a franchise tax rate during the first year equal to two-thirds of the full year amount. Also the change in municipal income tax is effective January 1, 2002. The Applicant is requesting recovery of these two taxes in rates in the year 2001. The Applicant proposes a reduction to regulatory assets based on one full year of municipal income taxes and one-third year of franchise taxes collected in the year 2001. See section F-9 for further discussion of this issue.

A-23. The Staff recommends that a tax credit rider be used to refund the franchise and municipal taxes to ratepayers during the first four months of 2000.

<u>Ohio Excise Tax Rider (Rider OET)</u>

The Applicant is proposing a new Rider OET. The Rider contains two parts. The first part includes the charges as contained in the Section 5727.81(A), Ohio Revised Code and are to become effective May 1, 2001. The second part of the rider includes a statuatory tax rate of 4.75% that is to become effective January 2001, and continue through April 30, 2002.

A-24. The Staff takes exception to the second part of Rider OET. Staff recommends that the tax rate should be the effective tax rate net of uncollectibles and non-taxable receipts. In addition, the Staff recommends that the second part of the rider terminate when the first part of the rider commences on May 1, 2001. If the second part of the rider were to remain in effect after May 1, 2001, the Applicant would be double recovering gross receipts tax since such tax has been incorporated into the rates that were designed for the first part of the rider.

5% Residential Reduction

A-25. The Applicant has adjusted rates for residential customers by applying a 5% reduction to the generation rate net of the RTC. Staff believes that Section 4928.40 (C), Revised Code, requires residential customers to receive a 5% reduction on the total Generation rate.

UNB-7 Adjusted and Unbundled Rates

In accordance with Section 4901:1-20-03, Appendix A, Section (F), the Applicant filed UNB-7 schedules in its transition plan filing. The UNB-7 schedules were to reflect the final rates the Applicant is proposing in its UNB-1 schedules.

Due to the mechanics of unbundling rates as mandated, it is impossible, at this time, for Staff to make recommendations as to the "correct" rate levels. Many rates are determined on a "residual" basis; thus, a change in one component results in changes to other components. Therefore, exceptions and Staff recommendations will be based more on the "methodology" of unbundling, rather than precise rate levels.

Determining the generation component

In its application, the Applicant has treated generation, which Staff refers to as “little g” (“little g” = G-RTC-GTC) as a residual amount. The Applicant has calculated a specific GTC revenue requirement for each class based on a dollar amount to be collected over a five year period. In addition, it has calculated an RTC revenue requirement for each class, representing the amount of regulatory assets that are contained in current base rates. To determine “little g”, the Applicant has taken the total revenues and subtracted all components discussed above, including the CTC and RTC, and the remaining revenues are considered “little g”, and it is this amount that a customer would not pay if they switched to an alternative energy provider.

A-26. If it is determined that the Applicant has GTC to recover, the Staff recommends that the GTC revenue for each rate schedule be determined by taking the generation revenue requirement (GTC, RTC and “little g”) for each schedule and subtracting the revenue requirement associated with the market rate and the RTC revenue requirement. The GTC and RTC revenue requirement as well as the revenue requirement for the energy portion of “little g” should be allocated through the energy blocks on a consistent basis. Unbundled unadjusted rates per block within each rate schedule are made equal to the current rates per block by making the total generation rate, which includes GTC, RTC and “little g”, the residual amount.

Rate Design of Residential Schedules

The Applicant is proposing to redesign its residential rate schedules (RS and ORH) in an attempt to levelize the rates within the declining block structure of the schedules. The redesign results in an increase in rates to higher usage customers since the tailblock rates have been significantly increased.

A-27. The Staff believes that the intent of Chapter 4928, Revised Code was to unbundle current rates and rate structures without creating adverse impacts for customers. Staff recognizes that there are mandates within Chapter 4928, Revised Code which create adverse impacts, however, to the degree that such impacts can be avoided or minimized, Staff recommends that the necessary steps be taken to do so. In this instance, the Applicant, not the Revised Code, is creating the adverse impact; therefore, Staff recommends that the Applicant maintain the current rate relationships within the blocks.

Rate Design of Commercial and Industrial Schedules

The Applicant's proposed rate design of its Schedule DM and Schedule TS increases the tailblock rate in each of these schedules. The redesign results in an increase in rates to higher usage customers.

A-28. The Staff believes that the intent of Chapter 4928, Revised Code was to unbundle current rates and rate structures, without creating adverse impacts for customers. Staff recognizes that there are mandates within Chapter 4928, Revised Code which create adverse impacts, however, to the degree that such impacts can be avoided, Staff recommends that the necessary steps be taken to do so. In this instance, the Applicant, not the Revised Code, is creating the adverse impact; therefore, Staff recommends that Applicant maintain the current rate relationships within the blocks.

Rate Design of RTC and GTC

To develop GTC and RTC rates, the Applicant developed class revenue requirements and divided the revenue requirements by the class specific kWh's to determine an average kWh rate for each class. This approach which charges the same kWh rate for every kWh billed is not consistent with the current rate design of the rate schedules and results in adverse impacts to higher usage customers. The majority of the Applicant's rate schedules have blocked rate schedules whereby the rate varies (generally on a declining basis) for each block. Consequently, when the rate schedules are unbundled, the same rate block relationships should be maintained in an attempt to make unbundled rates equal to bundled rates and at the same time minimizing the impacts to all customers.

A-29. The Staff recognizes that Chapter 4928, Revised Code mandates that such charges should be billed on a kWh basis; however, the Staff does not believe that the Applicant is restricted from designing blocked kWh rates to recover the GTC and RTC revenue requirements. As Staff recommended in exception A-25, Staff reiterates it recommendation that the total generation rate which includes the GTC and RTC should be allocated through the rate blocks on a consistent basis.

Rate Design of 5% Residential Reduction

A-30. The Applicant is proposing to apply its 5% residential discount by implementing a Rider that contains a single kWh rate that is to be applied to all kWhs billed to a customer. This approach which provides the same kWh rate discount for every kWh billed is not consistent with the current rate design of the rate schedules and results in an inequitable result for the lower usage customers. The Staff recommends that the Rider be designed such that each customer receives a 5% reduction on the generation portion their monthly bill.

UNB-8 Typical Bill Comparisons

In accordance with Rule 4901:1-20-03, Appendix A, Section (F), the Applicant provided UNB-8 schedules in its transition plan filing. The residential proposed bills include the effects of the mandated 5% residential reduction.

A-31. In reviewing the UNB-8 schedules, the effects of the tax-related adjustments become apparent. This is a result of property taxes being removed from rates based on how they were included in rates in the last rate case (predominantly on a demand basis), and then a new tax being levied on only the kWh consumption rates. This results in more taxes being collected through the energy rates than the demand rates, therefore, creating adverse impacts for higher load factor classes and customers. Staff recommends that the Applicant, when designing its rates, take into consideration the resulting typical bill impacts for all customers.

Other Issues Not Addressed in the UNB Schedules

A-32. The Commission's Second Entry On Rehearing in Case No. 99-1141-EL-ORD issued on January 27, 2000 requires that dollar amounts in the current bundled rates associated with metering services and billing and collection services be "identified". The Applicant should provide the identification of those amounts within thirty days of the issuance of this report, as well as provide arguments as to whether those services should be or should not be unbundled portions of the distribution function.

