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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Approval of Ohio Site Deployment of the Smart Grid Modernization Initiative and Timely Recovery of Associated Costs.	:	Case Nos. 09-1820-EL-ATA 09-1821-EL-GRD 09-1822-EL-EEC 09-1823-EL-AAM

COMMENTS
SUBMITTED ON BEHALF OF THE STAFF OF
THE PUBLIC UTILITIES COMMISSION OF OHIO

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January 13, 2010

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INTRODUCTION

On December 30, 2009, an entry was issued inviting all interested stakeholders to submit written comments on FirstEnergy's application for approval of the proposed Ohio Site Deployment (OSD) and related matters. The OSD was part of FE's Smart Grid Modernization Initiative filed several months earlier with the U.S. Department of Energy. Under the aforementioned entry, initial comments on the application are due on January 13, 2010, and reply comments are due on January 20, 2010. The comments that follow are timely submitted on behalf of the Staff of the Public Utilities Commission of Ohio (Commission).

BACKGROUND

The Applicants, The Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company (the "Companies") have asked the Commission approve their OSD pilot program proposed as described in the connection with FirstEnergy's Smart Grid Modernization Initiative filed with the U.S. Department of Energy as a result of the Smart Grid Investment Grant Program (SGIG). Such projects are eligible for funding for up to 50% of the eligible costs. In this case, the Ohio based FirstEnergy distribution companies are eligible to receive up to $36.1 million or 50% of their projected OSD project costs of approximately $72.2 million.

As filed on July 1, 2009, the Companies' confidential Exhibit 1 does not reflect a complete smart grid business case. Typically, smart grid business cases include estimated utility operational costs savings as well as some estimated customer driven savings. Because this is a limited pilot effecting only up to 5% of the Companies' Ohio customers, the Staff does not believe there will be a large amount of operational savings, *e.g.* reduced number of meter readers, reduced call center calls etc. However, if some operational cost savings occur during the pilot, then such cost savings should be credited against the rider. If the Companies were to apply to proceed with a much larger scale smart grid rollout beyond the size of this pilot project, the Staff recommends that the Companies file a complete and robust business case, including estimates for all of the benefits associated with the rollout.

The Staff's comments and recommendations follow.

COMMENTS

A. Advanced Metering Infrastructure

1. Advanced Meters and Labor Costs

Staff has reviewed the Companies' proposed advanced meter and meter material costs. The costs of the meters as proposed are expected to be $400 plus an additional amount of meter material costs at $50 per meter. Staff's review of various metering sources indicates that single phase advanced meters typically cost $110 to $125. Included in the Companies' metering costs will be enabling technology, *i.e.* programmable thermostats which currently cost in the range of $250 - $275.[1] The bulk of the Companies' deployment will be to residential and small commercial customers. However, it is unlikely that all of these customers will adopt the Companies' enabling technology and, therefore, that the Companies' metering and metering material costs will not likely rise to the level of $450 per endpoint for all 44,000 customers in the pilot.

An additional amount for contract labor to install the meters and enabling technologies, educate customers about the use of the enabling technologies and perform meter data management is estimated to cost approximately $461.27 per meter.[2] Labor costs of this magnitude seem rather excessive since meter switch outs typically do not take that long, *i.e.* 30 minutes. The Staff does not know how long it will take to install the programmable thermostats and other enabling technologies, but it is unlikely that it

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1 From oral discovery with FE personnel on January 11, 2009.

2 Derived from FE's Budget Costs Table from Staff Data Request 1.

would take the entire day. The Staff does understand that there are other associated costs with the customer's selection and education pertaining to the use of the in-home enabling technologies which could be significant. Customers can choose either a programmable thermostat, an in-home dispay, an in-home dispay with a power switch or just the power switch. Educating every customer how to manage their electrical use in the pilot regarding the use of these in-the-home technologies will take time. In addition, the Companies have included the management of meter data under the category of contractual meter costs in their filing. All the contractual meter costs associated with this aspect of the pilot assume that all 44,000 customers will receive an advanced meter and participate in the use of some form of in-the-home enabling technology during the pilot.

