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VIA FEDERAL EXPRESS

April 20, 2009

James J. McNulty, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, Pennsylvania 17120

Re: Smart Meter Procurement and Installation Plans
Docket No. M-2009-2092655

Dear Mr. McNulty:

Enclosed for filing on behalf of PPL Electric Utilities Corporation ("PPL Electric") are an original and fifteen (15) copies of PPL Electric's comments in the above-captioned proceeding. PPL Electric is submitting these comments pursuant to the Public Utility Commission's ("Commission") Secretarial letter dated March 30, 2009.

Pursuant to the Commission's March 30, 2009 Secretarial letter, PPL Electric is sending the enclosed comments to the Commission's Act 129 e-mail account. In addition, PPL Electric is posting this filing on its Act 129 website. The URL address for that website, which is available to all interested parties and to the public, is www.pplact129.com.

Pursuant to 52 Pa. Code 1.11, the enclosed document is to be deemed filled on April 20, 2009, which is the date it was deposited with an overnight express delivery as shown on the delivery receipt attached to the mailing envelope.

In addition, please date and time-stamp the enclosed extra copy of this letter and return it to me in the envelope provided.

If you have any questions regarding this filing or PPL Electric's Act 129 website, please call me at (610) 774-4254.

Very truly yours,

Paul E. Russell

Enclosures

cc: Kriss E. Brown, Esquire
Charles F. Covage

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Re: Smart Meter Procurement and	:	
Installation Plans	:	Docket No. M-2009-2092655
	:	

Comments of PPL Electric Utilities Corporation

TO THE PENNSYLVANIA PUBLIC UTILITY COMMISSION:

I. <u>Introduction</u>

On October 15, 2008, Governor Rendell signed HB 2200 into law as Act 129 of 2008 ("Act 129" or the "Act") with an effective date of November 14, 2008. The Act expands the oversight responsibilities of the Public Utility Commission ("PUC" or the "Commission") and imposes new requirements on Electric Distribution Companies ("EDCs") with the overall goal of reducing energy consumption and demand, enhancing procurement of generation supply for default service, expanding the installation of smart meter technology, and expanding alternative energy sources.

By Secretarial Letter dated March 30, 2009, the Commission requested comments on a draft staff proposal regarding EDC smart meter procurement and installation plans. The staff proposal, which is included with the Secretarial Letter as Attachment B, sets out proposed standards each EDC plan must meet and provides guidance on the procedures to be followed for submittal, review and approval of all aspects of each smart meter plan. The staff proposal also sets out proposed minimum smart meter capabilities, guidance on deployment of smart meters and cost recovery.

Also included with the Secretarial Letter, as Attachment A, is a list of additional questions regarding specific detailed aspects of smart meter technology. While the Secretarial Letter established a due date of April 15, 2009 for comments and April 27, 2009 for reply comments, these dates were subsequently extended to April 20, 2009 for comments and April 29, 2009 for reply comments.

PPL Electric Utilities Corporation ("PPL Electric" or the "Company") is an EDC serving 1.4 million customers in central eastern Pennsylvania. PPL Electric was an active participant in the development of Act 129 and continues to be an active participant in the development of the rules and regulations necessary to implement Act 129. PPL Electric appreciates the opportunity to provide comments on the staff's proposal regarding smart metering, and provide answers and information in response to the additional questions. For the sake of efficiency, PPL Electric has followed the same organization as the March 30, 2009 Secretarial Letter. Attachment A contains PPL Electric's responses to the questions set forth in Attachment A to the Commission's letter. Attachment B is a copy of the proposed order marked to reflect the Company's recommended revisions. Under the heading "Comments on Attachment B", below, the Company provides its rationale for the revisions proposed in Attachment B.

II. <u>Comments on Attachment B</u>

A. The Company endorses the concept of a "grace period" for the development and installation of a smart meter network as described in Section B. However, the 18 month period proposed is not sufficiently long to permit either smart meter technology requested by a customer or smart meter technology installed on new construction to be fully functional at the time of installation.

The Company endorses staff's recognition that smart meter capability requires the development of supporting infrastructure and, therefore, cannot be available on "Day One." The Company also believes that the 18 month period proposed is only sufficient time to provide reasonable assurance that the correct meter will be purchased for the customer. However, 18 months is not sufficient time to provide all of the "smart" functionality they may be contemplated. It is the

Company's experience that technology selection, procurement and deployment planning of the basic meter and communications infrastructure will require at least 18 months. The installation activities for a population of a million meters will require an additional 2 to 3 years. The Company believes that another, separate 18 month period is required for planning and development activities associated with meter data management, and an additional 2 years for procurement, installation, and integration of meter data management into an EDC's existing billing and customer information system. Meter data management system activities can run in parallel to meter deployment; although, they are likely to be more efficient if not started until the basic meter and communications infrastructure has been determined.

B. The list of capabilities provided in Section C includes both functionality that smart meter technology should support and, also, very specific technical requirements. PPL Electric believes the list should focus on functionality and require EDC plans indicate how they will address or evolve to address these capabilities. A set of technical requirements that is too prescriptive will drive technology choices in inefficient ways.

In Section C, the proposed Implementation Order states that the Commission believes that smart meter technology can support more than demand side response and pricing programs. PPL Electric agrees. Currently, the Company uses its own smart meter system for outage detection, outage restoration, theft detection, net-metering, energy settlement, curtailment verification, customer usage analyses, and responding to customer inquiries regarding high use among other functions. In many cases, however, the ability to perform these functions is evolving and, in some, such as remote disconnect, there are institutional impediments to deployment. Furthermore, the list of capabilities in Section C includes some, such as remote programming capability, that are vague and, depending on how they are further defined, could themselves drive technology choices in less efficient ways. PPL Electric believes that the list of sixteen capabilities provided in Section C should be edited as the Company proposes in Attachment B. The following provides the rationale for each of the proposed revisions:

1. **Bidirectional data communications capability.** PPL Electric believes that bidirectional communication is essential and, consistent with the language of Act 129, should employ network communications systems.
2. **Remote disconnection and reconnection.** PPL Electric's meters are capable of being upgraded with features to permit remote disconnection and reconnection and the Company has considered this option. At this time, the Company cannot identify sufficient economic or service benefits for customers. As long as Chapter 56 requires personal contact with the customer, remote disconnection and reconnection should not be a required feature of smart meter technology.
3. **Ability to provide 15-minute or shorter interval data to customers, EGSs, third-parties and the regional transmission organization ("RTO") on a daily basis, consistent with the data availability, transfer and security standards adopted by the RTO.** PPL Electric believes that there is less need today than in the past for 15-minute data. Generally prices are stated and settlement is conducted on an hourly basis. Also, settlement is conducted on the basis of aggregated load information provided to the RTO, so there is no need to send individual customer usage data to the RTO. The Company acknowledges that some demand-side programs require intervals that are less than hourly – in some cases less than fifteen minutes. PPL Electric believes that these are specialized programs for a limited group of customers. Accordingly, the Company recommends that EDC plans demonstrate how the Company will address this need, but the widespread deployment of this capability is unnecessary.
4. **A minimum of hourly reads delivered at least once per day.** While the Company's smart meter system delivers hourly reads to its meter central repository three times per day, this type of requirement could unnecessarily exclude certain technologies or system design options. In particular, if requirement 6 (for 14 days of storage capability) means storage at the meter, then designing a communications infrastructure to deliver reads once per day may be inefficient.