ATA Applications

In Case No. 99-1659-EL-ATA, the Applicant has requested authority to make changes to its filed tariffs that are required to implement retail electric competition. In Case No. 99-1660-EL-ATA, the Applicant is requesting approval of new tariffs. The Staff has identified numerous exceptions to the proposed tariff changes as well as to the new tariffs that have been proposed. Such exceptions have been outlined throughout this report.

Part B - Corporate Separation Plan

Introduction

Section 4928.17(A) of the Revised Code sets out three primary objectives for Corporate Separation plans. These objectives as summarized are:

- Providing for the provision of competitive retail electric service or the non-electric product or service through a fully separate affiliate, with separate accounting requirements and a Code of Conduct as ordered by the Commission;

- Satisfying the public interest in preventing the abuse of market power; and

- Ensuring no undue preference or advantage is extended to any affiliate, division or part of the business engaged in supplying competitive retail electric service or a non-electric product or service.

Summary Description of the Applicant's Corporate Separation Plan

Under CG&E's corporate separation plan, starting January 1, 2001, the Applicant will provide only non-competitive retail electric service (distribution and transmission service). The Applicant contemplates transferring all of its generation assets to an affiliate Electric Wholesale Generator (EWG), which would be a special purpose company dedicated to owning and/or operating electric generating facilities whose power is sold in the wholesale market. Application 99-1663-EL-UNC requests Commission approval for the transfer of the generating facilities to a separate affiliated company with EWG status. The Applicant also, submitted a detailed timeline (Exhibit B-1), outlining the progression towards EWG approval and a post-restructuring organization structure chart (Exhibit B-2).

Under Section 32 of the Public Utilities Holding Company Act (PUHCA), prior to any transfer of generating facilities to EWG status, the Commission would need to determine that the transfer 1) benefits consumers; 2) is in the public interest; and 3) does not violate state law. The Applicant plans to have it's transmission assets controlled by the FERC approved Midwest Independent System Operator (MISO). In addition, the Applicant stated that it would transfer all non-tariffed services to non-regulated affiliates, cease offering such services, or tariff such services.

The Applicant stated, "If CG&E does not have an affiliated certified supplier, it cannot provide improper subsidies or information to such suppliers to the determent of competitive retail electric market. Under such circumstances, CG&E will be in compliance with the affiliated transaction requirements" (Paul Smith's direct testimony page 4). In supplemental testimony the Applicant stated that "CG&E believes the reason for such rules is to prevent an electric utility from providing an unfair competitive advantage to its affiliated Certified Supplier," (Paul Smith supplemental testimony pg. 2).

Interim Functional Separation

Attachment I to the Commission Finding and Order 99-1141-EL-ORD (pg. 43-44), states that, except as the Commission may approve, the financial arrangements of an electric utility are subject to certain restrictions.[1] These restrictions among other things, seek to eliminate the exposure to the electric utility based on actions of a competitive business, and require the competitive businesses to obtain financial arrangements that better reflect their business risk. However, the Staff recognizes that under the previous regulatory structure the electric utilities, in an attempt to lower their cost of capital entered into some financial arrangements that appear to be in violation to the current rules. These arrangements include sale-leaseback transactions, pollution control notes and mortgage bonds. Pollution control bonds lower the cost of capital because they are tax-exempt and mortgage bonds are secured, often through liens, against general plant and/ or equipment, giving the investor added security that the payment will be met.

The Applicant stated that they will address the financial arrangement issue through AIS (Application to Issue Securities), cases to be filed with the Commission. Furthermore, the Applicant stated that it's ability to minimize the costs associated with the transfer of generation assets hinge on three key factors: 1) what steps CG&E has to take to adjust its capital structure as a result of the corporate separation plan; 2) whether it can release the generation from the mortgage without having to redeem the first mortgage bonds; and 3) whether it can eliminate or minimize the tax obligations, which may arise from the transfer.

In addition, the Applicant said, it is seeking to avoid or minimize the amount of outstanding debt that needs to be redeemed because of favorable associated imbedded rates and to avoid the high cost of redemption. Also, CG&E is seeking to release the generation assets from existing first mortgage liens by replacing the generation assets with other bondable CG&E property. The Applicant intends to maintain sufficient equity capitalization to keep its investment grade rating. Based on the Applicant's

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[1] The restrictions are as follows:

a. Any indebtedness incurred by an affiliate shall be without recourse to the electric utility.
b. An electric utility shall not enter into any agreement with terms under which the electric utility is obligated to commit funds to maintain the financial viability of an affiliate.
c. An electric utility shall not make any investment in an affiliate under any circumstances in which the electric utility would be liable for the debts and/ or liabilities of the affiliate incurred as a result of actions or omissions of an affiliate.
d. An electric utility shall not issue any security for the purpose of financing the acquisitions, ownership, or operation of an affiliate.
e. An electric utility shall not assume any obligation or liability as a guarantor, endorser, surety or otherwise with respect to any security of an affiliate.
f. An electric utility shall not pledge, mortgage or use as collateral any assets of the electric utility for the benefit of an affiliate.

projected capital structure, after separating the generating assets CG&E predicts its pretax cost of capital declining from 9.23% to 9.13%.

Staff Exceptions and Recommendations

B-1. The Staff believes that the Commission's Corporate Separation Rules, 4901:1-20-16 (D),[2] prohibits the cross-subsidization and inappropriate information flow between an electric utility and all affiliates, not just an affiliated competitive retail electric supplier (CRES). Therefore, the Staff takes exception to CG&E's claim that it is in compliance with the Commission's corporate separation rules, by default, if it does not have an affiliated CRES.

B-2. Because the generation asset transfer will not be completed before January 1, 2001 (see Exhibit B-1), the Staff believes CG&E will be operating under an interim functional separation plan. Staff believes this may be prudent to allow this flexibility however, additional monitoring, during this period is warranted.

[2] Cross-subsidies between an electric utility and its affiliates are prohibited. An electric utility's operating employees and those of its affiliates shall work /function independently of each other.

EXHIBIT B-1

TIMELINE FOR FORMATION OF CINERGY OHIO GENCO*

December 28, 1999

- Transition Plan filed with Public Utilities Commission of Ohio (PUCO), including request for authority to transfer CG&E's Ohio generation assets to EWG, and request for statutory findings on Requirements Commodity Service Agreement.

May 1, 2000

- Approximate deadline for filing with Indiana Utility Regulatory Commission (IURC) authority to transfer CG&E's Ohio generation assets to EWG and any necessary associated Operating Agreement amendments, in order to be assured of receiving approval by October 31, 2000.

May 15, 2000

- Approximate last day to file at PUCO for approval of Cinergy Ohio GENCO financing by CG&E (if necessary) and any Operating Agreement amendments in order to obtain approvals by October 31, 2000.
- Approximate last day to file for authority to transfer CG&E's Ohio generation assets to EWG from Kentucky Public Service Commission (KyPSC) in order to obtain approvals by October 31, 2000.