The total all-in proposed meter costs, enabling technology, installation, education and meter data management are estimated to be $41,215,580. Based on the 44,000 customer rollout for the 3-year pilot, the total costs for the advanced metering infrastructure would be approximately $936.72 per endpoint. The Staff is concerned with the overall level of these costs for this pilot project. The Staff recommends that only those actual costs that are found to be reasonably incurred and are incremental as part of the pilot project should be recovered through the Revised Rider AMI.

2. Momentary Interruption Data

The Commission in its Finding and Order and Entry on Rehearing in Case No. 06-653-EL-ORD[3] directed Staff to continue to monitor the ability of electric utilities to accurately measure and report the momentary average interruption frequency index (MAIFI)[4] and to make recommendations with respect to momentary interruptions and their impact on customers. MAIFI can be used to measure momentary interruption frequency for each distribution circuit and across an electric utility's distribution system. In its Finding and Order, the Commission declined to require the electric utilities "to take steps necessary to manually gather MAIFI information throughout its system and report it,"[5] but noted its awareness that "as technology is deployed throughout the electric distribution systems, this information will become more accurate and widely available."[6] In its Entry on Rehearing, the Commission further stated that "it would be imprudent for the electric utilities to make investments to improve MAIFI accuracy without taking the time to consider integrating such improvements with other potential programs such as an automated metering infrastructure and/or distribution automation".[7]

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3 *In the Matter of the Commission's Review of Chapters 4901:1-9, 4901:1-10, 4901:1-21, 4901:1-22, 4901:1-23, 4901:1-24, and 4901:1-25 of the Ohio Administrative Code* , Case No. 06-653-EL-ORD (hereinafter "In re Commission Review") (Entry on Rehearing at 10) (May 6, 2009); *In re Commission Review* (Finding and Order at 14) (November 5, 2008).

4 MAIFI = the total number of customer momentary interruptions divided by the total number of customers served.

5 *In re Commission Review* (Finding and Order at 14) (November 5, 2008).

6 *Id.*

7 *In re Commission Review* (Entry on Rehearing at 10) (May 6, 2009).

In response to this Commission directive, Staff inquired of FirstEnergy (FE) the extent to which the new smart meter technology will be used to compile momentary interruption data to compute MAIFI performance at the circuit and distribution levels. Based on data request responses[8], Staff understands that FE will be able to use its new technology to compile momentary interruption data from smart meters. Staff recommends that FE utilize this ability and proceed with the accumulation of customer-specific momentary interruption information in a database suitable for future analysis.

B. Smart Grid Plan (Distribution Automation and Voltage/Var Control)

The Smart Grid portion of the Companies' OSD involves providing distribution automation (DA) and voltage/VAR control (VVC) over a three-year period to 34 distribution circuits served by 14 substations and directly benefitting 44,000 customers in the Cleveland Electric Illuminating (CEI)'s service territory. This plan relies on the concurrent implementation of a communications[9] and data infrastructure that would also support the AMI portion of the OSD as discussed in the previous section. The Companies' application states that the planned DA implementation would improve electric reliability by reducing the system average interruption duration index

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8 *See* FE's Responses to Staff Data Requests 2 and 7.

9 The communications infrastructure would be installed over the first two years.

(SAIDI) by 30 percent for the targeted circuits as a group.[10] The application also states that the VVC implementation will reduce energy losses and peak demand and help establish a more consistent voltage profile on each of those circuits as well.[11] Finally, the application states that lessons learned from the OSD would "be evaluated in determining whether to expand the technology on a broader scale, potentially across all three service territories."[12]

1. Staff's Investigation of DA/SA Project Scope & Design Criteria

a. Ohio Site Deployment

The Companies in their application state "[t]he Ohio Site Deployment has been targeted to include a particular geographic area located in CEI's service territory comprised of a mix of residential and commercial customers."[13] One of Staff's objectives in reviewing the Companies' application was to evaluate the DA and SA project scope, assumptions and the design criteria used by the Companies for its Smart Grid pilot project. Staff's evaluation began with an investigation of the project area selected by the Companies' for the OSD, and included an analysis of the following information:

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10 *In the Matter of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Approval of Ohio Site Deployment of the Smart Grid Modernization Initiative and Timely Recovery of Associated Costs*, Case No. 09-1820-EL-ATA, *et al.* (Application at 36, Ex. B, Fig. 1.6.3-2) (November 18, 2009).