5. **On-board meter storage of meter data that complies with nationally recognized non-proprietary standards such as ANSI C12.19 tables.** The Company agrees that standards should be followed as appropriate. However, the Company questions why it is necessary to follow a standard protocol for the storage of data in the meter that is unlikely to be communicated anywhere but to the EDC's data repository and meter data management system. If the Commission anticipates a future need, then this requirement should be limited to only industrial customers as a class and to other customers on an as-requested basis.
6. **Minimum of 14 days storage capability.** The storage of raw, unvalidated data in the meter should be designed around the capability of the communications system to retrieve the data and that, in turn, is driven by the other functions that the communications system must perform. The need for data storage may be different in a system where a communications system is dedicated to data retrieval as opposed to one in which a communications system performs multiple functions.
7. **Open standards and protocols that comply with nationally recognized non-proprietary standards.** As stated above, the Company believes that open standards and protocols should be employed to the extent appropriate and practical. The Company recommends that standardization efforts be focused on the key interfaces that must be accessible by multiple parties to avoid placing the EDC in the position of having to be a barrier in order to operate the system, maintain reliability, and perform billing and customer service functions.
8. **Ability to upgrade these minimum capabilities as technology advances and becomes economically feasible.** The Company believes that smart meter technology will continue to evolve in ways that cannot, at this time, be known. The Company believes that it is more important to build flexibility into smart meter systems than it is to attempt to anticipate every future need.
9. **Ability to monitor voltage at each meter and report data in a manner that allows EDC to react to the information.** The Company believes it is premature to assume that meter-level voltage monitoring has value. The

Company believes that such a requirement may be appropriate in certain evolutions of smart grid technology; it may also be true that most of anticipated benefits can be achieved with feeder level voltage measurements. While the Company's existing smart meter deployment does provide voltage data for the purpose of performing planning studies, the collection of real time voltage data would have to presume the existence of an operations management system and remotely controllable equipment which could actually make use of that data.

10. **Remote programming capability.** It is unclear what functions the statement intends to be remotely programmed.
11. **Communicate outages and restorations.** Because different technologies approach outage information differently, the Company proposes a more generic objective to avoid dictating a particular approach.
12. **Ability to support net metering of customer-generators.** The Company believes that the ability to net-meter consistent with the Alternative Energy Portfolio Standards Act and the Commission's regulations is essential.
13. **Support service limiting and prepaid service programs.** Consistent with its comments on requirement 2, above, the Company believes that the availability of such service options must be harmonized with the requirements of Chapter 56 before the widespread deployment of such functionality is mandated.
14. **Support automatic load control by EDC, customer and third-parties, with customer consent.** Consistent with the language of Act 129, this is a basic functionality that is required. The Company believes that the proposed language does not inappropriately limit technology choices.
15. **Support time-of-use and real-time pricing programs.** Consistent with the language of Act 129, this is a basic functionality that is required. The Company believes that the proposed language does not inappropriately limit technology choices.
16. **Provide customer direct access to consumption and pricing information.** Consistent with the language of Act 129, the basic functionality required for customers is to "directly provide customers with information on their hourly consumption" and to "enable time-of-use rates and real-time price programs."

The Company is concerned that the term "direct access" can be interpreted as direct access to data within the meter which would be raw (i.e., unvalidated) data. Such information would be costly to provide to all customers, and unnecessary for most. Accordingly, the Company is proposing a modest revision to clarify that this means access to information (at least validated, but likely presented in meaningful formats) and not to raw data.

C. Issues associated with access to meters and their data should be clarified; in particular the three statements in Section D.

Consistent with its comments above in Section 2, requirement 16, the Company is concerned about use of the terms "access" and "direct access." It is not clear whether they mean access to raw data, validated data, communication systems, customer equipment, the meter, or other elements within what may be described as "smart meter technology". Meters are fundamentally counting devices and the Company believes that the most important functionality of meters is the data they collect. There are a limited number of specialized applications that require real time data and, therefore, require direct access to meter data. The Company believes that, overwhelmingly, most applications involves data that has been validated and edited (as necessary), stored in a repository, and made available to applications that will format the data in ways that will turn it into information that is useful to customers. Access to these data should be easy for both the customer and any other party, including electric generation suppliers the customer designates. This should include electronic access via standard electronic data interchange formats and via spreadsheet that can be downloaded and reconfigured by the customer or a designated third-party.

A part of the smart meter technology is network communications technology. The Company is concerned that use of the term "access" with no other clarification may be interpreted to mean access to a utility communication system, when access to control customer equipment or to send customers information can be done by a variety of network means (for example, internet, radio frequency, cellular, and direct wired) that do not need to involve the utility.

D. The allocation of benefits (i.e., reductions in operating costs) arising from the installation of smart metering systems for revenue recovery purposes under Section E should be consistent with standard expense allocation methodologies.

The Company believes that, where benefits are attributed to the installation of smart meter technology and are reflected as an offset to costs for recovery purposes, those benefits should be monetized consistent with a standard test year approach and allocated among customer classes consistent with standard allocation principles. For example, if the installation of smart meter technology permits the EDC to reduce its cost of meter reading, then the test year expense reduction associated with avoided meter reading costs should be reflected and allocated among customer classes on the same basis that meter reading expenses are allocated to those classes.

III. Conclusion

For all of the reasons stated above, PPL Electric Utilities Corporation recommends that the Public Utility Commission proceed with development of the draft staff proposal regarding electric distribution company smart meter procurement and installation plans consistent with PPL Electric Utilities Corporation's comments.

ATTACHMENT A

Additional Questions Related to the Commission's
Smart Meter Procurement and Installation Program at Docket No. M-2009-2092655

1. Overall Adaptability:

a. Should there be some common "plug and play" format and/or hardware on the meter to accommodate future technology changes? If so, provide suggested standards for this capability.