October 31, 2000

- PUCO approval of transfer of CG&E's Ohio generation assets to EWG and statutory findings on Requirements Commodity Service Agreement
- PUCO approval of Operating Agreement modifications (if necessary)
- PUCO approval of Cinergy Ohio GENCO financing by CG&E (if necessary)
- KyPSC approval of transfer of CG&E's Ohio generation assets to EWG and statutory findings on Requirements Commodity Service Agreement
- IURC approval of transfer of CG&E's Ohio generation assets to EWG and statutory findings on Requirements Commodity Service Agreement
- IURC approval of Operating Agreement modifications (if necessary)
- EWG corporation created

November 15, 2000

- File for Operating Agreement modification approval at FERC (if necessary)
- File for approval of Requirements Commodity Service Agreement at FERC
- File for EWG approval at FERC

March 1, 2001

- FERC approval of Operating Agreement modifications
- FERC approval of Requirements Commodity Service Agreement and Connection and Site Agreement
- FERC approval of EWG

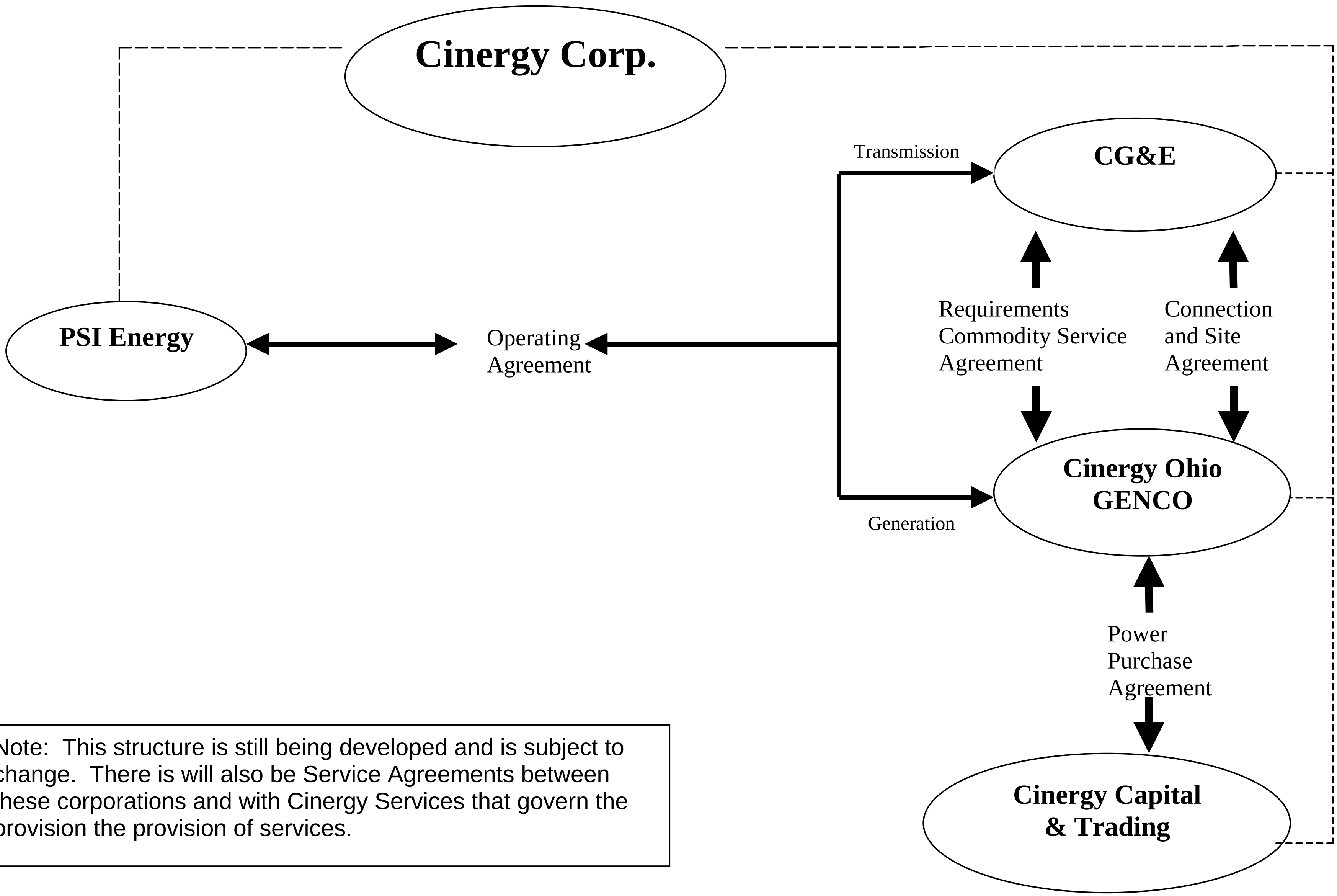
May 1, 2001

- First possible closing of transfer of all or some portion of assets to EWG

* This timeline and any associated regulatory requirements are still being developed, are dependent upon structure, and are subject to change.

Exhibit B-2

Post-Restructuring Organization Structure



Note: This structure is still being developed and is subject to change. There is will also be Service Agreements between these corporations and with Cinergy Services that govern the provision the provision of services.

Part C - Operational Support Plan

Introduction

Section 4928.31(A)(3), Revised Code and the PUCO's rules require each electric utility to file an operational support plan as part of the overall transition plan. The operational support plan outlines areas required to implement customer choice in Ohio, including a timetable and work plan for development of the systems to permit certified suppliers and companies to handle customer information in an efficient manner.

Summary Description of the Applicant's Operational Support Plan

The Company proposes an operational support plan that is to comply with Commission rules pursuant to 4901:1-20-03 Appendix B and 4928.31(A)(3) Revised Code. It is proposed to be sufficient to address operational support systems and technical implementation issues pertinent to competitive retail electric service. It is designed to meet the implementation of customer choice by January 1, 2001. The operational support plan is presented in greater detail in the Applicant's Application, its Operational Support Plan, and in the testimony of Company witness Morris.

Staff Exceptions and Recommendations

C-1. The staff is currently conducting a workshop to address some of the issues that are related to operational support. Recommendations from those workshops will be presented to the Commission when they are available. The staff finds no specific exceptions or recommendations to the Company's proposed operational support plan.

Part D – Consumer Education Plan

Introduction

The Ohio Electric Restructuring Act of 1999 contains several provisions for consumer education to ensure that consumers understand the options they will have -- and the buying decisions they will have to make -- in a competitive electricity marketplace. Recognizing the scope of this challenge, the law directs the state's investor-owned electric companies to spend up to $16 million for statewide and local consumer education programs prior to and during the first year of electric competition, which begins January 1, 2001, and an additional $17 million thereafter during the transition period.

On November 30, 1999, the PUCO adopted The General Plan for Consumer Education. This plan divided the total consumer education campaign into a two-pronged effort, calling for a statewide campaign and a service territory-specific campaign. The total $33 million was divided in the plan for first year spending of 70% for the statewide campaign and 30% for the local service territory efforts by each of the utility companies. Thereafter, the funding allocation is 40% for the statewide effort and 60% for the local efforts.

The Public Utilities Commission of Ohio (PUCO), in consultation with the Ohio Consumers' Counsel (OCC), will oversee this consumer education project. The Ohio Electric Utility Institute (OEUI), the trade association for the state's investor-owned electric utilities, will administer the day-to-day implementation of the statewide consumer education program and coordinate these statewide activities with the local educational efforts of the individual electric companies. While the PUCO will work with the OCC and the OEUI on the consumer education project, the PUCO provides ultimate approval for the content and conduct of the campaign.

The General Plan for Consumer Education required that the utilities provide the following information as part of their Transition Plan filings: contact information for the lead on the project, plans for the creation of an advisory group, the general tactics the utility is anticipating utilizing, a timeline for implementation and a general budget.