11 *Id.* at 5 and 6.

12 *Id.* at 3.

13 *Id.* at 4.

- Substation and circuit identification of the 34 circuits and 14 substations located in CEI territory selected for the pilot project.
- Physical characteristics and total circuit miles for each of the 34 circuits selected in the pilot project area (OSD).
- 2008 CAIDI (customer average interruption duration) and SAIFI (system average interruption frequency) indices for the 34 circuits selected.
- Projected CAIDI and SAIFI indices for the 34 circuits selected upon completion of distribution automation.
- A map of the area showing the topology in which the Ohio Site Deployment will be implemented.

In response to Staff data requests, the Companies maintained that the OSD project area was chosen primarily to meet the criteria of the U.S. DOE SGIG Program requirements. According to the SGIG program document submitted to Staff, an eligible Smart Grid project must meet the DOE's criteria which include the following:[14]

1) The ability to sense and localize disruptions or changes in power flows on the grid and communicate such information instantaneously and automatically for purposes of enabling automatic protective responses to sustain reliability and security of grid operations;

2) The ability of any appliance or machine to respond to such signals, measurements, or communications automatically or in a manner programmed by its owner or operator without independent human intervention;

3) The ability to use digital information to operate functionalities on the electric utility grid that were previously electro-mechanical or manual; and,

4) The ability to use digital controls to manage and modify electricity demand, enable congestion management, assist in voltage control, provide operating reserves, and provide frequency regulation.

The Companies in its applications state its "distribution automation technology has the potential to improve service reliability for customers by reducing the number of custom-

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14 U.S. DOE Financial Assistance Funding Opportunity Announcement at 14.

ers affected by sustained outages and enabling more rapid fault isolation and repair."[15] Staff agrees that the implementation of the Companies' DA and SA program provides the opportunity for remote sensing and control such that customer outages may be shortened and automatically and/or remotely controlled. Staff also recognizes that implementation of the Companies' proposed VVC system may reduce voltage variation on distribution feeders and increase the efficiency of the distribution system through increased power factor. Increased efficiency of the distribution system in effect delays the need to increase system capacity through other means such as larger conductors, transformers, circuit breakers, and other circuit devices.

In addition to meeting the DOE program criteria, the Companies maintain that the OSD project area was selected because the existing infrastructure was capable of implementing DA and SA without requiring major upgrade work to the lines or substations. Further, the majority of the substations selected are supplied from the Companies' 138kV transmission system allowing DA to function for most outages. The project area also has a semi-rural make-up where the circuits are longer with more exposure but still have large pockets of customers. Finally, due to the added circuit lengths and the large customer counts, reliability has been an issue for many of the customers.

Staff agrees the OSD project area selected by the Companies provides a desirable mix of residential and commercial customers in a suburban setting. The circuits selected

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15 *In the Matter of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Approval of Ohio Site Deployment of the Smart Grid Modernization Initiative and Timely Recovery of Associated Costs*, Case No. 09-1820-EL-ATA, et al. (Application at 5) (November 18, 2009)

operate at a standard distribution voltage and are capable of supporting Smart Grid functionality without requiring major infrastructure investment such as installing larger conductors or transformers. Lastly, the area is particularly well suited for automated restoration due to the long circuit lengths and high customer concentrations in some areas. Thus, Staff agrees that the area selected for the pilot smart grid project is appropriate.

Staff also examined a breakdown by circuit of the field devices to be installed as a part of DA. For example, Staff investigated the Company's criteria and assumptions used to estimate the number of field devices required for each circuit. According to the Company, circuit topology dictated the locations for most recloser installations. According to the Companies, the project's PODs (Premium Operating Districts) were limited to 800 customers where-ever possible. For most circuits this meant that the design included three PODs per circuit, two reclosers per circuit with a common open recloser between adjacent POD circuits.[16]

[16] *See* FE's response to Staff Data Request 6.