As stated in its general comments (see Section II), PPL Electric believes that smart meter systems should be adaptable in terms of the functions they may be called on to support and technologies that they will be called on to interface with. Functions and technology will continue to evolve in response to a variety of stimuli including market pressures, competitive pressures, technology advancements, and customer preferences. That evolution is desirable and needs to be accommodated. PPL Electric believes that overly prescriptive hardware and software requirements may have the effect of impeding that evolution, delaying the availability of functionality to customers, and increasing costs. PPL Electric believes that the best approach to the development and on-going operation of smart metering systems is to adopt an open architecture consisting of modular elements that can be upgraded/replaced as they become technologically, functionally, or economically obsolete and focus any necessary standardization efforts on the interfaces between the modules where multiple parties need either physical access or access to data. In this regard, the use of the term "plug and play" suggests a direct physical connection to the meter. Act 129 does require accommodation for a direct physical connection and, consistent with PPL Electric's view of architecture, this is an interface where multiple parties might be accessing the system and it may be appropriate to establish a standard configuration for the data port through which meter pulses are obtained. This could be either a single port configuration or it could be a list of readily available and acceptable configurations.

2. Home Area Network (HAN) Protocols:

a. What HAN protocol may be appropriate from the meter to the customer? What HAN open protocols are most readily available and accessible to customers? Should the Commission standardize a protocol? Should there be more than one protocol?

While HAN is a widely used term, PPL Electric does not believe that there exists a standard definition of what a HAN is and what it includes. PPL Electric believes that HANs consist fundamentally of three components: (1) equipment and appliances that are controlled remotely (air conditioning, heating, washing machines, clothes dryers, etc); (2) computing capability that establishes control points (on/off logic, thermostat settings, etc.); and (3) communications between the computing capability and the equipment/appliances. The term HAN certainly implies that these three functionalities all reside within the home; however, it is important to understand that many of the energy use and conservation benefits that a HAN would seek to achieve are currently available without a HAN. Utilities and third-party providers already control in-home equipment remotely using radio and cellular technologies. Many residential customers already control their use with programmable thermostats and timers. Therefore, PPL Electric does not believe the Commission should prescribe a standard HAN protocol between the meter and the customer.

In order to control equipment/appliances, the computing capability may need data regarding ambient or in-home conditions, time of day and day of the week, electricity price, and/or usage. Only one of these elements of data, usage, actually is unique to the meter. To the extent that the computing capability requires real-time usage data, that data would have to come directly from the meter and here it might be appropriate to establish standard protocol(s). PPL Electric does not believe that most customers will have a need for real-time usage data and their need for usage data can be satisfied via standard web-based or electronic methods. For that small percentage of customers who will have need for real-time data, PPL Electric believes that pulse data is the appropriate approach.

b. Should smart meter information be available through a HAN or an internet browser? If through an internet browser, should this come from a website, or directly from the meter, or both? Through which browsers should this be made available?

Consistent with the Company's response to Question 2a, above, PPL Electric believes that the data that is unique to the smart meter is usage. To the extent that a particular application requires real-time usage data, that data, of necessity must come directly from the meter, but has no value unless it is integrated over an appropriate period of use (for example, last hour, last fifteen minutes, etc.). Historical usage information should, logically, be validated data that is stored in a central repository, is likely to be voluminous, and is best provided through website or other electronic data interchange methods. The website should be accessible through all industry browsers. PPL Electric currently makes twenty five months of historical hourly usage data (about 18,000 data points for each of its 1.4 million customers) available to customers through its website. This data can be downloaded via Excel spreadsheet. The Company will, in the near future, be making the same data available to EGSs via EDI transactions to the extent that customers have authorized the release of such data to EGSs. EGSs can then make the data available to customers or, more likely, feed that data into an application that can provide customers information on rate options. Similarly, if that data is made available, subject to customer authorization, to curtailment service providers, conservation service providers, or other third-parties, those entities can feed the data into their own applications and provide customers information on various energy use and pricing issues.

c. Should there be other interconnectivity between the meter and other equipment in the home? If so, how much? [read capability vs. two way communication]

   PPL Electric believes that there is no additional need for communication between the meter and other equipment.

3. Utility usage data and meter access:

a. What usage data should the utility acquire through the smart metering system?

   PPL Electric believes the usage data that the utility should acquire through the smart metering system is daily consumption, hourly consumption and monthly billing for all customers.

   Daily usage provides a customer with the ability to project their monthly billing while hourly consumption provides the granularity to make better informed energy efficiency decisions.

   Hourly usage data provides the ability to support TOU rates, RTP rates, and can be aggregated and analyzed to provide improved forecasting for distribution planning and operations, and load research. It can also support revenue protection in detection of theft and/or meter equipment malfunctions.

   To the extent that specialized customers require more granularity in data, that granularity should be provided on a case by case basis. For example, PJM's synchronous response program, which requires an affirmative load response within ten minutes, requires data at no less than a one-minute scan rate. This is not a program that large numbers of customers will participate in, therefore, it would be inappropriate to require a meter plan that includes a widespread deployment of such sophisticated metering equipment and supporting communications capability. Likewise, when a CSP requests 15-minute usage data, a meter specially configured to provide this data granularity can be installed to meet their requirements.

b. Should the Commission establish minimum standards on how often the utility should acquire the usage data from the meter?

PPL Electric believes there should not be a standard set on how often a utility should acquire the usage data from the meter, but rather to specify the functional requirements of the meter data. The specific technology implemented for a smart meter system will then dictate how often a utility must acquire data from the meter to meet the requirements.

The tariff establishes the standard to provide billing data to customers. If additional standards are to be established, they should include different functions to be supported by data from the smart meter system. For example, one of these functions might be to enable customers to make prudent energy efficiency decisions by accessing the data from an EDC's website. It might be appropriate to establish the frequency with which an EDC updates customers' historical usage data so that customers performing such analysis can be assured of having available reasonably current data.

PPL Electric's data acquisition process involves the capture and validation of the data from the meter and storage in a repository for use in various applications. The process begins with the collection of usage in the meter to the integrated AMI module within the meter. Once the usage has been stored in the module, the metering acquisition system secures the data from the module across the communication infrastructure and delivers it to a central repository. This process is initiated every 8 hours for hourly interval data. Then, the data is processed, validated and stored into the meter data management system (MDMS). In the MDMS, the data is stored in two versions, working (data acquired directly from the meter) and approved (validated data where the validation, editing, and estimating or "VEE" process was applied). This data is then available for the customer, CSP, EGS or EDC application.

c. Should the Commission establish minimum data intervals? If so, what should that be? [Examples: 15 minute, 30 minute, 1 hr.]

PPL Electric recommends a minimum data interval of 1 hour. The minimum data interval available should be defined to meet existing PUC regulations and customer and third party requirements (e.g., billing tariff, PJM market settlement, etc.). Hourly usage data along with available energy efficiency information, when viewed through an EDC's website, has proven to be useful to customers seeking to make informed decisions regarding energy use.