Summary Description of the Company's Consumer Education Plan

CG&E proposes a Consumer Education Plan that includes a statewide campaign undertaken and directed by the PUCO and administered through the Ohio Electric Utility Institute and a local campaign direct to service area customers. The Consumer Education Plan is intended to increase awareness, particularly in the residential and small commercial classes of the customer choice program and to provide customers information on how to participate. Statewide and local advisory groups will provide input into the statewide and local campaigns.

CG&E's contact for the program will be Diane M. Simpson, manager of paid media for the company. CG&E proposes to establish an advisory group made up of a Staff representative, OCC representative and at least two customer representatives, one representative from a community based organization and three Cinergy employees. The advisory group is scheduled to meet monthly to:

- Review and provide input on specific messages
- Review and provide input on all collateral
- Review the results of benchmark and tracking research and propose modifications to the plan to improve apparent areas of weakness
- Provide input to the service territory-specific plan for the period 2002 through the end of the market development period.

CG&E proposes to utilize tactics focusing on print media including bill inserts, collateral, and newspaper ads, seeking to not duplicate the efforts of statewide mass media buys in their service territory. CG&E also proposes an extensive outreach program including special promotional events, speaker's bureau presentations and news releases. The schedule and frequency for implementing these tactics would be developed after benchmarking surveys have been done.

CG&E proposes to begin the service territory-specific campaign coincident with the statewide campaign beginning in July 2000, but not later than the beginning of the third quarter in 2000. CG&E outlined a timeline generally through 2005.

CG&E proposes to provide $2,230,400 of the first year $16,000,000 for consumer education. Of these funds, $670,000 will be used for the service territory-specific program and $1,560,000 will be used for the statewide program.

Staff Exceptions and Recommendations

D-1. The Staff is, and will continue to work with each of the utilities to further develop their plans as well as ensure the messages are un-biased and supportive of the statewide effort. CG&E's proposed advisory group is lacking representation of the energy marketers, but Staff will work with the company to bring this issue into compliance with the General Plan for Consumer Education. Otherwise, CG&E's plan for consumer education is consistent with the General Plan for Consumer Education. Staff does not have any specific exceptions or recommendations to CG&E's plan for consumer education. Pursuant to Section 4928.32, Revised Code, the Staff does not believe that this section reasonably requires a hearing as part of the Transition Plan cases.

Part E - Employee Assistance Plan

Section 4928.31, Revised Code required each Applicant to file employee assistance plans as part of their overall transition plans. The plan is to identify any employee assistance that will be offered to employees whose employment is affected by electric industry restructuring. The PUCO has adopted rules for electric utilities to follow when preparing their employee assistance plans. These rules also overlap with the transition charges rules contained in the Administrative Code, Section 4901:1-20-03, the Revised Code Section 4928.37 and Section 4928.40 and Appendix D of Case No. 99-1141-EL-ORD. Certain employee assistance costs are eligible for transition cost recovery.

Section 4928.431, Revised Code created an Employee Assistance Advisory Board for the purpose of making recommendations to the PUCO after review of the transition plan filings made by each Applicant. The Employee Assistance Advisory Board has not been appointed.

Summary Description of the Company's Employee Assistance Plan

As described in Applicant witness Richard L. Bond's testimony, CG&E's Employee Assistance Plan (EAP) provides for severance, retraining, early retirement, retention, outplacement, and other assistance for utility company employees whose employment is affected by electric industry restructuring during the market development period. The company's plan for non-union employees addresses severance and ancillary benefits. While reserving the right to implement involuntary workforce reductions if necessary, CG&E stated that it intends to initially use voluntary programs to achieve workforce reductions that may be necessitated by electric industry restructuring in Ohio. The company's EAP for union employees provides that if utility restructuring affects employees covered by collective bargaining agreements, the company will meet with the appropriate collective bargaining agent to negotiate regarding the effects of the restructuring.

Staff Exceptions and Recommendations

The Staff is ready to assist the Employee Assistance Advisory Board with any technical assistance that Board may require. The board's relationship with Staff is not identified; therefore, any relationship will be developed on an ad hoc basis. Staff does not have any specific exceptions or recommendations to CG&E's employee assistance plan.

Part F – Transition Costs, Revenues, & Charges

Introduction

Transition costs are identified in Section 4928.39, Revised Code. Under that section, transition costs must meet all of the following criteria:

- The costs must have been prudently incurred.
- The costs must be legitimate, net, verifiable costs which can be directly assigned or allocated to Ohio.
- The costs must be costs that the utility could not recover in a competitive market
- The costs must be costs that the utility would otherwise be entitled an opportunity to recover.

In addition to costs that meet these criteria, Section 4928.39(D) Revised Code explicitly includes costs associated with the employee assistance plan described in Section 4928.33, Revised Code, to the extent that those costs exceed the costs contemplated in labor contracts in effect on the effective date of the restructuring statute.

Under the requirements of Section 4928.39, Revised Code, a utility filing an approved transition plan is eligible to receive the costs identified above as transition revenues.

Section 4928.37 of the Revised Code identifies two mechanisms for the recovery of transition revenues. Transition revenues are received by the utility through the payment of unbundled rates for retail electric services by those customers who receive their generation service from the electric distribution utility, and from the payment of a non-bypassable and competitively neutral transition charge by each customer who receives generation service from a competitive supplier. The structure of that transition charge is detailed in Section 4928.40, Revised Code.

Section 4928.39(D), Revised Code requires the Commission to separately identify regulatory assets, within the total transition costs, to be recovered through a separate charge. This charge is generally identified within this document as a Regulatory Transition Charge or RTC. The transition charge through which the utility may receive the remainder of the transition revenues is referred to in this report as the Competitive Transition Charge, or CTC.

Summary Description of the Applicant's Transition Revenue Plan

Generally speaking, CG&E's Transition Revenue Plan follows the design outlined in the introduction to this section. However, the Staff has found numerous areas where the Staff feels that CG&E has deviated from the intended structures, methodologies, and outcomes contemplated by Sections 4928.31 through 4928.40, Revised Code. These deviations, and the Staff's exceptions to them and recommendations for resolution are outlined in the following section.

Staff's Exceptions and Recommendations

As noted earlier, the Staff has found in its review numerous deviations from the structures, methodologies and outcomes contemplated by Sections 4928.31 through 4928.40 of the Revised Code. The Staff's discussion of these deviations is divided into Methodological Exceptions, Determination of Costs not Recoverable under Competition, Identification of Regulatory Assets, and Development of RTC Rates. This section concludes with a discussion of CG&E's proposed accounting authorizations.

Methodological Exceptions

As proposed by CG&E, the various rates and charges contemplated by Section 4928, Revised Code are calculated in the following manner:

- Retail Transmission rates were determined based on CG&E's Open Access Transmission Tariff (OATT).
- The existing rates are unbundled into Transmission & Distribution, Generation, and other charges.
- Distribution is determined by application of the Transmission rate, which is subtracted from the unbundled Transmission & Distribution rate, as discussed in Section 4928.34, Revised Code.
- OATT Ancillary Services rates were subtracted from the unbundled generation component.
- The regulatory asset charge (referred to as Regulatory Transition Charge, or RTC) is determined, per Section 4928.39, Revised Code, and also subtracted from the unbundled generation component.
- A rider was developed, that is referred to in CG&E's testimony as Rider RGR, which represents the 5% reduction on generation charges for the residential class of customers. This was developed based on the application of the 5% reduction to the unbundled generation component less the RTC.
- A rate rider to recover other transition costs is determined by identifying a revenue requirement associated with the cost of two of CG&E's generating stations (Zimmer and Woodsdale except Unit 1) that CG&E estimates is unrecoverable in a competitive market. This revenue requirement is allocated to customer classes based on a Coincident Peak (CP) demand allocator.
- CG&E proposes to update this calculation quarterly to adjust for variations in the market price for power.