For the capacitors, the Companies assumed that existing switched capacitor banks would have their controls upgraded for the VVC system. Additional capacitors are also being added to circuits to allow system Power Factor to be corrected to unity.[17] The DOE Stimulus package proposal also included the possibility of installing two sets of three-phase line-voltage regulators. The Companies' preliminary analysis indicates that these regulators are not needed for system voltage performance, but were included in the DOE project, with the objective of getting experience with the integration of such devices on future systems where they may not be optional. Primary line-voltage sensors will be installed as needed to ensure adequate real-time system voltage monitoring (*i.e.*, 5 per circuits).[18]

Relative to design criteria, Staff also evaluated when pole replacement is needed as a result of DA implementation. According to Company data request response, whenever possible, existing poles will be used for equipment locations. However, where required due to pole condition, height, pole class, or where existing pole are insufficient, the poles will be replaced. A conservative assumption was made that new poles will be needed for all of the recloser installations due to new construction standards. For new capacitor installations it was assumed that existing poles will be used. According to the

17 A Power Factor of one or "unity power factor" is a characteristic of a distribution circuit operating in its most efficient state. At unity power factor, real power (useful energy available to a customer) and the apparent power (actual energy supplied by the utility) are equal.

18 *See* FE's response to Staff Data Request 6.

Companies, not until final engineering is completed will the exact number of pole replacements be determined.[19]

Staff's believes the equipment and field devices selected by the Companies to be installed as part of DA are appropriate for the pilot project. In addition, Staff concludes that the assumptions and design criteria used to select reclosers, regulators, poles, capacitors, and VVC to be installed as a part of DA appear reasonable.

Another Staff objective was to investigate the different types of maintenance activities that will be required to maintain the new equipment associated with DA. According to the Companies, the routine inspection of the reclosers will be done annually as part of their current recloser maintenance and inspection program. Routine inspection of the remote terminal unit (RTU) interface will be performed twice annually. The routine inspection of the capacitors will be done annually as part of the Companies' current capacitor inspection program. The DA Master will be housed in a server connected to the Companies' network and will be maintained by IT in the same fashion as are all the Companies' servers. The system model will be maintained by CEI Planning & Protection personnel and updated as necessary to reflect permanent topography changes. Maintenance of devices similar to those already in service (reclosers, regulators, capacitors) will be the same as the non-DA versions of these devices. Distribution line voltage sensors are autonomous devices that would not impact system reliability should they fail. These are electronic devices, with real-time communications and no batteries, will not be

19 *See* FE's response to Staff Data Request 6.

included in an equipment specific maintenance program. The failure of such devices will be automatically reported by the VVC system, and repaired or replaced. Staff concludes at this time that the planned maintenance activities for the different types of new equipment associated with DA appear reasonable for the proposed pilot program.[20]

Staff also investigated the design of the dedicated controller(s) that are to be installed to control field devices associated with VVC. One of Staff's objectives was to determine where and how many capacitor switches are placed on each circuit. According to responses to Staff data requests, the integrated VVC will likely control "all" distribution line capacitors on the area circuits. A few unstitched capacitors may remain in service, but to maximize control and flexibility, all units would be controlled. To maximize the learning potential of an area, some existing unstitched capacitor banks may remain in service so the effects of integration with legacy circuit configurations can be more fully evaluated.[21]

The Companies assert there would be sufficient capacitors on each circuit to fully compensate for the VAR loading on the distribution systems. Capacitor numbers and the sizes will be determined after advanced metering is placed in substations and sufficient data is collected during the summer (peak-load period) of 2010.[22] Staff believes at this time the design of the controllers, the number of switches and their locations are reasonable.

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20 *See* FE's response to Staff Data Request 6.

21 *Id.*

22 *Id.*

Staff also investigated the proposed Substation Relay-based Protective Strategies. The Companies were asked to justify the single phase tripping, adaptive ground-fault protection, and high-speed bus differential protection strategies being implemented at nine of the incorporated substations. Staff also wanted to know why only nine of the fourteen substations are being implemented.[23]

According to the Companies, it is estimated that between 50 and 75 percent of feeder faults involve only a single phase, while only 10 to 15 percent involve three-phase. Further they maintain that traditional distribution feeders have been equipped with three-phase fault interrupters and thus as many as two-thirds of customers could be affected unnecessarily by a single-phase fault. The single phase tripping allows the Companies to isolate the smallest portion of the system possible to clear a fault. Finally, the Companies states that many utilities have been reluctant to consider single-phase tripping on the main three-phase line for a number of reasons, including a desire to protect three-phase loads, difficulty coordinating devices along the feeder, and a loss of sensitivity of the protective device for low-magnitude faults. Staff agrees with the Companies' statements and concludes that the use of single phase tripping is appropriate for this project.

The Companies propose to utilize adaptive ground-fault protection. The purpose is to mitigate an adverse result from the single phase tripping in the creation of

[23] *See* FE's response to Staff Data Request 6.

unbalanced load current (ground current). Utilizing local and remote information dynamically will control sensitive ground protection allowing the single phase tripping.[24]

The Company also proposes to use high-speed bus differential protection.[25] The bus differential protection is designed to identify/isolate any bus faults to minimize damage to expensive equipment inside the substation. The Companies contend that this is essential protection for critical substations even though smaller distribution stations do not typically have costly high-speed bus differential protection. Traditional high-speed bus differential protection is performed by a dedicated differential relay and dedicated controls and sensors. The proposed high-speed bus differential protection utilizes the existing overcurrent feeder relays and a logic processor to create the high speed bus differential protection scheme. The Companies believe that making this a part of the DA scheme will help in the identification and isolation of only the faulty part of the Smart Grid. Staff agrees that the use of high-speed bus differential protection is an appropriate part of the pilot project.

Finally, the Companies state that only nine of fourteen substations are being fully (all feeders) implemented into the DA scheme because the other five stations either have differential protection already or it is not needed for DA at this time.

In response to a data request question, the Companies indicate that it will not make projections for what changes may occur in the CAIDI and SAIFI indices following

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24 *See* FE's response to Staff Data Request 6.

25 This protection scheme clears damaging high fault currents quickly to minimize equipment damage.

completion of the project for the 34 circuits.[26] The Company estimated 30% SAIDI improvement on the selected circuits is based on historical circuit events and information available from other utilities that have implemented similar distribution system improvements.[27] They state that the estimated 25% to 30% savings in customer minutes of interruption (CMI) is an often quoted impact value for DA. Following the completion of the project and when the system is fully tested and enabled, the Companies anticipate the capability of similar performance benefits but have no specific prediction of the exact impact to the indices. Staff understands that it may be impractical to project CAIDI and SAIFI indices on a per circuit basis. However, Staff believes that setting target values for these indices in the project area is still appropriate. Staff recommends that the Companies set target values for CAIDI and SAIFI in the project area and report to Staff at the completion of the pilot project.

2. Analysis of Smart Grid Costs

Staff analyzed the Companies' planned Smart Grid costs to determine their relative size compared to the other major cost components of the OSD and also to identify the major drivers of cost within each of the DA and VVC components. The result of this analysis is presented the following tables, which indicate gross projected costs before any DOE reimbursement.

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26 *See* FE's response to Staff Data Request 6

27 *Id.*

Table 1 -- OSD Cost Components		
Smart Grid (DA+VCC)	$ 15,455,439	21%
AMI	$ 41,215,580	57%
Common	$ 15,528,957	22%
Total	$ 72,199,976	100%

As Table 1 indicates, the Smart Grid portion (DA and VCC), excluding common costs,[28] constitutes only 21 percent of the total projected OSD costs.

Table 2 -- Smart Grid Cost Components		
Distribution Automation	$ 10,590,728	69%
Voltage/Var Control	$ 4,864,711	31%
Total	$ 15,455,439	100%

Table 2 shows that the larger portion (69 percent) of the Smart Grid costs relate to DA, while only 31 percent of these costs relate to VVC.

28 Common costs include communications, project management, cyber security, and data integration/acquisition.

Table 3 -- DA Cost Components			
FE Personnel	$	989,430	9%
Equipment	$	4,633,488	44%
Contractor	$	4,967,810	47%
Total	$	10,590,728	100%

Table 3 lists the DA cost components and indicates that over 90 percent of these costs are divided fairly evenly between equipment and contractors.

Table 4 -- VVC Cost Components			
FE Personnel	$	827,060	17%
Equipment/Supplies	$	1,969,164	40%
Contractor	$	2,068,487	43%
Total	$	4,864,711	100%

Table 4 lists the VVC components and indicates that over 80 percent of these costs are divided fairly evenly between equipment/supplies and contractors, while only 17 percent relate to the Companies' personnel.

In summary, Tables 1 through 4 indicate that the Smart Grid programs for DA and VCC constitute only a minority of total project costs, that DA is the primary Smart Grid cost component, and that the Smart Grid costs are driven mostly by equipment and contractors. Staff focused its review, therefore, on the Companies' DA and VVC cost estimates for equipment and contractors. The Companies developed its cost estimates using vendor quotations, vendor price lists, engineering estimates based on historical price information and on known price algorithms (*e.g.*, cost per mile).[29] Staff reviewed the detailed worksheets the Companies used to develop its estimates and where possible, compared the unit prices of selected equipment against estimates for similar projects. Based on its review, Staff considers the Companies' Smart Grid cost estimates for DA and VVC appear reasonable for the pilot program. Staff will be reviewing the actual costs of this project, and expects that those actual costs will be more accurate for estimating the costs of any subsequent Smart Grid deployment across the remainder of the Companies' Ohio service territories.

C. Cost Accounting

The Companies should keep the accounting records for the actual OSD costs separate to facilitate review and verification.

Smart Grid Initiative costs included in this proceeding for recovery through Revised Rider AMI should be incremental to costs included in CEI's base rates. The Companies should demonstrate that any CEI labor costs incurred for the OSD represents the incremental cost. Also, the recoverable cost of newly installed Smart Grid plant that replaces existing plant should be the cost of the new plant less the net book value of the replaced plant.

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29 *See* FE's response to Staff Data Request 1.a.

The Companies propose that Revised Rider AMI provide for quarterly rather than annual cost recovery. Staff recommends true-up to actual costs occur no more frequently than annual to allow enough time and data for a more meaningful analysis.

The Companies further propose to fully recover costs under Revised Rider AMI over a period not to exceed one year from the date of the expenditures. Staff recommends that cost recovery for capital assets occur over the used and useful life of those assets. Should the Commission allow the Companies to recover Smart Grid capital cost on an accelerated basis as proposed, the book value should reflect zero at the end of the recovery period.

The Companies should report to the Commission its assessment results of the information and outcomes gained from the initial 5,000 meter deployment.

Staff recommends that the Commission allow carrying charges on deferred balances using the most recent Commission approved cost of debt rate component included in the rate of return calculation used in a CEI proceeding.

D. Revised Rider AMI

Rider AMI was established in Case No. 07-551-EL-AIR as the "Advanced Metering Infrastructure/Modern Grid Rider." The rate was set at zero cents per kwh in each of the Companies' tariffs.

In the instant Application, the Companies propose a Revised Rider AMI to recover one-half of its "Ohio Site Deployment" costs associated with its "FirstEnergy Smart Grid Modernization Initiative." A uniform rate of 0.0273 cents per kwh is proposed for all rate schedules of OE, CEI, and TE, with the exception that the rate not apply to Rate GT (General Service - Transmission) customers.[30]

Staff has reviewed Revised Rider AMI and offers the following comments. First, Staff recommends the rate be developed based on the Staff's recommended revenue requirement for this initiative. Secondly, Staff believes the AMI charge should be a fixed monthly charge rather than a usage-sensitive charge as proposed by the Companies. Staff does not believe there are any substantial AMI/Smart Grid costs that vary with energy usage. Accordingly, Staff recommends that 100% of the AMI/Smart Grid revenue requirement be recovered through fixed, monthly charges.

Lastly, Staff believes the Companies' proposal to recover its AMI/Smart Grid costs from customers of all three operating companies to be inappropriate. The AMI/Smart Grid project is exclusively sited in the service territory of CEI and only CEI customers will be able to participate in the project. OE and TE customers receive no direct benefit from this project and Staff does not believe the "cost sharing" proposed by the Companies is appropriate. In terms of rate development, Staff recommends that the AMI/Smart Grid revenue requirement be allocated to CEI's rate schedules using the stipulated revenue distribution from the Companies' most recent distribution rate case.[31] Staff recommends one adjustment to the distribution percentages shown on Schedule A, namely that the 0.17% assigned to Rate GT be ratably distributed to the remaining rate

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30 *See In re FirstEnergy*, Case No. 07-551-EL-AIR, *et al.* (Stipulation and Recommendation at Attachment A) (February 11, 2008)

31 *Id.*

schedules. The last steps to develop the monthly fixed charge rate are to divide each Rate Schedules' revenue responsibility by its most recent customer count, and to divide those results by twelve to arrive at a monthly rate.

CONCLUSIONS

- Staff agrees that the geographical area selected for the Companies' smart grid project is appropriate.
- Staff concludes the Distribution Automation equipment and field devices selected by the Companies and the Volt/VAR controls to be installed to be appropriate.
- Staff concludes that the maintenance activities associated with distribution automation are reasonable.
- Staff agrees with the Companies' statements and concludes that the use of single phase tripping is appropriate for this project.
- Staff agrees that the use of high-speed bus differential protection is an appropriate part of the pilot project.
- Staff concludes at this time the design of the controllers, number of switches, and their locations are reasonable.
- Staff considers that the Companies' distribution automation and the voltage/VAR cost estimates to be reasonable.
- Staff concludes that setting target values for the reliability indices for the pilot project are appropriate.

RECOMMENDATIONS

- Staff recommends the Companies create a database of customer-specific momentary interruption data.
- Staff recommends that only those actual costs that are incremental and reasonable with respect to this aspect of the pilot project should be recovered.
- Staff recommends that the Companies should keep the accounting records for the Ohio Site Deployment actual costs separate, to facilitate review and verification.
- Staff recommends that the Companies set target values for CAIDI And SAIFI in the project area and report to Staff at the completion of the pilot project.
- Staff recommends that the Companies demonstrate that any Cleveland Electric Illuminating labor and capital costs incurred for the Ohio Site Deployment are incremental costs.
- Staff recommends the recoverable cost of newly installed Smart Grid plant that replaces existing plant should be the cost of the new plant less the net book value of the replaced plant.
- Staff recommends a true-up to actual pilot project costs occur no more frequently than annually to allow for enough time to perform meaningful cost analysis.
- Staff recommends that the capital asset cost recovery associated with the project occur over the used and useful life of the assets.
- Staff recommends that the Commission allow carrying charges on deferred balances using the most recent Commission approved cost of debt rate component included in the rate of return calculation used in a CEI proceeding.
- Staff recommends that the revised rider AMI rate be developed based on the Staff's recommended revenue requirement for the pilot.
- Staff recommends that the rider AMI charge should be a fixed monthly charge rather than a usage sensitive charge.

- Staff recommends that the AMI/Smart Grid revenue requirement be allocated solely to CEI's rate schedules using the stipulated revenue distribution from the Company's most recent distribution rate case.

- Staff recommends that the metrics to determine the success of the pilot that are being developed by the Company in negotiations with the USDOE will be shared with the Staff and the Commission.

- Staff recommends the Companies report assessment results of the information and outcomes learned from the initial 5,000 meter deployment.

- Staff recommends that the Commission determine whether or not the pilot project has been successful and will go forward beyond the pilot period.

- Staff recommends that if the USDOE reduces any of the SGIG award from the eligible amount of $36.1 million, the Commission should reduce the remaining cost recovery contribution by the First-Energy Ohio jurisdictional ratepayers by an equal amount.

- Staff recommends one adjustment to the distribution percentages shown on Schedule A, namely that the 0.17% assigned to Rate GT be ratably distributed to the remaining rate schedules. The last steps to develop the monthly fixed charge rate are to divide each Rate Schedule's revenue responsibility by its most recent customer count, and to divide those results by twelve to arrive at a monthly rate.

The Staff respectfully requests that the commission give studied consideration to the merits of these initial comments.

Respectfully submitted,

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PROOF OF SERVICE

I hereby certify that a true copy of the foregoing **Comments** submitted on behalf of the Staff of the Public Utilities Commission of Ohio, was served by electronic mail, upon the following parties of record, this 13th day of January, 2010.

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