As referenced in 3a, to the extent that specialized customers require more granularity in data, which should be provided on a case by case basis. It may not be prudent to establish a minimum data interval for these types of customers because their needs will differ and, instead, establish access protocols for parties to obtain pulse data when hourly data is not sufficient.

d. What minimum timeframe should the Commission establish on when usage data is made available by the Meter Data Service Provider (MDSP, usually the EDC) to the EDC, CSPs/EGSs and customers, respectively?

PPL Electric believes the Commission should not establish a minimum timeframe on when usage data is made available. The EDC/MDSP is responsible to assure the data is available to meet the needs of customers and third parties. As referenced in 3b, data acquisition requires the capture and validation of the usage before it can be made available. Given that these activities involve large amounts of data, they will, of necessity, be batch processes that will need to be integrated with other batch processes. Some examples are monthly billing, enabling EGS billing (in either a single bill or dual bill format), and data availability to historical usage transactions. PPL Electric believes that it is not likely practical or necessary to require usage data for such purposes to be available in a shorter timeframe than two days.

e. Should this usage data be validated first?

PPL Electric believes that data should be validated for most applications. For data/intervals used for forecasting, the data should be validated and corrected (estimated/edited), to provide a more accurate forecast of usage. Intervals used for billing should be validated and corrected to support business rules for billing with interval data (e.g. estimate a missing interval using a customer's typical usage profile). When data is used to detect theft and/or equipment malfunctions (revenue protection), the non-validated data should be applied to provide actual anomalies in interval usage (e.g. find when usage is zero in 7 consecutive hourly intervals). In the settlement area, it is prudent to apply validated interval data to assure accuracy with forecasted loads during reconciliations. From a web presentment perspective, validated data should be presented to provide the information necessary to make informed energy efficiency decisions and to aid behavioral change.

To the extent data is required to support real time applications it must be understood that the data is not validated and may differ from validated data where established and proven methods are applied.

f. Should the Commission establish a common Validation, Error Detection, and Editing (VEE) protocol? If so, what should that be?

PPL Electric recommends applying established Validation routines which include spike check, missing interval check, negative check, and static check. However, Validation and Estimation configurations and specific rules/logic are a function of the system and should be defined to meet the requirements for applications.

g. Should the Commission establish a maximum period in which the MDSP should complete the VEE analysis? If so, what should that maximum period be?

   PPL Electric believes the Commission should not establish a maximum period to complete VEE analysis, but provide a reasonable period of time to have the analysis completed. The VEE analysis must be completed in the timeframe to support applications that utilize the results from VEE. For example, if interval data is used for billing, VEE must be completed in support of the monthly bill cycle. As referenced in 3b, data acquisition requires the capture and validation of the usage before it can be made available. As discussed in 3d, it is reasonable to expect that VEE analysis can be completed within 2 days of receiving the non-validated data from the smart meter system. However, there are times when the data may have to be re-VEE'd to secure the best data for applications. Since EDC's may need to re-VEE the data at times, PPL Electric believes that the Commission should not establish a maximum period that would prohibit the EDCs from re-VEEing the data.

h. How should customers be provided <u>direct</u> access to <u>usage</u> information? [examples, website access, HAN to an in-home display or other devices].

   PPL Electric believes that customers should be provided various options to access usage information, and not prescribe a specific messaging approach. For example, customers can access a website for daily and hourly consumption, or receive an e-mail message containing usage information, or a text message on a phone. As new technology evolves, additional options could be provided to customers to access usage information. See also 2b.

i. Should the Commission establish standard protocols and communication medium for providing direct access to usage information from the meter to the HAN? If so, what should those be? See also 2a.

j. How should this Commission provide <u>direct</u> access to the <u>meter</u> to third parties? What policies or regulations should this Commission promulgate to ensure that these third parties are provided timely access under reasonable terms and conditions to the customer metering facilities?

   PPL Electric believes that direct access to the meter for third parties should be provided through KYZ pulses from meters. This is a proven technology that has been applied throughout the industry and in Pennsylvania. The technology has been provided to a small population of customers that have requested it. Communication of pulses wirelessly with a collection device is not practical. Therefore, application of the proven technology should be continued to provide direct access for third parties.

The Commission should establish a policy that enables third parties access to the meter data, but should not establish a regulation that would inhibit the evolution of technology.

k. What communications, software or hardware can facilitate this <u>direct</u> access to the <u>meter</u> for customers and their third parties, and should the Commission establish requirements and or standards to facilitate this access?

Please reference the discussion in 3j.

l. What electronic access to customer meter data do CSPs and EGSs need from EDCs that they currently do not have? Provide specific examples where these entities do not have such access currently, and provide examples, if available, of electronic transactions that can be adopted by this Commission to comply with this statutory requirement.

PPL Electric believes our existing metering system supports all the needs of CSPs and EGSs for electronic access to customer meter data. To the extent that CSPs require KYZ pulses, PPL provides them as referenced in 3j.

CSPs should secure trading partner status under the EDI agreements. Once secured and tested on the appropriate set of EDI transactions, CSPs along with EGSs, can use existing mechanisms of EDI and internet in accordance with EDEWG guidelines to secure meter data. As an example of information to be provided, PPL Electric will be supporting in the near future the supply of historical hourly usage data to EGSs as referenced in 2b.

4. Meter to EDC Communications:

a. Should the Commission standardize public protocols from the meter to the grid?

Standard Development Organizations such as ANSI, IEC and IEEE are in the process of creating public open protocols for the meter to smart grid application. NIST has been charged by the DOE to make sure that the appropriate development and interoperability occurs. It is therefore important to allow the protocols to develop and mature as the market evolves. Communication from the meter to the grid may take many forms in different mediums for different applications. PPL believes it would not be in the best interest to standardize on one protocol but to allow NIST and the DOE to develop interoperability guidelines for all appropriate standards to meet.

b. If certain protocols are not effective in certain geographic or rural regions, should the Commission adopt a list of protocols that can accommodate all of Pennsylvania customer's communication requirements? If so, what additional protocols should be adopted?

   By protocols it is assumed the Commission means a defined communication application such as public cellular, private radio mesh or power line communication. The market should be allowed to evolve for the best operation in specific geographic or rural applications. Today's systems will generally migrate toward efficiency and cost effectiveness. Technology is always evolving and an approved a list of protocols would be obsolete the day it was published. Communication applications and its associated protocols will evolve to the best interest of the Commission without creating an approved list.

c. What bidirectional communication mediums [Example: broadband over power line, cellular, phone lines, RF] are least cost? What are the pros and cons of each?

   Competition is bringing least cost to the communications space. A smart meter technology solution may include a combination of public and private networks. Commenting on the relative pros and cons in general is not appropriate without a deeper understanding of the technology application being addressed. From a general aspect, public mediums provide minimal capital cost for deployment and continue to mature and operate with the latest generation of technology. On the down side it is a shared resource exhibiting some loss of operational control, has a higher security risk, and as a shared resource could encumber performance at peak use times. Private mediums are relatively more expensive to deploy and maintain but do provide more secure operation and control. Private mediums generally stagnate in technology if capital upgrades are not part of their build-out.