As the Staff understands Section 4928, Revised Code, the determination of the various components must proceed as follows:

- The existing rates are unbundled into Transmission & Distribution, Generation, and other charges, per Section 4928.34, Revised Code.
- The FERC Transmission rate is subtracted from the unbundled Transmission & Distribution rate to determine a Distribution only rate, as is discussed in Section 4928.34, Revised Code.

- The Generation component thus identified includes all costs related to the provision of bundled generation service, whether or not they relate to transition costs as identified in Section 4928.39, Revised Code.
- One of the criteria for determining transition costs is that the costs be unrecoverable in a competitive market [Section 4928.39(C), Revised Code]. Therefore, the transition cost related component of unbundled rates is determined by subtracting an externally identified market price for power for a given class of customers.
- From the transition cost related component of unbundled rates, the regulatory asset portion, as identified in Section 4928.01(A)(26), Revised Code, is broken out, as is required by Section 4928.39(D), Revised Code.
- Should the Commission determine that a shopping incentive is required in order to create an effective market during the market development period, the transition charges must be adjusted, as is described in Section 4928.39(A), Revised Code.
- The residential rate reduction described in Section 4928.40(C), Revised Code is to be calculated on the unbundled Generation component, including transition charges, as identified in the third bullet point, above.

Therefore, the Staff takes exception to CG&E's methodology for the following reasons:

F-1. The design and determination of the transition charges proposed by CG&E is contrary to the language in Section 4928.40(A), Revised Code identifying the need for a shopping incentive as a factor in determining appropriate transition charges.

F-2. Under Section 4928.40(A), Revised Code, the transition charges must be determined in a manner that takes into account the relevant market price of power for the individual classes of customers, and must take into account the shopping incentives required to generate an effective market during the market transition period. The methodology proposed by CG&E does neither.

F-3. CG&E's calculation of the residential rate reduction described in Section 4928.40(C), Revised Code is inappropriate in that it applies the reduction to a unbundled generation component that excludes regulatory assets charges.

Determination of Costs Not Recoverable Under Competition

CG&E's determination of the generation costs not recoverable under competition include only those generating units which are expected to have costs not recoverable under competition, rather than a calculation based on a unit by unit valuation of their full generation portfolio.

CG&E has estimated that its projected transition costs from above-market generation will be approximately $563 million as of January 1, 2001. These costs are derived solely from CG&E's investment in the Zimmer and Woodsdale 2-6 generating units, for which the portion of the investment recoverable in a competitive market is claimed to be slightly more than 30% of the regulated book investment in these facilities.

F-4. The Staff takes exception with CG&E's methodology, which restricts consideration to only the above-mentioned units, as discussed elsewhere. The Staff believes that above-market generation costs should be evaluated over the entire portfolio of generating assets of a utility, not over a restricted group of assets. The Staff notes that, using the market valuations put forward by CG&E, the total amount of above-market generation costs would be less if the entire portfolio of generation assets were considered.

F-5. In addition, Resource Data International (RDI), the Staff's consultant, is in the process of conducting an analysis regarding the economic capacity values of CG&E's generating facilities. While further refinements of RDI's valuation models need to be undertaken, Staff's discussions with the consultants indicates that the economically recoverable values claimed by CG&E are, in the opinion of RDI, likely to be understated.

Staff thus takes exception to the calculations and claims of above-market generation costs contained in the transition plans. The Staff will provide specific estimates of the recoverable value of CG&E's generation facilities in testimony at the time of hearing.

Identification of Regulatory Assets

Section 4928.01(A)(26), Revised Code defines Regulatory Assets as:

> ...the unamortized net regulatory assets that are capitalized or deferred on the regulatory books of the electric utility, pursuant to an order or practice of the public utilities commission or pursuant to generally accepted accounting principles as a result of a prior commission rate-making decision, and that would otherwise have been charged to expense as incurred or would not have been capitalized or otherwise deferred for future regulatory consideration absent commission action. "Regulatory assets" includes but is not limited to, all deferred demand-side management costs; all deferred percentage of income payment plan arrears; post-in-service capitalized charges and assets recognized in connection with statement of financial accounting standards No. 109 (receivables from customers for income taxes) future nuclear decommissioning costs and fuel disposal costs as these costs have been determined by the commission in the electric utility's most recent rate or accounting application proceeding addressing such costs; the undepreciated costs of safety and radiation control equipment on nuclear generating plants owned or leased by an electric utility; and fuel costs currently deferred pursuant to the terms of one or more settlement agreements approved by the commission.

The Staff has identified a number of instances where the Applicant's determination of regulatory assets for recovery in transition revenues is incorrect, inappropriate or has been insufficiently supported. These instances are detailed below. The current basis for some of the exceptions is that the figures are inadequately supported. The provision of additional information may resolve these exceptions, or may reveal additional bases for exception.

F-6. Emissions Rider – The Staff takes exception to the inclusion of the overaccrual of temporary Emissions Fees Rider revenues in the development regulatory assets. This rider is temporary and not part of base rates. This rider will have, by all expectations, expired prior to the commencement of hearings in this proceeding. The rider itself has provisions for the recovery or refund of any under or over-accruals. In addition, the Staff's exception here is necessitated by its exception to the inclusion of the rider in the determination of the RTC.

F-7. Woodsdale Deferred Operating Expenses – The Staff takes exception to CG&E's inclusion in regulatory assets of taxes on the carrying charges related to these deferrals. The Commission's Entry in Case No. 92-946-EL-AAM explicitly stated that the carrying charges were to be calculated net of taxes.

F-8. Zimmer Deferred Operating Expenses – The Staff takes exception to CG&E's inclusion in regulatory assets of taxes on the carrying charges related to these deferrals. The Commission's Entry in Case No. 91-2290-EL-AAM explicitly stated that the carrying charges were to be calculated net of taxes.

F-9. CG&E is proposing to reflect the collection of the Ohio franchise tax and the municipal income tax in rates effective January 1, 2001. Ohio's eight investor owned electric utilities are subject to these taxes beginning January 1, 2002, with tax years ending April 30 and December 3, respectively. From the discussion above, this would represent an over-collection.

The company, however, proposes to offset this disparity by reducing the regulatory asset balance at December 31, 2000 by one full year of municipal tax expense and one-third of a year of franchise taxes.

In accordance with the recommendation made by the Staff in Part A of this report regarding the refunding mechanism for franchise and municipal taxes, the Staff recommends that no reduction be applied to the regulatory asset balance at December 31, 2000.

F-10. The rate used to calculate carrying charges on regulatory assets is excessive and inconsistent with the risk associated with recovery of these regulatory assets.

Determination of Other Items Recoverable Through CTC

F-11. The rate used to calculate carrying charges on other transition costs is excessive and inconsistent with the risk associated with recovery of these transition costs.

F-12. Working Capital Prepayments – CG&E included a working capital component in its valuation of assets not recoverable in a competitive market. As part of this component, the company seeks recovery of a prepayment allowance. The Commission has consistently ruled against this item as a component of working capital in base rate cases, and, therefore, the Staff takes exception to its inclusion.

Development of the RTC

Section 4928.39(D), Revised Code states, in part:

> Further, The commission's order under this section shall identify separately regulatory assets of the utility that are a part of the total allowable transition costs determined under this section and separately identify that portion of a transitions charge determined under Section 4928.40 of the Revised Code that is allocable to those assets,...

This section, in combination with Section 4928.01(A)(26), Revised Code, and the requirement that "...the total of all unbundled components in the rate unbundling plan are capped and shall equal during the market development period... the total of all rates and charges in effect under the applicable bundled schedule of the electric utility...including the transition charge determined under section 4928.40 of the Revised Code..." [Section 4928.34(A)(6), Revised Code] together make it clear to the Staff that the determination of the regulatory transition charge is to be based on regulatory asset balances as they appeared in the Applicant's most recent rate proceeding, including the balances of certain other assets that were identified as included in regulatory assets under this statute.

In CG&E's case, the Staff believes that this requires that the RTC be determined based upon the recovery of regulatory assets as identified in Case No. 92-1464-EL-AIR.

In light of the foregoing discussion, the Staff takes exception with the Applicant's proposals and recommends that the Commission take the following action in determining appropriate RTC rates. It should be noted that the Staff's exceptions in this section are only with regard to the inclusion of these items in the determination of appropriate RTC values. Unless noted elsewhere, the Staff does not take exception to the inclusion of these items in the determination of Transition Costs.

F-13. Emissions Rider – The Staff takes exception to the inclusion of the temporary Emissions Fees Rider in the development of the RTC. This rider is temporary and not part of base rates. This rider will have, by all expectations, expired prior to the commencement of hearings in this proceeding. The rider itself has provisions for the recovery or refund of any under or over-accruals. In addition, even if the inclusion were deemed appropriate, the Staff is of the opinion that the method of inclusion is improper, in that it creates a distortion in other charges.

F-14. Deferred PIPP Uncollectibles – The Staff takes exception to CG&Es recognition of deferred PIPP uncollectibles in the determination of its proposed RTC, as the associated revenues were determined based on test year kWh sales from Case No. 92-1464-EL-AIR, rather than the kWh sales used in determining the PIPP uncollectible rider.

F-15. Deferred EFC Balance - The Staff takes exception to CG&Es recognition of deferred EFC balances in the determination of its proposed RTC, as the associated revenues were determined based on test year kWh sales from Case No. 92-1464-EL-AIR, rather than the kWh sales used in determining the rate.

F-16. FAS 109 - The Staff takes exception to CG&E's recognition of FAS 109 costs in the determination of its proposed RTC, as CG&E utilized an incorrect figure for this part of the calculation. In addition, the Staff takes exception to CG&E's recognition of FAS 109 costs in the determination of the RTC, to the extent it is affected by other exceptions.

Applications for Accounting Modifications (AAM)

In application 99-1661-EL-AAM, CG&E requests Commission authority to establish a regulatory asset to defer incremental transition plan expenses for recovery in the Applicant's next rate case proceeding following the market development period. The Applicant requests authority to defer incremental costs related to: a) preparing the Applicant's non-competitive utility operations for customer choice, including but not limited to costs of upgrading the customer service system; b) transition plan case expenses; c) development and implementation of customer education plan; d) implementation of an independent transmission plan; e) the Applicant's share of the fees associated with the PUCO's consultant; and f) establishing an Exempt Wholesale Generator (EWG). The Applicant requests authority to accrue a carrying charge on the unrecovered balance of these deferred costs using a carrying charge rate based on the Applicant's compounded embedded interest cost rate.

The Staff's position on each of these requests is included within each discussion below.

F-17. Transition Plan Case Expenses - The Staff is of the opinion that these deferrals are appropriate, consistent with a properly updated cost calculation. These deferrals should, however, be subject to a showing of material financial impact.

F-18. Transition Cost Consultant's Fees – The Staff is of the opinion that these deferrals are appropriate, consistent with a properly updated cost calculation. These deferrals should, however, be subject to a showing of material financial impact.

F-19. Electric Restructuring Consumer Education - The Staff is of the opinion that these deferrals are appropriate. These deferrals should, however, be subject to a showing of material financial impact.

F-20. Electric Restructuring Preparation Costs - The Staff is of the opinion that these deferrals are appropriate. These deferrals should, however, be subject to a showing of material financial impact.

F-21. Midwest ISO Costs - The Staff is of the opinion that these deferrals are appropriate to the extent that they are not recovered in a FERC transmission tariff, as discussed earlier. These deferrals should, however, be subject to a showing of material financial impact.

F-22. Costs to establish an Exempt Wholesale Generator – The Staff takes exception to the deferral of these costs for recovery through future Transmission and Distribution rates. The decision by CG&E's management to develop a subsidiary was not imposed by this Commission or by the Ohio Revised Code. The costs of establishing this line of business should be recovered through the operations of that business.

In application 99-1662-EL-AAM, CG&E requests Commission authority to establish a regulatory asset to defer transition costs determined by the Commission related to the book cost of specific generating facilities in excess of their market value. The Applicant requests authority to accrue a carrying charge on the unrecovered balance of these deferred costs using a carrying charge rate based on the Applicant's currently allowed cost of capital. The Applicant requests authority to recover these transition costs and to accrue carrying charges on the unrecovered balance through the end of the Applicant's market development period. See sections F-4, F-5, and F-11 for Staff discussion of this issue.

Additionally in 99-1662-EL-AAM, the Applicant requests Commission authority to continue to defer the unrecovered balance of deferred costs that are associated with its generation-related regulatory assets (currently booked by the Applicant) until such costs have been fully recovered or until December 31, 2010. The Applicant requests authority to accrue carrying charges on the unrecovered balance of these deferred costs using a carrying charge rate based on the Applicant's currently allowed cost of capital. See section F-10 for Staff discussion of this issue.

Part G – Transmission Plan

Introduction

Section 4928.12, Revised Code requires each electric utility owning transmission facilities to be a member of and transfer control of the transmission facilities it owns or controls within Ohio to a qualifying transmission entity. To be a qualifying independent transmission entity (ITE) it must satisfy the nine specifications listed in division (B) of Section 4928.12, Revised Code and the specifications as clarified in paragraph (B) of 4901:1-20-17, Ohio Administrative Code.

Summary Description of the Applicant's Transmission Plan

Cincinnati Gas and Electric is an original member of the Midwest Independent System Operator (Midwest ISO). In the transition plan filing, the company explains how the Midwest ISO complies with the ITE rules as found in 4901:1-20-17, Ohio Administrative Code.

Staff Exceptions and Recommendations

G-1. **Plan to minimize pancaked transmission rates in Ohio -** Rule 4901:1-20-17, paragraph (B)(3) requires that a qualifying transmission entity implement policies and procedures to minimize pancaked transmission rates within Ohio. The rule requires that electric utilities under the commission's jurisdiction should either: (1) all be in one transmission entity that minimizes pancaked rates to all retail customers within Ohio; or (2) provide appropriate reciprocity requirements between Ohio jurisdictional companies that minimizes pancaking of rates within the State; or (3) propose another means to effectuate the policy objectives that call for a minimization of pancaking of rates within Ohio.

Cincinnati Gas and Electric did not address Rule 4901:1-20-17, paragraph (B)(3) in the transition plan. Staff views the Rule 4901:1-20-17, paragraph (B)(3) as an important aspect of the requirements to comply with 4928.12, Revised Code. The Commission cannot approve Cincinnati Gas and Electric's transition plan until the company complies with this section in a manner satisfactory to this Commission.