5. Access to Price information:

a. How should customers be provided direct access to pricing information? [examples, website access, HAN to an in-home display or other devices]

   The Company believes that the Commission should anticipate that customers, their consultants, and, in some cases, customer equipment will be receiving price information that may be, depending on the application, real-time (i.e., streaming), day-ahead, or historic. The Commission should also anticipate that two different entities may offer two different real-time prices depending upon the adders (capacity, ancillaries, margin, risk, etc.) that they may apply to the zonal LMP price.

b. Should the Commission require the meter to communicate price information, or should this information be provided over another communication medium?

   The Commission should not require the meter to be the source of communication of price information. There is no price information inherently within the meter so that information would have to be communicated to the meter. Then, the meter would have to incorporate a communication protocol to communicate the information to the HAN, to some other display device, or, potentially, to equipment/appliances directly. If there was need for historical price data, or in the event that day-ahead-price data were to be used, storage would need to be added to the meter. If an EGS or curtailment service provider were to offer a pricing program that relied on prices other than those that a utility would post, then additional storage and protocols would need to be added for that information. The Company believes that is far more efficient for price information to be conveyed through existing communication channels including web-site, cellular, and radio (including paging). PPL Electric currently displays estimated real-time and day-ahead hourly prices on its web-site in an effort to educate customers regarding those prices and their hourly and seasonal variation (see www.pplelectric.com/electricity+market+price/).

c. What pricing information should the Commission require to be provided? [examples, RTP, Day ahead prices, default service rates]

   The Commission should require EDCs to make available information that is consistent with and supports the rate programs that they offer. Consistent with the Act 129 directive that EDCs be able to offer both time of use and real time price programs as well as whatever other fixed price service they may offer, EDCs should be required to make that data available to customers who are eligible for those programs. The Commission should not require EDCs to make available pricing data in support of programs that may be offered by EGSs, curtailment service providers, or conservation service providers.

d. Should the Commission establish minimum standards on how frequently price information should be provided? If so, what should be the minimum standard?

   Price information should be provided on a frequency which is consistent with the nature of the information. Therefore, hourly real-time price information should be provided hourly. While RTOs typically reveal an instantaneous price, that price is not, to PPL Electric's knowledge, ever used in settlement, therefore there is no need for information on a shorter interval or on a greater frequency than hourly. In the same way, day-ahead data would be provided once per day.

e. Should the Commission establish standard formats for presentation of price information? If so, suggest a format.

   PPL Electric does not believe there is a need for a standard format for the presentation of price data.

6. Automatic Control:

a. How can smart meters "effectively support" automatic control of customer's electricity consumption by customers, utilities and the customer's third party?

   Electric Utilities and communication vendors are promoting energy networks that integrate energy data, price information and device control for the customer. The network can be a self-contained home automation system but more likely will have a main connection to the EDC, EGS or CPS that provides energy and price information for appropriate control. The Home Area Network (HAN) connection to the outside entities can be provided by any number of public or private mediums selected by the customer.

   PPL Electric does not believe the meter should be the communication gateway to the energy network, and believes that energy networks would be more cost effective and technology efficient using public mediums for connectivity and application controls.

   An effective HAN architecture could be a control hub inside the home connected to the internet. The hub could communicate to consumer devices through an open architecture allowing various Home Area Network mediums to operate such as Zigbee, HomePlug or Zwave. This method would provide greater flexibility to the consumer and also provide them with a sense of ownership and control. The open architecture of this non-proprietary platform would allow the customer to select and install their own control and communication equipment from public resources such as the big box retailers. PPL EU or other entities could push data to the customer's HAN that would enable "prices to the devices" thereby allowing effective control of appliances and information display.

b. How is the smart metering system engaged in the initiation, maintenance, relinquishment, and verification of the automatic control of customer consumption?

The smart metering system provides the meter usage data. This system and the PPL suggested control hub applications would integrate to initiate, maintain and relinquish control of the customer's consumption. Energy measured by the smart metering system would provide the basis for data. This integration would provide automated control by the hub to appliance devices and subsequent verification to the homeowner by associated displays or user interfaces.

c. What smart metering protocols and communication mediums are needed to implement these automated controls? Should the Commission establish standard protocols and standards for this purpose?

PPL Electric believes the Commission should not establish standard protocols to implement automated controls, but allow technology and open standards to evolve. Vendors from the Consumer Electronics Association, AMI and Home Automation venues are all developing applications to enable automated controls. It is too early to define the winners in this developing industry, not only for the particular standards but also how the interoperability and control process will be best implemented.

d. What energy consuming customer assets can be controlled by these smart meter systems for each of the customer segments, and how is control of these assets impacted by the choice of communication medium and protocol?

Since PPL Electric is advocating a customer owned energy network with meter usage data supplemented by PPL Electric, it is best to allow the market to establish appropriate device controls in each of the customer segments. Residential, commercial and industrial segments all have different requirements for command and control of their devices. These requirements will provide the correct integration and application for the system architecture.

The usual space conditioning and lighting controls have always been effective in the past and these types of applications will most likely continue to be the market targets for the future.

7. Smart Metering Acceleration:

a. To the extent permissible under the law, should the Commission provide an incentive to EDCs to accelerate their smart meter deployment by giving a credit towards the required Energy Efficiency and Conservation Goals? If so, how should such credit be determined?

If elements of smart meter technology, such as providing hourly usage or bill-to-date information to a customer, are directly responsible for energy consumption or peak load reductions (i.e. the customer reduces its usage or peak demand based on information provided by the EDC's smart meter technology), those elements should be included as a "measure" in an EDC's Act 129 Energy Efficiency & Conservation Plan. However, if the cost of the smart meter technology is included in the cost of that measure, that measure will not likely meet the cost-effectiveness threshold of a TRC (Total Resource Cost Test). Therefore, to encourage the use of smart meter technology to reduce energy consumption/peak demand, the best incentive is if the Commission allows the EDC to exclude the direct cost of implementing smart meter technology from the TRC.

If an EDC implemented smart meter technology before Act 129 was issued, then that EDC should be eligible for the same credit towards the required EE&C goals as EDC's who implement smart meter technology in direct response to Act 129 Smart Metering requirements.

8. Cost Recovery:

a. Should the Commission establish a standard format for providing the various components of the capital and operating costs and benefits of these smart metering systems to facilitate the comparison of the EDC plans? If so, please provide a suggested standard format.

PPL Electric believes that the capital costs, operating costs, and related economic benefits that the EDC will experience as a result of the installation of smart meter technology should be captured in a revenue requirements format. Any additional benefits that customers may achieve (both monetized benefits and those that cannot be monetized) should be captured separately. Beyond that, the Company does not believe that there is a need for a standard format.