Part H - Shopping Incentive

Introduction

Chapter 4928, Revised Code, sets forth the statutory requirements for a shopping incentive first in Section 4928.40, (A), second paragraph, and again in Section 4928.37, (A)(1)(b). Section 4928.40, Revised Code, describes several factors that must be considered by the Commission in prescribing the expiration date of a utility company's market development period and the transition charge for each customer class and rate schedule of the utility, and provides that one such factor shall be, "….such shopping incentives by customer class as are considered necessary to induce, at the minimum, a twenty percent load switching rate by customer class halfway through the utility's market development period but not later than December 31, 2003. "

Chapter 4928, Revised Code, goes on to limit the potential amount of the shopping incentive by mandating that, "in no case shall the Commission establish a shopping incentive in an amount exceeding the unbundled component for retail electric generation service set in the utility's approved transition plan under section 4928.33 of the Revised Code, and in no case shall the Commission establish a transition charge in an amount less than zero." In Section 4928.40 (B)(2), Revised Code, satisfactory shopping incentive results (a 20% shifting of load from the incumbent in each customer class, as noted above) are referred to as one cause for the Commission to consider ending the market development period.

The shopping incentive is further elaborated in Section 4928.37, (A)(1)(b), Revised Code, where notice is given that, "additionally, as reflected in section 4928.40 of the Revised Code, the transition charges shall be structured to provide shopping incentives to customers sufficient to encourage the development of effective competition in the supply of retail electric generation service."

This section of the staff report is focused on evaluating the Applicant’s proposed plans for migrating 20% of the customer load from each customer class away from the incumbent to other suppliers of electricity per the mandates of Chapter 4928, Revised Code. Staff will review the Applicant's proposed shopping incentive plan in the context of the development of incentives to induce 20% of the load in each customer class to switch suppliers.

The Shopping Incentive Plan Proposed by the Applicant

The Applicant describes its proposed "Shopping Incentive Plan" (Plan) in Section H of its Transition Plan filing. Dr. Richard Stevie presents testimony in support of the Applicant's shopping incentive plan.

CG&E states that their research indicates that, "no shopping incentive is required in order to achieve a 20% level of switching by December 31, 2003" (Plan at page 15-16). Using customer satisfaction studies to project customer willingness to switch suppliers, levels of switching in other states, and a load switching forecast methodology that employs conjoint analysis to estimate how many customers would choose a competitive supplier's offer, the Applicant has projected that, "22.7% of the residential, 52.1% of the commercial, 89.5% of the industrial, and 69.0% of the government load, as measured by energy consumption, is expected to switch by the end of 2003" (Plan at page 15). Consequently, CG&E, "recommends that, at least initially, no shopping incentive be given to customers who switch" (Plan at page 16).

The Applicant suggests that, "(i)f marketers, competing on a level playing field, can offer some modest level of incremental value (e.g., about 2%) as perceived by customers, a sufficient number could reasonably be expected to switch their load without a shopping incentive" (Plan at page19). CG&E goes on to "encourage" the Commission, "to require marketers, whether through operational efficiency, aggressive marketing or innovative new energy products and services, to deliver real, substantive and incremental value in order to benefit Ohio consumers and grow market share" (Plan at page 19). The Applicant concludes that new market entrants should not be subsidized.

The Applicant does recommend, however, that if their switching forecasts prove to overstate the actual levels of customer switching over time, "the Commission should intervene to prompt further switching" (Plan at page 20). CG&E proposes that before the Commission implements any shopping incentive it should first "consider foregoing the 5% decrease in the unbundled generation component for residential customers, as authorized by R.C. 4828.40(C)," reasoning that,"(t)he 5% residential rate represents a significant barrier to entry into the competitive retail electric market." After the 5% residential rate reduction is ended, and switching levels remain significantly below the Applicant's forecasts, CG&E proposes that a shopping incentive be implemented in the following manner:

> If the level of switching in a given customer class is less than 10% by July 31, 2002, the shopping incentive is to be set at 2% of the unbundled generation rate for that customer class.
>
> If the level of switching in a given customer class is less than 15% by January 1, 2003, the shopping incentive is to be set at 5% of the unbundled generation rate for that customer class. (Applicant's Plan at page 21).

CG&E reasons that the above levels of shopping incentives would be adequate to achieve a 20% level of customer switching across all customer classes. The Applicant goes on to recommend that any shopping incentive that is implemented for a particular customer class be structured as a separate rider for that class only. This will allow the Applicant, "to realign or separate the tariff schedules according to customer class so that there is a one-to-one correspondence (instead of a one-to-many)" (Plan at page 22). Finally, the Applicant proposes that, once the target 20% level of switching is achieved in a customer class, any shopping incentive that was in place be eliminated.

Staff Exceptions and Recommendations

H-1. The Staff takes exception to the fact that the Applicant has not proposed shopping incentives as an initial part of its transition plan filing. CG&E shifts the responsibility to the new entrant marketer to provide the "incentive" for customers to switch through "real, substantive and incremental value" in their product offerings. Staff understands Section 4928.40, Revised Code, to require the Applicant to propose, as part of its transition charge structure, a shopping incentive sufficient to induce, at the minimum, 20% of load in each customer class to switch suppliers by the midpoint of the market development period. It is Staff's opinion that Section 4928.40, Revised Code, establishes that particular level of customer switching and the time frame to both encourage customers to choose alternative providers and to encourage the development of effective competition in the supply of retail electric generation service in the Applicant's service territory, notwithstanding any "innovative new energy products and services" offered by new entrant suppliers.

The Applicant's argument that "(r)egulators must focus on introducing efficient competition in retail electricity markets" (Plan at page 16) does not necessarily comport with Chapter 4928.40, Revised Code, at least for the market development period. The legislature specified that an incentive be considered such that 20% of the customer load of each customer class switch from the incumbent. It is implicit in the implementation of this consideration that the motivation to switch takes precedence over market signals and forces during the market development period. The legislature has spoken on the need to stimulate the marketplace by requiring an incentive. The economic arguments miss the point. Switching is primary and the economic efficiency of the marketplace is secondary insofar as Chapter 4928, Revised Code is concerned.

H-2. Staff has concerns with the Applicant's plans to wait until July 31, 2002 to implement shopping incentives. The Staff is not convinced that the Applicant has demonstrated that its proposal will result in 20% of the load of all customer classes switching suppliers by the midpoint of the market development period. CG&E projections that large numbers of customers in all classes will switch suppliers with 2% savings does not comport with the majority of empirical evidence from states where competition in the retail generation market has been implemented. Staff believes that any waiting to implement a shopping incentive would handicap the potential for customer switching and would put the Applicant at risk in its mandate to achieve the 20% target, especially for residential and small commercial customers.

H-3. The Staff recommends that the Applicant identify and implement an adequate shopping incentive from the beginning of the market development period in order to ensure a 20% switching rate for each customer class by the midpoint of the market development period. The Applicant's proposed transition plan fails to adequately demonstrate that providing no shopping incentive and putting the onus on competitive service providers to bring the value to the market to induce customers to switch will attain the customer switching goals that are clearly defined by Chapter 4928, Revised Code.

Part I - Potential Structural Impediments to Retail Competition

Introduction

In this section of the report, Staff addresses issues that are structural in nature and may impede customer choice or the development of effective competition in the provision of electric generation services in Ohio. The exceptions and Staff recommendations discussed here are intended to complement Staff recommendations found elsewhere in this report.