ATTACHMENT B

PENNSYLVANIA
PUBLIC UTILITY COMMISSION
Harrisburg, PA. 17105-3265

Public Meeting held

Commissioners Present:

James H. Cawley, Chairman
Tyrone J. Christy, Vice Chairman
Robert F. Powelson
Kim Pizzingrilli
Wayne E. Gardner

Smart Meter Procurement and Installation | Docket No. M-2009-2092655

IMPLEMENTATION ORDER

BY THE COMMISSION:

The Pennsylvania General Assembly ("General Assembly") has directed that electric distribution companies with more than 100,000 customers file smart meter technology procurement and installation plans with the Commission for approval. 66 Pa. C.S. § 2807(f). This Implementation Order will establish the standards each plan must meet and provide guidance on the procedures to be followed for submittal, review and approval of all aspects of each smart meter plan. This Implementation Order will also establish minimum smart meter capability and guidance on the Commission's expectations for deployment of smart meters.

BACKGROUND AND HISTORY OF THIS PROCEEDING

Governor Edward Rendell signed Act 129 of 2008 ("the Act" or "Act 129") into law on October 15, 2008. The Act took effect 30 days thereafter on November 14, 2008. Among other things, the Act specifically directed that within nine months of its effective date, electric distribution companies ("EDCs") are to file, with the Commission for approval, a smart meter technology procurement and installation plan. 66 Pa. C.S. § 2807(f)(1). Each EDC smart meter plan must describe the smart meter technologies the EDC proposes to install, upon request from a customer at the customer's expense, in new construction and in accordance with a depreciation schedule not to exceed 15 years. 66 Pa. C.S. §§ 2807(f)(1) and (2). The Act also establishes meter and meter data access by third parties. 66 Pa. C.S. § 2807(f)(3). The Act further defines minimum start meter technology capabilities. 66 Pa. C.S. § 2807(g). Finally, the Act establishes acceptable cost recovery methods. 66 Pa. C.S. § 2807(7).

DISCUSSION

In this section the Commission will outline the standards each plan must meet and provide guidance on the procedures to be followed for submittal, review and approval of all aspects of each smart meter plan. This section will also establish minimum smart meter capabilities, as well as guidance on the Commission's expectations for deployment of smart meters. Finally, in this section the Commission will provide guidance on EDC smart meter technology cost recovery.

A. Plan Approval Process

Within nine months after the effective date of Act 129, each EDC with more than 100,000 customers is to file a smart meter technology procurement and installation plan with the Commission for approval. 66 Pa. C.S. §§ 2807(f)(1) and (6). As Act 129 became effective on November 14, 2008, the smart meter plans must be submitted on or before August 14, 2009. Each smart meter plan should provide a summary of the EDC's current deployment of smart meter technology, if any, and a plan for future deployment, complete with dates for key milestones and measurable goals. The Plans shall be served on the Office of Consumer Advocate, the Office of Small Business Advocate, the Office of Trial Staff, Electric Generation Suppliers licensed to provide service in the Commonwealth and Conservation Service Providers that are registered with the Commission.

Comments to the smart meter plans will be permitted to be filed within twenty (20) days of service. Following the receipt of comments, the Plans will be referred to the Office of Administrative Law Judge for such proceedings as may be deemed necessary. There will be at least one technical conference scheduled for each Plan during which the filing EDC will present personnel with in-depth knowledge of the plan who can respond to questions regarding all aspects of the plan. The technical conference(s) shall be transcribed and the transcript(s) will become part of the record in the proceeding.[1]

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1 Any technical conference should be conducted as informally as possible, consistent with the good order of the proceedings. Lay persons will be permitted to directly ask questions of the EDC representatives, although such lay persons must be affiliated with an admitted Party of Record.

At the conclusion of the technical conference and any evidentiary hearings that may be necessary, an initial decision will be issued resolving all issues raised in the proceeding. It is anticipated that an Initial Decision will be issued within 120 days of the filing of the Plan. Parties will be permitted to file Exceptions and Reply Exceptions as set forth in Section 5.533 of the Commission's Regulations, 52 Pa. Code § 5.533. Parties are strongly encouraged to pursue settlement opportunities during the proceeding. It is expected that the comments and technical conference(s) will promote settlement efforts.

B. Smart Meter Deployment

Act 129 requires EDCs to furnish smart meter technology (1) upon request from a customer that agrees to pay the cost of the smart meter at the time of the request, (2) in new building construction, and (3) in accordance with a depreciation schedule not to exceed 15 years. 66 Pa. C.S. § 2807(f)(2). The Commission recognizes that a fully functional smart meter involves more than just the meter hardware attached to the customer's premises. A fully functional smart meter that supports the capabilities required by Act 129 and as outlined below, involves an entire network, to include the meter, two-way communication, computer hardware and software, and trained support personnel. The Commission also recognizes that it may take time for EDCs to select and install the required smart meter network components, and to train support personnel.

1. Network Development and Installation Grace Period

As EDCs may need time to develop and install the smart meter network, the Commission is granting a network development grace period of up to 18 months following plan approval. During this grace period the Commission will not require EDCs to install a smart meter at a customer's premises. However, during this grace period, the Commission will require EDCs to provide interval meters, if necessary, and direct access to customer meters to third-parties, such as EGSs or CSPs, upon customer request. In addition, EDCs will be permitted to continue to offer their already established and approved time-of-use rate programs.

The Commission directs all covered EDCs to include in its smart meter procurement and installation plan filing a proposed network design and development grace period not to exceed 18 months. Each covered EDC must include a justification and its plan for network design and rollout, and personnel training.

2. Customer Request

As pointed out above, the Commission will not require EDCs to deploy smart meters until after the Commission-approved network development grace period. Once this grace period expires, each covered EDC must supply a smart meter upon request by a customer, per Act 129.

The Commission recognizes that deployment of smart meters on a piecemeal or individual basis could involve greater costs than a systematic system-wide deployment. The General Assembly recognized this as well when it included the proviso that the customer requesting the smart meter must agree to pay for the cost of the smart meter. However, the Commission does not believe it was the intent of the General Assembly for this customer to pay the entire cost of the smart meter and its supporting infrastructure. Such a requirement would be so cost prohibitive that no customer would request a smart meter. Furthermore, the customer could be paying for the smart meter directly and also through the EDC's cost recovery mechanism (unless the particular meter is included in the EDC's Commission-approved plan as a specialized service, the cost of which is to be recovered directly from the customer). Such a result would be an absurd, impossible and unreasonable outcome, which is contrary to the rules of statutory construction. See 1 Pa. C.S. § 1922(1). To avoid this absurd result, the Commission believes that only the incremental costs over and above the cost for system-wide deployment are to be paid by customers requesting early deployment of a smart meter.