Transmission Requirements

CG&E's proposed plan for transmission requirements is described in direct testimony by Applicant witnesses John C. Procario and Paul K. Jett. Witness Procario states that the Applicant will transfer functional control of its transmission facilities over 100 kV and related facilities to the Midwest Independent System Operator (ISO). The Midwest ISO will calculate and disseminate available transfer capability (ATC) for the system and process users' requests to reserve transmission service. The Midwest ISO is not currently operational but is scheduled to become operational in 2001. *Procario Testimony* at 8-10, 12.

The Midwest ISO Open Access Tariff (MISO OATT) applies to customers or loads once those customers have the option to choose different suppliers. Whether the customer chooses a new supplier or not, the same tariff applies. If retail customers have choice but choose to continue to purchase power from the transmission owner, the transmission must take service from the Midwest ISO. *Id.* at 29-31. For the purpose of charging the MISO OATT Cost Adder, CG&E native load customers, regardless of whether they exercise their rights under the legislation to obtain their generation supply from another source, are considered "native load customers" at the outset of customer choice in Ohio. *Id.* At 51

The MISO OATT is intended to prevent network customers from tying up interfaces throughout the Midwest ISO (thereby reducing the ATC available for firm transmission) by giving them full unrestrained rights only to the interface capacity associated with the control area where the load is located. *Id.* at 45. According to witness Procario, any FERC jurisdictional transmission provided by CG&E to or for retail customers in Ohio after December 31, 2000, must be provided pursuant to the CG&E Open Access Transmission Tariff (CG&E OATT) in effect on the date of approval of the CG&E Transition Plan.[3] *Id.* at 53.

Applicant's witness Paul K. Jett states the purpose of his testimony is to explain the "switching rules that CG&E has established to govern procedures for an end-use customer to switch from CG&E's service to a Certified Supplier." Witness Jett also addresses transmission service under CG&E's current OATT, but only with regard to planned changes to Schedule 4 on energy imbalance services. *Jett Testimony* at 3.

[3] The CG&E OATT is presented as Exhibit PKJ-1 identified in the Direct Testimony of Applicant witness Paul K. Jett at 5.

Governmental Aggregation Program Customer Enrollment

In accordance with Section 4928.20 (D) Revised Code, the electric loads of residents and businesses located in municipal corporations, townships, or unincorporated areas of counties where electors approve passage of a ballot issue for automatic enrollment in a governmental aggregation program, are combined for the purpose of being served by competitive electric retail service until a person so enrolled affirmatively elects by a stated procedure not to remain so enrolled. Under section 4928.08, Revised Code, a governmental aggregator is subject to certification by the PUCO to the extent that it supplies a competitive retail electric service, but not transmission or distribution service through facilities in which it has some form of ownership. CG&E's proposed plan addresses governmental aggregation only if the governmental aggregator negotiates an agreement with a third-party "certified supplier:"

> Under the Electric Restructuring Bill, governmental aggregators may aggregate their load and negotiate an aggregation agreement with a Certified Supplier for energy supply. The Certified Supplier would enroll each aggregated end-use customer electronically through the use of the enrollment DASR [Direct Access Service Request] CG&E will provide information to governmental entities about aggregation and related end-use customer enrollment. In cases of governmental aggregation, CG&E will continue to provide transmission and distribution, default supply and energy imbalance service. *Operational Support Plan* at 28.

The CG&E DASR is described as requiring the Certified Supplier to "maintain records verifying that the end-use customer has authorized the Certified Supplier to enroll the end-use customer." *Id.* at 17.

Governmental Aggregation Program "Opt-out" Provision

Section 4928.20(D) Revised Code regarding governmental aggregation provides that "any person enrolled in the [automatic enrollment] aggregation program the opportunity to opt-out of the program every two years, without paying a switching fee…[and] default to the standard service offer provided under division (A) of section 4928.14 or division (D) of section 4928.35 of the Revised Code until the person chooses an alternative supplier." CG&E witness Paul K. Jett, however, states:

> An end use customer may voluntarily return to CG&E's standard service offer after being taken off CG&E's service by his or her Certified Supplier providing CG&E notice during October of any year of his or her intent to return to CG&E's service. The end-use customer will return to CG&E's standard offer rate, effective at the next regularly scheduled meter read date and will be required to remain on this rate for the next 24 billing cycles. *Testimony* at 12.

Staff Exceptions and Recommendations

I-1. Staff takes exception to the failure of the Applicant's proposed plan to address how transmission capacity calculated for delivery of the Applicant's generation to its standard offer service customers will be released for access by the customers or by certified suppliers to use on behalf of customers who migrate away from the standard offer. When the Applicant's obligation to serve energy to native load customers is converted to arrangements between those customers and certified suppliers, the capability to deliver that service must "follow the customer." Not to do so discriminates against the customers who switch to certified suppliers and denies them the comparable access to transmission capacity to satisfy their electricity requirements from a certified supplier promised by Substitute Amended Senate Bill 3 (S.B.3):

> [b]eginning on the starting date of competitive retail electric service and notwithstanding any other provision of law, each consumer in this state and the suppliers to a consumer shall have comparable and nondiscriminatory access to noncompetitive retail electric services of an electric utility in this state within its certified territory for the purpose of satisfying the customer's electricity requirements. Section 4928.03, Revised Code.

There is a finite amount of transmission capacity in Ohio which is scarce during peak periods. Under the arrangements cited above in witness Procario's testimony, full unrestrained rights will be given to network customers for the interface capacity associated with the control area where the load is located. A potential problem may exist, however, when retail customers' requirements for transmission facilities at these interfaces change due to changes in sources of supply. Under competitive retail electric service, network delivery from the Applicant's control area generation to the customer's load may be replaced by network delivery to customer's load from alternative sources. This network delivery to load inside the CG&E control area will still require access to the interface capacity associated with the CG&E control area. For that reason, Staff recommends the activation of the Network Operating Committee described in Section 35.3 of the CG&E OATT or, alternatively, an Ohio commission-sponsored collaborative approach, to negotiate procedural solutions for access to these CG&E-associated interface capacity rights by certified suppliers serving CG&E native load.[4]

[4] The stated purpose of the Network Operating Committee (Committee) is to coordinate operating criteria for the Parties' respective responsibilities under the Network Operating Agreement. The Cinergy OATT states that each Network Customer shall be entitled to have at least one representative on the Applicant's Committee, which is to meet from time to time as need requires, but no less than once each calendar year. Cinergy OATT First Revised Sheets No. 126-127 at 35.3.

The Network Operating Committee or the alternative Ohio-commission-sponsored collaborative should be given the opportunity to negotiate fair and non-discriminatory procedural “rules of the road” for releasing network capacity to accommodate the Applicant’s standard offer customers in Ohio who migrate to certified suppliers. Pricing of such released capacity should conform to FERC rules and the standards for sale, assignment or transfer of transmission service suggested by Section 23.1 of the CG&E OATT.

I-2. “Enrollment issues” are being discussed in the Operational Support Workgroups. Staff defers its recommendation on this issue pending the outcome of the workgroups and reserves the right to offer comments and testimony on this issue in the hearing of this case or other appropriate forum.

I-3. “Return-to-standard-offer issues” are being discussed in the Operational Support Workgroups. Staff defers its recommendation on this issue pending the outcome of the workgroups and reserves the right to offer comments and testimony on this issue in the hearing of this case or other appropriate forum.