The Commission directs each covered EDC to include in its smart meter plan a proposal to install individual smart meters in advance of the EDC's system-wide deployment and after the network grace period. This proposal should include an itemization of the estimated incremental costs. If an EDC cannot provide an estimate of the incremental costs at the time of its initial filing, it will have to seek Commission approval of these incremental charges prior to the expiration of the approved network grace period. If an EDC does not obtain approval of these incremental costs prior to the end of the grace period it must install individual smart meters at its own expense. Such costs are not recoverable from ratepayers.

3. New Construction

As with all equipment, meters have a useful life. EDCs determine how much to invest in meter equipment based on its useful life and have an opportunity to depreciate that investment over the useful life of the meter. In addition, EDCs have an opportunity to recover the cost of the meter from ratepayers. Therefore, if a meter is replaced prior to the end of its useful life, the EDC will not be able to take advantage of the full depreciation of that meter or the ratepayers will pay an increased rate to cover the cost of both meters. The Commission believes that the intent of the Act's provision for installing smart meters in new construction was to avoid this waste and added expense.

Again, the Commission will not require deployment of smart meters in new construction during the approved network grace period. However, the Commission directs all covered EDCs to install smart meters in new construction that is begun after the network grace period. Therefore, the Commission directs each covered EDC to include in its smart meter plan a proposal for deployment of smart meters in new construction. Such a proposal should include a plan to identify new development and construction early enough to incorporate it into the system-wide deployment proposal.

4. System-Wide Deployment

The Commission believes that it was the intent of the General Assembly to require all covered EDCs to deploy smart meters system-wide when it included a requirement for smart meter deployment "in accordance with a depreciation schedule not to exceed 15 years." It is this system-wide deployment that will provide the foundation for the EDCs' smart meter installation plans. Therefore, it is crucial for the EDCs to develop a plan that will best meet the needs of their service territory, while at the same time operating in a manner that is both cost and time effective.

The EDCs shall detail their system-wide deployment plans to the Commission, including any type of tiered rollout the company proposes, as well as the associated costs and benefits incurred from such a rollout. This system-wide plan should also incorporate a coordination element with the new construction deployment component. Furthermore, the Commission will require all EDCs to file a "Smart Meter Progress" report on an annual basis that will update the status of their installation plans, including the number of customers who received meters in the prior year, the estimated number of customers scheduled to receive meters in the coming year, and all costs associated with the meter plan incurred during the previous year.

It should also be noted that Act 129 uses the language "not to exceed 15 years." An EDC is encouraged to expedite the deployment process if it will provide increased customer benefits in a cost-effective manner. Again, the primary goal of the EDC deployment plan should be to implement a deployment and installation schedule that best balances the overall efficiency and timeliness of the smart meter installations with the costs incurred.

C. Smart Meter Capabilities

Act 129 defines smart meter technology as including metering technology and network communications technology capable of bidirectional communication that records electricity usage on at least an hourly basis, including related electric distribution system upgrades to enable the technology. 66 Pa. C.S. § 2807(g). The Act further states that the smart meter technology must provide customers with direct access to and use of price and consumption information, to include, (1) direct information on their hourly consumption, (2) enable time-of-use rates and real-time price programs, and (3) effectively support the automatic control of electricity consumption by, the customer, the EDC or a third-party, at the customer's request. 66 Pa. C.S. § 2807(g).

The Act further requires that default service providers submit time-of-use rates and real-time pricing plans by January 1, 2010, or at the end of the applicable generation rate cap period, whichever is later. Default service providers must offer the time-of-use rates and real-time pricing plans to all customers that have been provided with smart meter technology. 66 Pa. C.S. § 2807(f)(5). Real-time pricing is defined as "a rate that directly reflects the different cost of energy during each hour." 66 Pa. C.S. § 2806.1(m). A time-of-use rate is defined as "a rate that reflects the costs of serving customers during different time periods, including off-peak and on-peak periods, but not as frequently as each hour." *Id.*

The Commission believes that the smart meter capability requirements set out in Act 129 are minimal requirements. The Commission also recognizes that smart meter technology can support more than demand response and pricing programs. Smart meters have the ability to support maintenance and repair functions, theft detection, system security, consumer assistance programs, customer-generator net metering, and other programs that increase an EDC's efficiencies and reduce operating costs. Therefore, the Commission directs that a covered EDC's plan to deploy smart meter technology must address how it will support the following capabilities:

1. Bidirectional data communications capability.
2. The future provision of remote disconnection and reconnection.
3. The need and ability to provide 15-minute or shorter interval data to customers, EGSs, third-parties and the regional transmission organization ("RTO") on a daily basis, consistent with the data availability, transfer and security standards adopted by the RTO.
4. A minimum of hourly reads (or usages) delivered to the EDC's data repository at least once per day.
5. On-board meter storage of meter data that complies with nationally recognized non-proprietary standards such as ANSI C12.19 tables for those applications where raw data stored in the meter is to be directly available to customers and their designees.
6. Data storage capability, both on board the meter and within a centralized repository, which is consistent with data availability requirements of applications served by the smart meter technology.

7. Open standards and protocols at points in the system where third-party access is appropriate that comply with nationally recognized non-proprietary standards.
8. Ability to upgrade these minimum capabilities as technology advances and becomes economically feasible.
9. Ability to monitor voltage at each meter and report data in concert with the future evolution of smart grid technologies.
10. Remote programming capabilities that will be inherent in the proposed system.
11. Communicate data useful to identifying outages and their extent, and to managing restorations.
12. Ability to support net metering of customer-generators.
13. Support the future provision of service limiting and prepaid service programs.
14. Support automatic load control by EDC, customer and third-parties, with customer consent
15. Support time-of-use and real-time pricing programs.
16. Provide customer access to consumption and pricing information.

D. Access to smart meters and data

Act 129 requires EDCs to make available to third parties, including electric generation suppliers and providers of conservation and load management services, with customer consent, direct access to the meter and electronic meter data. 66 Pa. C.S. § 2807(f)(3). The Commission believes that the true usefulness of smart meters is to provide information to empower customers to control their electric use. For knowledge itself is power.[2]

[2] Francis Bacon.

In order for customers to be empowered they, or their designated representatives, must have direct access to their consumption data and price data. Therefore, the Commission directs that all covered EDCs must provide at least the following access to their smart meters and data:

1. Non-discriminatory direct access to the meter for the purpose of obtaining real-time data upon customer consent for retail electric suppliers and third-parties, such as EGSs, and conservation and load management service providers.
2. Open, non-proprietary two-way communications access for electric suppliers and third-parties, such as EGSs, and conservation and load management service providers for the purpose of controlling a customer's consumption of electricity.
3. Non-discriminatory electronic access through standard protocols and formats to customers and their representatives to stored meter data upon customer consent.

The Commission further directs that each EDC plan must address standards and formats for electronic data communications with customers and third parties. There are many approaches for requesting and providing meter-level data today, e.g. electronic bulletin board, pass-key protected websites, compact disk, etc. In addition, EDI (ASC X12 standards) capability has been built by the electricity industry in the Commonwealth to facilitate a reliable, secure economic approach for customer data communication for electric choice. Regardless of the standard or format identified, compliance with Commission orders relating to electronic data communications and the approved Internet protocol at Docket No. M-00960890F0015, is required for third-party access to EDC meter data. The third-party must be EDI tested and certified with the EDC and is free to transcribe that data into any format to meet the customer's specific needs. In order to achieve the capabilities of smart meter technology, however, EDCs are required to implement EDI Change Request #50 relating to 814 Enrollment and the new historical interval usage 867 HIU transactions. The 867 HIU must be updated to facilitate third-party exchange of interval usage at the meter level. A new 867 MIU transaction will also need to be developed and implemented for the exchange of monthly interval usage at the meter level. These and other developments necessary for the implementation of smart meter technology plans require EDC and third-party participation in the Commission's Electronic Data Exchange Working Group ("EDEWG"). The EDEWG is directed to create EDI capabilities for this purpose for implementation no later than January 1, 2010. One alternate solution to the use of EDI specifically for the purpose of smart meter technology implementation that would be acceptable, is the use of retail energy standards and formats relating to demand response and energy efficiency that would be developed for meter level data communication by the North American Energy Standards Board ("NAESB"). Such NAESB standards must be available for implementation no later than January 1, 2010, or at the end of the EDC generation rate cap period. A second alternate and expedient, interim solution is partnership with an EDI-compliant third-party contractor who in turn, would provide data to the customer's authorized agent in any format specified by agreement between those two parties.

E. EDC Cost Recovery

Act 129 allows an EDC to recover reasonable and prudent costs of providing smart meter technology, to include annual depreciation and capital costs over the life of the smart meter technology and the cost of any system upgrades required to enable the use of the smart meter technology, incurred after November 14, 2008, less operating and capital cost savings realized by the electric distribution company from the installation and use of the technology. Smart meter technology is deemed to be a new service offered for the first time under Section 2804(4)(vi).

1. Cost Recovery Mechanism

An EDC may recover smart meter technology costs through (1) base rates, including a deferral for future base rate recovery of current basis with carrying charge as determined by the Commission; or (2) on a full and current basis through a reconcilable automatic adjustment clause under Section 1307. 66 Pa. C.S. § 2807(f)(7). However, in no event shall lost or decreased revenues by an EDC due to reduced electricity consumption or shifting energy demand be considered a cost of the smart meter technology recoverable under a reconcilable automatic adjustment clause under Section 1307(b), except that decreased revenues and reduced energy consumption may be reflected in the revenue and sales data used to calculate rates in a distribution rate base rate proceeding filed under Section 1308 (relating to voluntary change in rates), or a recoverable cost. 66 Pa. C.S. § 2807(f)(4).

Act 129 allows an EDC to recover "all reasonable and prudent costs of providing smart meter technology." In order to determine what these costs are, each EDC will provide a careful estimate of all costs relating to its smart meter deployment and installation plan. These costs will include both capital and expense items relating to all plan elements, equipment and facilities, as well as an analysis of all related administrative costs. More specifically, these costs would include, but not be limited to, capital expenditures for any equipment and facilities that may be required to implement the smart meter plan, as well as depreciation, operating and maintenance expenses, a return component based on the EDC's weighted cost of capital, and taxes. Administrative costs would include, but not be limited to, costs relating to plan development, cost analysis, and reporting. In addition, the plan should include cost estimates for testing, upgrades, maintenance and personnel training. The EDC must also provide sufficient support to demonstrate that all such costs are reasonable and prudent with respect to its smart meter plan.

If an EDC decides to recover its smart meter technology costs through a reconcilable automatic adjustment clause tariff mechanism in accordance with 66 Pa. C.S. § 1307, The Commission will require that this mechanism be included in that EDC's smart meter plan. Such a mechanism shall be designed to recover, on a full and current basis from each customer class, all prudent and reasonable smart meter net costs. An EDC may only recover reasonable and prudent smart meter technology costs, to include "annual depreciation and capital costs over the life of the smart meter technology and the cost of any system upgrades that the [EDC] may require...incurred after [November 14, 2008,] less operating and capital cost savings realized by the [EDC] from the installation and use of the smart meter technology." 66 Pa. C.S. § 2807(f)(7). The mechanism shall be set forth in the EDC's tariff, accompanied by a full and clear explanation as to its operation and applicability to each customer class. The tariff mechanism will be subject to an annual review and reconciliation in accordance with 66 Pa. C.S. § 1307(e). Such annual review and reconciliation will be scheduled to coincide with the submission of the "Smart Meter Progress" annual report outlined in B.4.

2. Allocation of Costs to Customer Classes

The Commission will require that all measures associated with an EDC's smart metering plan shall be financed by the customer class that receives the benefit of such measures. In order to ensure that proper allocation takes place, it will be necessary for the utilities to determine the total costs related to their smart metering plans, as discussed in E.1. Once these costs have been determined, we will require the EDC to allocate those costs to the classes whom derive benefit from such costs. Any costs that can be clearly shown to benefit solely one specific class should be assigned wholly to that class. Those costs that provide benefit across multiple classes should be allocated among the appropriate classes using reasonable cost of service practices.

CONCLUSION

This Implementation Order establishes the Commission's smart meter technology procurement and installation standards each EDC plan must meet. This Order also provides guidance on the procedures to be followed for submittal, review and approval of all aspects of each smart meter plan. In addition, it established the Commission's minimum smart meter capability and guidance on deployment of smart meter technology. We extend our thanks to those who participated by providing comments on this crucial and timely energy program. We would especially like to note our appreciation for the cooperation and courtesy extended by all, which was essential in meeting the aggressive timelines established by the General Assembly for Act 129 implementation.

THEREFORE,

IT IS ORDERED:

1. That the Commission establishes specific smart meter technology minimum capabilities and procedures for submittal, review and approval of all aspects of each smart meter plan to include cost recovery.

2. That electric distribution companies with greater than 100,000 customers adhere to the guidelines for smart meter technology procurement and installation identified in this Implementation Order.

3. That all electric distribution companies that are required to file a smart meter technology procurement and installation plan do so by August 14, 2009.

4. That this Implementation Order be published in the *Pennsylvania Bulletin* and served on the Office of Consumer Advocate, Office of Small Business Advocate, Office of Trial Staff, and all jurisdictional electric distribution companies.

BY THE COMMISSION

James J. McNulty
Secretary

(SEAL)

ORDER ADOPTED:

ORDER ENTERED: