Reference Manual and Procedures for Implementation of the "PURPA Standards" in the Energy Independence and Security Act of 2007

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Preface

This manual was prepared by Kenneth Rose, a consultant and Senior Fellow at the Institute of Public Utilities at Michigan State University, and Mike Murphy, Graduate Research Associate at The Ohio State University. This manual was sponsored by the American Public Power Association (APPA), the Edison Electric Institute (EEI), the National Association of Regulatory Utility Commissioners (NARUC), and the National Rural Electric Cooperative Association (NRECA). This is intended to be used as an aid to state commissions and utilities as they consider the federal standards that are part of the Energy Independence and Security Act of 2007. This is not intended to provide any specific recommendations on the adoption of the standards or to suggest a course of action, beyond what is required by the 2007 Act and the Public Utility Regulatory Policies Act (PURPA) of 1978, as amended.

A Note on the Energy Independence and Security Act of 2007

The Energy Independence and Security Act of 2007 (EISA) contains four new PURPA standards and a fifth non-PURPA "standard." It should be noted at the outset that this new law presents an additional challenge to state commissions and utilities due to obvious errors in the drafting of the statute. As is explained in the text of the manual, these errors cause some confusion and ambiguity in the numbering of the standards and the timing of the requirements under PURPA, as amended. The interpretations and solutions provided in this manual are intended to be policy suggestions based on the wording provided in the law, and should not be viewed as legal advice or counsel. States and utilities should examine the wording of the statute and make their own determination.

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Overview and Background of the PURPA Standards in the Energy Independence and Security Act of 2007

1.1. Introduction

This reference manual is intended to be used as an aid to state commissions and utilities as they consider the new federal standards that are part of the Energy Independence and Security Act of 2007 (or EISA, sections 374, 531, 532, and 1307). This is an update of the 1979 "Reference Manual and Procedures for Implementing PURPA"[1] that provided assistance to commissions and utilities when they were implementing the Public Utility Regulatory Policies Act (PURPA) of 1978 and the 2006 "Reference Manual and Procedures for Implementation of the 'PURPA Standards' in the Energy Policy Act of 2005."[2] This manual is sponsored, as the 1979 and 2006 manuals were also, by the American Public Power Association (APPA), the Edison Electric Institute (EEI), the National Association of Regulatory Utility Commissioners (NARUC), and the National Rural Electric Cooperative Association (NRECA).

The purpose of this manual is to provide state commissions and utilities with resources and a discussion that can be used when addressing the new standards. The manual covers the four new PURPA standards that the 2007 statute added and a fifth federal standard that is not a PURPA standard, but has some similarities. This is not intended to provide any recommendations on the adoption of the standards or to suggest a course of action, beyond what is required by PURPA and EISA.

The manual is organized into two main sections. The first section summarizes state commission and nonregulated utility requirements under the EISA and includes

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[1] Electric Utility Rate Design Study, *Reference Manual and Procedures for Implementing PURPA*, A Report to the National Association of Regulatory Utility Commissioners, March 1979.

[2] Kenneth Rose and Karl Meeusen, *Reference Manual and Procedures for Implementation of the "PURPA Standards" in the Energy Policy Act of 2005*, March 22, 2006.

background on the original and subsequent standards. The first section also summarizes the implementation procedures and issues that need to be considered when implementing the standards. The second section defines each of the five new standards and provides a discussion of issues that may be considered when addressing the standards in commission and utility proceedings. This includes references and other resources that were used in the development of this manual and that may be useful in state commission and utility proceedings.

1.2. Background and Summary of the Federal PURPA Standards

The purpose of Title I ("Retail Regulatory Policies for Electric Utilities") of PURPA, as stated in the 1978 law, was to encourage: (1) conservation of energy supplied by electric utilities, (2) optimal efficiency of electric utility facilities and resources, and (3) equitable rates for electric consumers (PURPA section 101). PURPA originally included in Title I six federal standards in Subtitle B ("Standards for Electric Utilities"). The first five of these federal standards concerned customer rate determination and design. They dealt with: (1) cost of service, (2) declining block rates, (3) time-of-day rates, (4) seasonal rates, and (5) interruptible rates. The last federal standard in the 1978 law was (6) load management techniques. All six standards are listed in PURPA section 111(d).

PURPA stated that "each state regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility[3] shall consider each standard" and then "make a determination concerning whether or not it is appropriate to implement such standard" (PURPA section 111(a)). PURPA also states that "nothing in this subsection prohibits any state regulatory authority or nonregulated electric utility from making any determination that it is not appropriate to implement any such standard" (PURPA section 111(a)).

[3]This phrase used in PURPA "state regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility" is abbreviated in this manual as "state commissions and nonregulated utilities." PURPA defines a "nonregulated electric utility" as "any electric utility other than a state regulated electric utility."

From this language it is clear that while state commissions and nonregulated utilities are required to consider the standards, they are not required to adopt them. PURPA also states that state commissions and nonregulated utilities may adopt any standard, decline to implement any standard, or adopt different or modified standards from those described in the statute (PURPA section 117(b)). However, if they decline, they are required to state in writing the reason for their decision and make that statement available to the public (PURPA section 111(c)). State commissions and nonregulated utilities may also take into account prior determination on the standards if it complies with the requirement of Title I of PURPA (PURPA section 112(a)).

PURPA also specifies the "procedural requirements for consideration and determination" that state commissions and utilities are to follow. After "public notice and hearing" a state commission's or a utility's determination is to be made "(A) in writing, (B) based upon findings included in such determination and upon the evidence presented at the hearing, and (C) available to the public" (PURPA section 111(b)(1)). This appears to allow a range of consideration of the federal standards by state commissions and utilities, from a "paper" hearing, for example, where the commission makes a determination based on the written filings from interested parties, to a full evidentiary hearing with written testimony from expert witnesses, rebuttals, and an opportunity for cross-examination of the witnesses by the participating parties.

The Title I requirements apply to utilities with total annual retail sales greater than 500 million kilowatthours (kWh, or 500,000 megawatthours – MWh). Wholesale sales are explicitly excluded from this sales calculation. The baseline year for the retail sales calculation is two years before the year when the standards are being considered (discussed in more detail in section 2.3 of this manual).

If a state commission or nonregulated utility failed to comply and did not consider the PURPA 111(d) standards, then it was to be considered and a determination made in the first rate proceeding three years after the law was enacted (PURPA section 112(c)).

The Energy Policy Act of 1992 amended PURPA section 111(d) and added four additional federal standards. Three federal standards were in Title I ("Energy Efficiency") Subtitle B ("Utilities"), and required state commissions and utilities to consider (standard 7) integrated resource planning, (8) investments in conservation and demand management, (9) energy efficiency investment in power generation and supply. The tenth federal standard was in Title VII ("Electricity"), Subtitle A ("Exempt Wholesale Generators") of the 1992 Energy Policy Act, and added (10) "consideration of the effects of wholesale power purchases on utility cost of capital; effects of leveraged capital structures on the reliability of wholesale power sellers; and assurance of adequate fuel supplies."

There were five additional PURPA standards in the Energy Policy Act of 2005. They were (11) net metering, (12) fuel diversity, (13) fossil fuel generation efficiency (section 1251 of 2005 EPAct), (14) time-based metering and communications (section 1252) and (15) interconnection standards for distributed resources (section 1254). Implementation of these standards was the subject of the 2006 Reference Manual.

1.3. The New Standards and Requirements of the Energy Independence and Security Act of 2007

The President signed the Energy Independence and Security Act of 2007 into law on December 19, 2007, which is the date of enactment for purposes of the deadlines set by the law. The statute adds four new federal standards to PURPA section 111(d) for state commissions and utilities to consider and a fifth "standard" that is not labeled as a PURPA standard, but is similar in some respects. The title, table of contents, and the relevant sections of EISA are reproduced in the Appendices (A, B, and C) of this manual.

The first two PURPA standards in EISA are (16), "Integrated Resource Planning " and (17), "Rate Design Modifications to Promote Energy Efficiency Investments" (Subtitle D, "Energy Efficiency of Public Institutions," section 532 of EISA, sections 111(d)(16) and (17) of PURPA).[4] The section of the statute with these new PURPA standards are shown in Box 1.[5]

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[4]These standards are similar to PURPA 111(d) standards (7) and (8) that were added by the Energy Policy Act of 1992.

[5]Section 532 of EISA also includes PURPA standards for natural gas utilities that are very similar to standards 16 and 17. This is an amendment to section 303(b) of PURPA Title III, "Retail Policies for Natural Gas Utilities". The implementation of these

Box 1. Section 532 PURPA 111(d) Standards.

(16) INTEGRATED RESOURCE PLANNING.—Each electric utility shall—

> (A) integrate energy efficiency resources into utility, State, and regional plans; and
>
> (B) adopt policies establishing cost-effective energy efficiency as a priority resource.

(17) RATE DESIGN MODIFICATIONS TO PROMOTE ENERGY EFFICIENCY INVESTMENTS.—

> (A) IN GENERAL.—The rates allowed to be charged by any electric utility shall—
>
> > (i) align utility incentives with the delivery of cost-effective energy efficiency; and
> >
> > (ii) promote energy efficiency investments.
>
> (B) POLICY OPTIONS.—In complying with subparagraph (A), each State regulatory authority and each nonregulated utility shall consider—
>
> > (i) removing the throughput incentive and other regulatory and management disincentives to energy efficiency;
> >
> > (ii) providing utility incentives for the successful management of energy efficiency programs;
> >
> > (iii) including the impact on adoption of energy efficiency as 1 of the goals of retail rate design, recognizing that energy efficiency must be balanced with other objectives;
> >
> > (iv) adopting rate designs that encourage energy efficiency for each customer class;
> >
> > (v) allowing timely recovery of energy efficiency-related costs; and
> >
> > (vi) offering home energy audits, offering demand response programs, publicizing the financial and environmental benefits associated with making home energy efficiency improvements, and educating homeowners about all existing Federal and State incentives, including the availability of low-cost loans, that make energy efficiency improvements more affordable.

Two additional PURPA 111(d) standards are also in section 1307 of EISA. Confusingly, these are labeled with the same standard numbers as the section 532 standards. They are labeled as (16) Consideration of Smart Grid Investments and (17)

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section 303(b) PURPA standards for natural gas utilities is not covered in this report.

Smart Grid Information. A truncated version of the statute's text of these standards is shown in Box 2. The full text of the standards is shown in Appendix B.

Box 2. Section 1307 PURPA 111(d) Standards.

(16) CONSIDERATION OF SMART GRID INVESTMENTS.—

(A) IN GENERAL.—Each State shall consider requiring that, prior to undertaking investments in nonadvanced grid technologies, an electric utility of the State demonstrate to the State that the electric utility considered an investment in a qualified smart grid system based on appropriate factors, including—

(i) total costs;
(ii) cost-effectiveness;
(iii) improved reliability;
(iv) security;
(v) system performance; and
(vi) societal benefit.

(17) SMART GRID INFORMATION.—

(A) STANDARD.—All electricity purchasers shall be provided direct access, in written or electronic machine-readable form as appropriate, to information from their electricity provider as provided in subparagraph (B).

(B) INFORMATION.—Information provided under this section, to the extent practicable, shall include:

(i) PRICES.—Purchasers and other interested persons shall be provided with information on—

(I) time-based electricity prices in the wholesale electricity market; and

(II) time-based electricity retail prices or rates that are available to the purchasers.

(ii) USAGE.—Purchasers shall be provided with the number of electricity units, expressed in kwh, purchased by them.

(iii) INTERVALS AND PROJECTIONS.—Updates of information on prices and usage shall be offered on not less than a daily basis, shall include hourly price and use information, where available, and shall include a day-ahead projection of such price information to the extent available.

(iv) SOURCES.—Purchasers and other interested persons shall be provided annually with written information on the sources of the power provided by the utility, to the extent it can be determined, by type of generation, including greenhouse gas emissions associated with each type of generation, for intervals during which such information is available on a cost-effective basis.

1.3.1. Time Limitations

The time limits for the PURPA standards are summarized here in this section. They are discussed again in section 2.5, along with a diagram of the compliance time lines, and also in the standard-specific sections of this manual. For the first two PURPA standards in section 532 of the new 2007 statute, a time limit for how long states and utilities have to begin consideration and make a determination is not specified. Time limits are specified in PURPA section 112, however, this section of PURPA was amended by the Energy Policy Act of 1992 and again in 2005 to refer to specific standards and with two different time limits.

The compliance deadlines for the Smart Grid section 1307 standards are specified in the statute (section 1307(b)(1) of EISA, "Time Limitations," amended section 112(b) of PURPA). The deadline for compliance is one year after enactment (December 19, 2008). By that date, state commissions and nonregulated utilities are to begin consideration or set a hearing date for consideration. Within two years after enactment (December 19, 2009) state commissions and utilities are to have completed their consideration and made a determination on whether or not to adopt the standards.

Unfortunately, the standard numbers referred to in this subsection of the new statute are inconsistent and likely erroneously labeled. EISA's "Time Limitation" language refers to "the standards established by paragraphs (17) through (18) of section 111(d)" of PURPA (section 1307 (b)(1) of EISA). If they were labeled sequentially in the statute, these would be labeled as standards (18) and (19) or the subsection would reference all the new 2007 standards (16) through (19).[6] This ambiguity makes it unclear if this time limit refers to just the Smart Grid standards of section 1307, just standard (17) "Smart Grid Information," both standards labeled as "(17)," or if it refers to all four of the numbered standards. There is no standard labeled as "(18)" anywhere in the statute. It therefore has no corresponding standard or reference to a standard.

[6] Of course, they could be labeled in a different sequence than the order they appear in the 2007 statute.

A plain reading of the section suggests that the time limits only apply to the standard numbers specified in the statute.[7] Therefore, for both standards labeled (17) ("Rate Design Modifications to Promote Energy Efficiency Investments" and "Smart Grid Information"), state commissions and nonregulated utilities have one year after enactment (December 19, 2008) to begin consideration or set a hearing date for consideration and up to two years after enactment (December 19, 2009) to complete their consideration and make a determination on whether or not to adopt the standard. Since no time limit is specified for the standards labeled (16) ("Integrated Resource Planning" and "Consideration of Smart Grid Investments") and, as noted, PURPA section 112(b) has been amended to refer to specific standards in past legislation, there simply are no time limits specified for the states and utilities to begin consideration and make a determination.

It may be advisable to consider all four of the standards in the same time frame since the standards labeled (16) are related to the subsequent standards labeled (17) of the same section of EISA.

1.3.2. Failure to Comply

PURPA stipulated the consequences for failure to comply, that is, when a state regulatory commission or nonregulated utility fails to meet the statutory time frame. If this occurs, the standard or standards are to be considered and a determination made in the first rate proceeding three years after the law was originally enacted in 1978 (PURPA section 112(c)), if the standards were not already considered in a separate hearing. In 2005, Section 112(c) was amended to state that the "date of enactment" should be considered the date of enactment of PURPA section 111(d)(11) through (15).

There is a similar provision for a failure to comply in section 1307 of EISA (section 1307(b)(2)), accompanying the two smart grid standards. That section amends PURPA section 112(c) to require that if the standard is not considered and a determination made by the statutory deadline, then it shall be considered in the first rate

[7] While perhaps inelegant, a plain interpretation is the only option available. Otherwise Congressional intent would have to be inferred. Authority to judge Congressional intent is beyond the scope of the parties involved with this document.

proceeding after three years after enactment, with the date of enactment for the 2007 PURPA standards being considered the actual date of enactment for those standards (as noted, December 19, 2007). Here again, the numbering of the 2007 standards are likely in error, section 1307(b)(2) of EISA refers to standards (16) through (19) of PURPA 111(d). That would be the correct sequence of all the numbered standards in the 2007 statute, if they were numbered in sequence. While confusing and probably in error, it does not present a problem for any of the numbered standards since the same three year time frame is given of all the PURPA standards for failure to comply and all four standards in the statute are numbered (16) or (17), which is included in the subsection. There simply are no standards (18) and (19) or references to them.

The practical effect of the language in EISA section 1307(b)(2) is to establish a deadline for consideration of all four new standards in the EISA, including the two PURPA section 111(d)(16) standards for which there would not otherwise have been any deadlines due to the confusion in numbering. If any of the four standards has not been considered for a utility by December 2010, it must be considered in that utility's next rate case.

1.3.3. Prior State Actions

Prior actions are “grandfathered” under most subsections of PURPA section 111 if (1) the state implemented the standard or a comparable standard, (2) the state commission or nonregulated utility has conducted a proceeding to consider implementation of the standard or a comparable standard, or (3) the state’s legislature voted on implementation of the standard or comparable standard (section 112(d), (e), and (f) of PURPA). If these conditions are met with respect to most standards, the obligation to consider the standards is waived and no new consideration process is required. However, when Congress enacted EISA, it misnumbered the grandfathering provisions as well.

Section (1307(b)(3)), which includes the grandfathering provisions for the new EISA standards, references only standards (17) and (18). A plain reading again (as with the time limitations subsection) would mean that both standards labeled (17) would have the PURPA section 112(d) three grandfathering conditions apply. However, the two standards labeled (16) *have no prior state action waiver* since PURPA was amended previously to refer to specific standards and the 2007 statute only amends PURPA for the standards labeled as (17) (and a standard "(18)," which does not exist). States and nonregulated utility are, therefore, required to consider and make a determination on the standards labeled 111(d)(16), even if they had previously considered those standards or comparable standards. Of course, if there were prior actions by the state or utility, that could be considered when making a decision on whether or not to adopt the standard.

For the standards labeled (17), there was no time limit specified as to when these prior state actions should have occurred for the waiver to apply. This means that previous consideration of the standards or comparable standards by the states and nonregulated electric utilities should fall under the grandfathering provision, no matter how far back in the past they took place.

The risk that states and nonregulated utilities take in this plain interpretation of the statute is that it could be challenged by a party that believes that the time limits specified in section 1307(b)(1) for standard 111(d)(17) (that is, as noted above, one year to begin consideration and up to two years to make a determination) applies to the standards labeled as (16) as well (rather than no time limit at all). However, the consequence of being incorrect in this interpretation is not that severe since it would mean that the PURPA "failure to comply" subsection (section 112(c)) would then apply, since this was amended to apply to all four of the numbered standards labeled (16) and (17) (and two standards that do not exist). This would mean that states and nonregulated utilities would have to consider and make a determination in the first rate proceeding three years after the date of enactment (or December 19, 2010). If states and nonregulated utilities complete their determination within three years, they would have already complied with the statutory requirements.

1.3.4. Non-PURPA Standard

The Energy Independence and Security Act of 2007 also added a standalone "standard" that is not an amendment to PURPA. This is in section 374, "Additional Incentives for Recovery, Use, and Prevention of Industrial Waste Energy." Subsections

(a) and (b) of the standard are reproduced in Box 3. The complete text of the standard is in Appendix C. This standard has specific options and implementation procedures that are similar to the PURPA procedures, but not identical. For this reason, the options, procedures, and implementation of this standard are dealt with separately in section 6 of this manual.

Box 3. Section 374 (Non-PURPA) Standard (subsections (a) and (b) only).

ADDITIONAL INCENTIVES FOR RECOVERY, USE, AND PREVENTION OF INDUSTRIAL WASTE ENERGY.

(a) CONSIDERATION OF STANDARD.—

(1) IN GENERAL.—Not later than 180 days after the receipt by a State regulatory authority (with respect to each electric utility for which the authority has ratemaking authority), or nonregulated electric utility, of a request from a project sponsor or owner or operator, the State regulatory authority or nonregulated electric utility shall—

(A) provide public notice and conduct a hearing respecting the standard established by subsection (b); and

(B) on the basis of the hearing, consider and make a determination whether or not it is appropriate to implement the standard to carry out the purposes of this part.

(2) RELATIONSHIP TO STATE LAW.—For purposes of any determination under paragraph (1) and any review of the determination in any court, the purposes of this section supplement otherwise applicable State law.

(3) NONADOPTION OF STANDARD.—Nothing in this part prohibits any State regulatory authority or nonregulated electric utility from making any determination that it is not appropriate to adopt any standard described in paragraph (1), pursuant to authority under otherwise applicable State law.

(b) STANDARD FOR SALES OF EXCESS POWER.—For purposes of this section, the standard referred to in subsection (a) shall provide that an owner or operator of a waste energy recovery project identified on the Registry that generates net excess power shall be eligible to benefit from at least 1 of the options described in subsection (c) for disposal of the net excess power in accordance with the rate conditions and limitations described in subsection (d).

An important difference of note concerning this non-PURPA standard is that this standard does not specify a minimum size of utility over which the standard applies, as does Title I of PURPA (that is, total annual retail sales greater than 500,000 MWh, as discussed in section 2.3 of this manual). This essentially means that it must be considered by state commissions for all their jurisdictional utilities and by all nonregulated utilities.

2. Implementation Procedures and Issues for the PURPA Standards

PURPA did not change the responsibility of states or nonregulated utilities with respect to authority to determine electric rates. However, Title I did impose certain obligations on states commissions and nonregulated utilities and gives certain rights to persons to go before state commissions and state courts. This section delineates these responsibilities and obligations.

Each state commission and covered nonregulated utility must make its own independent determination on the new PURPA standards. This manual suggests general procedures for implementing the provisions of the new law, issues that may be considered when evaluating the standards and deciding whether or not to adopt them, and it provides a reference to further information. This is intended as a general guide to the procedures and an aid to the evaluation process, not a substitute for the state or nonregulated utilities' own evaluation. Because states have different laws and procedures, some have already addressed the issues raised by the standards, and some may have already adopted comparable standards, each state and affected nonregulated utility needs to consider how the standards fit with their conditions, procedures, and prior actions.

2.1. Purposes and goals of PURPA

As noted in the summary, the stated purpose of the PURPA Title I standards are to encourage (1) conservation of energy supplied by electric utilities, (2) optimal efficiency of electric utility facilities and resources, and (3) equitable rates for electric consumers (PURPA section 101). The Conference Committee Report[8] that accompanied the passage of PURPA explained further that the first purpose of the Title was to foster conservation by end-users of electricity. The second purpose was directed at utilities and their use of energy and their facilities, including capital resources, and intended this to include "conserving scarce energy resources by techniques of rate reform which substitute the use of more plentiful resources produced in the United States in lieu of less plentiful resources, especially those imported into this

[8]"Joint Explanatory Statement of the Committee of Conference," Conference Committee Report accompanying Public Law 95-617 (PURPA), 1978.

country."[9] Nothing further was added to the third purpose beyond what was said in the statute, that is, that it was intended to encourage equitable rates for consumers.

The Conference Committee Report states that the purposes are independent of one another and not listed in order of preference or priority. Also noted by the conferees is that it is not necessary that all three purposes be achieved, "[r]ather, if any of these purposes is achieved and the others are not negatively impacted, a finding can be made that the purposes of the title are carried out."[10]

The legislators that passed PURPA (in the Conference Committee Report) intended that consideration of the standards focus on how implementation would affect each utility and its consumers in terms of the three Title I purposes. That is, would implementation aid energy conservation by consumers? Would it help the utility optimize the efficient use of resources and facilities? Would it provide equity to rate payers? Other purposes may be considered as well to comply with state law or to meet policy goals set be the state commission.[11]

2.2. State commission and nonregulated utility responsibilities and obligations

A primary responsibility for state commissions and nonregulated utilities is to consider and make a specific determination on whether implementation of the federal standards is appropriate to carry out the Title I purposes (PURPA section 111(a)). State commissions and nonregulated utilities may implement any standard or decline to implement any standard. However, if they decline, they are required to state in writing the reason for their decision and make that statement available to the public (PURPA section 111(c)). State commissions and nonregulated utilities may also take into account prior determination on the standards if it complies with the requirement of Title I (PURPA section 112(a)). State commissions and nonregulated utilities are not prohibited from modifying any standard, adopting additional standards, or more or less

[9]Conference Committee Report, p. 69.

[10]Conference Committee Report, p. 69.

[11]Conference Committee Report, p. 70.

stringent standards, or only some of the standards, to the extent that is permitted by state law (PURPA section 117(b)).

In addition to obligating state commissions and nonregulated utilities to consider and make a determination on each standard, PURPA Title I also requires state commissions and nonregulated utilities to consider the standards and make a determination when requested to do so by a participant or intervenor in a proceeding relating to rates (PURPA section 112).

The legislators expected that state commissions and nonregulated utilities would consider the impact of federal standards with respect to the PURPA stated purposes on a particular utility and its customers, and consider utility-specific conditions and circumstances when conducting the evaluation.[12]

2.3. Definitions and application

A particularly important question, and one that determines which companies the PURPA Title I requirements apply to, is: what is an electric utility? PURPA originally defined the term “electric utility” as “any person, State agency, or Federal agency, which sells electric energy.” PURPA also defines a “nonregulated electric utility” as simply “any electric utility other than a State regulated electric utility”[13] and a “State regulated electric utility” as “any electric utility with respect to which a State regulatory authority has ratemaking authority.” Today, more than three thousand entities fit the definition of an electric utility since they “sell electric energy.” However, PURPA reduces that number by stating that the Title only applies to utilities with total annual retail sales greater than 500 million kilowatthours (kWh, or 500,000 megawatthours – MWh, PURPA section 102(a)) and explicitly excludes wholesale sales from the sales calculation (PURPA section 102(b)).

The baseline year for the calculation is two years before the year when the standards are being considered. For example, if a hearing or proceeding is being held

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[12] Conference Committee Report, p. 70.

[13] This manual also uses the term “nonregulated utility” to refer to the same type of companies with respect to the requirements of the PURPA federal standards.

in 2006, retail sales data from 2004 should be used to determine if there is Title I compliance requirement (PURPA section 102(a)).[14] No further guidance is provided in the statute or in the Conference Committee Report regarding the utilities to which the requirements apply. This implies that even if the utility may soon qualify in some future year, if it did not reach the 500,000 MWh threshold in the baseline year, as calculated during the standard's consideration and determination period, the Title I requirements would not apply. If at any time during the consideration and determination period the threshold is crossed, however, the Title I provisions may then apply.

Under PURPA, the Department of Energy (DOE) is required to publish a list identifying each electric utility that Title I applies to (PURPA section 102(c)).[15] Afterwards, each state commission is to notify DOE of which companies on the list the state commission has ratemaking authority. It is important to recognize, however, that the burden of determining eligibility under the Title I requirements falls on the utility companies. Potentially affected electric utilities need to determine if their company qualifies. State commissions need to indicate whether the utility is state jurisdictional. The Conference Committee Report states that the DOE list is intended to reduce uncertainty as to which companies are covered and the requirement that state commissions identify which companies that it has ratemaking authority is intended to distinguish regulated electric utilities from nonregulated utilities. The conferees stressed that the DOE list is informational and for the convenience of the public, and does not affect the legal obligations of utilities or state commissions. The conferees note that even if a utility is not listed, it could still be covered, and conversely, if they are on the DOE list, a utility may not be covered.

At the time this manual was being prepared, DOE had not yet published an updated list of covered utilities, as required under PURPA Title I. However, this does

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[14]This baseline year description is taken from the Conference Committee Report that states: "the baseline year is two years before the year in question." Conference Committee Report, p. 69.

[15]DOE posted a list of electric utilities in 2006 (for implementation of the standards in the Energy Policy Act of 2005) on their web site at: http://www.oe.energy.gov/DocumentsandMedia/PURPA_2006_final.pdf

not release state commissions and nonregulated utilities from making their own determination on eligibility or any obligations they may have to comply with the requirements under PURPA.

Another important consideration is wholesale sales and the changing structure of the electric supply industry. As noted, wholesale sales are explicitly excluded from the sales calculation (PURPA section 102(b)) to determine if annual retail sales are greater than 500,000 MWh. In recent years, the percentage of electric generating capacity of electric utilities has decreased considerably. In 1993, electric utilities accounted for 93 percent of the net summer capacity and independent power producers had less than two percent of the total capacity. By 2004 electricity utilities accounted for 57 percent of the total net summer capacity, while the independent power producers' share had grown to 36 percent. This has been due to the reclassification of electric utility capacity to independent power as generating units are sold or transferred to an affiliate and from independent power producers building new capacity.

This shift from utility to independent power requirement, means that fewer generating companies (and a lower percentage of the total kilowatt hours sold) will be subject to the Title I requirements than in 1978 or 1992 laws (but about the same as the 2005 law). Of course, some utilities have always been or have been for many years all requirements customers, purchasing all the company's needs from others.

Since there are different types of electric utility companies, either by tradition or because of the restructuring of the industry, whether the PURPA requirements apply and the state commission or nonregulated utility must consider the standards, breaks down into four basic categories of utilities. First are vertically integrated utilities, that generate all or some of the company's power needs and distribute power to retail customers, and have total annual retail sales greater than 500,000 MWh. These utilities can implement all of the new federal standards in EISA. Second, those companies that are distribution only and own no generation, and have total annual retail sales greater than 500,000 MWh, would most likely be able to implement the new federal Smart Grid standards (the section 1307 standards) and standard (17) of section 532 (Rate Design Modifications to Promote Energy Efficiency Investments). These may also apply to transmission only companies, to the extent that they are covered under the PURPA section 102 definition. However, it would have to be determined if these companies would be in a position to implement standard (16) of section 532 (Integrated Resource Planning or IRP).

Because these utilities do not own or control generation capacity, they cannot address generation and demand resource use *directly*. However, if the utility is buying power supply from someone else for resale to its own retail consumers, it may still have an obligation to consider whether to adopt the standard indirectly, through its power supply contracts. For example, IRP typically balances demand-side options with supply options, including "conventional" and renewable resources. Consequently an IRP process could take these options into consideration when planning long-term wholesale purchases. Unfortunately, the 2007 and the previous statutes are not explicit on the types of utilities and their obligations to consider the standards.

The third category includes generation owning companies with retail customers, and total annual retail sales greater than 500,000 MWh.[16] They would be able to implement new federal standard (16) of section 532 (Integrated Resource Planning) and standard (17) of section 532 (Rate Design Modifications to Promote Energy Efficiency Investments). However, because these companies do not own distribution facilities and do not control the metering of customer usage and connection to the distribution system, they would not be in a position to implement the Smart Grid standards of section 1307.

Finally, the fourth category of companies are generation only with no retail customers that sell wholesale only or those that have total annual retail sales of less than 500,000 MWh in the baseline year. Since these companies are not included in the definition of section 102 of PURPA, they would not be subject to the new federal standards.

2.4. Procedural requirements for consideration and determination

PURPA specifies the procedural requirements for consideration of the standards. Consideration is to be made after public notice and hearing and the determination is to

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[16]This could include aggregators or retail marketers with some generation, but no distribution facilities.

be made (1) in writing, (2) based upon findings and on evidence presented in the hearing, and (3) available to the public (PURPA section 111(b)). This definition typically conforms to state hearings.

A report by the National Regulatory Research Institute (NRRI) from 1993,[17] noted that state commissions could use expedited procedures, such as a “paper hearing” or abbreviated hearing, where the parties submit written direct and rebuttal testimony, with an abbreviated hearing for cross-examination. Other options for state commission procedures (and nonregulated utilities as well) cited in the report are collaborative processes, such as a problem-solving workshop, an open technical conference, or negotiated rulemaking. These options could be used as long as they comply with the conditions specified by PURPA for a hearing. (The results of a survey from this NRRI report on what type of processes state commissions were planing to use for the 1992 standards is summarized below.)

The schematic shown in Figure 2.1 is based on a figure from the 1979 Reference Manual.[18] This schematic explains the relationship of the Title I provisions to each other and to state law and policy in summary form. More detail is provided on some of the more important provisions in the following sections.

As noted, the procedural requirements under PURPA placed on state commissions and nonregulated utilities when considering each standard are to provide a public hearing, after adequate public notice, and make a determination in writing (PURPA section 111(b)(1)). This determination must include written findings, be based on the evidence established in the hearing, and be available to the public. In outline form, the procedural responsibilities imposed on DOE, state commissions, and nonregulated utilities by PURPA are (as shown in Figure 2.1):

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[17] Robert E. Burns and Mark Eifert, “A White Paper on the Energy Policy Act of 1992: An Overview for State Commissions of New PURPA Statutory Standards,” NRRI 93-6 (Columbus, OH: NRRI, April 1993).

[18] Electric Utility Rate Design Study, *Reference Manual and Procedures for Implementing PURPA*, p. 2-8.

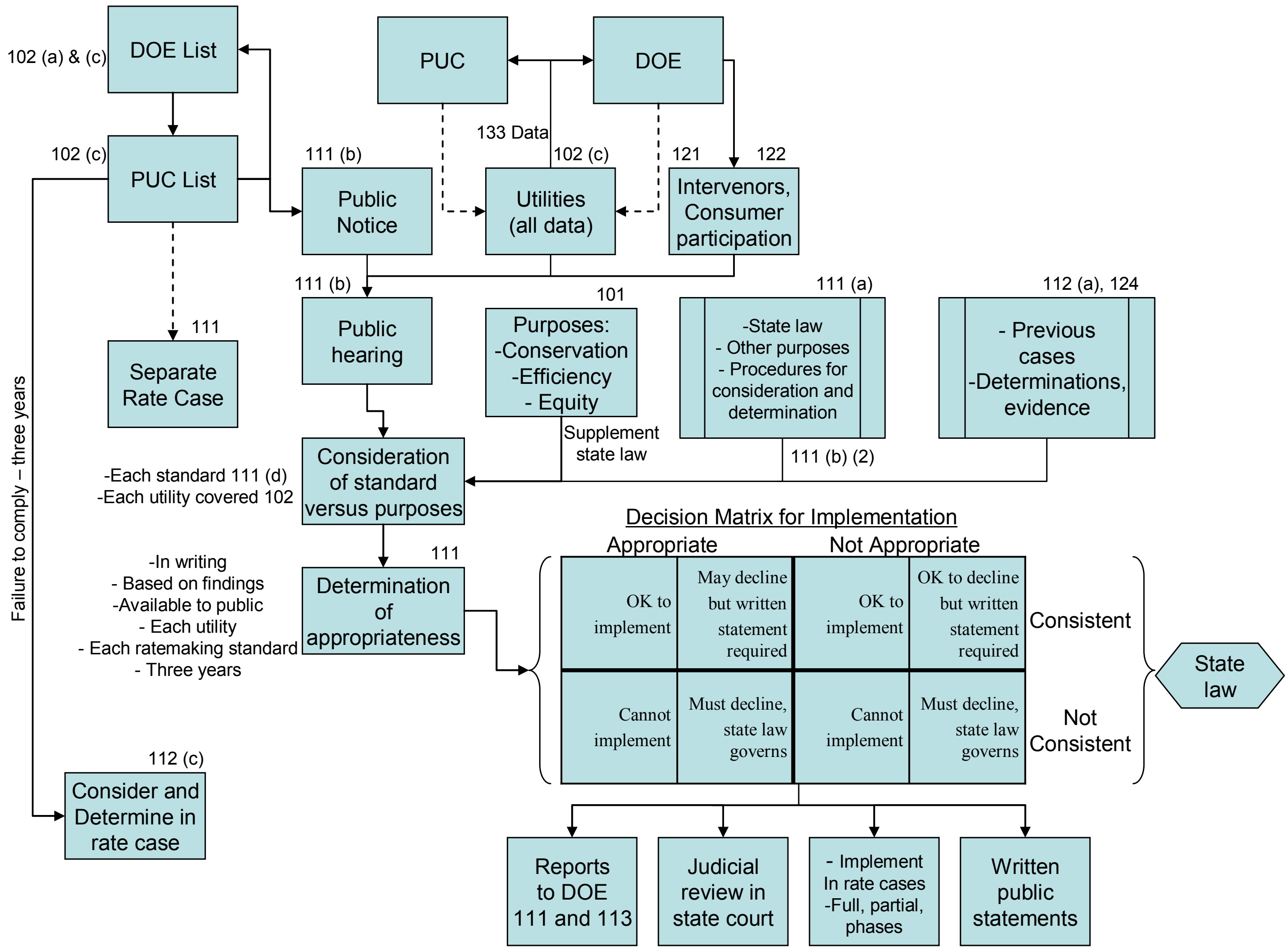

Figure 2.1. Procedures for considering PURPA 111 standards.
Source: “Reference Manual and Procedures for Implementing PURPA,” 1979.

- PURPA requires DOE to publish a list of utilities to which the Title I provisions apply
- From the DOE list, the state commissions identify the utilities under its ratemaking jurisdiction and then notifies the Department of Energy of each electric utility covered by Title I and over which the state commission has ratemaking authority;
- State commissions and nonregulated utilities decide on the hearing process to consider the federal standards, alternatives include:
    - rulemaking
    - generic – all utilities in one hearing (non-rate level)
    - generic – followed by
        - individual utility hearings separate from rate application hearings
        - company-specific findings in conjunction with rate hearings
- State commissions and nonregulated utilities issue public notice, or orders as appropriate under state law, of forthcoming hearings on federal standards
    - Public notice of generic hearings on the federal standards may include, depending on state law:
        - timing and description of procedural steps as dictated by PURPA and state law
        - participants, intervenors, and consumer representation
        - scope
        - listing of three PURPA purposes (PURPA section 101)
        - procedure for incorporating determinations and evidence from prior proceedings (PURPA sections 112 and 124)
        - responsibilities of commission staff
- State commissions and nonregulated utilities prescribe filing requirements for:
    - data, information, and analysis
    - any filing exemptions
- State commissions and nonregulated utilities conduct public hearings using procedures established by the state commissions or nonregulated utilities and consistent with PURPA provisions

- State commissions and nonregulated utilities undertake consideration of each ratemaking standard generally, and for each utility, considering:
    - three purposes of PURPA
    - other purposes identified by the state commission or nonregulated utility pursuant to state law
    - findings and evidence from previous hearings held
- State commissions and nonregulated utilities determine appropriateness of each federal standard:
    - in writing, available to public
    - based on evidence in hearing
    - for each utility (perhaps for each customer class)
    - by the deadlines prescribed (Figure 2.2)
    - in relation to the three purposes of PURPA and other state law purposes, if identified
- State commissions and nonregulated utilities decide (Decision Matrix in Figure 2.1) on implementation of each federal standard for each utility (for each customer class):
    - considering other purposes, if identified
    - complying with state law
    - ordering implementation if so decided (full, partial, or phased-in)
    - explaining in writing if *not* implemented
- State commissions and nonregulated utilities consider and determine all of the above in "next" rate case after December 19, 2010 if not done before that date

2.5. Time limitations for compliance

The original PURPA had time requirements for when the Title I standards were to be considered and a determination made. EISA established specific time limits in section 1307 (State Consideration of Smart Grid). The time limits provided are one year to begin consideration (December 19, 2008) and a two year limit to make a determination (December 19, 2009). As discussed in the first section of this manual, the standards are most likely misnumbered and the standards reference by number in

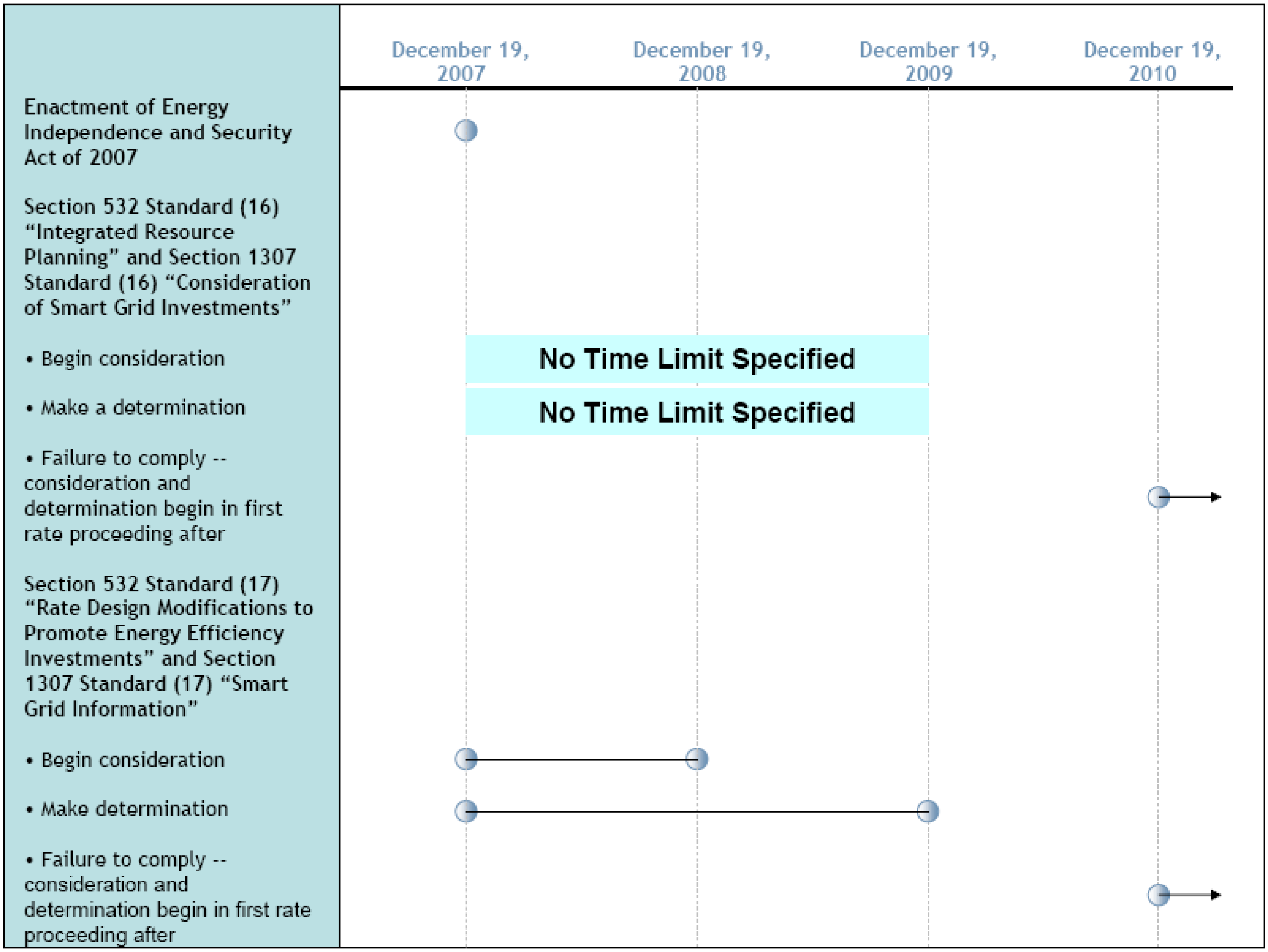

Figure 2.2. Compliance deadlines for PURPA standards in the Energy Independence and Security Act of 2007.

section 1307 are also likely in error. Consequently, there is no time limit specified for the two standards labeled (16) and the time limitation specified in section 1307 only applies to the standards labeled (17).

The time limits for the EISA standards are depicted in Figure 2.2. They are also discussed in the standard-specific sections of this manual.

2.6. Failure to comply

If a state commission or nonregulated utility does not consider and make a determination on the standards by the time prescribed by the PURPA requirements, they are to do so in the first rate proceeding applicable to the utility after three years have passed after the date of enactment, or after December 19, 2010 (PURPA section 112(c)).

There are no monetary penalties specified in the statute. However, as discussed below (in the subsection "Judicial review and enforcement"), any person may bring an action to enforce the requirements of Title I in the appropriate state court as outlined in the statute. In the event of a failure to comply, this process would begin in the first rate case after December 19, 2010 for all of the standards. The final outcome of any subsequent court proceedings would, of course, be uncertain.

As noted in the first section of this manual, this provision was amended to apply to all of the numbered standards in the 2007 statute.

2.7. Implementation issues

2.7.1. State Commission actions on previous PURPA standards

It may be useful to consider how state commissions implemented the 1978, 1992, and 2005 federal standards. NARUC conducted a survey of state commissions in 1982 on the PURPA activities.[19] This was after the deadline had passed for when the state commissions and utilities were to have completed the consideration and make a decision on the PURPA standards (which was November 8, 1981, after which the

[19]Paul Rodgers and Charles D. Gray, "Second Report on State Commission Progress Under the Public Utility Regulatory Policies Act of 1978, (Washington, D.C.: NARUC, October 20, 1982).

standards were to be considered in the next rate case).[20] A response was received by 41 of the 54 commissions and agencies[21] that were sent a questionnaire. The survey found that in the "vast majority" of cases, state commissions considered the PURPA section 111 federal standards on a utility-specific basis, rather than through generic proceedings.[22] The survey response on the section 111 standards involved 127 utilities. The commissions reported that for about one-fourth of the utilities the standards were still under consideration. However, for most utilities the standards were adopted or implemented.[23] There were relatively few rejections of the standards. Five of the six standards were rejected by the commissions for eight or fewer utilities. One standard (seasonal rates), was rejected for 19 utilities (in contrast, this standard was implemented for 47 utilities).

The reason why about one-fourth of the utilities were still having the standards considered by the state commissions after the deadline had passed likely may have been litigation involving PURPA. The NARUC survey report states that in June 1982, the U.S. Supreme Court upheld the constitutionality of PURPA and reversed an earlier Federal District Court decision that struck down Titles I, II, and III of PURPA as applied

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[20] This may have been the last survey conducted on state commission consideration of the 1978 federal standards. The cover letter that accompanied the questionnaire indicated that the Department of Energy was likely discontinuing its survey of state commissions on PURPA activity.

[21] This number included the 50 state commissions, the District of Columbia Commission, the Tennessee Valley Authority, the Texas Railroad Commission, and the Power Authority of the State of New York.

[22] In contrast, for the PURPA section 113 or "Regulatory Standards," most commissions reported in the survey that these standards were considered through generic proceedings – that is, where all the affected utilities were considered in a single case or rulemaking procedure.

[23] The survey defined "adopted" when the standard was adopted after the commission considered the standard, reached its decision, and found in favor of the standard. "Implemented" was defined as when the standard was considered, adopted, or ordered to be put into effect, and customers were actually having it applied to them.

to state commissions.[24] The report states that prior to the Supreme Court decision, "a number of states, in reliance on the District Court decision, had suspended their PURPA related activities." The report notes that with the resolution of the statute's constitutionality, these states would resume and complete their PURPA activities.

A survey conducted by NRRI in early 1993 addressed state commission plans to consider the standards in the 1992 EPAct.[25] This survey asked about plans to open a docket and the process used by the commission to consider the standards. Of the 38 state commissions that responded to the survey, two-thirds had either opened a docket (ten states) on the standards or planned to open a docket shortly thereafter (14 states). On the process chosen for consideration and making a determination on the standards, 15 states chose informal rulemaking, eight states chose adjudicatory hearings, and five states chose paper hearings. No state commission chose negotiated rulemaking or alternative dispute resolution procedures.

The Interstate Renewable Energy Council (IREC) has been conducting a monthly survey of state implementation of the 2005 EPAct net-metering and interconnection standards.[26] The most recent survey available at this time shows that most states had made a decision on both of these standards (41 of the commissions had adopted, rejected, or modified the standards) or still were considering it (nine states were considering one or both). This survey does not summarize the procedures used by the states, however, it does provide links to the specific docket, case, or order number and has references to related state legislation.

The Federal Energy Regulatory Commission (FERC) in a 2007 staff report on demand response and advanced metering included a survey of state activity on the 2005 EPAct section 1252 standards (smart metering and interconnection).[27] The survey

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[24]From the NARUC survey report, this case is cited as: *FERC v. Mississippi*, 50 U.S.L.W. 4566 (June 1, 1982).

[25]Burns and Eifert, "A White Paper on the Energy Policy Act of 1992," p. 5.

[26]A link to this survey is available at: http://www.irecusa.org/index.php?id=31

[27]"2007 Assessment of Demand Response and Advanced Metering." Staff Report, Federal Energy Regulatory Commission, September 2007. Available at: http://www.ferc.gov/legal/staff-reports/09-07-demand-response.pdf

information is current as of July 1, 2007. At that time, 27 states had open proceeding on these standards, 12 had closed their proceedings, two states had adopted the standards, 11 decided to not adopt the standards, and four states deferred a decision to adopt. The FERC staff survey also has a state-by-state summary of state actions.

2.7.2. State authority

PURPA did not take the primary responsibility over electric utility rates from the states. The Title I standards imposed certain obligations on state regulatory commissions and gave certain rights to persons to go before state regulatory commissions and state courts. However, under PURPA and its amendments, states retain primary responsibility with respect to retail electric rates. PURPA and the three purposes are intended to supplement state law, but do not override state law.[28] Also, states may consider other purposes as well that are not specified by PURPA. State commissions and nonregulated utilities are not required to take actions that conflict with state law. The legislators' intention was to preserve the discretion of state commissions and nonregulated utilities that is provided by state law – except to the extent that Title I imposes *procedural* requirements, such as requirements to hold hearings and consider and make a determination, as discussed above.[29]

If state law is in conflict with the procedural provisions of Title I, the PURPA provisions override state procedural law to the extent of such conflict (PURPA section 111(b)(2)). What the lawmakers intended was that the procedural features of the consideration and determination process, including concepts such as the nature of evidence and the relationship between findings and the record of a proceeding, would be governed by state law.[30] State law governs also on burden of proof, standard for review in state courts, and any other matters *not inconsistent with the requirements of Title I of PURPA*. New procedures are not necessary; existing procedures may be adequate if they are consistent with the requirements of Title I.

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[28] Conference Committee Report, pp. 70 - 71.

[29] Conference Committee Report, p. 71.

[30] Conference Committee Report, pp. 71 - 72.

A decision that is reserved to states to decide is whether to have individual or generic rate proceedings when considering the standards. Many of the issues raised by the standards are common to more than one utility under the jurisdiction of a single state commission, and could best be handled in a generic proceeding. State commissions also have the discretion to have individual proceedings, separate consideration of the standards from rate case proceedings, distinct from specific rate cases, or in conjunction with rate proceedings.

2.7.3. Authority to intervene, participate, and access to information (PURPA Section 121)

The statute allows the Secretary of Energy, any affected electric utility, or any electric consumer of an affected electric utility to intervene and participate in any proceeding that is conducted by a state commission or nonregulated electric utility to consider the standards. Also, PURPA states that any intervenor or participant shall have access to information available to other parties in the proceedings if the information is relevant to the issues in the proceedings. This information is to be "obtained through reasonable rules relating to discovery of information" as prescribed by the state commission or nonregulated utility. The Conference Committee Report states that "this section creates a Federal right of participation and intervention in ratemaking proceedings or other appropriate regulatory proceedings conducted by a State regulatory authority or by a nonregulated electric utility."[31] They also explain that they intended "the term intervention to be interpreted broadly to include intervention or participation at the beginning of a proceeding or otherwise but do not intend for such term to connote a right to initiate a proceeding." They also explain that the phrase "affected electric utility" refers to "any utility which is subject to regulation by the same regulatory authority which utility might be affected by precedents set in a case relating to another utility" and would "include utilities permitted to participate or intervene under State law." The presumption is that state commissions will consider the federal

[31] Conference Committee Report, p. 81.

standards, whether or not utilities, intervenors, or others raise them in a rate proceeding.

Also, intervenors or participants should be "timely and not disruptive of the proceeding and is in accordance with otherwise applicable law." Moreover, state commissions and nonregulated utilities "should provide maximum opportunity under State law to participate in ongoing proceedings."

2.7.4. Consumer representation and compensation (PURPA Section 122)

PURPA stipulates that, under certain conditions, compensation should be made to consumers for the cost of participation or intervention. PURPA specifies a two-part mechanism to assure that the interest of electric consumers is represented at the state level in the Title I standard proceedings. The first mechanism makes the utility liable to provide compensation directly to consumers. In this case, compensation is required if no alternative means is available to assure representation of electric consumers and if a consumer's participation substantially contributed, in whole or in part, to the approval of the position advocated by the consumer in a proceeding relating to any standard. In this case, the utility is liable to compensate the consumer for reasonable attorney's fees, expert witness fees, and other reasonable costs incurred in preparation and advocacy of their position (PURPA section 122(a)(1)).

The consumer that is entitled to this compensation may collect from a utility by bringing a civil action in a jurisdictional state court, unless the state commission or nonregulated electric utility has adopted a reasonable procedure that determines the amount of compensation and includes an award of the compensation in its order in the proceeding (PURPA section 122(a)(2)). The procedure used by the state commission or nonregulated utility may include a preliminary proceeding to require that, as a condition of receiving compensation, (1) the consumer must demonstrate that, without an award for compensation, participation or intervention in the proceeding may be a significant financial hardship, and (2) persons with the same or similar interests have a common legal representative in the proceeding (PURPA section 122(a)(3)).

The second compensation mechanism created by PURPA provides that the state, state commission, or nonregulated utility may have a program to otherwise provide adequate compensation to consumers. In this second case, compensation is not required from the utility if the state, state commission, or nonregulated utility has provided an alternative means for providing adequate compensation to those who, (1) have or represent an interest that would not otherwise be adequately represented in the proceeding and such representation is necessary for fair determination in the proceeding, and (2) represent an interest that is unable to effectively participate or intervene in the proceeding because they cannot afford to pay reasonable attorney's fees, expert witness fees, and other reasonable costs of preparing for and participating or intervening in the proceeding (PURPA section 122(b)). The Conference Committee Report states that this type of program "may include an adequately funded office of public counsel which adequately represents the interests of persons described [in the statute]."[32]

The conferees also state that "the phrase 'substantially contribute to the approval, in whole or in part,' be broadly construed by the State agencies, nonregulated utilities, and the courts to effectively provide for compensation commensurate with the contribution to the approval of one or more of the standards." Also, the phrase "significant financial hardship" should

> be construed broadly, the determination not being restricted to whether the consumer can participate in that particular case but given consideration to other financial burdens, including those associated with intervention in other cases. The intention is not to compensate intervenors who can afford to intervene in any event if the State regulatory authority or nonregulated utility adopts the procedures in [the statute][33]

PURPA stipulates that any federal payments to intervenors are subject to the availability of appropriated funds.

2.7.5. Judicial review and enforcement (PURPA Section 123)

PURPA provides for judicial review and enforcement of Title I (specifically subtitles A, B, and C of Title I for purposes of this section). In general, federal court

[32]Conference Committee Report, p. 83.

[33]Conference Committee Report, p. 83.

jurisdiction is limited by this section (PURPA section 123), which gives state courts primary review and enforcement jurisdiction. (The case history is not reviewed in this manual.) As provided by existing law, the U.S. Supreme Court can consider any action upon appeal from the highest court of a state (PURPA section 123(a)(2)). The Secretary of Energy may enforce a right to intervene or participate under section 121(a) in federal courts (PURPA section 123(b)(1)). Also, any electric utility or electric consumer who also has a right to intervene under section 121(a) and who is denied that right, may bring an action in federal court to enforce that right, having first tried to enforce that right in state court (PURPA section 123(b)(2)).

The Conference Committee Report states that the conferees wanted to make enforcement of the right to participate and intervene in proceedings before state commissions and nonregulated utilities as rapid as possible. They note that intervenors or participants must first go to state court to enforce this right, but are not required to appeal through the state court system. The federal court can only require that the intervenor be allowed to participate to the extent provided under the Title I provision, and cannot require any particular outcome.

PURPA section 123(c)(1) deals with review of determinations and enforcement of Title I requirements in state courts for utilities (which are not federal agencies[34]). Under this provision, any person, including the Secretary of Energy, can obtain a review of any determination made under Title I with respect to any electric utility (except one that is a federal agency) in state court, if the person (or the Secretary) intervened or otherwise participated in the original proceeding or if state law permits such review. Also, any person (including the Secretary) may bring an action to enforce the requirements of this Title in the appropriate state court.

The Conference Committee Report explains that this section provides enforcement authority for the obligation that state commissions and nonregulated utilities have to hold hearings, make determinations, and comply with all other Title I

[34]Review of determinations made by a federal agency is covered by PURPA section 123(c)(2).

requirements.[35] The conferees state that the enforcement authority does not provide independent authority to attack a final determination of a state commission or nonregulated utility. They also note that any appeal of a final determination by a state commission or nonregulated utility will be in that state's courts and pursuant to state law. The court's findings and determinations are reviewable under standards of review established under state law. These standards are supplemented by the Title I purposes, although discretion under state law is not restricted.

The Secretary of Energy may file an *amicus curiae* brief in a judicial review of a proceeding of a state commission or nonregulated utility regardless of whether the Secretary participated in the original proceeding (PURPA section 123(c)(3)). Also, this section does not prohibit the Secretary from intervening and participating in any proceeding or any review by any court (PURPA section 123(d)).

2.7.6. Prior and pending proceedings and comparable actions (PURPA Section 124)

For most PURPA standards, including both standards labeled 111(d)(17), prior state actions are grandfathered and no further consideration of the standards is required if (1) the state already implemented the standard or comparable standard, (2) the state commission or nonregulated utility has conducted a proceeding considering implementation of the standard or comparable standard, or (3) the state's legislature voted on implementation of the standard or comparable standard (PURPA 112(d)).

The lawmakers that passed PURPA in 1978 recognized that states and utilities may have already considered similar standards to the ones in the law or have a proceeding underway. This was the case in 1978 and again when the Energy Policy Act of 1992 and 2005 were passed (but, as discussed above likely due to error, not in all cases with the standards in EISA). When a provision for prior action has been added, the law recognizes the possibility of prior or pending action by a state commission or an nonregulated utility. The statute states (PURPA section 124) that proceedings by state commissions and nonregulated utilities that commenced before

[35] Conference Committee Report, p. 84.

the law was enacted (in the case of EISA, before December 19, 2007) and actions taken before this date “shall be treated as complying with the requirements” of Title I if these “proceedings and actions substantially conform” to the requirements. Also, any proceeding or action commenced before the date of enactment but not yet completed, must comply with the requirements “to the maximum extent practicable.”

Further explanation is provided in the Conference Committee Report,[36] where the conferees note that “[i]t is not the intention of the conferees that the standards be reconsidered at great expense and without purpose if the original proceedings substantially conformed with the requirements.” They further note that the “essential feature of the process” in the Title “is that there be utility-by-utility analysis of the appropriateness of these standards to carry out the [three PURPA] purposes specified.” They allow that no one could precisely follow the exact requirements before the law was passed. They then conclude that it is up to state commissions and nonregulated utilities “to determine whether they substantially conformed to the requirements of the title and the courts will be able to review this determination.”

With respect to pending proceedings or actions, the conferees note that a proceeding begun prior to enactment, would not “require restarting the entire proceeding to give any person a right to participate or intervene if such right would be untimely.” They add that if there was no determination of prior proceedings or actions, then the requirements of Title I to make a written determination based upon findings and evidence presented at the hearing that are publically available must be followed.

As discussed in section 1 of this manual, the Prior State Actions provision of PURPA was amended only for the two standards labeled (17) by the 2007 statute. For the two standards labeled (16), no prior state action waiver exists and states and utilities must consider the standards and make a decision, even if they had only recently considered the same or comparable standards.

No time limit was placed on the two 2007 statute’s standards labeled (17), leaving it to the state commission’s and nonregulated utility’s discretion to determine if prior actions “substantially conformed” to the Title I requirements.

[36] Conference Committee Report, p. 85.

Considerations for the Evaluation of the PURPA Standards of the Energy Independence and Security Act of 2007

3. Integrated Resource Planning

3.1. Introduction to Integrated Resource Planning

3.1.1. Statement of Amendment to PURPA: Standard (16)

Section 532 of the Energy Independence and Security Act of 2007 amends PURPA 111(d)(16) by adding a new standard that requires consideration of "Integrated Resource Planning" for electric utilities. The new standard reads as follows:

> (16) INTEGRATED RESOURCE PLANNING.—Each electric utility shall—
> (A) integrate energy efficiency resources into utility, State, and regional plans; and
> (B) adopt policies establishing cost-effective energy efficiency as a priority resource.

As discussed in sections 1 and 2 of this manual, whether by an oversight of Congress or by design, this standard does not have time limits specified in the 2007 statute that indicate when consideration and determination must be completed. Also, the prior state action provision of PURPA, that grandfathers previous considerations and implementation of a comparable standard by states and nonregulated utilities, was not amended to include this standard. Therefore states and nonregulated utilities cannot use their prior actions to exempt themselves from considering and making a determination on this standard. As discussed in more detail below, prior decisions can be used to form the basis of this standard's consideration and implementation in a new proceeding. The failure to comply provision of PURPA section 112(c) was amended to include this standard. Thus, if the state commission or nonregulated utility does not consider and make a determination on the standard, then it could occur in the first rate proceeding after three years from the date of enactment of the statute (or after December 19, 2010).

3.1.2. Purpose and Policy Context of the Standard

The term "Integrated Resource Planning" (IRP), broadly defined, refers to a comprehensive planning process intended to systematically consider appropriate supply and demand resources to meet current and future load requirements within the context of local, state, and federal policy goals and objectives. States and utilities began using IRP in the 1980s, often called "least-cost planning" at that time, after significant rate increases and from a concern that not all supply and demand resource alternatives were being fairly considered with existing planning processes. By the mid-1990s, many states and utilities had some type of IRP process in place.

Figure 3.1 summarized the steps involved in a typical IRP process. The basic objectives of the IRP process are determined with input from the utility, state legislation and commission policy, and other interested parties. Current and future demand is projected based on recent data to determine supply and demand resources required for continued reliable service. A common goal of IRP is to consider both supply and demand resources on an as equivalent basis as possible, given that a direct comparison is not entirely achievable. There may be several iterations to settle on a combination of resources that satisfies as many of the stated objectives as possible before a final plan is chosen for implementation. Finally, the plan's implementation, progress, and results are monitored and evaluated, and, if necessary, corrective steps are taken.

While IRP has many facets and objectives,[37] this PURPA standard is written to specifically address one aspect of IRP, integrating energy efficiency into utility plans and adopting policies that encourage cost-effective energy efficiency. The term "energy efficiency" generally refers to efforts that allow consumers to use less energy without altering their behavior, for example, through increased deployment of newer technologies or replacement of existing energy-consuming devices with newer versions that accomplish the same tasks as earlier versions while consuming less energy. Some utility programs designed to promote energy efficiency include rebates or incentives for

[37] The Tellus Institute report, *Best Practices Guide: Integrated Resource Planning for Electricity*, lists 12 "possible" objectives for IRP (p. 7). These include reliability, supply diversity, cost minimization, and providing social benefits.

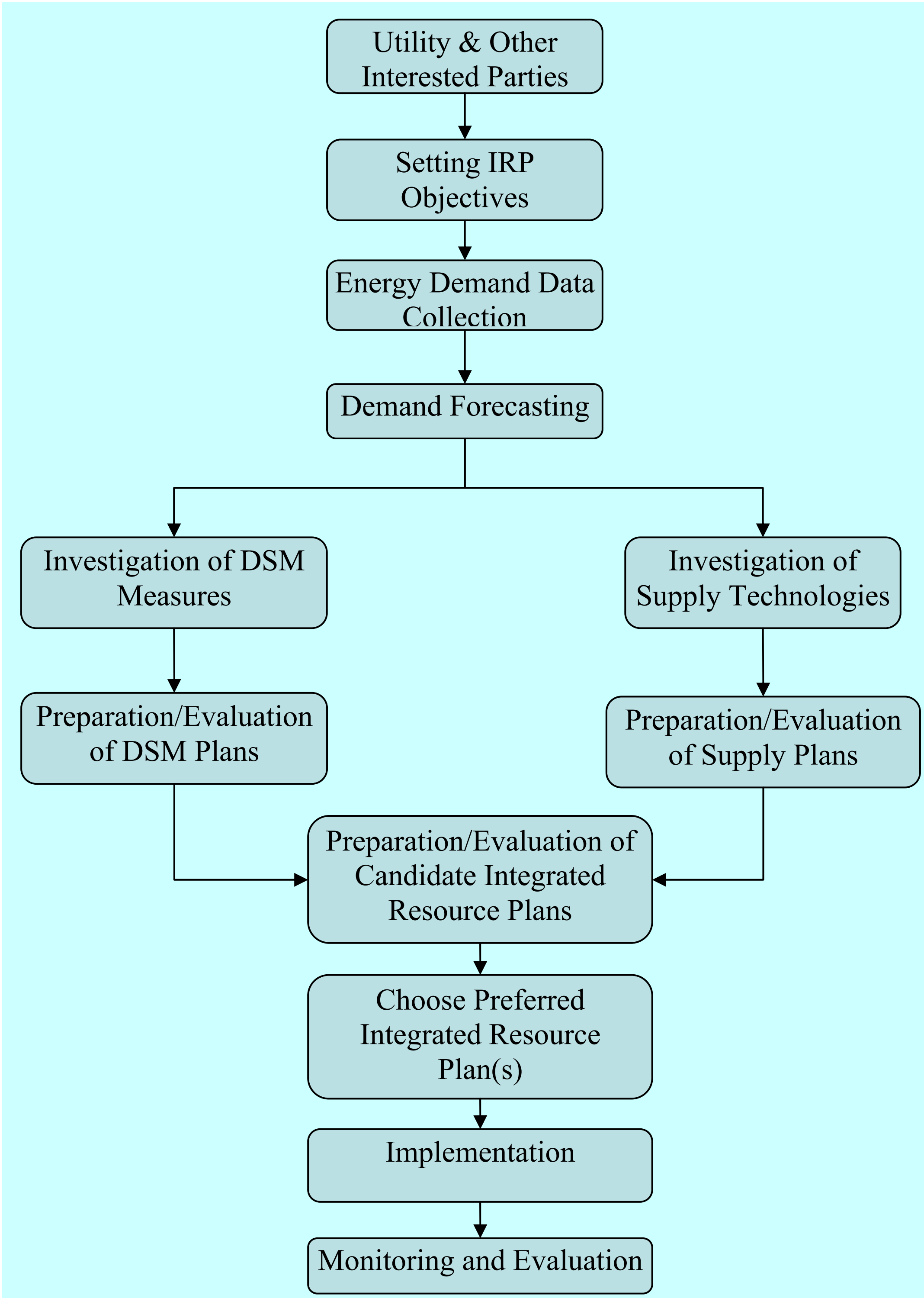

Figure 3.1. The Integrated Resource Planning Process.

Source: Adapted from The Tellus Institute, *Best Practices Guide: Integrated Resource Planning for Electricity*, (undated manuscript).

consumers to replace air conditioners, refrigerators, and other appliances with higher efficiency models and replacing incandescent light bulbs with compact fluorescent lights or other more efficient lighting. Energy efficiency can also be accomplished on the utility side of the meter through upgrades to the system to improve generation heat rates and to reduce losses on the grid. Energy efficiency is usually distinguished from load management techniques designed to shift electricity use from peak times of the day without necessarily reducing total energy use. Nevertheless, many states and nonregulated electric utilities include both energy efficiency (which reduces total energy consumption) and demand response (which reduces peak demand) in their IRP. The value of each tool for a particular system depends on the nature of their load and the resources available to serve that load.

State commissions and utilities that have an IRP process already in place, like the general process just described, would most likely already meet the requirements of the standard. However, as noted, the prior state actions section of PURPA (112(d)) was amended by the 2005 Energy Policy Act to refer to specific standards (11) through (15) and no reference was added in the 2007 statute to extend the provision to this standard (16). Since the grandfathering provision of PURPA was not extended to this standard, states will have to at least consider the standard and make a determination, following PURPA's procedural requirements outlined in sections 1 and 2 of this manual. Of course, if a state or nonregulated utility has already implemented a comparable IRP and energy efficiency standard, then that action can be used as a basis of the state's or nonregulated utility's finding to not adopt this standard, because a comparable standard has already been adopted; again, provided the PURPA-required procedures are followed.

Some states with retail access[38] had an IRP process in place at one time, but may have discontinued it since the state may no longer regulate generation

[38] Retail access is defined here as simply allowing retail customers an option to select a supplier they choose themselves (when options are available), remain with a "utility" option, or be placed with a "default" or "last resort" option. This is

resources in the state, thus eliminating a state's control of an important part of the IRP process. In this case, it is possible that a state had an IRP process in place that included integrated energy efficiency resources and a policy of establishing cost-effective energy efficiency as a priority, but then discontinued it when retail access was introduced. This fact could also be used in a proceeding to determine that the state has already considered the standard or similar standard, previously decided to discontinue it or not implement it, and then use that decision as the basis for a determination on this new IRP standard. Again, since the grandfathering provisions do not apply to this standard, the standard must be considered and a determination made following the PURPA prescribed procedures.

Another possibility is that a state modified its IRP process after retail access was implemented to still include energy efficiency resources in utility planning processes, rather than completely eliminating the process. Similar to states with a full IRP process in place, they may determine in a proceeding that a comparable standard is already in place.

Finally, a state may have no current IRP processes or energy efficiency policies for utilities in place because they were simply never adopted. In this case, the state will have to consider the standard and either adopt it or reject it based on current findings in the proceedings.

With respect to the three stated PURPA purposes, this standard is clearly consistent with the first purpose—to encourage conservation of energy supplied by electric utilities. Whether a particular energy efficiency program serves the second PURPA purpose—encouraging optimal efficiency of electric utility facilities and resources—will be situation specific. Unlike demand response programs that are specifically aimed at improving a utility's load factor (that is, optimizing utilization of a utility's existing resources), an efficiency program could actually reduce the utility's load factor. The impact of the program will depend on

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also referred to as "retail choice" and, less specifically, as a part of industry "restructuring." In most cases, but not all, this also meant that the state no longer regulated generation resources in the state.

a range of factors including the utility's resource mix, load factor, and the design of the efficiency program. On the other hand, a program designed to improve utility efficiency such as power plant and conductor upgrades will, by definition, satisfy the second PURPA purpose. The impact on the third PURPA purpose, to encourage equitable rates for electric consumers, may depend on the energy efficiency option. Some customers could contribute to the cost of efficiency improvements from which they themselves do not receive any direct or indirect benefit (energy savings or system benefits), this may be seen as less equitable than a program where all customers benefit or where costs are allocated to those that receive the direct benefit of the efficiency programs. State commissions or covered nonregulated electric utilities can examine the distribution of program benefits and costs as part of their program evaluation process.

3.1.3. Evaluation of Energy Efficiency Technologies and Programs

Hirst[39] notes that because an IRP process is complicated and there are potentially many technologies and programs to consider, a screening process is necessary to reduce the number to a manageable size. This requires a means to evaluate the programs in a standardized way so a fair comparison can be made. Hirst notes also that the particular tests to be used, how they should be used, and sensitivity of the results to input assumptions should be clearly stated. After the screening process is completed, the remaining demand-side options can then be assessed and integrated with supply options as part of the final stages of an IRP process.

The California Public Utilities Commission and the California Energy Commission over the last two decades have developed and refined several economic tests to assess demand-side programs. These tests are published in

[39] Eric Hirst, "A Good Integrated Resource Plan: Guidelines for Electric Utilities and Regulators," Oak Ridge National Laboratory, ORNL/CON—354, December 1992.

the *California Standard Practice Manual*,[40] and are used in California and are also widely used by others to screen and evaluate demand-side programs. The latest versions (from 2001) of these tests are briefly summarized below. These tests are intended to provide cost/benefit estimates of the programs being considered as part of an overall evaluation. They are not intended to provide a definitive answer on whether to proceed with a program. A state or nonregulated utility may want to consider other objectives and factors.

In general, the tests are all variations on the simple benefit/cost test, where the decision to implement or continue with further evaluation of a demand-side option depends on whether the benefits exceeds the costs (or the benefits to costs ratio is greater than one). The primary difference between these tests is how benefits and costs are defined.

3.1.3.1. Participant Test

The basic formula of the Participant Test is simply the net present value of the benefits to participants minus the net present value of the costs to participants. Alternatively, this can also be expressed as a benefit to cost ratio (benefits to participants divided by costs to participants). Benefits include the reduction in the participants' utility bill, any incentive received from the utility or others, and any tax credits received. Participant costs include direct expenses paid by the participant for being in the program (for example, equipment or materials purchased), any increase in the customer's utility bill, any operation or maintenance expenses, and the value of the customer's time involved in program participation.

The Participant Test is relatively simple to calculate and can be used as a screening tool to make a general assessment and comparison of different programs. This test can also provide an indication as to how many customers

[40] *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects*, online July 2002 version. This manual was first published in 1983 and revised in 1987 and 2001. The latest online version is from 2001 and is available from the California Measurement Advisory Council at: http://www.calmac.org/toolkitEE.asp

may want to participate in a program. A limitation of this test is that it only considers the direct costs and benefits to customers; it does not consider broader utility system-wide benefits or the potential costs to other non-participating customers. It also does not consider social or externality costs and benefits.

3.1.3.2. The Ratepayer Impact Measure Test

The Ratepayer Impact Measure (RIM) estimates the impact on customer bills or rates by comparing the change in utility revenue and operating costs due to the demand-side option being considered. The benefits include avoided generation, capacity, transmission, and distribution costs from reduced energy and load reductions. The costs are utility program costs including incentive payments to participants and the utility net lost revenue caused by the reduction in sales, plus any program costs incurred by other entities. If the net effect of the demand-side option being examined causes rates to increase, customers not participating in the program could see their bills increase, while program participants may see their bills decrease if their energy use falls sufficiently. By definition, to pass the RIM test utility rates or bills cannot increase for customers, including non-participating customers, as a result of the demand-side program. Customer rates will decrease if the benefits to the utility are greater than the costs of the program.[41]

The RIM test can be used for all conservation and energy efficiency programs as well as other demand-side programs (such as load management programs) so that a consistent comparison of the various programs can be made during evaluation. A limitation to the test is the relative uncertainty of the benefit and cost estimates, including the estimated long-term generation costs, which can have significant impact on rates over time. Hirst suggests that the RIM test

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[41] Various calculation formulas for the RIM test are in the *California Standard Practice Manual* (2001). Examples of RIM test calculations are in Swisher, Jannuzzi, and Redlinger, *Tools and Methods for Integrated Resource Planning*, November 1997.

is best suited for the resource-integration step in an IRP process, where it can estimate the rate impact of all demand-side programs being considered.[42]

3.1.3.3. Total Resource Cost Test

The Total Resource Cost (TRC) test compares the total costs of the demand-side option with the avoided costs of the energy supplied. Similar to the RIM test, the benefits are the avoided supply costs, including generation, capacity, transmission, and distribution costs. The costs under this test, however, are the total program costs to the utility, that is similar to the RIM test, but then also adds the in the participants' costs. The TRC test is, therefore, the sum of the benefits and costs of the Participant Test plus the RIM test.

A closely related variant, and sometimes considered a separate test, is the Societal Test. The Societal Test is the TRC test plus estimates of environmental and other externalities that are added to the benefits calculation.

The scope of the TRC test is considered an advantage of the test, since it includes the most comprehensive definition of costs and benefits (including environmental considerations, if added in a Societal Test). This comprehensiveness makes it possible to compare demand-side options with supply-side resources. A limitation is that this test may not account for any lost revenues incurred by the utility due to the program's energy savings (the direct total program costs, including incentives to participants, are assumed to be recovered from all utility ratepayers). Also, if the TRC test is expanded to a Societal Test, any environmental and other societal considerations used in the estimate can be difficult to monetize and build a broad base of agreement on the values that should be used in the estimate.

3.1.3.4. Program Administrator Cost Test

The Program Administrator Cost test estimates the benefits of a program similar to the TRC test, but estimates the costs based on the costs to the

[42] Hirst, *A Good Integrated Resource Plan*, 1992.

program administrator (including incentives) and excludes costs incurred by the program participant. Costs incurred by the program administrator include incentives paid to the customers, any increased supply costs from load shifting, cost of equipment, operation and maintenance, installation, program administration, and equipment removal. The benefits and costs are relatively straight-forward to calculate with this test. However, a limitation of this test is that it only considers the costs of the program administrator and not the full cost of the program. Also, similar to the TRC test, utility lost revenues and rate impacts on non-participants are not explicitly considered.

EEI[43] provides examples of regulatory and legislative actions on energy efficiency and other demand-side program in 2005 through 2007. The EEI report notes that, based on its survey, the assumptions used to measure savings and program benefits differ by state and utility. EEI also notes that program evaluation has been evolving with experience and with increasing interest in using cost-effective energy efficiency programs.

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[43] State Regulatory Update: Energy Efficiency, Edison Electric Institute, February 2008. Posted at: http://www.eei.org/industry_issues/retail_services_and_delivery/wise_energy_use/state_reg_update_efficiency.pdf

4. Rate Design Modifications to Promote Energy Efficiency Investments

4.1. Introduction to Rate Design Modifications to Promote Energy Efficiency Investments

4.1.1. Statement of Amendment to PURPA: Standard (17)

Section 532 of the Energy Independence and Security Act of 2007 amends PURPA 111(d)(17) by adding a new standard that requires consideration of "Rate Design Modifications to Promote Energy Efficiency Investments." The statute states:

> (17) RATE DESIGN MODIFICATIONS TO PROMOTE ENERGY EFFICIENCY INVESTMENTS.—
> (A) IN GENERAL.—The rates allowed to be charged by any electric utility shall—
> (i) align utility incentives with the delivery of cost-effective energy efficiency; and
> (ii) promote energy efficiency investments.
> (B) POLICY OPTIONS.—In complying with subparagraph (A), each State regulatory authority and each nonregulated utility shall consider—
> (i) removing the throughput incentive and other regulatory and management disincentives to energy efficiency;
> (ii) providing utility incentives for the successful management of energy efficiency programs;
> (iii) including the impact on adoption of energy efficiency as 1 of the goals of retail rate design, recognizing that energy efficiency must be balanced with other objectives;
> (iv) adopting rate designs that encourage energy efficiency for each customer class;
> (v) allowing timely recovery of energy efficiency-related costs; and
> (vi) offering home energy audits, offering demand response programs, publicizing the financial and environmental benefits associated with making home energy efficiency improvements, and educating homeowners about all existing Federal and State incentives, including the availability of low-cost loans, that make energy efficiency improvements more affordable.

As discussed in sections 1 and 2 of this manual, state commissions and nonregulated utilities have one year after enactment to begin consideration of this standard (December 19, 2008) and up to two years after enactment

(December 19, 2009) to complete their consideration and make a determination. These time limits for standard (17) are not provided in section 532 of the 2007 statute, but are specified in section 1307 (State Consideration of Smart Grid, section 1307(b)). Standard (17) is also included in the failure to comply amendment of PURPA section 112(c). This section provides that, if there is a failure to comply by the state commission or nonregulated utility, consideration and determination of the standard may commence in the first rate proceeding after three years from the date of enactment (December 19, 2010).

Also, the grandfathering provision of section 112(d) was amended so that if (1) the standard or a comparable standard was implemented by a state, (2) the state commission or nonregulated utility conducted a proceeding to consider implementation of the standard or comparable standard, or (3) the state legislature voted on the implementation of the standard or comparable standard, then this standard does not need to be reconsidered. No time limit was specified for the prior action to grandfather a prior consideration of the standard.[44] As is discussed in more detail below, many states have already modified or considered modifying their rate design practices or are currently considering doing so, because of concern over the incentives regulated utilities have to offer and manage energy efficiency programs. These prior actions can be taken into account when considering this standard and, if found to be comparable, used as the basis to either make a decision or take no further action on this standard.

It should also be noted that section 532 of the EISA also contains a subsection (b) for natural gas utilities that is similar to subsection (a) for electric utilities. This amends PURPA section 303(b) and adds two standards, (5) "energy efficiency" and (6) "rate design modifications to promote energy efficiency investments" (these standards are included in Appendix A of this manual). The energy efficiency standard is similar to the integrated resource

[44] Section 112(d) of PURPA (as amended previously and by EISA of 2007) does not specify a timeframe for prior actions to qualify for this grandfathering provision.

planning section for electric utilities (the subject of section 3 of this manual)[45] and the rate design modification standard is similar to the electric utility standard with the same title, which is covered in this section. The implementation of PURPA section 303(b) and how it pertains to natural gas utilities is not covered in this manual; however, many policy issues and considerations many be similar for both types of utilities.

4.1.2. Purpose of the Standard

There has been concern in recent years that standard ratemaking practices may not encourage, or could even discourage, utilities from adopting energy conservation measures. This concern has led some states to "decouple" utility earnings from the sales of electricity or natural gas or use other means to modify the rate design. This standard directs states to consider the incentives that utilities have to use and invest in energy efficiency measures. For nonregulated publicly-owned and cooperatively-owned utilities, the impact can be similar, except in this case rather than earnings, a decrease in sales revenue could lead to a decrease in the net operating margin required to operate and maintain the utility.[46]

The six "policy options" listed in the standard under subsection (B) are intended to guide states and nonregulated utilities when considering the standard. These raise specific issues related to utility incentives that may affect adoption of or investment in energy efficiency. The first, "removing the throughput incentive and other regulatory and management disincentives to energy efficiency" (subpart i), refers to the link between a utility's sales (kWh or ccf) and the earnings of the company. Generally, an increase (decrease) in

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[45] Note, however, that the term "integrated resource planning" (IRP) is not used for the PURPA standard applicable to natural gas utilities.

[46] Decoupling, which is described in more detail below, does not apply to nonregulated utilities the same way as it does for regulated utilities. Nonregulated utilities do not require an automatic process for a rate increase that bypasses a rate proceeding since they do not have the same regulatory procedures. For these nonregulated utilities, rates would simply be increased by some mechanism to recover any lost net operating margins.

sales means an increase (decrease) in earnings as well because fixed costs and profits or margins are typically recovered in the per-unit segment of the rate. Therefore, a decrease in utility sales that results from an energy efficiency program could also mean a decrease in earnings and even the inability to recover some portion of the utility's fixed costs for providing service – damping the incentive a utility may have to offer or encourage customer participation in such measures to decrease electricity or natural gas use.[47] If the goal is to expand the use and effectiveness of energy efficiency programs, then this goal could be at odds with the utility's throughput incentive under traditional cost-based regulation. This throughput incentive is discussed in more detail below.

The second subpart (ii) is focused on utility incentives and the management of energy efficiency programs. If energy efficiency programs have a negative effect on utility earnings, then any program the utility is required to provide could be undermined by financial disincentives that negate the incentive to fully pursue implementation of the programs.

The third subpart (iii) asks that commissions and utilities consider energy efficiency as a goal of retail rate design, while balancing that goal with other objectives. Most states have general regulatory goals or objectives that they consider during the ratemaking process. These include quality of utility service, public safety, reliability, just and reasonable rates, efficient utility operation, and economical and fair regulation.[48] State commissions may consider adding the encouragement of cost-effective energy efficiency programs as a regulatory goal,

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[47] Declining sales in general, whether caused by utility conservation programs or from the customers' own initiative, may increase interest by utilities in changing their rate design to ensure adequate cost recovery and preserve their earnings or margin. However, this PURPA standard is focused on "rate design modifications to promote energy efficiency investments" and is therefore the focus of this discussion.

[48] See, for example, state and federal commission mission statements in Janice A. Beecher, "Commission Mission Statements," Institute of Public Utilities, Michigan State University, June 2006. Posted at: http://ipu.msu.edu/research/pdfs/research_beecher_mission_statements06.pdf

if it has not already been considered or adopted. Nonregulated utilities could consider making energy efficiency a goal as well.

Considering each customer class and the impact that rate design has on encouraging energy efficiency is the goal of the fourth (iv) subpart. Not all customer classes may respond in the same manner to energy efficiency programs, so different programs may have to be developed for each customer class. Also, there may be opportunities to obtain cost-effective energy efficiency from programs aimed at previously overlooked customer classes.

Timely recovery of energy efficiency program costs, the subject of the fifth (v) subpart, can encourage utility participation, cooperation, and support. Conversely, untimely or uncertain cost recovery may discourage a regulated utility's cooperation. However, state commissions may want to consider conditioning cost recovery on economical and verifiable implementation of energy efficiency programs, to encourage cost minimization and program results.

The sixth subpart (vi), lists specific types or categories of demand-side management programs. Most of those listed are intended to educate or inform customers of program opportunities or about their own energy use. These include home energy audits and publicizing the financial and environmental benefits of and educating customers about incentives and loans for energy efficiency improvements. The remaining item listed is offering demand response programs. This is a general category that can include both energy efficiency and load control programs.

4.1.3. Policy Context

As noted, utilities may be concerned that promoting an increase in energy efficiency programs would lead to a decrease in revenue and company earnings or operating margin for not-for-profit utilities and failure to recover the full fixed costs of providing service to consumers. How this could occur for a regulated utility can be seen by considering how rates are set under standard cost-based regulation. Typically, a "revenue requirement" is calculated based on the expenses the utility incurs to serve its customers, including operating and maintenance expenses, depreciation and amortization expenses, and taxes. These expenses are added to the value of the company's property, net of accrued depreciation (referred to as the "rate base"), and then multiplied by the allowed rate of return. A "test year" or base period is used to estimate a representative sample of the utility's sales revenue and operating expenses that is used to calculate the revenue requirement.

Rates are then set for each class of customers, so that when rates are multiplied by the expected sales, it adds up to the total revenue requirement. In effect, the average rate would equal the total revenue requirement divided by the sales (kWh or ccf).[49] Once the rates are established for each customer group, unless adjustments are made, any decrease or "attrition" in the utility's sales could mean that the company is not able to fully recover the allowed revenue requirement from customers. The company's earnings may decline as well, since that is a component of the revenue requirement formula. This is the "management disincentives to energy efficiency" referred to in the standard's language.

Most utilities have a fixed monthly charge on their bills, but that access or customer charge is typically insufficient to recover much more than the costs of metering and billing. That fixed monthly charge does not recover fixed costs and profit or margin. Those fixed costs must still be recovered through the throughput-based rate. Thus, if sales decline too far, the utility will not recover its fixed costs of providing service or its profit or margin. Although, when sales decline, incremental cost of providing service also declines, but because the rate recovers more than incremental costs, the revenue loss also cuts into fixed cost recovery.[50]

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[49] Rates vary for each customer class, so that the total revenue requirement equals the sum of each customer class' rate times the expected sales of electricity or natural gas for that class.

[50] In the 1980s, when utilities were ramping up both their efficiency programs and bringing a great deal of new generation on-line, some utilities experienced a

Several approaches have been proposed and are being used to counteract or correct this disincentive a utility may have to pursue and manage energy efficiency programs. In some cases the intent is to not only remove any disincentive, but to provide a strong incentive to offer, develop, and administer efficiency programs on the utility's own initiative.

The National Action Plan for Energy Efficiency report[51] describes approaches states have used and contains several case studies of applications of the approaches. The report breaks the approaches states have used into three general categories, (1) direct cost recovery, (2) fixed cost recovery, and (3) performance incentives. The report also contains a survey of state actions on cost recovery and incentive mechanisms for investor-owned utilities. These approaches are not mutually exclusive, and the survey shows that states often use a combination of them.

The first category described in the National Action Plan report is simply allowing the direct costs of efficiency programs to be recovered by the utility. This includes administrative and implementation costs and any incentives given to program participants. Obviously, not allowing recovery of the direct costs will discourage utility commitment, since it would directly impact the utility's earnings. For regulated utilities, commissions may consider balancing timely recovery of costs that are incurred by the company with sufficient oversight of the expenditures. How these are recovered may vary depending on the size of the expenditure and type and duration of any equipment involved. Three

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noteworthy vicious cycle. Conservation efforts reduced demand; reduced demand reduced the number of kWh over which the costs of the new capital investments could be spread, causing electric rates to rise; rising rates encouraged greater conservation, further reducing kWh sales and thus further raising rates. Ultimately, rate increases reached politically unsustainable levels, forcing some utilities to take large losses and in some cases declare bankruptcy. This experience is still remembered by some utility managers and directors.

[51] National Action Plan for Energy Efficiency (2007). *Aligning Utility Incentives with Investment in Energy Efficiency*. Prepared by Val R. Jensen, ICF International. http://www.epa.gov/cleanenergy/documents/incentives.pdf

mechanisms cited in the survey are recovery through (1) a rate case, (2) a "system benefits charge," or (3) a tariff rider or surcharge.

The second category of the approaches described in the National Action Plan report is either to allow recovery of fixed costs through a "lost revenue adjustment mechanism" or to "decouple" utility revenues from sales. In the first case, the utility is compensated for the impact of decrease of sales due to energy efficiency programs, but the link between sales and earnings from standard ratemaking remains. The second case, decoupling revenues from sales, provides recovery of lost revenue and also removes "the throughput incentive" utilities have to increase sales and "other regulatory and management disincentives to energy efficiency" that would decrease sales (subpart (B)(i) of the standard).

According to the survey in the National Action Plan report, decoupling is more common among state mechanisms for investor-owned utilities than are lost revenue adjustments. Twenty-eight states either had implemented decoupling or were considering it for either electric or natural gas utilities, or for both. Six states used a lost revenue mechanism (one of those for just electric utilities). Also, more states had the mechanism in place for natural gas utilities than electric. Of the 16 states that had it in place, 11 had it for gas utilities, one had it for only electric utilities, and four were for both utilities. However, there were slightly more pending decisions in states for electric than for natural gas utilities. Of the 14 states with pending decisions, seven were electric, five were natural gas, and two were for both utilities.[52]

Costello describes revenue decoupling as "a 'tracking' mechanism that adjust rates and revenues whenever sales deviate from their targeted level."[53] Costello offers a "stylized" description of a revenue decoupling mechanism:

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[52] There were two states that had a decoupling mechanism in place for natural gas utilities and also a pending decision for electric utilities, which is why there are 30 states with the mechanism in place or pending decision, but there are 28 states total.

[53] Ken Costello, "Revenue Decoupling for Natural Gas Utilities," NRRI Briefing Paper (06-06), April 2006, p. 9.

“whenever sales deviate from a specified ‘baseline,’ the utility is able to adjust its rates without having to file a formal rate case, so as to earn its authorized earnings.”[54] Revenue decoupling would keep the utility’s earnings between rate cases close to the authorized earnings. This differs from traditional ratemaking practice under which if sales decline, the utility would have to wait until the next rate case for an adjustment in rates.[55]

Costello also notes that tracking mechanisms such as revenue decoupling have been justified based on three tests: (1) the cause of the revenue decline is largely outside the control of the utility, (2) the impact on the utility’s earnings is more than minimal, and (3) the actual outcome deviates from baseline projections. These tests can be used by states when considering whether to adopt this PURPA standard, if a similar standard has not already been considered or is already in place.

The third category of approaches described in the National Action Plan report is providing the utility with performance incentives. This is consistent with subpart (B)(ii) of the standard that calls for “providing utility incentives for the successful management of energy efficiency programs.” The aim of this approach is to not only remove any disincentive a utility may have to invest in and manage energy efficiency programs, but to provide a financial incentive to do so as well. The intent is to place energy efficiency on a similar footing as supply options, that is, make it profitable, not just “a break-even activity.”

The report describes three types of performance incentive mechanisms: performance target incentives, shared savings incentives, and rate of return adders. Target incentives set a performance range for energy savings that increases the incentive paid as the energy savings increase, with a minimum level of savings performance that must be achieved before any incentives are paid and an upper bound or maximum incentive level. Shared savings split the benefit from efficiency programs between the utility and its customers. These

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[54] Costello, “Revenue Decoupling,” p. 10.
[55] Ibid.

may also have a range of energy savings performance that determines the incentive level and the sharing percentages. Finally, the rate of return adder, described in the report as “not common,” capitalizes energy efficiency expenditures and allows the utility to earn a return on those expenditures.[56]

There is some disagreement on the need for performance incentives for further encouragement of energy efficiency programs by utilities. While some see it as necessary to place energy efficiency on a comparable basis as supply-side options, others see it as an obligation the utility should already have and that it is sufficient to remove any disincentives. Another criticism is that it will simply raise the price consumers pay while not necessarily encouraging the utility to manage its system more efficiently.

Another approach being taken by some utilities is to increase their fixed monthly access or customer charge until it recovers all of the utility's fixed costs of serving customers. When that is accomplished, the throughput rate recovers only the variable costs of service. Under this rate structure, if done properly, reductions in energy use should not undermine cost recovery because the lost revenue should reflect reduced incremental costs of service.

Finally, a National Action Plan for Energy Efficiency report notes several additional rate design options to encourage customers to use energy efficiency.[57] These include “inclining tier block” or “inverted block” rates. This is a rate structure where the per unit price increases in incremental steps (or “blocks”) as the quantity consumed increases. Each step has a consumption range where the price stays the same before the next step up to the higher price. This

[56] Examples of performance incentives used by states include (from an EEI survey): (1) annual energy efficiency/DSM performance incentive (AZ), (2) incentive payments (CT,MA, NH, NY, RI), (3) shared savings DSM (MN), (4) five percent incentive over allowed ROE (NV), and (5) restore ROE on DSM investments to overall return (WI).

[57] National Action Plan for Energy Efficiency; the entire report and links for additional material are at: http://www.epa.gov/cleanenergy/energy-programs/napee/resources/action-plan.html . The rate options are discussed in chapter 5 of the report. The rate designs mentioned here have more relevance for electric utilities than for natural gas utilities.

provides a rate structure that can encourage customers to curb their total energy use. This can be combined with a customer charge that recovers the utility's fixed costs, as just described, and the increasing rate structure can be designed in such a way so that the utility is able to recover its variable costs through the inverted block rates (again, any utility lost revenue should be reflected in the reduced incremental costs of service). Unfortunately, this type of block rate does not always align time-varying costs with time-varying rates, so that consumers with low usage may continue to use more energy during high cost periods if they have not yet exceeded the lowest block.

The National Action Plan report also describes two time-varying pricing methods, time-of-use rates and dynamic rates. These methods are defined in the next section on the smart grid PURPA standard. Time-varying methods can encourage customer conservation during peak times and shifting of use to non-peak times. They can also be designed to recover the fixed and variable costs, when combined with a customer charge.

These last three approaches (customer charges that recover the utility's fixed costs, inverted block rates, or time-varying rates) do not necessarily provide an incentive for a utility to offer additional energy efficiency options to customers. However, if the utility is recovering both fixed and variable costs, then these rate designs should at least remove "other regulatory and management disincentives to energy efficiency" programs (subpart (B)(i) of the standard).

4.1.4. Arguments in Support of and Opposed to Revenue Decoupling

Since the idea of revenue decoupling has been debated for a number of years, there are many arguments for and against the concept. Some of the commonly cited arguments for decoupling have been referred to here already. Costello compiled a list of the arguments made by proponents and opponents from testimony, commission orders, briefs and other documents filed in regulatory proceedings. Some of the more significant arguments are listed here and could be used in a proceeding to begin the discussion when considering this standard. Briefly, the arguments for decoupling include:

- standard cost-based ratemaking practice may discourage utilities from offering or carefully managing energy efficiency programs
- regulatory lag may mean that any loss of sales revenue from efficiency programs could build up over time and lead to a significant loss of earnings between rate cases
- allowing an adjustment to revenue losses could mean fewer rate cases
- a relatively small reduction in sales can significantly affect utility earnings
- a utility should be allowed an opportunity to recover authorized fixed costs between rate filings, particularly when revenue loss was beyond the utility's control or due to efficiency programs
- a utility will have less incentive to increase sales and more incentive to minimize costs

Some of the commonly cited arguments against decoupling include:

- regulated utilities are not guaranteed to earn the authorized rate of return due to changes in demand or consumption patterns
- shifts risks away from the utility toward consumers
- a rate case is the proper forum to adjust rates to new consumption patterns
- there is no proof that decoupling is necessary to encourage utility-funded energy efficiency programs since they existed before revenue decoupling and in areas that do not have decoupling
- may lower the quality of service
- may destabilize rates
- does not distinguish that the reason for a sales decline was due to energy efficiency, separate from other possible causes
- by itself, decoupling does not provide a utility a positive incentive to offer or manage energy efficiency; it only removes a possible disincentive
- when rates are "adjusted" to ensure cost recovery, it means rates are increased—those rate increases may be borne disproportionately by those least able to make conservation investments, for example, renters and the poorest consumers, unless some provision is made to offset this for these customers

5. Smart Grid

5.1. Introduction to Smart Grid

5.1.1. Statement of Amendment to PURPA: Standards (16) and (17)

The smart grid title of EISA of 2007 amends PURPA by adding two additional standards that state regulatory authorities and non-regulated entities must consider and make a determination as to whether to adopt, modify or reject. Section 1307 (PURPA standard (16)) of the statute ("State Consideration of Smart Grid") states:

> (16) CONSIDERATION OF SMART GRID INVESTMENTS-
> (A) IN GENERAL- Each State shall consider requiring that, prior to undertaking investments in nonadvanced grid technologies, an electric utility of the State demonstrate to the State that the electric utility considered an investment in a qualified smart grid system based on appropriate factors, including
> (i) total costs;
> (ii) cost-effectiveness;
> (iii) improved reliability;
> (iv) security;
> (v) system performance; and
> (vi) societal benefit.

Subsection (A) of the standard asks states to consider requiring utilities to examine smart grid technologies before investing in traditional transmission and distribution systems. Six factors (or potential costs and benefits) that can be used to determine whether smart grid investments are appropriate are listed.

> (B) RATE RECOVERY- Each State shall consider authorizing each electric utility of the State to recover from ratepayers any capital, operating expenditure, or other costs of the electric utility relating to the deployment of a qualified smart grid system, including a reasonable rate of return on the capital expenditures of the electric utility for the deployment of the qualified smart grid system.

Since utilities and the investment community may have concerns that smart grid investments and expenditures may not be completely recovered or in a timely manner, and this concern may limit utility investment, subsection (B) of the standard asks states to consider allowing utilities to recover the costs of smart grid investments and expenditures. In addition, states are asked to consider allowing a return on the investments utilities make in smart grid technologies, conforming these investments with the treatment of other comparable capital expenditures. The regulatory treatment of utility investments and expenditures has developed over many decades in most states. Developing new procedures to consider and examine smart grid investments and expenditures may not be needed; however, states may consider updating or expanding these procedures, if necessary.

> (C) OBSOLETE EQUIPMENT- Each State shall consider authorizing any electric utility or other party of the State to deploy a qualified smart grid system to recover in a timely manner the remaining book-value costs of any equipment rendered obsolete by the deployment of the qualified smart grid system, based on the remaining depreciable life of the obsolete equipment.

Subsection (C) of the standard asks states to consider permitting utilities to be compensated for the remaining book value of infrastructure made obsolete by smart grid investments. This is intended to remove another possible impediment to smart grid investment by utilities, that is, they may be concerned that they will not be able to recover the cost of the obsolete equipment. The fear is that a state regulatory authority may conclude that recovery is barred because the obsolete equipment is not “used and useful” or that the initial investment in “old” technology was imprudent because the utility should have moved to newer technologies sooner.

Generally, state commissions already have procedures in place that address the possibility that existing long-lived technology could have to be replaced during its operational life because it has become obsolete. Therefore, states may have to just consider whether their procedures need to be updated or expanded to include equipment made obsolete by smart grid investments.

> (17) SMART GRID INFORMATION-
> (A) STANDARD- All electricity purchasers shall be provided direct access, in written or electronic machine-readable form

as appropriate, to information from their electricity provider as provided in subparagraph (B).

(B) INFORMATION- Information provided under this section, to the extent practicable, shall include:
   (i) PRICES- Purchasers and other interested persons shall be provided with information on—
      (I) time-based electricity prices in the wholesale electricity market; and
      (II) time-based electricity retail prices or rates that are available to the purchasers.
   (ii) USAGE- Purchasers shall be provided with the number of electricity units, expressed in kwh, purchased by them.
   (iii) INTERVALS AND PROJECTIONS- Updates of information on prices and usage shall be offered on not less than a daily basis, shall include hourly price and use information, where available, and shall include a day-ahead projection of such price information to the extent available.
   (iv) SOURCES- Purchasers and other interested persons shall be provided annually with written information on the sources of the power provided by the utility, to the extent it can be determined, by type of generation, including greenhouse gas emissions associated with each type of generation, for intervals during which such information is available on a cost-effective basis.

(C) ACCESS- Purchasers shall be able to access their own information at any time through the Internet and on other means of communication elected by that utility for Smart Grid applications. Other interested persons shall be able to access information not specific to any purchaser through the Internet. Information specific to any purchaser shall be provided solely to that purchaser.

Standard 17 is intended to require that electricity purchasers be provided with direct access to information concerning pricing, usage, intervals, and sources (including generation type and greenhouse gas emissions), either in writing or in electronic form.

Simply restating the standards, standard (16) asks that states consider requiring utilities to invest in smart grid technologies before investing in traditional transmission and distribution systems, allowing utilities to recover the costs of smart grid investments, and permitting utilities to be compensated for the remaining book value of infrastructure made obsolete by smart grid investments.

Standard (17) asks that states consider providing electricity purchasers with access to information concerning pricing, usage, intervals, and sources, either in writing or in electronic form.

As noted in several places in this manual, there is no time line specified for standard (16) for consideration and to make a decision. For standard (17), state commissions and nonregulated utilities have up to one year after enactment (or until December 19, 2008) to begin consideration of the standard and up to two years after enactment (or until December 19, 2009) to make a determination. Since these smart grid standards are closely related, and since some may argue that having no time line is not what Congress intended, states and nonregulated utilities may decide to place them on the same consideration and decision time line. This consolidates the time and effort involved in dealing with both standards and avoids a possible challenge that the state or utility failed to comply. The "failure to comply" PURPA provision was amended to include both standards labeled (16) and (17). If the state commission or nonregulated utility does not comply with the statute, then the standards must be raised for consideration in the first rate proceeding three years after enactment, or after December 19, 2010 for both of these standards.

As also noted previously, the "prior state actions" provision was not extended to the two standards labeled "(16)," but it was extended to the two standards labeled "(17)." Since this provision was added to section 1307, the section of the 2007 statute that added the smart grid standards, there is a chance that Congress intended to extend the provision to both of the smart grid standards. However, that is not how the statute was written. The states and nonregulated utilities, therefore, will have to consider smart grid standard (16), even if a comparable standard already exists in the state. Any previous action may be used to form the basis of a decision, but the standard will need to be considered to fully comply with the law as written. But if a state or nonregulated utility already adopted a comparable standard to smart grid standard (17), then no further action is required.

Another potential concern with consideration of these standards is that they do not use the phrase that was usually used to describe the implementing authority in other PURPA standards. In the smart grid standard numbered (16), only the word "State" is used, not "state regulatory authority" and no mention is made of "non-regulated" utilities at all. The fact that the actual "standard" may be misworded, unclear or ambiguous does not change the fact that PURPA requires state regulatory authorities and non-regulated entities to consider the standard as drafted, and determine whether to adopt it as drafted, to modify it, or reject it.

For nonregulated electric utilities, the consideration is complicated because the nonregulated electric utilities simply lack the authority to implement the standard as drafted: they cannot by adopting the standard require the State to consider any action. Moreover, (16)(B) and (16)(C) are not relevant for most nonregulated electric utilities, which set their own rates and which cannot recover the costs of either new investments or obsolete equipment from anyone other than their ratepayers. Nevertheless, the nonregulated electric utilities are required by law to hold a hearing to consider the standard. In that process, nonregulated electric utilities should consider disregarding the sloppy drafting of the legislative language and evaluating whether any of the substantive elements in 16(A) would make sense for their system in light of the three PURPA goals and otherwise applicable state law.

5.1.2. Statement of Policy on Modernization of the Electricity Grid

The Energy Independence and Security Act of 2007 also contained a statement of support for a national policy for the development of a smart grid intended to modernize the electricity transmission and distribution system. Section 1301 of the statute states:

> It is the policy of the United States to support the modernization of the Nation's electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet future demand growth and to achieve each of the following, which together characterize a Smart Grid:

(1) Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid.
(2) Dynamic optimization of grid operations and resources, with full cyber-security.
(3) Deployment and integration of distributed resources and generation, including renewable resources.
(4) Development and incorporation of demand response, demand-side resources, and energy-efficiency resources.
(5) Deployment of ''smart'' technologies (real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering, communications concerning grid operations and status, and distribution automation.
(6) Integration of ''smart'' appliances and consumer devices.
(7) Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air conditioning.
(8) Provision to consumers of timely information and control options.
(9) Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid.
(10) Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services.

Neither the statute, nor any other law defines the term "smart grid." Rather, the term "smart grid" refers to a system that incorporates a range of technological options that provide certain enumerated functions or values. The ten items listed in the statute are one listing of those functions or values. DOE also has a separate list:

- Enabling active participation by consumers
- Accommodating all generation and storage options
- Enabling new products, services, and markets

- Optimizing assets and operating efficiently
- Anticipating and responding to system disturbances in a self-healing manner
- Operating resiliently against physical and cyber attack and natural disasters
- Providing the power quality for the range of needs in a digital economy

Some of the basic components that are generally considered to make a smart grid include smart appliances, advanced meter infrastructure (AMI), transmission and distribution automation equipment, and digital communications technology. No one expects that any utility will deploy all of these components at once to have the "smartest" grid. Instead, deployment of these technologies will likely unfold gradually over time, as the deployment creates value for consumers in each state and each utility service territory. Different utilities are already rolling out different elements of the smart grid in their territories as those elements meet local needs.

As noted above, one of the many components of a smart grid is smart meters, which were the topic of a previous PURPA standard in the 2005 law. The Energy Policy Act of 2005[58] called on states to consider the use of smart meters. This was discussed in section 6 of the 2006 PURPA standards reference manual, and includes discussion of issues for states and utilities to consider regarding dynamic pricing.[59] Smart meters allow for the flow of information in two directions—from the consumer to the utility and from the utility to the consumer, enabling price signals to be sent to consumers if and when the price of electricity fluctuates during the day. The Energy Policy Act of 2005 mentioned three types of time varying pricing methods: time-of-use pricing, critical peak

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[58] Energy Policy Act of 2005, Public Law 109-58, 119 Stat. 594 (8 August 2005).
[59] Kenneth Rose and Karl Meeusen, Reference Manual and Procedures for Implementation of the "PURPA Standards" in the Energy Policy Act of 2005 (2006).

pricing, and real time pricing.[60] When the price fluctuation is based on cost or market condition changes (and not by preset arrangement), this is often called dynamic pricing.[61]

By offering increased information flow between consumers and utilities, AMI and other new technologies can permit utilities to communicate better price and direct control signals to consumers and consumer-side devices such as thermostats, appliances, distributed generation, and local storage, permitting the development of more sophisticated rate and demand-response programs. This has been shown in some pilots to reduce peak demand for electricity (by up to ~40% depending upon the saturation of smart thermostats and other devices) to improve the reliability of the transmission and distribution grid, and to mitigate the need for adding new generation capacity (particularly peaking plants) as well as transmission and distribution facilities.

On the utility side, the smart grid includes a number of technologies, software packages, and functions that have previously been called down-line automation such as: fault location, isolation, and service restoration, including sensing devices and electrically operable switches; feeder load balancing; VAR dispatch; voltage control; integrated Volt-VAR control; equipment condition monitoring; and, remote controlled fuse saving. These technologies, combined with an advanced communications backbone and information flow from customer meters, would allow utilities to operate their systems more efficiently, better

[60] The Energy Policy Act of 2005 included time-of-use pricing as a “dynamic pricing” method, however, it is usually not included in the definition (see the definition in the next footnote). This is because even though the price may vary with time-of-use by the time of day, it is on a fixed schedule and does not change with respect to costs or market prices.

[61] A California “Report of Working Group 3 to Working Group 1” defined a “dynamic rate” as “a rate in which prices can be adjusted on short notice (typically an hour or day ahead) as a function of system conditions. A dynamic rate cannot be fully predetermined at the time the tariff goes into effect; either the price or the timing is unknown until real-time system conditions warrant a price adjustment. Examples: real-time pricing (RTP), critical peak pricing (CPP).” From “Proposed Pilot Projects and Market Research to Assess the Potential for Deployment of Dynamic Tariffs for Residential and Small Commercial Customers,” December 2002.

integrate non-traditional resources, improve reliability, protect the system from cyber attacks and speed restoration from outages It would also provide the information utilities need to reduce theft, reduce losses, improve load factors, and perform more intelligent preventative maintenance.

Integrated, two-way communications will be required to make each of these elements of the smart grid work. Broadband or wireless communications technology (e.g., broadband over power line, WiFi, or fiber optics) combined with computing technology help the electricity grid to be operated as an integrated network. Advanced communications also allow for better integration of distributed generation, microgrids, and electricity storage.

Of course, how the smart grid is built will vary broadly across systems. There is no one smart grid and no two utilities can or should implement the smart grid to the same degree or in the same way. Whether a utility is looking at improving metering, communications, VAR control, or any of the other pieces that together make up the smart grid, there will be a multitude of options. There are different basic technologies performing similar tasks; different vendors offering similar technologies with different capabilities and functional options at different prices depending on the selected options; and different software vendors offering different ways to integrate the varying technology options with each other and with utility operations. The choices a utility makes among the options will depend on a broad range of issues including very local matters such as the legacy system with which new elements need to work, customer density, customer preferences, and even local topography.

5.2. Application

The standard in section1307 of the statute requires each state to consider requiring utilities, before they make investments in traditional grid technologies to demonstrate to the state that the utility has first considered an investment in smart grid technologies, based on:

- Total costs

- Cost effectiveness
- Improved reliability
- Security
- System performance
- Societal benefit

Read literally, the standard would require the utility to come into the state commission to demonstrate in advance the prudence of each and every investment in traditional grid technologies. That could prove highly costly and burdensome to both utilities and commission staff. And considering the number of vendors and variety of "smart grid technologies," it could also increase the frequency and cost of litigation over very technical technology decisions.

While this is the approach Congress has required states to consider, they can modify or decline to adopt it. States and nonregulated electric utilities could instead adopt the more strategic approach now being used by some states and utilities considering smart grid investments. Rather than litigate over the prudence of each investment decision, those entities are stepping back and developing a "technology plan" after looking at the following factors:

- The goal(s) the regulators and/or utilities wish to accomplish
- The value the goal(s) offer utilities and consumers
- The different technologies available to meet the goal(s)
- The manner in which different goals and technology choices may interact, and the options for optimizing the investment to maximize accomplishment of the goal(s) ;
- The options for ensuring interoperability of different technologies with each other and with the legacy system
- The time frame(s) over which implementation of different investments can be implemented
- Options for "future proofing" investments, i.e., making certain that the investment does not rapidly become obsolete as additional goals are pursued or additional smart grid elements are added to the system
- The cost of different investment options, including the cost implications for combining different investments and adjusting the timing of the investments
- The balance of value against cost for the goal(s) being pursued
- How costs should be recovered

- How grid infrastructure investments made obsolete by smart grids should be recovered by utilities.

States and nonregulated electric utilities are not alone in this process. The EISA (section1303) calls for the establishment of a Department of Energy Smart Grid Advisory Committee and a federal agency Smart Grid Task Force. A smart grid interoperability framework will be developed with protocols and standards (section1305). One way for states to keep informed on these issues is through the Smart Grid Collaborative between FERC and NARUC.[62] The Electric Power Research Institute has catalogued smart grid research and development programs and compiled a list of references.[63] The Cooperative Research Network is also doing extensive work in this area that is available to electric cooperatives.

Section1307 of the EISA requires states to consider authorizing utilities to recover the costs associated with the development of a smart grid system from ratepayers. The costs will include, but are not limited to:

- Capital costs
- Installation costs
- Operation and maintenance costs
- Administrative costs for handling the vastly increased data flows arising from smart grid and for making use of that data
- Recovery of the cost of legacy systems and equipment which would otherwise be booked as a loss
- The cost of integrative planning

Whether these are net costs attributable to smart grid investments – i.e., whether the capital and other costs of the smart grid investments are greater than the costs that would otherwise have been incurred if the utility continued to use traditional technologies will depend on individual circumstances. For example, the cost of a sophisticated digital meter capable of two-way communications may be more expensive than the cost of a traditional meter, but the digital meter is

[62] http://smartgrid.webexworkspace.com/
[63] See, e.g., EPRI, Profiling and Mapping of Intelligent Grid R&D Programs (2006). http://my.epri.com/portal/server.pt?Abstract_id=000000000001014600

unlikely to require the same level of maintenance and is less likely to "slow down" over its lifetime than the analog meter.

The first issue to be addressed is whether any existing state laws (for example, a distribution rate cap) would inhibit or prohibit cost recovery. If no existing law bars the recovery of smart grid costs, state commissions might take into account the net costs or benefits of the project and how costs will be allocated. One study of states that have considered smart grids observed that, short of a full rate case process, several cost recovery mechanisms have been developed:

- "None": No cost recovery method was developed
- "Trackers": A mechanism that follows costs over a year
- "Balanced Accounts/Rate Base": Track and recover reasonable and prudent costs not recovered through retail bills due to the application of rate freezes or ceilings
- "Customer Surcharge": A charge is imposed on customers to recover utility expenses (often a marginal cost approach)
- "State Funding": Projects are funded from state accounts.[64]

Revenue decoupling, the topic of one of the other standards in the 2007 statute, may be considered to provide additional incentives for adopting smart grid technologies. As discussed in section 4 of this manual, revenue decoupling refers to rate adjustment mechanisms that separate a utility's profits and recovery of its fixed costs from the volume of its sales (kWh).[65] Of course, the costs and benefits of a decoupling policy need to be carefully considered for its overall impact as well.

Section 16(C) calls on states to consider the related issue of recovering the remaining book-value costs of any equipment rendered obsolete by the deployment of a smart grid. In a 2007 resolution, referring to AMI expenditures,

[64] Will McNamara & Matthew Smith, Duke Energy's Utility of the Future: Developing a Smart Grid Regulatory Strategy across Multi-State Jurisdictions (2007). www.gridwiseac.org/pdfs/forum_papers/155_paper_final.pdf

[65] For more on revenue decoupling, see, e.g., Ken Costello, Natural-Gas Revenue Decoupling: Good for the Utility, or for Consumers? *Public Utilities Fortnightly* (April 2007).

NARUC recommended that commissions address this issue by considering several regulatory options including:

> provide for timely cost recovery of prudently incurred AMI expenditures, including accelerated recovery of investment in existing metering infrastructure, in order to provide cash flow to help finance new AMI deployment.[66]

5.3. Implementation

Implementation of smart grid programs requires an integrated network for both digital data and electrons between consumers, transmission and distribution, and generators. Therefore, the development of smart grid programs requires a great deal of consideration of technology. Such programs might entail investments in communications infrastructure, control equipment and software, sensing equipment, advanced grid components, smart meters, and smart appliances. There are many options for each of these technologies, each with different associated costs and advantages.[67] Considerations can be made for the cost of implementing a given technology as well as the benefits in terms of cost savings and maintenance.

Because smart grids are made up of many components they will be built incrementally. The incremental approach is inevitable because some elements of smart grids are presently commercial, economic, and being installed by some utilities today. Some components of the smart grid, like local electric storage and smart appliances are not yet widely commercial or not yet economic. Furthermore, the smart grid is not the responsibility of any one entity. Some elements must be installed by transmission or market operators, some must be

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[66] "Resolution to Remove Regulatory Barriers to the Broad Implementation of Advanced Metering Infrastructure," NARUC resolution, adopted by the NARUC Board of Directors February 21, 2007. The entire resolution is shown in Appendix D of this manual.

[67] For an example of one study considering the different technologies involved see The Energy Policy Initiatives Center, University of San Diego School of Law, San Diego Smart Grid Study Final Report (2006). http://www.sandiego.edu/EPIC/publications/documents/061017_SDSmartGridStudyFINAL.pdf

installed by transmission owners, some must be installed by distribution owners, and some must be installed by consumers. At each level, the responsible parties have different interests and different levels of awareness concerning the potential costs and benefits of the smart grid.

Because of these factors, the full implementation process for a smart grid might take several decades and some elements now being promoted might never materialize. In addition, the components of a smart grid (such as advanced metering infrastructure, advanced distribution operations, advanced transmission operations, and advanced asset management) need to be interoperable. Whatever approach is taken, it should be based upon a careful consideration of the costs and benefits to utilities and their consumers, with "deployment at the speed of value." A modular, phased approach could provide the flexibility to build a smart grid incrementally while allowing for the integration of new technology and coordination with other projects. The phased implementation and uncertainty about the exact end point for which all parties might be striving means that all investments also have to be as "future proof" as possible. They have to be designed to be flexible, so that they will work with future implementation phases.

Because the vision of a fully implemented smart grid anticipates customer participation in the operation of the grid, implementation of the smart grid may also require consideration of the rate structures and demand response programs that would enable or encourage that participation. For example, in response to rate design or program incentives, customers may opt to install home energy management systems that permit their appliances to respond to price or operational signals. In the GridWise test, most customers chose to have energy-intensive appliances automatically controlled to maximize savings and only occasionally manually overrode the automatic settings.[68] State commissions and utilities might want to consider automatic control settings for ease of use and the

[68] Pacific Northwest National Laboratory, Pacific Northwest GridWise Testbed Demonstration Projects: Part I. Olympic Peninsula Project (2007). http://www.fypower.org/pdf/PNNL_OP_Project.pdf

capability of manual settings for greater flexibility. Customers might also be given remote control of their appliances via the Internet.

5.4. Current Practices

There are several collaborative smart grid initiatives planned or in progress, including:

- IntelliGrid (EPRI)
- Modern Grid Strategy (NETL)
- Grid 2030
- GridWise Alliance (DOE & private companies)
- Pacific Northwest GridWise Testbed Demonstration Projects
- Advanced Grid Applications Consortium (GridApp)
- Power Systems Engineering Research Center (PSERC)
- Consortium for Electric Reliability Technology Solutions (CERTS)
- California Energy Commission—Public Interest Energy Research
- New York State Energy Research and Development Authority

Also, there are a number of utility-level smart grid projects already installed or underway. More than half of all cooperatives, for example, have already installed AMI and 26% of co-ops have already integrated their outage management systems with their AMI.

Most current projects have started with smart meters and advanced communications technology.[69] However, there are a few projects that are trying to implement many other smart grid functions (XCEL, Centerpoint) and others are doing research on other smart grid functions (AEP's Utility Scale Battery Storage). Three examples are briefly described next.

5.4.1. Southern California Edison

In July of 2007, Southern California Edison (SCE) applied to the California Public Utilities Commission for approval of an AMI deployment and cost

[69] See the 2006 PURPA Reference Manual, section 6 for additional case studies on demand response programs.

recovery. The Edison SmartConnect program is currently pending commission approval.[70] SCE spent several years developing a business case that the approximately $1.7 billion in costs was less than the expected benefits of a smart grid to both the utility and consumers. Beginning in 2008, and continuing through 2012, the Edison SmartConnect program will install around 5.3 million smart meters in homes and businesses that use less than 200 kW.

SCE expects that the program will mitigate up to 1 MW of capacity additions due to demand response and energy conservation. The program is also projected to deliver $116 million in net present value benefits to customers over the lifetime of the program. Other benefits will include enhanced reliability, automated outage information, and improved energy forecasting.

The main components of the Edison SmartConnect program are: the home area network (HAN), the local area network (LAN), the wide area network (WAN), the network management system, and the network operating center. The HAN uses a non-proprietary open standard technology to enable messaging to smart thermostats, in-home display, and/or customer devices. The LAN collects and transmits the communicated meter data to an electricity aggregator. The WAN transmits the information from the smart meter and the LAN to the utility. The network management center manages and configures the network. The network operating center provides network systems operations capability.

The Edison SmartConnect program will have time-of-use and critical peak pricing as rate options for customers. Both options are opt-in. There will also be a peak time rebate. The rebate will be credit in addition to any savings from dynamic pricing.

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[70] http://www.sce.com/PowerandEnvironment/smartconnect/ The Edison SmartConnect website provides links to some technical data as well as regulatory filings.

5.4.2. TXU

TXU plans to install around 3 million smart meters in the Dallas-Ft. Worth region of Texas by 2011. Several hundred thousand smart meters are already installed, some of which have broadband over power line capability. The current smart grid is mainly intended to improve reliability, but TXU intends to eventually include time-of-use billing. The Utility Commission has approved cost recovery.[71]

5.4.3. Pacific Northwest GridWise Testbed Demonstration

The Pacific Northwest GridWise Testbed Demonstration is a partnership between the U.S. Department of Energy and group of utilities in Oregon and Washington.[72] The first part of the demonstration was conducted in the Olympic Peninsula and included 112 residential customers, several commercial buildings, municipal water pumps, and distributed generators.

The demonstration market employed real time pricing at five-minute intervals. The smart grid was monitored at the Pacific Northwest National Laboratory. The residential customers were provided with smart electric water heaters and thermostats. They were given the means to assign a degree of automated price responsiveness. Most customers were content with a degree of automation, and saved around 10 percent on their bills.

The key findings of the demonstration were that:

- Consumers accepted and participated in the project
- Internet-based communications performed well
- Distributed generation served as a valuable resource
- Peak load was reduced
- Market-based control was demonstrated
- Distribution constraints were managed.

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[71] Public Utility Commission of Texas, Project Number 31418, Rulemaking Related to Advanced Metering (10 May 2007).

[72] Pacific Northwest National Laboratory, Pacific Northwest GridWise Testbed Demonstration Projects: Part I. Olympic Peninsula Project (2007). http://www.fypower.org/pdf/PNNL_OP_Project.pdf

6. Section 374 Standard: Additional Incentives for Recovery, Use, and Prevention of Industrial Waste Energy

6.1. Introduction to the Section 374 Standard

The Energy Independence and Security Act of 2007 contained a standard for states and nonregulated utilities to consider that is not an amendment to PURPA. While some of the provisions for consideration are similar to the PURPA standards, this standard has distinctive requirements written as part of the standard's statutory language. This standard is in section 374 of EISA that is titled, "Additional Incentives for Recovery, Use, and Prevention of Industrial Waste Energy." The entire section 374 standard and other related sections of EISA are shown in Appendix C of this manual.

The focus of this standard is to encourage "waste energy recovery" projects that generate "net excess power." Examples of waste energy that are given in the statute include ''exhaust heat or flared gas from any industrial process" and "waste gas or industrial tail gas that would otherwise be flared, incinerated, or vented" (section 371(8)(A) through (D)). The term "net excess power" is defined as generation form these facilities "of electricity in quantities exceeding the total consumption of electricity at the specific time of generation on the site at which the facility is located" (section 371(3)).

The standard is divided into six main subsections. They are, with a brief description:

(a) *Consideration of Standard*. Establishes a time limit for state commissions and nonregulated utilities to begin consideration and make a determination.

(b) *Standard for Sales of Excess Power*. Contains the standard's general language that is to be considered by state commissions and nonregulated utilities.

(c) *Options*. Contains four options for the treatment of net excess power from a project owner or operator of an eligible waste energy recovery project.

(d) *Rate Conditions and Criteria*. Contains definitions and rate conditions for the sale and transport of power from eligible waste energy recovery projects.

(e) *Procedural Requirements for Consideration and Determination*. Sets the requirements for public notice and hearing, intervention by the Environmental Protection Agency Administrator, and the procedures for consideration and determination of the standard by states and nonregulated utilities.

(f) *Implementation*. Contains a general implementation requirement for state commissions and nonregulated utilities to implement or decline to implement the standard and additional requirements if the standard is declined.

As noted in the overview, this standard does *not* specify a minimum size of utility over which the standard applies, as does Title I of PURPA.[73] This essentially means that it must be considered by state commissions for all their jurisdictional utilities and by all nonregulated utilities.

Each subsection is discussed in more detail below. The four subsections that contain the wording of the standard, the procedural requirements for consideration and determination, and implementation are discussed first ((a), (b), (e), and (f)). Following that discussion, specific options and rate considerations contained in the standard are discussed ((c) and (d)). Appendix C contains the entire section 374 standard and related sections in the 2007 statute (sections 371 through 374 of EISA).

6.2. Consideration of the Standard

The standard in section 374, begins with subsection (a) that outlines the consideration of the standard:

[73] PURPA standards apply to utilities with total annual retail sales greater than 500,000 MWh, as of two years before the year when the standards are being considered. This is discussed in section 2.3 of this manual.

(a) CONSIDERATION OF STANDARD.—
(1) IN GENERAL.—Not later than 180 days after the receipt by a State regulatory authority (with respect to each electric utility for which the authority has ratemaking authority), or nonregulated electric utility, of a request from a project sponsor or owner or operator, the State regulatory authority or nonregulated electric utility shall—
(A) provide public notice and conduct a hearing respecting the standard established by subsection (b); and
(B) on the basis of the hearing, consider and make a determination whether or not it is appropriate to implement the standard to carry out the purposes of this part.
(2) RELATIONSHIP TO STATE LAW.—For purposes of any determination under paragraph (1) and any review of the determination in any court, the purposes of this section supplement otherwise applicable State law.
(3) NONADOPTION OF STANDARD.—Nothing in this part prohibits any State regulatory authority or nonregulated electric utility from making any determination that it is not appropriate to adopt any standard described in paragraph (1), pursuant to authority under otherwise applicable State law.

In other words, within six months of receiving a request from a project sponsor, owner, or operator, a state commission or nonregulated electric utility is to provide public notice and conduct a hearing on the standard and, based on the hearing, consider and make a determination on whether or not to implement the standard.[74] Similar to the PURPA standards, nothing prohibits a state commission or nonregulated electric utility from deciding that it is not appropriate to implement the standard. However, if the standard is declined, subsection (f) places additional requirements on state commissions and nonregulated utilities, which are discussed below.

The actual general language of the standard to be considered is stated in subsection (b):

(b) STANDARD FOR SALES OF EXCESS POWER.—For purposes of this section, the standard referred to in subsection (a) shall provide that an owner or operator of a waste energy recovery project identified on the Registry that generates net excess power shall be eligible to benefit from

[74] This standard uses similar terms as those defined in Title I of PURPA. Such as "electric utility," "nonregulated electric utility," and "State regulated electric utility" (section 371(9)).

at least 1 of the options described in subsection (c) for disposal of the net excess power in accordance with the rate conditions and limitations described in subsection (d).

Restated, an owner or operator of a waste energy recovery project that is on the "*Registry*" that generates *net excess power* is eligible for one of the sale options described in subsection (c) and the rate conditions and limitations of subsection (d). These subsections (and the Registry) are described below. Definitions are provided in section 371 of the statute (this entire section is in Appendix C). These definitions include the following:

- The term "combined heat and power system" is defined as a facility that "simultaneously and efficiently produces useful thermal energy and electricity" and "recovers not less than 60 percent of the energy value in the fuel (on a higher-heating-value basis) in the form of useful thermal energy and electricity."
- The term "net excess power" is defined as "recoverable waste energy recovered in the form of electricity in quantities exceeding the total consumption of electricity at the specific time of generation on the site at which the facility is located."
- A "project" is a "recoverable waste energy project or a combined heat and power system project."
- "Recoverable waste energy" is "waste energy from which electricity or useful thermal energy may be recovered through modification of an existing facility or addition of a new facility.
- The "Registry" refers to the "Registry of Recoverable Waste Energy Sources established under section 372(d).
- '"Useful thermal energy" is energy "(A) in the form of direct heat, steam, hot water, or other thermal form that is used in production and beneficial measures for heating, cooling, humidity control, process use, or other valid thermal end-use energy requirements; and (B) for which fuel or electricity would otherwise be consumed."
- "Waste energy" is defined as "(A) exhaust heat or flared gas from any industrial process; (B) waste gas or industrial tail gas that would otherwise be flared, incinerated, or vented; (C) a pressure drop in any gas, excluding any pressure drop to a condenser that subsequently vents the resulting heat; and (D) such other forms of waste energy as the Administrator may determine."
- The "Administrator" is the Administrator of the Environmental Protection Agency (EPA).

Section 372 of the statute contains details on the “Registry” of facilities and related tasks for EPA’s Administrator. This includes a requirement for the Administrator to conduct an “ongoing survey” of all major industrial and commercial “combustion sources” in the U.S. and where they are located. Within nine months of enactment (September 19, 2008) the Administrator is to publish rules for the criteria of sites to be included in the Registry. To be included on the Registry, a project has to be “economically feasible by virtue of offering a payback of invested costs not later than 5 years after the date of first full project operation (including incentives offered under this part)” (section 372(b)(2)(A)). However, if the project is developed or used “for the primary purpose of making sales of excess electric power” it cannot qualify for the Registry.

The Secretary of Energy is to provide technical support at the request of the owner or operator of a facility on the Registry and offer partial funding of up to one-half the total cost of feasibility studies to determine if the facility would have a payback period of five years or less (section 372(c)).

One year after enactment (December 19, 2008), the EPA Administrator is to establish the “Registry of Recoverable Waste Energy Sources” and specify the location of the facilities, based on the criteria established by the statute and the Administrator’s implementing rulemaking (section 372(d)(1)(A)). The Administrator is to update the Registry “on a regular basis” and make the Registry available to the public on EPA’s website (section 372(d)(1)(B)). Also, any “State, electric utility, or other interested person may contest the listing of any source or site by submitting a petition to the Administrator” (section 372(d)(1)(C)). (See Appendix C for other details specified in the section.)

6.3. Procedural and Implementation Requirements

The standard section (section 374) also has procedural requirements for consideration and determination that are similar, but not identical to PURPA’s requirements. Subpart (e) states (in its entirety):

(e) PROCEDURAL REQUIREMENTS FOR CONSIDERATION AND DETERMINATION.—

(1) PUBLIC NOTICE AND HEARING.—

(A) IN GENERAL.—The consideration referred to in subsection (a) shall be made after public notice and hearing.

(B) ADMINISTRATION.—The determination referred to in subsection (a) shall be—

(i) in writing;

(ii) based on findings included in the determination and on the evidence presented at the hearing; and

(iii) available to the public.

(2) INTERVENTION BY ADMINISTRATOR.—The Administrator may intervene as a matter of right in a proceeding conducted under this section—

(A) to calculate—

(i) the energy and emissions likely to be saved by electing to adopt 1 or more of the options; and

(ii) the costs and benefits to ratepayers and the utility; and

(B) to advocate for the waste-energy recovery opportunity.

(3) PROCEDURES.—

(A) IN GENERAL.—Except as otherwise provided in paragraphs (1) and (2), the procedures for the consideration and determination referred to in subsection (a) shall be the procedures established by the State regulatory authority or the nonregulated electric utility.

(B) MULTIPLE PROJECTS.—If there is more than 1 project seeking consideration simultaneously in connection with the same utility, the proceeding may encompass all such projects, if full attention is paid to individual circumstances and merits and an individual judgment is reached with respect to each project.

Part (1) of the subsection is nearly identical to the analogous PURPA requirement. That is, the consideration of the standard must be made after public notice and hearing and the determination must be in writing, based on evidence presented, and be available to the public. (This is nearly identical to PURPA section 111(b)(1), which was covered in part two of this manual.)

Part (2) of subsection (e) allows the EPA Administrator to intervene in a proceeding to calculate energy and emissions possibly saved by using one or more of the four options for the sale of power described in subpart (c) (discussed below), calculate the costs and benefits to ratepayers and utilities, and advocate for waste energy recovery opportunities.

Part (3) of subsection (e) is a savings clause that allows the states and nonregulated utilities to establish the procedures to consider and make a determination on the standard, except for what is required under parts (1) and (2), of this subsection. Paragraph (B) permits the consolidation of multiple projects that are simultaneously seeking consideration in a proceeding with the same utility as long as full attention is paid to the individual circumstances and merits and an individual judgment is reached with respect to each project.

Subsection (f) outlines the implementation of the section 374 standard and begins with a similar provision to PURPA section 111(c) on implementation. However, the requirements are significantly different for non-implementation of the standard.

> (f) IMPLEMENTATION.—
> (1) IN GENERAL.—The State regulatory authority (with respect to each electric utility for which the authority has ratemaking authority) or nonregulated electric utility may, to the extent consistent with otherwise applicable State law—
> (A) implement the standard determined under this section; or
> (B) decline to implement any such standard.
> (2) NONIMPLEMENTATION OF STANDARD.—
> (A) IN GENERAL.—If a State regulatory authority (with respect to each electric utility for which the authority has ratemaking authority) or nonregulated electric utility declines to implement any standard established by this section, the authority or nonregulated electric utility shall state in writing the reasons for declining to implement the standard.
> (B) AVAILABILITY TO PUBLIC.—The statement of reasons shall be available to the public.
> (C) ANNUAL REPORT.—The Administrator shall include in an annual report submitted to Congress a description of the lost opportunities for waste-heat recovery from the project described in subparagraph (A), specifically identifying the utility and stating the quantity of lost energy and emissions savings calculated.
> (D) NEW PETITION.—If a State regulatory authority (with respect to each electric utility for which the authority has ratemaking authority) or nonregulated electric utility

> declines to implement the standard established by this section, the project sponsor may submit a new petition under this section with respect to the project at any time after the date that is 2 years after the date on which the State regulatory authority or nonregulated utility declined to implement the standard.

Under part (1), as with the PURPA standards, state commissions and nonregulated utilities can either implement the standard or decline to implement the standard. Also similar to PURPA standards, if the state commission or nonregulated utility declines to implement the standard, the reason why it was declined must be stated in writing and that statement must be available to the public.

Differences from PURPA are in subparts (C) and (D). The requirement of subpart (C) does not obligate a state authority or utility directly, but does require the EPA Administrator to submit to Congress an annual report with "a description of the lost opportunities for waste-heat recovery" from projects adversely affected by non-implementation of the standard. The Administrator in its report must specifically identify the utilities and the quantity of energy and emissions savings potential that was lost.

Subpart (D) provides that if a state commission or nonregulated electric utility declines to implement the standard, a project sponsor may submit a new project petition at any time two years after the date on which the state commission or nonregulated utility declined to implement the standard.

It is important to note several other differences from PURPA standards. First, there is no specified deadline to begin consideration of the standard or to make a decision. The standard states (374(a)(1)) that "not later than 180 days after the receipt" by a state commission or nonregulated electric utility "of a request from a project sponsor or owner or operator." In other words, the six month clock for the standard's consideration *and* for when a determination must be made begins when a request is received, not for a period of time after the statute's date of enactment and with separate deadlines for consideration and determination, as with the PURPA standards. Second, separate consideration and determinations are needed for each project, unless, as noted, multiple projects are consolidated using the provision that allows simultaneous consideration in a proceeding with the same utility (section 374(e)(3)(B)).

Third, the stated three purposes of the PURPA Title I (PURPA section 101) are not present in this standard, and there is no reference to another basis for a decision. Finally, there is no grandfathering provision. Projects are considered on a project-by-project basis or multiple projects are consolidated for hearing, but with each project receiving a separate evaluation and determination. Also, project sponsors can resubmit a petition for a project after two years after the date a state commission or nonregulated utility declined to implement the standard.

6.4. Prescribed Alternatives for the Sale of Power

Subpart (c) outlines four alternatives for the sale of power from an eligible waste energy recovery project.

(c) OPTIONS.—The options referred to in subsection (b) are as follows:
- (1) SALE OF NET EXCESS POWER TO UTILITY.—The electric utility shall purchase the net excess power from the owner or operator of the eligible waste energy recovery project during the operation of the project under a contract entered into for that purpose.
- (2) TRANSPORT BY UTILITY FOR DIRECT SALE TO THIRD PARTY.—The electric utility shall transmit the net excess power on behalf of the project owner or operator to up to 3 separate locations on the system of the utility for direct sale by the owner or operator to third parties at those locations.
- (3) TRANSPORT OVER PRIVATE TRANSMISSION LINES.—The State and the electric utility shall permit, and shall waive or modify such laws as would otherwise prohibit, the construction and operation of private electric wires constructed, owned, and operated by the project owner or operator, to transport the power to up to 3 purchasers within a 3-mile radius of the project, allowing the wires to use or cross public rights-of-way, without subjecting the project to regulation as a public utility, and according the wires the same treatment for safety, zoning, land use, and other legal privileges as apply or would apply to the wires of the utility, except that—
  - (A) there shall be no grant of any power of eminent domain to take or cross private property for the wires; and

(B) the wires shall be physically segregated and not interconnected with any portion of the system of the utility, except on the customer side of the revenue meter of the utility and in a manner that precludes any possible export of the electricity onto the utility system, or disruption of the system.

(4) AGREED ON ALTERNATIVES.—The utility and the owner or operator of the project may reach agreement on any alternate arrangement and payments or rates associated with the arrangement that is mutually satisfactory and in accord with State law.

The first option is the sale of power to the utility under a contract arrangement between the project owner or operator and the utility. Depending on the level of development of the wholesale market at a particular location, under federal law the project owner or operator may be able to sell the power back to the utility, or it may have to sell the excess power on the wholesale market and find a buyer to contract with for the sale of the power.[75] It is not specified anywhere in this standard how it relates with existing federal law for PURPA qualified facilities (QFs).

Under the second option, the utility transmits the power to third parties on the utility's system for sale by the project owner or operator to up to three separate locations. In this case, the utility would either have to grant access to its system, or be required to by state law or regulation.

The effect of this second option is to allow retail sales on the utility's system directly to retail customers. In non-retail access states, this would typically violate utility territorial laws. In retail access states, this could subject the project to regulation as an electric utility or as a competitive retail supplier. If this is seen as a wholesale sale, it would in effect make the project a public utility and subject it to regulation under the Federal Power Act, including the obligation

[75] Under the original PURPA provisions, utilities were required to interconnect with and purchase power from "qualified facilities" (among other benefits a "QF" could receive). This included cogenerators of power (a combined heat and power facility). This mandatory purchase requirement was modified by the 2005 EPAct and, under current FERC rule (Order No. 688), utilities can now file with FERC for relief from the PURPA mandatory purchase obligation in existing "Day 2" regional transmission organization (RTO) markets, if it is determined that the QF has non-discriminatory access to the RTO's markets. QFs have an opportunity to rebut whether they actually have non-discriminatory access.

to file rates or file for market based rate authority with FERC. By transmitting the power across its system for a wholesale sale, the utility would likely be subjecting a portion of its now state-regulated distribution system to regulation by FERC as transmission, something many states would view negatively. For these reasons alone, this second option needs to be carefully considered by state commissions and nonregulated utilities for jurisdictional complications and potential conflicts with state and federal law before a decision is made to use this option for a project.

The third option would authorize the project to build and operate a private transmission/distribution system and to transmit the excess power from the project to up to three retail or wholesale customers within a three-mile radius of the project across those private lines. The state or other relevant legal authority would have to waive or change existing laws that prohibits the construction and operation of private electric wires to transmit power—and do so without subjecting the project to regulation as a public utility, but "according the wires the same treatment for safety, zoning, land use, and other legal privileges as apply or would apply to the wires of the utility." The exceptions are that there would be no granting of any power of eminent domain and the project's wires would not be interconnected with the utility's system.

This option is likely to be very problematic since it likely conflicts with existing state laws. A state commission or nonregulated utility may not be able to approve such an arrangement without legislation that either permits them to do so, or at the least, modifies existing state laws that currently prevent such actions. Only the state's legislature would have the authority to change this. However, historically most states have explicitly rejected such options because of the duplication of resources, the infringement on the public rights of way, and for health and safety concerns. For these reasons, most states have prohibited duplicative distribution systems.

Another issue may be the siting of the lines and the construction and operation of the lines by a non-utility. This also may not be permissible under existing state laws. (Depending on location of the project, obtaining the needed siting approvals for the lines by *any* entity may be difficult.) Also, like the second option, this option may violate state territorial laws in states without retail competition if the power is sold to retail customers. The private distribution system then cannot be interconnected with the broader grid. This would mean that the project and all its customers would be isolated from the grid—which would reduce reliability for retail customers considerably. For these reasons, this option may simply be impossible to adopt.

From a practical standpoint, many industrial and commercial sites that might have the potential to host waste energy projects would not always be generating sufficient amounts of power to meet their own needs at all times. Hence, they would still need, at least some times during project operations, to purchase power from the utility to meet their power needs, and to have access to backup power when necessary. Therefore, such projects could lose important benefits if not interconnected to the utility's distribution system. Lack of interconnection would also limit a project's opportunities to sell any excess power generated. If the project is connected to the utility's distribution system, then it is not clear why the new lines are necessary.[76] This could limit the need and usefulness of this option even if it could be done legally.

The fourth option is simply that the project owner or operator reaches an agreement on an arrangement that is in accordance with state law. This of course depends on the nature of the arrangement and would raise similar issues as options (1) and (2).

6.5. Prescribed Rate Criteria and Options for the Sale of Power

There are four main parts to subsection (d) that outlines the standard's rate criteria. Part (1) defines three terms: (A) per unit distribution costs, (B) per unit distribution margin, and (C) per unit transmission costs. Part (2) specifies that these rate definitions are to be used for the sale of power for options (1) and

[76] Given the cost of new power lines, the additional cost could negate any potential benefits from the sale of excess power from a combined heat and power facility to a third party.

(2) of subpart (c), and for the rate applications described in part (3) of subpart (d). The two rate applications specified in part (3) are (A) rates applicable to sale of net excess power and (B) rates applicable to transport by utility for direct sale to third parties. Part (4) specifies limitations.

(d) RATE CONDITIONS AND CRITERIA.—
(1) DEFINITIONS.—In this subsection:
(A) PER UNIT DISTRIBUTION COSTS.—The term 'per unit distribution costs' means (in kilowatt hours) the quotient obtained by dividing—
(i) the depreciated book-value distribution system costs of a utility; by
(ii) the volume of utility electricity sales or transmission during the previous year at the distribution level.
(B) PER UNIT DISTRIBUTION MARGIN.—The term 'per unit distribution margin' means—
(i) in the case of a State-regulated electric utility, a per-unit gross pretax profit equal to the product obtained by multiplying—
(I) the State-approved percentage rate of return for the utility for distribution system assets; by
(II) the per unit distribution costs; and
(ii) in the case of a nonregulated utility, a per unit contribution to net revenues determined multiplying—
(I) the percentage (but not less than 10 percent) obtained by dividing—
(aa) the amount of any net revenue payment or contribution to the owners or subscribers of the nonregulated utility during the prior year; by
(bb) the gross revenues of the utility during the prior year to obtain a percentage; by
(II) the per unit distribution costs.
(C) PER UNIT TRANSMISSION COSTS.—The term 'per unit transmission costs' means the total cost of those transmission services purchased or provided by a utility on a per-kilowatt-hour basis as included in the retail rate of the utility.
(2) OPTIONS.—The options described in paragraphs (1) and (2) in subsection (c) shall be offered under purchase and transport rate conditions that reflect the rate components defined under paragraph (1) as applicable under the circumstances described in paragraph (3).
(3) APPLICABLE RATES.—
(A) RATES APPLICABLE TO SALE OF NET EXCESS POWER.—
(i) IN GENERAL.—Sales made by a project owner or operator of a facility under the option described in subsection

(c)(1) shall be paid for on a per kilowatt hour basis that shall equal the full undiscounted retail rate paid to the utility for power purchased by the facility minus per unit distribution costs, that applies to the type of utility purchasing the power.

(ii) VOLTAGES EXCEEDING 25 KILOVOLTS.—If the net excess power is made available for purchase at voltages that must be transformed to or from voltages exceeding 25 kilovolts to be available for resale by the utility, the purchase price shall further be reduced by per unit transmission costs.

(B) RATES APPLICABLE TO TRANSPORT BY UTILITY FOR DIRECT SALE TO THIRD PARTIES.—

(i) IN GENERAL.—Transportation by utilities of power on behalf of the owner or operator of a project under the option described in subsection (c)(2) shall incur a transportation rate that shall equal the per unit distribution costs and per unit distribution margin, that applies to the type of utility transporting the power.

(ii) VOLTAGES EXCEEDING 25 KILOVOLTS.—If the net excess power is made available for transportation at voltages that must be transformed to or from voltages exceeding 25 kilovolts to be transported to the designated third-party purchasers, the transport rate shall further be increased by per unit transmission costs.

(iii) STATES WITH COMPETITIVE RETAIL MARKETS FOR ELECTRICITY.—In a State with a competitive retail market for electricity, the applicable transportation rate for similar transportation shall be applied in lieu of any rate calculated under this paragraph.

(4) LIMITATIONS.—

(A) IN GENERAL.—Any rate established for sale or transportation under this section shall—

(i) be modified over time with changes in the underlying costs or rates of the electric utility; and

(ii) reflect the same time-sensitivity and billing periods as are established in the retail sales or transportation rates offered by the utility.

(B) LIMITATION.—No utility shall be required to purchase or transport a quantity of net excess power under this section that exceeds the available capacity of the wires, meter, or other equipment of the electric utility serving the site unless the owner or operator of the project agrees to pay necessary and reasonable upgrade costs.

As summarized in equation form in text Box 4, the “per unit distribution costs” is defined as the depreciated book value of the distribution system divided by utility sales. The “per unit distribution margin” is defined as the per-unit gross pretax profit for regulated utilities, or rate-of-return on distribution assets times the per unit distribution costs. For nonregulated utilities, the per unit distribution margin is the per-unit contribution to net revenues, defined as the percentage (not to be less than 10 percent) obtained by dividing net revenue payment or contribution to the nonregulated utility during the prior year by the gross revenues of the utility, then multiplied by the per unit distribution cost. Subpart (C) defines the “per unit transmission costs” as the total cost of transmission services purchased or provided by the utility per kWh included in the retail rate.

Box 4. Equations from Section 374(d)(1)(A) and (B).

$$\text{Per Unit Distribution Cost (kWh)} = \frac{\text{Depreciated Book Value of Dist. System}}{\text{Utility Sales}}$$

$$\text{Per Unit Distribution Margin (for regulated utilities)} = \text{Per-Unit Gross Pretax Profit} = \text{Rate-of-Return on Distribution Assets} \times \text{Per Unit Distribution Cost}$$

$$\text{Per Unit Distribution Margin (for nonregulated utilities)} = \text{Per-Unit Contribution to Net Revenues} = \frac{\text{Net Revenue Payment or Contribution}}{\text{Gross Revenues of the utility}} \times \text{Per Unit Distribution Cost}$$

(this quotient, expressed as a percentage, is not to be less than 10%)

These rate conditions and criteria need to be carefully considered. Many states and nonregulated utilities may find that the definitions and rate options for the sale of the power from a project are incompatible or inconsistent with their current regulatory standards and practices. There are potentially at least two problems that may be encountered. First, not all utilities (regulated or nonregulated) have unbundled or separated the distribution costs from the non-distribution costs of the utility. This is most likely the case for states with vertically-integrated regulated utilities (many “restructured” states with retail access have unbundled their rates). So, for example, calculating the “rate-of-return on distribution assets” for regulated utilities (or the per-unit contribution to net revenues for nonregulated utilities) may require first examining all utility costs and identifying the distribution-only costs, a nontrivial task for any utility that has not already completed it.

However, even for those states and utilities that have unbundled, this approach would be an enormous departure in rate design from what is currently done anywhere in the country. There is a great deal of detail left out on methodology and cost definitions that states and FERC typically consider when they establish retail rates and transmission rates. State commissions and nonregulated utilities would likely examine these criteria and determine that, without further detail, it could significantly shift costs to other consumers on the utility’s system.

The second possible difficultly is that the definitions are expressed as system averages. Assuming data availability, this could be calculated. However, what most customers typically pay is not the “average,” but a specific rate determined by customer class through the rate design. This could be less than or greater than the system average. While these formulae may look complicated, determining an individual customer’s distribution cost and margin would be even more complex. While perhaps not impossible, a good faith attempt would have to be made to fairly allocate costs among the various customers on the utility’s system.

Part (3)(A) of subpart (d) deals with the rates for the sales of excess power by a project owner or operator. For the rate option of (c)(1), that is, the sale of power to the utility under a contract arrangement between the project owner or operator and the utility, the project owner or operator is to be paid (per kWh) the “full undiscounted retail rate paid to the utility for power purchased by the facility minus per unit distribution costs.” When the voltages exceeds 25 kilovolts, the purchase price is also reduced by the per unit transmission cost.

Part (3)(B) is for sales under option (c)(2), that is, when the utility transmits the power to third parties on the utility's system for sale by the project owner or operator. In this case, the transportation rate is to be the per unit distribution costs and per unit distribution margin. For voltages exceeding 25 kilovolts, the transportation rate is to be increased by the per unit transmission costs. In states with retail markets, the transportation rate for similar transportation is to be applied rather than using the rate calculation of the standard.

States and utilities may already have rates for the sale of power back to or transfer by utilities. This may be for power sold by PURPA QFs, as part of existing regulations addressing buy-back rates. It would have to be determined if this standard's rate setting provisions are comparable to existing rules, are compatible or in conflict with current rules, whether existing rules could be (or should be) modified to accommodate this standard, or whether a similar provision for power being sold back to the utility has already been examined and rejected.

Finally, part (4) specifies that the rates for sale or transport can be modified when costs or utility rates change over time and that these rates should reflect the same time-sensitivity and billing periods as established in the utility's retail or transportation rates. Part (4) also specifies that a utility is not required to purchase or transport net excess power that exceeds available capacity of the wires, meter, or other equipment of the utility, unless the project owner or operator pays for necessary and reasonable upgrades.

6.6. Modification of the Standard

While this standard is very specific and does not state a procedure for modification, it should be remembered that it is a standard with the PURPA-like provision that it can be adopted as is or rejected by states and nonregulated utilities, provided the requirements for rejecting the standard are followed. Presumably, this means that a state commission or nonregulated utility could modify the standard and indicate that as the reason why the standard, as written, was declined. This standard does have the added feature that if the standard is declined, a project sponsor may submit a new petition two years after a state commission or nonregulated utility declined to implement the standard. However, if a state commission or nonregulated utility adopted a modified version of a similar standard that specifically dealt with how waste energy recovery projects that are on the Registry should be addressed, or stated the reason for not adopting a standard at all, that may be sufficient to meet the requirements of the statute. Therefore, if a new petition is received after a decision was made, then the state or nonregulated utility might consider as a possible response referring to its prior modified standard or the statement of why it was declined–without restarting the consideration of this standard as written in the statute from the beginning.

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Cooperative Research Network (CRN)
Energy Efficiency Resource Materials

Utility Trends and Best Practices in Energy Efficiency (07-23C)
More utilities are launching new energy-efficiency programs, more customers are participating in them, and energy efficiency has become a recurring headline in the popular media. This report details the latest news in utility-sponsored energy-efficiency programs and will spark new ideas into programs that CRN members may be able to implement at their co-ops. This report is produced by Chartwell, and is made available to all CRN members through our membership in Chartwell.

Best Practices in Energy Efficiency (06-17)
CRN's *Best Practices in Energy Efficiency* will help co-ops take a strategic approach to energy savings that help both consumers and the co-op. The guide will show how rising energy costs, fuel switching, and new technologies are creating opportunities for co-ops to help reduce costs to members, improve load factor, and boost the co-op's financial health. It also will identify and evaluate technology and service options a co-op can pursue or promote to help lower costs for consumers. The menu of energy savings options will target residential and small commercial consumers.

Solar Thermal Economics (07-13)
A cost-benefit analysis of solar thermal for domestic hot water, utilizing a cooperative-controlled pilot installation at co-op member homes, will give co-ops across the country a real-world understanding of the potential value of solar thermal as a technology to control costs and meet renewable energy mandates. The field test also lead the creation of a calculator to help co-ops and consumer determine return the economics of the systems.

Evaluate Low Temperature Heat Pumps (06-16)
The adoption of heat pump technology combined with the increase in the cost of propane is resulting in additional winter electric loads for electric co-ops. Unfortunately, air source heat pumps can add a significant and costly peak when temperatures fall

below freezing and the heat pumps call upon secondary resistive heat to maintain temperature in the home. The efficiency of conventional air source heat pumps drops at 25 to 30 degrees F. CRN has launched a comprehensive testing program of low temperature heat pumps from two manufacturers. The testing assessed performance and reliability and maturity of product development.

Products, Services & Programs for C&I Customers Data Summary & Report 2007 (07-23D)
This report showcases a study of utility programs and services aimed at commercial and industrial (C&I) customers. Readers will learn about the wide range of services that utilities are offering C&I customers, and they will be able to understand the effectiveness of the program and if the program could be explored for delivery to their members.

Flex-Microturbine (02-18)
This project explores a modified microturbine that can run off low-energy fuels such as biomass. The Flex-Microturbine and its gasifier can make locally produced waste yield locally produced energy. Together, they have the potential to bring energy self-sufficiency to woody-waste–producing agriculture and industry, and even to entire rural communities.

Low-Income Energy Efficiency Programs (03-24A)
CRN, through its membership in Chartwell, provides electric cooperatives with information on low-income energy efficiency programs and how to promote them. This information will not only aid utilities in keeping down billing/dunning costs and shutdown and restart-of-service costs, but will in turn help a growing segment of co-op customers save money and improve their quality of life.

Reshaping and Reducing Demand In An Era of Rising Costs: An Overview of Load Management (05-18A)
Constraints in capacity, rising costs, government policy and the market mechanisms of Independent System Operators and Regional Transmission Operators are among the factors leading to renewed attention to shaping, shifting and reducing load. This report examines the latest trends in load management, which combine aspects of traditional demand side management (DSM) programs, energy efficiency and demand response. The issue of demand response is addressed to provide an understanding of the link between rates and rate structures on the success of load management initiatives. Data on consumer attitudes towards the use of price signals and the elasticity of response to price signals in each of these sectors is explored.

Marketing & Communicating a Demand Response Program (07-23A)
CRN, through its membership in Chartwell is providing its members with an in-depth report communicating a Demand Response (DR) program to your membership.

White Tags and Carbon Offsets (07-14E)
This roundtable, sponsored by CRN's partner E Source, will give readers an understanding of some of the issues surrounding white tags. Panelists discussed the burgeoning market for energy savings credits and how it may impact utility companies.

Streamlined Energy Audits: Using Handheld Computers for Onsite Small Business Audits (07-14A)

Through its membership in E Source, CRN explores a new trend in the field of energy auditing.

Top 10 Ways to Help Consumers Save Energy (Tech Surveillance)
Something good is coming from rising power costs—increased attention to energy efficiency. This *TechSurveillance* report introduces 10 activities and programs that utilities across the country have used to help members save money.

What Co-ops Can Do To Increase Energy Efficiency in Member Homes (Tech Surveillance)
Electric co-ops have long provided energy-efficiency programs. Many co-ops are planning to expand pre-existing programs while creating new ones. Some, like Wabash Valley Power Association (Indianapolis, Ind.), see their energy-efficiency programs as attractive options to offset the increase in peak load demand. This is especially true when contrasted with the costly options of investing in peak load generation infrastructure.

Additional Software Now Available to Evaluate DSM Programs (Tech Surveillance)
Demand-side management (DSM) programs require software platforms that can effectively calculate and asses DSM portfolios.

Energy Efficiency Improvements in Manufactured Housing — The Industry Responds (Tech Surveillance)
For the typical customer, a monthly electric bill of $600 or $700 would be surprising and disconcerting. Imagine the shock and bewilderment if that bill is for a small manufactured home. This is unfortunately not an uncommon occurrence for many co-op customers.

Demand Response – New Name, New Game (Tech Surveillance)
Even as markets for electric power become more openly competitive, many of the "rules of the road" still need to be defined. One area in need of more definition is the role of demand response programs in competitive wholesale power markets. Such programs include load management, real-time pricing, distributed generation, and targeted energy efficiency. Demand response is the new term, which reflects the growing role customers can play in load curtailment.

Innovations in Cooling Technology (Tech Surveillance)
New ideas in air conditioning and cooling technology hold out hope for significant reductions in energy consumption.

Is LEED Certification Right for You? (Tech Surveillance)
Several U.S. electric co-ops have decided to invest additional funds to achieve certification for the construction of their new headquarters from the “Leadership in Energy and Environmental Design” (LEED) Green Building Rating System.

Winter Peaking in the South: What Approaches and Technologies Can Help? (Tech Surveillance)
Increasingly, co-ops in the southern United States are experiencing their highest peak demands in the wintertime. Central Electric Power Cooperative, a South Carolina G&T, has been a winter-peaking co-op for several years. Central’s winter peak has exceeded its summer peak in five of the past six years—by anywhere from 123 megawatts (MW) to 754 MW, during the exceptionally cold winter of 2003. Over this period, the average

difference has been 368 MW, making Central's winter peaks 117% higher than its summer ones.

Energy Efficiency: Seven Things You May Not Know About Air-Source Heat Pumps (Tech Surveillance)
For the first time since 1992, the federal government last year raised the minimum standards for heat pump efficiency. Effective in 2006, all heat pumps used in new housing, as well as retrofit applications, must meet standards that effectively increase efficiency by 30%. The cooling standard—SEER or seasonal efficiency energy rating—must be at least 13, and the heating standard—HSPF or heating seasonal performance factor—must be at least 7.7. The previous minimums were 10 SEER and 6.8 HSPF.

CHP and DG: A Match Made for a Rising Fuels Market? (Tech Surveillance)
CHP and DG: A Match Made for a Rising Fuels Market?

A Different Type of Heat Pump That Draws Less Current (Tech Surveillance)
Co-ops and their members are always looking for a way to increase energy savings. Heat pumps have many energy-efficient options to achieve this goal.

Tankless Water Heaters: Energy Savers or Demand Busters? (Tech Surveillance)
Tankless, or instantaneous, water heaters are being sold to consumers and home builders with the promise of energy savings and an endless supply of hot water. A few localities are starting to see installations of these units, and particularly worrisome is their use in new subdivisions. Are consumers well-served by tankless water heaters? Could they create unwieldy spikes in demand for electric co-ops? CRN commissioned James Tidwell, a former co-op manager and HVAC contractor, to investigate this potentially disruptive technology and analyze its potential impact on co-ops and their consumer members.

Heat Pumps No Longer Have A Southern Accent, Co-ops Find (Tech Surveillance)
Heat pumps no longer have a Southern accent. For a long time, heat pumps were thought to be used best in the South, where cooling loads are high in summer and heating loads are low in winter. But technology improvements and recent uncertainty in gas prices have made heat pumps a potentially productive proposition even for co-ops far more to the north.

Home Energy Calculator: A Sample of What's Online (Tech Surveillance)
A web-based energy calculator is an important tool for cooperatives and their members. With varying inputs, the calculator user will be able to review different scenarios, allowing members to forecast probable heat load pricing.

NETL Report Offers Technology, Performance, and Cost Data for Fossil Plants (Tech Surveillance)
The Department of Energy's National Energy Technology Laboratory (NETL) has published a series of reports on the cost and performance baseline for fossil energy plants. The series is broken up into three different volumes.

How to Make the Finances of Manure to Power Add Up (Tech Surveillance)
Manure to Power (MtoP) projects are generating increasing interest from electric cooperatives and their agricultural members. The potential is fairly large. On any

particular day, there are more than 60 million swine, 9 million dairy animals, 7.7 billion poultry, and 90 million cattle confined in feeding operations across the U.S.

Market Snapshot: Demand Response (Tech Surveillance)
Demand response (DR) is being elevated as a key alternative energy source of sorts, potentially in offsetting the need for some new generation and transmission construction.

Energy Farming: Who's Doing What in Biomass Generation and Co-Firing (Tech Surveillance)
DOE's Office of Energy Efficiency and Renewable Energy has reported that biomass energy can provide as much as 15% of the total energy input for boiler types commonly used by electric utilities, when some modifications (including those to the intake system and burner) are made.

A Bright Future for Residential LEDs? (Tech Surveillance)
The semiconductor diodes known as Light Emitting Diodes (LEDs) are superior to incandescent and fluorescent bulbs in that they are less fragile, more efficient, and last longer.

Makers of Air Source Heat Pumps Ramp Up Efficiency of Units (Tech Surveillance)
Air-source heat pumps are more efficient than ever, and their use is growing. The technology continues to make strides, pushed by new government efficiency standards.

The ABCs of a Co-op Home Energy Makeover Contest (Tech Surveillance)
Delta Montrose Electric Association, Montrose, Colo., recently announced the three winners of its 2005 Home Energy Makeover contest. The homes, selected from 130 entries by homeowners who believed their dwellings were wasting energy, received up to $45,000 worth of energy saving improvements donated by local stores and contractors.

Electricity and the Environment: The Importance of the Infrastructure (Tech Surveillance)
Nearly all American households are dependent on electric power for everything from lighting to entertainment, but many are unaware of the infrastructure required to produce and distribute that power, or of the environmental implications of generating electricity. The purpose of this paper is to explain the relationships between electricity use, electric generation, and the emissions of substances that affect air quality, particularly with regard to the unique characteristics of rural electric cooperatives.

Demand Control Devices — How Can They Help Your Co-op? (Tech Surveillance)
As co-ops look to methods to better manage load, demand control devices that can help stabilize load and reduce peak demand appear to be attractive options.

Edison Electric Institute
Integrated Resource Planning Materials

Assessment of Achievable Potential for Energy Efficiency and Demand Response in the U.S. (2010 – 2030), Global Energy Partners, LLC, *The Brattle Group,* The Electric Power Research Institute, Edison Electric Institute, 2008 - This study estimates the realistic achievable potential for energy efficiency that would occur with the implementation and full operation of EE and DR programs and initiatives nationwide. The analysis evaluates the potential for energy efficiency improvement in the major categories of energy end use through the year 2030 for the four U.S. Census regions. This paper presents preliminary results from the EPRI/EEI study for the U.S. as a whole. The conference presentation will include final savings estimates by Census region, as well as the results of the scenario analysis. http://www.eei.org

State Regulatory Update: Energy Efficiency, Edison Electric Institute, 2008 – A mid-year summary and trend analysis of state regulatory actions on energy efficiency for 2008 http://www.eei.org/industry_issues/retail_services_and_delivery/wise_energy_use/EnergyEfficiencyLegisUpdateJun2008.pdf

"Capitalizing on Energy" *PUF SPARK*, April 2008 Energy efficiency grows more important each year. Rising energy prices. Growing concerns about the environment. Increasing stress on the country's electricity system. All point to the need for helping homes and businesses to get more use out of every kilowatt-hour of electricity they consume. To offer that help, many states and consumers are turning to the electric company.
(www.fortnightly.com/exclusive.cfm?o_id=62)

"**Modeling New Approaches for Electric Energy Efficiency**" *Electricity Journal*, March 2008 To align utilities and consumers' interests, three incentive methods have emerged to foster efficiency: shared savings, bonus return on equity, and energy service company. A fourth incentive method, virtual power plant, is being proposed by Duke Energy.

State Regulatory Update: Energy Efficiency, Edison Electric Institute, February 2008 – A summary and trend analysis of state regulatory actions on energy efficiency for 2005-2007
http://www.eei.org/industry_issues/retail_services_and_delivery/wise_energy_use/state_reg_update_efficiency.pdf

"**A New Vision For Energy Efficiency**" *Business Xpansion Journal*, January 2008 To keep pace with the country's projected growth in demand, the nation's electric companies will be investing in new power plants. They will be installing environmental controls to meet increasingly stringent environmental rules. And they will be modernizing the nation's aging
transmission and distribution infrastructure. But, importantly, they will also be expanding their commitment to energy efficiency.
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http://www.eei.org/industry_issues/retail_services_and_delivery/wise_energy_use/programs_and_incentives/progs.pdf

"Turning Energy Efficiency into a Business" Electric Light & Power, November 2007 - Growing demand, rising costs and increasing concerns about the environment—each, by itself justifies expanding energy efficiency's role as a resource for the electric power industry. Taken together, they create the urgent need to make energy efficiency a sustainable business within every electric company.

Making a Business of Energy Efficiency: Sustainable Business Models for Utilities, National Economic Research Associates, May, 2007 - Focuses on regulatory models that maximize the incentives for utilities to create sustainable businesses supplying energy efficiency products and services. Identifies and characterizes three families of business models that would let utilities make a margin on efficiency. Also addresses needed enabling regulatory policies.
http://www.eei.org/industry_issues/retail_services_and_delivery/wise_energy_use/Making_Business_Energy_Efficiency.pdf
Utility Supply Portfolio Diversity Requirements, *The Brattle Group*, May 2007 - Addresses the PURPA Fuel Source Standard and discusses the limitations of financial portfolio theory as applied to utility resource diversification. http://www.eei.org/state-policy-research

"Electric Companies Expanding Energy Efficiency's Role" Business Xpansion Journal, April 2007 -
America's dynamic economy continues to fuel a growing demand for electricity. Within the next 20 years, the U.S. is expected to be using close to 30-percent more electricity than it does today. To supply it, America's electric utility companies are building more power plants and transmission wires. But perhaps more importantly, they are also pursuing new initiatives to encourage businesses and homes to use their electricity more efficiently.
www.bxjonline.com/bxj/article.asp?magarticle_id=1106

"Do More With Less" Power Engineering, December 2006 - Electric utility industry structural change, rising fuel costs, and growing public concern over the environment, have all increased the value of energy efficiency as a resource for meeting customer demand. At the same time, advances in electric metering, 2-way communication, and electric appliances and technologies are rapidly creating cost effective tools for managing energy demand and use. The goal now is to create the business and regulatory models that can enable these technologies to make energy efficiency a sustainable business for electric utilities.

"A New Vision for Energy Efficiency" Power, November 2006 - The U.S. electric utility industry has long encouraged its customers to get more value from their electricity dollar. Today, the industry—facing volatile costs and mounting concerns about the environment—is coming together to create a new role for energy efficiency—one that enables technology to deliver more value to customers and electric utilities alike.
www.powermag.com/ArchivedArticleDisplay.aspx?y=2006&m=December&a=144-DEPT_COMM.xml

Electric Utility Automatic Adjustment Clauses: Benefits and Design Considerations, *The Brattle Group*, November 2006 – Provides an overview on the need for, and benefits

of, properly designed AACs. Provides policy arguments to rebut commonly heard objections.
http://www.eei.org/industry_issues/electricity_policy/state_and_local_policies/adjustment_clauses.pdf

"Time to Re-Invent Efficiency" Electric Light & Power, October, 2006 - Way back in '64, Bob Dylan had a huge hit that gave notice about the dramatic changes that lay ahead for society. Today, "The Times, They Are A-Changing," could just as easily be the title for a song about energy efficiency. And the lyrics would talk about the potential for changes that are equally as dramatic.

"Energizing Efficiency's Potential" Electricity Journal, October, 2006 - Over the next 20 years, America's electricity use is projected to grow nearly 30-percent. As part of our package of resource options to meet this demand, EEI and its members are pursuing new approaches for energy efficiency that speed up the development of advanced technologies and create new regulatory paradigms and business models. In so doing, we believe energy efficiency can return even greater economic, environmental and social benefits for the nation.

"Capitalizing on Energy Efficiency" World Energy, Fall 2006 - America's dynamic economy continues to fuel a growing demand for electricity. Within the next 20 years, the U.S. is expected to be using 30-percent more electricity than it does today. To supply it, America's electric utility companies will clearly need to build more generation and transmission. But perhaps more importantly, we are also pursuing new initiatives that encourage even greater energy efficiency.
www.worldenergysource.com/wes/stores/1/Capitalizing-on-Energy-Efficiency-P195C34.aspx

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http://www.eei.org/industry_issues/electricity_policy/state_and_local_policies/resource_procurement_prudence/nonav_resource_procurement_prudence/ResourcePlanningProcurement.pdf

Section 4: Rate Design Modifications to Promote Energy Efficiency Investments

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Edison Electric Institute
Rate Design Modifications to Promote Energy Efficiency Investments
Resource Materials

Quantifying the Benefits of Dynamic Pricing in Mass Markets, *The Brattle Group*, January 2008 – Reviews various smart metering programs in developing a spreadsheet based estimate of utility specific, potential demand response benefits from smart meters, smart thermostats and dynamic pricing. Also discusses how more accurate pricing signals can actually lower consumers' bills by eliminating utility hedging premiums, and compares smart metering and dynamic pricing with other demand response alternatives.
http://www.eei.org/ami

Retail Electricity Pricing and Rate Design in Evolving Markets, Christensen Associates, February 2007 – Reviews the critical role that efficient rate design needs to play in today's electricity markets, and suggests practical strategies for overcoming historical barriers to implementing such rates. Elaborates the properties and forms of efficient electricity pricing, contrasting efficient rates with existing, traditional rates. Examines current market developments that appear to offer new opportunities for more efficient rates. Considers strategies for overcoming traditional barriers (e.g., treatments to address the under-recovery of fixed costs, adjustments to standard flat rates to cover revenues lost due to adverse selection, financial incentives for utilities to offer voluntary time-based rates, simple rate options with appropriate risk premiums for guaranteed prices, greater refinement of rate classes).
http://www.eei.org/industry_issues/electricity_policy/state_and_local_policies/rising_electricity_costs/Retail_Electricity_Pricing.pdf

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Additional resource material from NARUC available at:
http://www.naruc.org/ and http://www.naruc.org/resources.cfm
Also from: http://www.nrri.org/

APPA's "Demonstration of Energy-Efficient Developments (DEED)" Program

For additional information on DEED studies and analysis and contact information, see:
http://www.appanet.org/research/research.cfm?ItemNumber=17580&navItemNumber=20949

DEED Projects:

Internet Enabled AMR/LM Technology Assessment – completed in 2005 - This project was undertaken by the City of Wadsworth Electric & Communications Department in Wadsworth, Ohio to assist in the decision making of municipal systems considering automated meter reading and load management. After reviewing the report, a municipal system should be able to determine the best systems for their needs in an informed manner and with less investment of time for market research that would otherwise be required.

Power Quality Pilot Program – completed 2005 - This project was undertaken by the City of Anaheim Public Utilities, Calif. to test a power quality technology, SoftSwitching Technologies I-Sense Monitors, at 30 sites with residential, commercial, and industrial customers. This technology was identified as a low-cost, simple device for identifying power quality problems. The Monitors have provided invaluable information on power quality inside customers' facility and add value to existing services but an expanded power quality program with these devices will not be deployed by Anaheim. Read the final report for details on this technology and how it worked in the pilot test.

Residential Demand Response Triggered by the Wholesale Price - Current Project - This project will study residential demand response triggered by wholesale price levels. Throughout the summer of 2008, we will evaluate various ways to cycle residential cooling systems through a smart thermostat at different wholesale price points under varying temperature and humidity conditions. The two-way AMR system that is now deployed gives us a full load profile on each residential customer and enables us to quantify the actual load reduction from each program participant.

Combined Application of Thermal Energy Storage and Time-of-Use Rates in a Desert Climate – current project - Imperial, Calif., Irrigation District received a $30,000 grant to explore using a combined application of thermal energy storage (using an "Ice Bear" TES device) and time-of-use rates to reduce costs in delivering energy to customers by shifting the high-priced energy available during critical peak times to low-cost energy available during off-peak times, thereby saving customers money. A tool will be developed for analyzing the application of TES and TOU rates.

Retail Load Management and Automatic Meter Reading – completed in July 1990 - Investigated and field tested microcomputer-based automatic meter reading systems. The project examined the accuracy, reliability, cost-effectiveness, and load management potential of such systems. The project was to also develop an interface for possible incorporation into APPA's PowerManager Utility Billing package.

Peak Power – completed in 2004 - This project will look at the commercial viability of a cost-efficient microprocessor-based system that enables the remote monitoring, controlling and metering of standby generator sets (gensets) in a multi-site network. The resource assessment guide, developed as a result of this project will assist other utilities in evaluating the potential for this type of system in their service areas.

Cooperative Research Network (CRN)
Smart Grid-Related Resource Materials

Advanced Metering Infrastructure

AMI: Value Beyond Meter Reading (06-20)
CRN's *AMI: Value Beyond Meter Reading* will help co-ops obtain ideas on innovative ways to use their automated meter reading (AMR) systems to enhance efficiency, control costs, and improve work processes. The project is part of CRN's ongoing campaign to help co-ops get more from their existing technology investments.

AMR Vendors & Technologies 2008 (07-23J)
This report will bring member utilities up to speed on the latest AMR and AMI technologies, plus offerings from the leading vendors. This report is produced by Chartwell and is made available to all CRN members through our membership in Chartwell.

AMI Enabled Demand Response (07-23B)
CRN, through its membership in Chartwell is providing its members with an in-depth report on AMI Demand Response (DR) programs.

Smart Grid - How Utilities View the Grid of the Future (07-23L)
Talk of smart grid is everywhere. Separating fact from hope and hype can be difficult to do. While NRECA research shows that co-ops lead in the deployment of AMI and related smart grid technologies, it is important to keep up with the latest happenings with the other industry players. It is also important to stay on top of what regulators and others are asking for from utilities when it comes to smart grid.

The Chartwell AMR Report 2007, 12th Edition (07-23G)
The *Chartwell AMR Report 2007* will bring readers up to speed on the latest trends and news in automatic meter reading (AMR) deployments. This document has become a must read for anyone wanting to know more about who is doing what with AMR. This report is produced by Chartwell and is made available to all CRN members through our membership in Chartwell.

Metering Industry Update - Monthly Newsletter (07-23I)
Metering Industry Update is a monthly newsletter that delivers the latest news and events in the world of metering. This newsletter is produced by Chartwell, and is made available to all CRN members through our membership in Chartwell.

Overview of Utility Experiments with Dynamic Prices for Residential Customers (07-14K)
This report offers a high-level review of several dynamic pricing pilot programs currently being conducted by investor-owned utilities and municipalities across North America. Co-op staff can use the information in this report to get up to speed on these programs.

Issues in Demand Response (06-17A)
CRN is providing its members two products that can help in the deployment and optimization of Demand Response (DR) programs. The two reports, "Will Demand Response Work at My Co-op?" and "Demand Response Programs Can Save Energy – If They're Designed To," offer excellent information that can support co-ops as they explore DR options.

Telecommunications

Assessment of Digital Land Mobile Radios (07-09)
This report will help co-ops to better understand the present and possible future technologies available for mobile automation and voice telecommunication. This in turn will enable co-ops to make better-informed decisions about when and with what to replace outdated communication equipment.

The New Telecommunications Environment: Opportunities for Electric Cooperatives (95-24)
This report is designed to be read in conjunction with Implementing Projects on the Information Highway (CRN Project 94-19), this source book provides cooperatives with a broad overview of the many telecommunications opportunities and the pro-competitive, deregulatory policies being advanced at the federal and state levels. Together, these two publications provide a basic framework for your cooperative to use in considering any new telecommunications project.

Improving Energy Storage at Substations and Telecommunications Sites (08-05)
Phase 1 of this project will compare lithium ion (Li-ion) batteries to other advanced batteries, and to lead-acid batteries, for specific utility applications. The project will determine which battery can best replace lead-acid batteries for utilities. It will summarize key information, including projected costs, environmental and safety considerations, and supply/market factors. This project will also assess the value and timeliness of a field demonstration of Li-ion batteries in a substation or telecommunications application. If appropriate, it will provide a detailed scope of work that can be used in a subsequent competitive solicitation.

A Low-Cost Automation/Telecommunications System for Cooperatives (97-30)
This report provides assistance and technical guidance for cooperatives to meet the requirements of supervisory control and data acquisition (SCADA), distribution automation (DA) and automatic meter reading (AMR).

Consumer's Report for Telecommunications Technologies (05-03)
This report is an updated version of CRN's Publication 02-26 "Communications Technologies for SCADA, AMR, Mobile Radio, and Distribution Automation." This update includes (1) the addition of a "watch list" of promising technologies that have not been widely deployed; (2) an update of technology and vendor product summaries; (3) new subchapters on emerging communications products like Wireless Fidelity (WiFi)—802.11, WiMAX—802.16, licensed 700 MHz radio, and new cellular products; and (4) a new section on IP.

Tech Surveillance Special Issue: Broadband Technologies (06-07)
Tech Surveillance created this special issue to provide CRN members with updates on broadband technologies, to help co-ops improve core business functions and consumer services. Funded by CRN's Information Digital Communications Technology research area, the goal is to provide unbiased, practical information that cuts through media hype in order to help co-ops track developments in this fast-paced industry. The remaining Special Issues under this project will cover Smart Grid issues, technologies and technology applications.

Proceedings: A Strategic Telecommunications Workshop for Rural Electric Cooperatives (94-18)
Provides a summary of discussions and presentations at the workshop focusing on a range of ways in which electric co-ops can participate in the evolving information superhighway.

Objective Field Test of BPL Technologies (04-13)
CRN's trial of broadband over power line (BPL) demonstrates where and how far BPL can extend broadband service into a typical electric distribution system. Also, it provides co-ops the information they need to help make decisions about deploying BPL, avoid pitfalls, and operate their BPL systems. Finally, the trial will create common measurement standards and methodology among manufacturers so that co-ops can compare "apples to apples" when they evaluate competing BPL systems.

Building Your Broadband Network with Grant Money (Tech Surveillance)
Co-ops and their members can apply for certain grant programs that offer millions of dollars in assistance building broadband networks for to rural areas around the country.

Does the Distribution Grid of the Future Need Broadband Communications? (Tech Surveillance)
At least nine initiatives under way in the United States focus on modernizing the transmission and distribution grids.

Could New Power Line Technologies Bring Broadband to Rural America? There Is Potential but the Jury's Still Out (Tech Surveillance)
Many electric co-op communities are standing on the wrong side of the digital divide. About 65% of communities with populations greater than 100,000 have access to broadband, while just 5% of their rural counterparts enjoy this opportunity. Economic, business, and educational experts predict that access to broadband Internet service will be a prime indicator of a community's economic future. Given the stakes, technologies that use power lines to deliver high-speed Internet service have instant curb appeal to electric cooperatives.

Smart Moves and Pitfalls of IP Networking: A Case Study of Great River Energy (Tech Surveillance)
Great River Energy (GRE) of Elk River, Minn., offers wholesale electric service to 28 distribution cooperatives in Minnesota and Wisconsin. For many years, the utility has relied on a network composed of a mix of technologies, but GRE determined that its existing infrastructure could not offer the features a 21st century network. The network it needed had to be fast, routable, homogeneous, standards-based and protected (licensed). After careful consideration, GRE chose to implement an advanced telecommunications backbone based on the Internet Protocol (IP). The IP network is slated to be completed in the 2008.

Can Commercial Broadband be a Solution to Co-ops Growing Bandwidth Requirements? (Tech Surveillance)
Increased deployment of computerized systems in the field to monitor and control the electrical distribution systems have become critical to the reliable operation of the distribution grid. Field systems have increased abilities to monitor, store, and transmit more and more data.

Broadband to the Substations: More than One Means to the End (Tech Surveillance)
This article is the first of two looking at high-speed communication choices co-ops have to support the increasing number of applications they are using at their substations. Different applications require different bandwidth and Tech Surveillance presents through this series the different solutions being used.

Using Broadband to Protect Your Substation (Tech Surveillance)
Using broadband technology for substation security could be a valuable tool in securing an important part of the co-op distribution chain. Considering that substations now have smart meters and other network-enabled hardware, both physical and cyber security should be a significant concern. Certain security enhancements at substations require network connections with home offices. Broadband could be a tool that can help establish these connections that will enable these new security upgrades.

The Economics of Fiber: Various Factors Have Driven Costs Down (Tech Surveillance)
Fiber optic cable and transport systems remain among the most highly preferred backbone technologies for delivery of broadband network connectivity. Utilities (including electric co-ops) have an interest in extending broadband networks to their substations, and some G&Ts have begun to invest heavily in fiber optic networks.

Illinois Deploys Unique Fixed Wireless Network (Tech Surveillance)
Fiber optic cable and transport systems remain among the most highly preferred backbone technologies for delivery of broadband network connectivity. Utilities (including electric co-ops) have an interest in extending broadband networks to their substations, and some G&Ts have begun to invest heavily in fiber optic networks.

Wireless: Co-ops Have Technology Choices with More on the Way (Tech Surveillance)
In the not-too-distant past wireless technologies were simply not an option for rural co-ops, but that is no longer the case. Today, a co-op considering a wireless deployment likely would have several solid technology contenders to consider in the first cut.

Is BPL for Co-ops? Only Time and More Trials Will Tell (Tech Surveillance)
Concrete progress has been made recently in understanding how BPL works in real-world applications. This report provides a close look at electric co-ops and other utilities that are gaining experience with BPL. It also offers expert opinions on the smart moves in approaches to broadband technology in general and to the business realities of a BPL deployment.

BPL Update: Pilots Plug In Co-op Customers (Tech Surveillance)
A key technical question surrounding broadband over power line is whether data can be regenerated repeatedly over long distances. Previously, just a handful of regenerators were deployed in sequence. Now one co-op has successfully deployed a chain of 25.

Progress Picking Up for IP-Based Private Mobile Radio (Tech Surveillance)
The pace of product advancement for licensed private mobile radio technology has been slow compared to other wireless technologies, such as commercial cellular and WiFi. For example, the best data throughput for private mobile radio is around 19.2 Kbps, compared to more than 50 Kbps for third-generation cellular. Handsets and modems cost a lot more with private mobile technology—from $700 to as much as $3,000—while this equipment for cellular often comes in at less than $300.

Down-line Automation

Guide to Down Line Automation (06-05)
CRN's *Guide to Down Line Automation* will help co-ops evaluate their options by presenting clear and concise guidance to help them make informed decisions. This will be accomplished through a series of *Tech Surveillance* articles, online presentations and the guide itself.

Strategic Technology Planning (07-08)
This executive brief discusses key aspects of the challenges cooperative CEOs face in trying to choose the best investments from among a vast array of technologies while ensuring the investments produce the desired returns and produce benefits for members. It will help the distribution co-op community understand the need for developing a technology plan and will provide strategies to help co-ops spend their technology funds in the most effective way.

Automating a Distribution Cooperative A to Z (03-02)
This updated edition of *Automating a Distribution Cooperative from A to Z* is designed to help co-op management and staff develop a cost-effective automation program and act as a "primer" to train employees on the various automation technologies. This report gives the background needed to recognize automation opportunities, form a team, and create awareness of key technical and strategic issues and challenges. Most important, it offers a valuable starting point to help achieve business goals and improve operations.

Communication Infrastructure for Electric System Automation (04-157)
This report examines four communications technologies that electric utilities can use to implement system automation. It is excellent background reading for anyone dealing with system automation.

A Summary Report on Mobile Workforce Management (MWM) (04-14)
This report evaluates the leading MWM products and communication networks, to help co-ops choose the system that best meets their needs.

Down Line Automation 101: An Introduction to Down Line Automation Concepts (Tech Surveillance)
Monitoring and control of electric distribution feeders has been a manual process for the most part. Co-op personnel in charge of distribution feeder management and operation have virtually no "visibility" of actual electrical conditions on distribution feeders and have no ability to remotely control feeder equipment located outside the substation fence.

Is DLA Right for You and Your Members? (Tech Surveillance)
Down Line Automation (DLA) is the remote monitoring and control of equipment that is installed on distribution feeders.This equipment includes voltage regulators, line capacitor banks, and feeder switches that are mounted on poles (for overhead lines) or installed in pad-mounted or vault-mounted enclosures (for underground lines). DLA is also referred to as Feeder Automation.

Edison Electric Institute
Smart Grid Resource Materials

***Quantifying the Benefits of Dynamic Pricing in Mass Markets*,** *The Brattle Group*, January 2008 – Reviews various smart metering programs in developing a spreadsheet based estimate of utility specific, potential demand response benefits from smart meters, smart thermostats and dynamic pricing. Also discusses how more accurate pricing signals can actually lower consumers' bills by eliminating utility hedging premiums, and compares smart metering and dynamic pricing with other demand response alternatives. http://www.eei.org/ami

"**Advancing Energy Efficiency**" *Utility Automation & Engineering*, April 2007 -New technologies such as advanced metering infrastructure (AMI) are at the heart of an effort by the nation's electric utility industry to broaden the scope—and consequently the benefits—of energy efficiency in America.

"**Plugging In AMI"** *Electric Energy T&D*, January 2007 - The country's demand for electricity continues to grow. To supply it, America's electric utility companies are building more generation and transmission. But at the same time, with industry structural change, rising costs, and the need for even greater environmental protection, the industry recognizes that it must increase its commitment to customer energy efficiency as well. A crucial building block for a more energy-efficient future will be AMI—advanced metering infrastructure.
(www.electricenergyonline.com/article.asp?m=9&mag=39&article=301)

Deciding on "Smart" Meters: The Technology Implications of Section 1252 of the Energy Policy Act of 2005, Plexus Research, September 2006 - Provides practical guidance on how to build cases evaluating the cost-effectiveness of advanced metering infrastructure applications. Including valuable lessons learned regarding the effective organization and management of AMI applications, and best practices for purchasing, installation and integration. http://www.eei.org/ami

Responding to EPAct 2005: Looking at Smart Meters for electricity Time-based Rate Structures, and net metering, National Economic Research Associates, May 2006 – PURPA as amended by EPAct 2005, directs state regulators to take a new look at time-based rates, interruptible rates, standby or backup rates, and net metering. This report presents the economic principles and policy issues that a Commission needs to consider when evaluating rate options, and provides guidance to regulators on whether to adopt the proposed standards. http://www.eei.org/ami

Section 6: Section 374 Standard: Additional Incentives for Recovery, Use, and Prevention of Industrial Waste Energy

Edison Electric Institute Resource Material

PURPA: Making the Sequel Better than the Original, *The Brattle Group,* December 2006 –Addresses the issues and challenges of avoided cost, net metering and credits for customer demand reductions.
http://www.eei.org/industry_issues/electricity_policy/federal_legislation/purpa.pdf

Appendix A
Excerpts of the
Energy Independence and Security Act of 2007
Table of Contents, Effective Date, and
Section 532 PURPA Standards

ENERGY INDEPENDENCE AND SECURITY ACT OF 2007

Public Law 110–140
110th Congress

An Act

Dec. 19, 2007
[H.R. 6]

To move the United States toward greater energy independence and security, to increase the production of clean renewable fuels, to protect consumers, to increase the efficiency of products, buildings, and vehicles, to promote research on and deploy greenhouse gas capture and storage options, and to improve the energy performance of the Federal Government, and for other purposes.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

Energy Independence and Security Act of 2007.
42 USC 17001 note.

SECTION 1. SHORT TITLE; TABLE OF CONTENTS.

(a) SHORT TITLE.—This Act may be cited as the "Energy Independence and Security Act of 2007".

(b) TABLE OF CONTENTS.—The table of contents of this Act is as follows:

TITLE II—ENERGY SECURITY THROUGH INCREASED PRODUCTION OF BIOFUELS

Subtitle A—Renewable Fuel Standard

Subtitle B—Biofuels Research and Development

Subtitle C—Biofuels Infrastructure

Subtitle D—Environmental Safeguards

TITLE III—ENERGY SAVINGS THROUGH IMPROVED STANDARDS FOR APPLIANCE AND LIGHTING

Subtitle A—Appliance Energy Efficiency

Subtitle B—Lighting Energy Efficiency

42 USC 17001.

SEC. 2. DEFINITIONS.

In this Act:

(1) DEPARTMENT.—The term "Department" means the Department of Energy.

(2) INSTITUTION OF HIGHER EDUCATION.—The term "institution of higher education" has the meaning given the term in section 101(a) of the Higher Education Act of 1965 (20 U.S.C. 1001(a)).

(3) SECRETARY.—The term "Secretary" means the Secretary of Energy.

42 USC 17002.

SEC. 3. RELATIONSHIP TO OTHER LAW.

Except to the extent expressly provided in this Act or an amendment made by this Act, nothing in this Act or an amendment made by this Act supersedes, limits the authority provided or responsibility conferred by, or authorizes any violation of any provision of law (including a regulation), including any energy or environmental law or regulation.

TITLE XVI—EFFECTIVE DATE

SEC. 1601. EFFECTIVE DATE. 2 USC 1824 note.

This Act and the amendments made by this Act take effect on the date that is 1 day after the date of enactment of this Act.

Approved December 19, 2007.

<u>LEGISLATIVE HISTORY</u>—H.R. 6:

CONGRESSIONAL RECORD, Vol. 153 (2007):
- Jan. 18, considered and passed House.
- June 12–15, 18–21, considered and passed Senate, amended.
- Dec. 6, House concurred in Senate amendments with amendments.
- Dec. 12, 13, Senate considered and concurred in House amendments with an amendment.
- Dec. 18, House concurred in Senate amendment.

WEEKLY COMPILATION OF PRESIDENTIAL DOCUMENTS, Vol. 43 (2007):
- Dec. 19, Presidential remarks.

○

Subtitle D—Energy Efficiency of Public Institutions

SEC. 531. REAUTHORIZATION OF STATE ENERGY PROGRAMS.

Section 365(f) of the Energy Policy and Conservation Act (42 U.S.C. 6325(f)) is amended by striking "$100,000,000 for each of the fiscal years 2006 and 2007 and $125,000,000 for fiscal year 2008" and inserting "$125,000,000 for each of fiscal years 2007 through 2012".

SEC. 532. UTILITY ENERGY EFFICIENCY PROGRAMS.

Section 532
PURPA Standards

(a) ELECTRIC UTILITIES.—Section 111(d) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2621(d)) is amended by adding at the end the following:

"(16) INTEGRATED RESOURCE PLANNING.—Each electric utility shall—

"(A) integrate energy efficiency resources into utility, State, and regional plans; and

"(B) adopt policies establishing cost-effective energy efficiency as a priority resource.

"(17) RATE DESIGN MODIFICATIONS TO PROMOTE ENERGY EFFICIENCY INVESTMENTS.—

"(A) IN GENERAL.—The rates allowed to be charged by any electric utility shall—

"(i) align utility incentives with the delivery of cost-effective energy efficiency; and

"(ii) promote energy efficiency investments.

"(B) POLICY OPTIONS.—In complying with subparagraph (A), each State regulatory authority and each nonregulated utility shall consider—

"(i) removing the throughput incentive and other regulatory and management disincentives to energy efficiency;

"(ii) providing utility incentives for the successful management of energy efficiency programs;

"(iii) including the impact on adoption of energy efficiency as 1 of the goals of retail rate design, recognizing that energy efficiency must be balanced with other objectives;

"(iv) adopting rate designs that encourage energy efficiency for each customer class;

"(v) allowing timely recovery of energy efficiency-related costs; and

"(vi) offering home energy audits, offering demand response programs, publicizing the financial and environmental benefits associated with making home energy efficiency improvements, and educating homeowners about all existing Federal and State incentives, including the availability of low-cost loans, that make energy efficiency improvements more affordable.".

(b) NATURAL GAS UTILITIES.—Section 303(b) of the Public Utility Regulatory Policies Act of 1978 (15 U.S.C. 3203(b)) is amended by adding at the end the following:

"(5) ENERGY EFFICIENCY.—Each natural gas utility shall—

"(A) integrate energy efficiency resources into the plans and planning processes of the natural gas utility; and

"(B) adopt policies that establish energy efficiency as a priority resource in the plans and planning processes of the natural gas utility.

"(6) RATE DESIGN MODIFICATIONS TO PROMOTE ENERGY EFFICIENCY INVESTMENTS.—

"(A) IN GENERAL.—The rates allowed to be charged by a natural gas utility shall align utility incentives with the deployment of cost-effective energy efficiency.

"(B) POLICY OPTIONS.—In complying with subparagraph (A), each State regulatory authority and each nonregulated utility shall consider—

"(i) separating fixed-cost revenue recovery from the volume of transportation or sales service provided to the customer;

"(ii) providing to utilities incentives for the successful management of energy efficiency programs, such as allowing utilities to retain a portion of the cost-reducing benefits accruing from the programs;

"(iii) promoting the impact on adoption of energy efficiency as 1 of the goals of retail rate design, recognizing that energy efficiency must be balanced with other objectives; and

"(iv) adopting rate designs that encourage energy efficiency for each customer class.

For purposes of applying the provisions of this subtitle to this paragraph, any reference in this subtitle to the date of enactment of this Act shall be treated as a reference to the date of enactment of this paragraph.".

(c) CONFORMING AMENDMENT.—Section 303(a) of the Public Utility Regulatory Policies Act of 1978 (15 U.S.C. 3203(a)) is amended by striking "and (4)" inserting "(4), (5), and (6)".

Appendix B
Excerpts of the
Energy Independence and Security Act of 2007
Smart Grid Sections
Sections 1301 to 1309

TITLE XIII—SMART GRID

SEC. 1301. STATEMENT OF POLICY ON MODERNIZATION OF ELECTRICITY GRID. 15 USC 17381.

It is the policy of the United States to support the modernization of the Nation's electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet future demand growth and to achieve each of the following, which together characterize a Smart Grid:

(1) Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid.

(2) Dynamic optimization of grid operations and resources, with full cyber-security.

(3) Deployment and integration of distributed resources and generation, including renewable resources.

(4) Development and incorporation of demand response, demand-side resources, and energy-efficiency resources.

(5) Deployment of "smart" technologies (real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering, communications concerning grid operations and status, and distribution automation.

(6) Integration of "smart" appliances and consumer devices.

(7) Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air conditioning.

(8) Provision to consumers of timely information and control options.

(9) Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid.

(10) Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services.

15 USC 17382.

SEC. 1302. SMART GRID SYSTEM REPORT.

The Secretary, acting through the Assistant Secretary of the Office of Electricity Delivery and Energy Reliability (referred to in this section as the "OEDER") and through the Smart Grid Task Force established in section 1303, shall, after consulting with any interested individual or entity as appropriate, no later than 1 year after enactment, and every 2 years thereafter, report to Congress concerning the status of smart grid deployments nationwide and any regulatory or government barriers to continued deployment. The report shall provide the current status and prospects of smart grid development, including information on technology penetration, communications network capabilities, costs, and obstacles. It may include recommendations for State and Federal policies or actions helpful to facilitate the transition to a smart grid. To the extent appropriate, it should take a regional perspective. In preparing this report, the Secretary shall solicit advice and contributions from the Smart Grid Advisory Committee created in section 1303; from other involved Federal agencies including but not limited to the Federal Energy Regulatory Commission ("Commission"), the National Institute of Standards and Technology ("Institute"), and the Department of Homeland Security; and from other stakeholder groups not already represented on the Smart Grid Advisory Committee.

15 USC 17383.

SEC. 1303. SMART GRID ADVISORY COMMITTEE AND SMART GRID TASK FORCE.

(a) SMART GRID ADVISORY COMMITTEE.—

(1) ESTABLISHMENT.—The Secretary shall establish, within 90 days of enactment of this Part, a Smart Grid Advisory Committee (either as an independent entity or as a designated sub-part of a larger advisory committee on electricity matters). The Smart Grid Advisory Committee shall include eight or more members appointed by the Secretary who have sufficient experience and expertise to represent the full range of smart grid technologies and services, to represent both private and non-Federal public sector stakeholders. One member shall be appointed by the Secretary to Chair the Smart Grid Advisory Committee. Deadline.

(2) MISSION.—The mission of the Smart Grid Advisory Committee shall be to advise the Secretary, the Assistant Secretary, and other relevant Federal officials concerning the development of smart grid technologies, the progress of a national transition to the use of smart-grid technologies and services, the evolution of widely-accepted technical and practical standards and protocols to allow interoperability and inter-communication among smart-grid capable devices, and the optimum means of using Federal incentive authority to encourage such progress.

(3) APPLICABILITY OF FEDERAL ADVISORY COMMITTEE ACT.—The Federal Advisory Committee Act (5 U.S.C. App.) shall apply to the Smart Grid Advisory Committee.

(b) SMART GRID TASK FORCE.—

(1) ESTABLISHMENT.—The Assistant Secretary of the Office of Electricity Delivery and Energy Reliability shall establish, within 90 days of enactment of this Part, a Smart Grid Task Force composed of designated employees from the various divisions of that office who have responsibilities related to the transition to smart-grid technologies and practices. The Assistant Secretary or his designee shall be identified as the Director of the Smart Grid Task Force. The Chairman of the Federal Energy Regulatory Commission and the Director of the National Institute of Standards and Technology shall each designate at least one employee to participate on the Smart Grid Task Force. Other members may come from other agencies at the invitation of the Assistant Secretary or the nomination of the head of such other agency. The Smart Grid Task Force shall, without disrupting the work of the Divisions or Offices from which its members are drawn, provide an identifiable Federal entity to embody the Federal role in the national transition toward development and use of smart grid technologies. Deadline.

(2) MISSION.—The mission of the Smart Grid Task Force shall be to insure awareness, coordination and integration of the diverse activities of the Office and elsewhere in the Federal Government related to smart-grid technologies and practices, including but not limited to: smart grid research and development; development of widely accepted smart-grid standards and protocols; the relationship of smart-grid technologies and practices to electric utility regulation; the relationship of smart-grid technologies and practices to infrastructure development, system reliability and security; and the relationship of smart-grid technologies and practices to other facets of electricity supply, demand, transmission, distribution, and policy. The Smart Grid Task Force shall collaborate with the Smart Grid Advisory Committee and other Federal agencies and offices.

The Smart Grid Task Force shall meet at the call of its Director as necessary to accomplish its mission.

(c) AUTHORIZATION.—There are authorized to be appropriated for the purposes of this section such sums as are necessary to the Secretary to support the operations of the Smart Grid Advisory Committee and Smart Grid Task Force for each of fiscal years 2008 through 2020.

42 USC 17384.

SEC. 1304. SMART GRID TECHNOLOGY RESEARCH, DEVELOPMENT, AND DEMONSTRATION.

(a) POWER GRID DIGITAL INFORMATION TECHNOLOGY.—The Secretary, in consultation with the Federal Energy Regulatory Commission and other appropriate agencies, electric utilities, the States, and other stakeholders, shall carry out a program—

(1) to develop advanced techniques for measuring peak load reductions and energy-efficiency savings from smart metering, demand response, distributed generation, and electricity storage systems;

(2) to investigate means for demand response, distributed generation, and storage to provide ancillary services;

(3) to conduct research to advance the use of wide-area measurement and control networks, including data mining, visualization, advanced computing, and secure and dependable communications in a highly-distributed environment;

(4) to test new reliability technologies, including those concerning communications network capabilities, in a grid control room environment against a representative set of local outage and wide area blackout scenarios;

(5) to identify communications network capacity needed to implement advanced technologies.

(6) to investigate the feasibility of a transition to time-of-use and real-time electricity pricing;

(7) to develop algorithms for use in electric transmission system software applications;

(8) to promote the use of underutilized electricity generation capacity in any substitution of electricity for liquid fuels in the transportation system of the United States; and

(9) in consultation with the Federal Energy Regulatory Commission, to propose interconnection protocols to enable electric utilities to access electricity stored in vehicles to help meet peak demand loads.

(b) SMART GRID REGIONAL DEMONSTRATION INITIATIVE.—

(1) IN GENERAL.—The Secretary shall establish a smart grid regional demonstration initiative (referred to in this subsection as the "Initiative") composed of demonstration projects specifically focused on advanced technologies for use in power grid sensing, communications, analysis, and power flow control. The Secretary shall seek to leverage existing smart grid deployments.

(2) GOALS.—The goals of the Initiative shall be—

(A) to demonstrate the potential benefits of concentrated investments in advanced grid technologies on a regional grid;

(B) to facilitate the commercial transition from the current power transmission and distribution system technologies to advanced technologies;

(C) to facilitate the integration of advanced technologies in existing electric networks to improve system performance, power flow control, and reliability;

(D) to demonstrate protocols and standards that allow for the measurement and validation of the energy savings and fossil fuel emission reductions associated with the installation and use of energy efficiency and demand response technologies and practices; and

(E) to investigate differences in each region and regulatory environment regarding best practices in implementing smart grid technologies.

(3) DEMONSTRATION PROJECTS.—

(A) IN GENERAL.—In carrying out the initiative, the Secretary shall carry out smart grid demonstration projects in up to 5 electricity control areas, including rural areas and at least 1 area in which the majority of generation and transmission assets are controlled by a tax-exempt entity.

(B) COOPERATION.—A demonstration project under subparagraph (A) shall be carried out in cooperation with the electric utility that owns the grid facilities in the electricity control area in which the demonstration project is carried out.

(C) FEDERAL SHARE OF COST OF TECHNOLOGY INVESTMENTS.—The Secretary shall provide to an electric utility described in subparagraph (B) financial assistance for use in paying an amount equal to not more than 50 percent of the cost of qualifying advanced grid technology investments made by the electric utility to carry out a demonstration project.

(D) INELIGIBILITY FOR GRANTS.—No person or entity participating in any demonstration project conducted under this subsection shall be eligible for grants under section 1306 for otherwise qualifying investments made as part of that demonstration project.

(c) AUTHORIZATION OF APPROPRIATIONS.—There are authorized to be appropriated—

(1) to carry out subsection (a), such sums as are necessary for each of fiscal years 2008 through 2012; and

(2) to carry out subsection (b), $100,000,000 for each of fiscal years 2008 through 2012.

SEC. 1305. SMART GRID INTEROPERABILITY FRAMEWORK. 15 USC 17385.

(a) INTEROPERABILITY FRAMEWORK.—The Director of the National Institute of Standards and Technology shall have primary responsibility to coordinate the development of a framework that includes protocols and model standards for information management to achieve interoperability of smart grid devices and systems. Such protocols and standards shall further align policy, business, and technology approaches in a manner that would enable all electric resources, including demand-side resources, to contribute to an efficient, reliable electricity network. In developing such protocols and standards—

(1) the Director shall seek input and cooperation from the Commission, OEDER and its Smart Grid Task Force, the Smart Grid Advisory Committee, other relevant Federal and State agencies; and

(2) the Director shall also solicit input and cooperation from private entities interested in such protocols and standards, including but not limited to the Gridwise Architecture Council, the International Electrical and Electronics Engineers, the National Electric Reliability Organization recognized by the Federal Energy Regulatory Commission, and National Electrical Manufacturer's Association.

(b) SCOPE OF FRAMEWORK.—The framework developed under subsection (a) shall be flexible, uniform and technology neutral, including but not limited to technologies for managing smart grid information, and designed—

(1) to accommodate traditional, centralized generation and transmission resources and consumer distributed resources, including distributed generation, renewable generation, energy storage, energy efficiency, and demand response and enabling devices and systems;

(2) to be flexible to incorporate—

(A) regional and organizational differences; and

(B) technological innovations;

(3) to consider the use of voluntary uniform standards for certain classes of mass-produced electric appliances and equipment for homes and businesses that enable customers, at their election and consistent with applicable State and Federal laws, and are manufactured with the ability to respond to electric grid emergencies and demand response signals by curtailing all, or a portion of, the electrical power consumed by the appliances or equipment in response to an emergency or demand response signal, including through—

(A) load reduction to reduce total electrical demand;

(B) adjustment of load to provide grid ancillary services; and

(C) in the event of a reliability crisis that threatens an outage, short-term load shedding to help preserve the stability of the grid; and

(4) such voluntary standards should incorporate appropriate manufacturer lead time.

(c) TIMING OF FRAMEWORK DEVELOPMENT.—The Institute shall begin work pursuant to this section within 60 days of enactment. The Institute shall provide and publish an initial report on progress toward recommended or consensus standards and protocols within 1 year after enactment, further reports at such times as developments warrant in the judgment of the Institute, and a final report when the Institute determines that the work is completed or that a Federal role is no longer necessary.

(d) STANDARDS FOR INTEROPERABILITY IN FEDERAL JURISDICTION.—At any time after the Institute's work has led to sufficient consensus in the Commission's judgment, the Commission shall institute a rulemaking proceeding to adopt such standards and protocols as may be necessary to insure smart-grid functionality and interoperability in interstate transmission of electric power, and regional and wholesale electricity markets.

(e) AUTHORIZATION.—There are authorized to be appropriated for the purposes of this section $5,000,000 to the Institute to support the activities required by this subsection for each of fiscal years 2008 through 2012.

SEC. 1306. FEDERAL MATCHING FUND FOR SMART GRID INVESTMENT COSTS. 42 USC 17386.

(a) MATCHING FUND.—The Secretary shall establish a Smart Grid Investment Matching Grant Program to provide reimbursement of one-fifth (20 percent) of qualifying Smart Grid investments.

(b) QUALIFYING INVESTMENTS.—Qualifying Smart Grid investments may include any of the following made on or after the date of enactment of this Act:

(1) In the case of appliances covered for purposes of establishing energy conservation standards under part B of title III of the Energy Policy and Conservation Act of 1975 (42 U.S.C. 6291 et seq.), the documented expenditures incurred by a manufacturer of such appliances associated with purchasing or designing, creating the ability to manufacture, and manufacturing and installing for one calendar year, internal devices that allow the appliance to engage in Smart Grid functions.

(2) In the case of specialized electricity-using equipment, including motors and drivers, installed in industrial or commercial applications, the documented expenditures incurred by its owner or its manufacturer of installing devices or modifying that equipment to engage in Smart Grid functions.

(3) In the case of transmission and distribution equipment fitted with monitoring and communications devices to enable smart grid functions, the documented expenditures incurred by the electric utility to purchase and install such monitoring and communications devices.

(4) In the case of metering devices, sensors, control devices, and other devices integrated with and attached to an electric utility system or retail distributor or marketer of electricity that are capable of engaging in Smart Grid functions, the documented expenditures incurred by the electric utility, distributor, or marketer and its customers to purchase and install such devices.

(5) In the case of software that enables devices or computers to engage in Smart Grid functions, the documented purchase costs of the software.

(6) In the case of entities that operate or coordinate operations of regional electric grids, the documented expenditures for purchasing and installing such equipment that allows Smart Grid functions to operate and be combined or coordinated among multiple electric utilities and between that region and other regions.

(7) In the case of persons or entities other than electric utilities owning and operating a distributed electricity generator, the documented expenditures of enabling that generator to be monitored, controlled, or otherwise integrated into grid operations and electricity flows on the grid utilizing Smart Grid functions.

(8) In the case of electric or hybrid-electric vehicles, the documented expenses for devices that allow the vehicle to engage in Smart Grid functions (but not the costs of electricity storage for the vehicle).

(9) The documented expenditures related to purchasing and implementing Smart Grid functions in such other cases as the Secretary shall identify. In making such grants, the Secretary shall seek to reward innovation and early adaptation,

even if success is not complete, rather than deployment of proven and commercially viable technologies.

(c) INVESTMENTS NOT INCLUDED.—Qualifying Smart Grid investments do not include any of the following:

(1) Investments or expenditures for Smart Grid technologies, devices, or equipment that are eligible for specific tax credits or deductions under the Internal Revenue Code, as amended.

(2) Expenditures for electricity generation, transmission, or distribution infrastructure or equipment not directly related to enabling Smart Grid functions.

(3) After the final date for State consideration of the Smart Grid Information Standard under section 1307 (paragraph (17) of section 111(d) of the Public Utility Regulatory Policies Act of 1978), an investment that is not in compliance with such standard.

(4) After the development and publication by the Institute of protocols and model standards for interoperability of smart grid devices and technologies, an investment that fails to incorporate any of such protocols or model standards.

(5) Expenditures for physical interconnection of generators or other devices to the grid except those that are directly related to enabling Smart Grid functions.

(6) Expenditures for ongoing salaries, benefits, or personnel costs not incurred in the initial installation, training, or start up of smart grid functions.

(7) Expenditures for travel, lodging, meals or other personal costs.

(8) Ongoing or routine operation, billing, customer relations, security, and maintenance expenditures.

(9) Such other expenditures that the Secretary determines not to be Qualifying Smart Grid Investments by reason of the lack of the ability to perform Smart Grid functions or lack of direct relationship to Smart Grid functions.

(d) SMART GRID FUNCTIONS.—The term “smart grid functions” means any of the following:

(1) The ability to develop, store, send and receive digital information concerning electricity use, costs, prices, time of use, nature of use, storage, or other information relevant to device, grid, or utility operations, to or from or by means of the electric utility system, through one or a combination of devices and technologies.

(2) The ability to develop, store, send and receive digital information concerning electricity use, costs, prices, time of use, nature of use, storage, or other information relevant to device, grid, or utility operations to or from a computer or other control device.

(3) The ability to measure or monitor electricity use as a function of time of day, power quality characteristics such as voltage level, current, cycles per second, or source or type of generation and to store, synthesize or report that information by digital means.

(4) 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.

(5) The ability to detect, prevent, communicate with regard to, respond to, or recover from system security threats, including cyber-security threats and terrorism, using digital information, media, and devices.

(6) 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.

(7) The ability to use digital information to operate functionalities on the electric utility grid that were previously electro-mechanical or manual.

(8) 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.

(9) Such other functions as the Secretary may identify as being necessary or useful to the operation of a Smart Grid.

(e) The Secretary shall— Procedures.

(1) establish and publish in the Federal Register, within 1 year after the enactment of this Act procedures by which applicants who have made qualifying Smart Grid investments can seek and obtain reimbursement of one-fifth of their documented expenditures; Federal Register, publication. Deadline.

(2) establish procedures to ensure that there is no duplication or multiple reimbursement for the same investment or costs, that the reimbursement goes to the party making the actual expenditures for Qualifying Smart Grid Investments, and that the grants made have significant effect in encouraging and facilitating the development of a smart grid;

(3) maintain public records of reimbursements made, recipients, and qualifying Smart Grid investments which have received reimbursements; Records.

(4) establish procedures to provide, in cases deemed by the Secretary to be warranted, advance payment of moneys up to the full amount of the projected eventual reimbursement, to creditworthy applicants whose ability to make Qualifying Smart Grid Investments may be hindered by lack of initial capital, in lieu of any later reimbursement for which that applicant qualifies, and subject to full return of the advance payment in the event that the Qualifying Smart Grid investment is not made; and

(5) have and exercise the discretion to deny grants for investments that do not qualify in the reasonable judgment of the Secretary.

(f) AUTHORIZATION OF APPROPRIATIONS.—There are authorized to be appropriated to the Secretary such sums as are necessary for the administration of this section and the grants to be made pursuant to this section for fiscal years 2008 through 2012.

SEC. 1307. STATE CONSIDERATION OF SMART GRID.

Section 1307 PURPA Standards

(a) Section 111(d) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2621(d)) is amended by adding at the end the following:

"(16) CONSIDERATION OF SMART GRID INVESTMENTS.—

"(A) IN GENERAL.—Each State shall consider requiring that, prior to undertaking investments in nonadvanced grid technologies, an electric utility of the State demonstrate to the State that the electric utility considered an investment in a qualified smart grid system based on appropriate factors, including—

"(i) total costs;

"(ii) cost-effectiveness;

"(iii) improved reliability;

"(iv) security;

"(v) system performance; and

"(vi) societal benefit.

"(B) RATE RECOVERY.—Each State shall consider authorizing each electric utility of the State to recover from ratepayers any capital, operating expenditure, or other costs of the electric utility relating to the deployment of a qualified smart grid system, including a reasonable rate of return on the capital expenditures of the electric utility for the deployment of the qualified smart grid system.

"(C) OBSOLETE EQUIPMENT.—Each State shall consider authorizing any electric utility or other party of the State to deploy a qualified smart grid system to recover in a timely manner the remaining book-value costs of any equipment rendered obsolete by the deployment of the qualified smart grid system, based on the remaining depreciable life of the obsolete equipment.

"(17) SMART GRID INFORMATION.—

"(A) STANDARD.—All electricity purchasers shall be provided direct access, in written or electronic machine-readable form as appropriate, to information from their electricity provider as provided in subparagraph (B).

"(B) INFORMATION.—Information provided under this section, to the extent practicable, shall include:

"(i) PRICES.—Purchasers and other interested persons shall be provided with information on—

"(I) time-based electricity prices in the wholesale electricity market; and

"(II) time-based electricity retail prices or rates that are available to the purchasers.

"(ii) USAGE.—Purchasers shall be provided with the number of electricity units, expressed in kwh, purchased by them.

"(iii) INTERVALS AND PROJECTIONS.—Updates of information on prices and usage shall be offered on not less than a daily basis, shall include hourly price and use information, where available, and shall include a day-ahead projection of such price information to the extent available.

"(iv) SOURCES.—Purchasers and other interested persons shall be provided annually with written information on the sources of the power provided by the utility, to the extent it can be determined, by type of generation, including greenhouse gas emissions associated with each type of generation, for intervals during which such information is available on a cost-effective basis.

"(C) ACCESS.—Purchasers shall be able to access their own information at any time through the Internet and on other means of communication elected by that utility for Smart Grid applications. Other interested persons shall be able to access information not specific to any purchaser through the Internet. Information specific to any purchaser shall be provided solely to that purchaser.".

(b) COMPLIANCE.—

(1) TIME LIMITATIONS.—Section 112(b) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2622(b)) is amended by adding the following at the end thereof:

"(6)(A) Not later than 1 year after the enactment of this paragraph, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated utility shall commence the consideration referred to in section 111, or set a hearing date for consideration, with respect to the standards established by paragraphs (17) through (18) of section 111(d). Deadlines.

"(B) Not later than 2 years after the date of the enactment of this paragraph, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority), and each nonregulated electric utility, shall complete the consideration, and shall make the determination, referred to in section 111 with respect to each standard established by paragraphs (17) through (18) of section 111(d).".

(2) FAILURE TO COMPLY.—Section 112(c) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2622(c)) is amended by adding the following at the end:

"In the case of the standards established by paragraphs (16) through (19) of section 111(d), the reference contained in this subsection to the date of enactment of this Act shall be deemed to be a reference to the date of enactment of such paragraphs.".

(3) PRIOR STATE ACTIONS.—Section 112(d) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2622(d)) is amended by inserting "and paragraphs (17) through (18)" before "of section 111(d)".

SEC. 1308. STUDY OF THE EFFECT OF PRIVATE WIRE LAWS ON THE DEVELOPMENT OF COMBINED HEAT AND POWER FACILITIES.

(a) STUDY.—

(1) IN GENERAL.—The Secretary, in consultation with the States and other appropriate entities, shall conduct a study of the laws (including regulations) affecting the siting of privately owned electric distribution wires on and across public rights-of-way.

(2) REQUIREMENTS.—The study under paragraph (1) shall include—

(A) an evaluation of—

(i) the purposes of the laws; and

(ii) the effect the laws have on the development of combined heat and power facilities;

(B) a determination of whether a change in the laws would have any operating, reliability, cost, or other impacts on electric utilities and the customers of the electric utilities; and

(C) an assessment of—

(i) whether privately owned electric distribution wires would result in duplicative facilities; and

(ii) whether duplicative facilities are necessary or desirable.

(b) REPORT.—Not later than 1 year after the date of enactment of this Act, the Secretary shall submit to Congress a report that describes the results of the study conducted under subsection (a).

SEC. 1309. DOE STUDY OF SECURITY ATTRIBUTES OF SMART GRID SYSTEMS.

Deadline. Reports.

(a) DOE STUDY.—The Secretary shall, within 18 months after the date of enactment of this Act, submit a report to Congress that provides a quantitative assessment and determination of the existing and potential impacts of the deployment of Smart Grid systems on improving the security of the Nation's electricity infrastructure and operating capability. The report shall include but not be limited to specific recommendations on each of the following:

(1) How smart grid systems can help in making the Nation's electricity system less vulnerable to disruptions due to intentional acts against the system.

(2) How smart grid systems can help in restoring the integrity of the Nation's electricity system subsequent to disruptions.

(3) How smart grid systems can facilitate nationwide, interoperable emergency communications and control of the Nation's electricity system during times of localized, regional, or nationwide emergency.

(4) What risks must be taken into account that smart grid systems may, if not carefully created and managed, create vulnerability to security threats of any sort, and how such risks may be mitigated.

(b) CONSULTATION.—The Secretary shall consult with other Federal agencies in the development of the report under this section, including but not limited to the Secretary of Homeland Security, the Federal Energy Regulatory Commission, and the Electric Reliability Organization certified by the Commission under section 215(c) of the Federal Power Act (16 U.S.C. 824o) as added by section 1211 of the Energy Policy Act of 2005 (Public Law 109–58; 119 Stat. 941).

Appendix C
Excerpts of the
Energy Independence and Security Act of 2007
Industrial Waste Energy Sections
Sections 451 and 371 to 374

Subtitle D—Industrial Energy Efficiency

SEC. 451. INDUSTRIAL ENERGY EFFICIENCY.

(a) IN GENERAL.—Title III of the Energy Policy and Conservation Act (42 U.S.C. 6291 et seq.) is amended by inserting after part D the following:

"PART E—INDUSTRIAL ENERGY EFFICIENCY

"SEC. 371. DEFINITIONS. 42 USC 6341.

"In this part:

"(1) ADMINISTRATOR.—The term 'Administrator' means the Administrator of the Environmental Protection Agency.

"(2) COMBINED HEAT AND POWER.—The term 'combined heat and power system' means a facility that—

"(A) simultaneously and efficiently produces useful thermal energy and electricity; and

"(B) recovers not less than 60 percent of the energy value in the fuel (on a higher-heating-value basis) in the form of useful thermal energy and electricity.

"(3) NET EXCESS POWER.—The term 'net excess power' means, for any facility, recoverable waste energy recovered in the form of electricity in quantities exceeding the total consumption of electricity at the specific time of generation on the site at which the facility is located.

"(4) PROJECT.—The term 'project' means a recoverable waste energy project or a combined heat and power system project.

"(5) RECOVERABLE WASTE ENERGY.—The term 'recoverable waste energy' means waste energy from which electricity or useful thermal energy may be recovered through modification of an existing facility or addition of a new facility.

"(6) REGISTRY.—The term 'Registry' means the Registry of Recoverable Waste Energy Sources established under section 372(d).

"(7) USEFUL THERMAL ENERGY.—The term 'useful thermal energy' means energy—

"(A) in the form of direct heat, steam, hot water, or other thermal form that is used in production and beneficial measures for heating, cooling, humidity control, process use, or other valid thermal end-use energy requirements; and

"(B) for which fuel or electricity would otherwise be consumed.

"(8) WASTE ENERGY.—The term 'waste energy' means—

"(A) exhaust heat or flared gas from any industrial process;

"(B) waste gas or industrial tail gas that would otherwise be flared, incinerated, or vented;

"(C) a pressure drop in any gas, excluding any pressure drop to a condenser that subsequently vents the resulting heat; and

"(D) such other forms of waste energy as the Administrator may determine.

"(9) OTHER TERMS.—The terms 'electric utility', 'nonregulated electric utility', 'State regulated electric utility', and other terms have the meanings given those terms in title I of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2611 et seq.).

42 USC 6342.

"SEC. 372. SURVEY AND REGISTRY.

"(a) RECOVERABLE WASTE ENERGY INVENTORY PROGRAM.—

"(1) IN GENERAL.—The Administrator, in cooperation with the Secretary and State energy offices, shall establish a recoverable waste energy inventory program.

"(2) SURVEY.—The program shall include—

"(A) an ongoing survey of all major industrial and large commercial combustion sources in the United States (as defined by the Administrator) and the sites at which the sources are located; and

"(B) a review of each source for the quantity and quality of waste energy produced at the source.

"(b) CRITERIA.—

Deadline. Publication. Regulations.

"(1) IN GENERAL.—Not later than 270 days after the date of enactment of the Energy Independence and Security Act of 2007, the Administrator shall publish a rule for establishing criteria for including sites in the Registry.

"(2) INCLUSIONS.—The criteria shall include—

"(A) a requirement that, to be included in the Registry, a project at the site shall be determined to be economically feasible by virtue of offering a payback of invested costs not later than 5 years after the date of first full project operation (including incentives offered under this part);

"(B) standards to ensure that projects proposed for inclusion in the Registry are not developed or used for the primary purpose of making sales of excess electric power under the regulatory provisions of this part; and

"(C) procedures for contesting the listing of any source or site on the Registry by any State, utility, or other interested person.

"(c) TECHNICAL SUPPORT.—On the request of the owner or operator of a source or site included in the Registry, the Secretary shall—

"(1) provide to owners or operators of combustion sources technical support; and

"(2) offer partial funding (in an amount equal to not more than one-half of total costs) for feasibility studies to confirm whether or not investment in recovery of waste energy or combined heat and power at a source would offer a payback period of 5 years or less.

"(d) REGISTRY.—

"(1) ESTABLISHMENT.—

Deadline.

"(A) IN GENERAL.—Not later than 1 year after the date of enactment of the Energy Independence and Security Act of 2007, the Administrator shall establish a Registry of Recoverable Waste Energy Sources, and sites on which the sources are located, that meet the criteria established under subsection (b).

"(B) UPDATES; AVAILABILITY.—The Administrator shall—

"(i) update the Registry on a regular basis; and

Public information. Website.

"(ii) make the Registry available to the public on the website of the Environmental Protection Agency.

"(C) CONTESTING LISTING.—Any State, electric utility, or other interested person may contest the listing of any source or site by submitting a petition to the Administrator.

"(2) CONTENTS.—

"(A) IN GENERAL.—The Administrator shall register and include on the Registry all sites meeting the criteria established under subsection (b).

"(B) QUANTITY OF RECOVERABLE WASTE ENERGY.—The Administrator shall—

"(i) calculate the total quantities of potentially recoverable waste energy from sources at the sites, nationally and by State; and

"(ii) make public—

"(I) the total quantities described in clause (i); and

"(II) information on the criteria pollutant and greenhouse gas emissions savings that might be achieved with recovery of the waste energy from all sources and sites listed on the Registry.

"(3) AVAILABILITY OF INFORMATION.—

Notification.

"(A) IN GENERAL.—The Administrator shall notify owners or operators of recoverable waste energy sources and sites listed on the Registry prior to publishing the listing.

"(B) DETAILED QUANTITATIVE INFORMATION.—

"(i) IN GENERAL.—Except as provided in clause (ii), the owner or operator of a source at a site may elect to have detailed quantitative information concerning the site not made public by notifying the Administrator of the election.

"(ii) LIMITED AVAILABILITY.—The information shall be made available to—

"(I) the applicable State energy office; and

"(II) any utility requested to support recovery of waste energy from the source pursuant to the incentives provided under section 374.

"(iii) STATE TOTALS.—Information concerning the site shall be included in the total quantity of recoverable waste energy for a State unless there are fewer than 3 sites in the State.

"(4) REMOVAL OF PROJECTS FROM REGISTRY.—

"(A) IN GENERAL.—Subject to subparagraph (B), as a project achieves successful recovery of waste energy, the Administrator shall—

"(i) remove the related sites or sources from the Registry; and

"(ii) designate the removed projects as eligible for incentives under section 374.

"(B) LIMITATION.—No project shall be removed from the Registry without the consent of the owner or operator of the project if—

"(i) the owner or operator has submitted a petition under section 374; and

"(ii) the petition has not been acted on or denied.

"(5) INELIGIBILITY OF CERTAIN SOURCES.—The Administrator shall not list any source constructed after the date of the enactment of the Energy Independence and Security Act of 2007 on the Registry if the Administrator determines that the source—

"(A) was developed for the primary purpose of making sales of excess electric power under the regulatory provisions of this part; or

"(B) does not capture at least 60 percent of the total energy value of the fuels used (on a higher-heating-value basis) in the form of useful thermal energy, electricity, mechanical energy, chemical output, or any combination thereof.

"(e) SELF-CERTIFICATION.—

"(1) IN GENERAL.—Subject to any procedures that are established by the Administrator, an owner, operator, or third-party developer of a recoverable waste energy project that qualifies under standards established by the Administrator may self-certify the sites or sources of the owner, operator, or developer to the Administrator for inclusion in the Registry.

"(2) REVIEW AND APPROVAL.—To prevent a fraudulent listing, a site or source shall be included on the Registry only if the Administrator reviews and approves the self-certification.

"(f) NEW FACILITIES.—As a new energy-consuming industrial facility is developed after the date of enactment of the Energy Independence and Security Act of 2007, to the extent the facility may constitute a site with recoverable waste energy that may qualify for inclusion on the Registry, the Administrator may elect to include the facility on the Registry, at the request of the owner, operator, or developer of the facility, on a conditional basis with the site to be removed from the Registry if the development ceases or the site fails to qualify for listing under this part.

"(g) OPTIMUM MEANS OF RECOVERY.—For each site listed in the Registry, at the request of the owner or operator of the site, the Administrator shall offer, in cooperation with Clean Energy Application Centers operated by the Secretary of Energy, suggestions for optimum means of recovery of value from waste energy stream in the form of electricity, useful thermal energy, or other energy-related products.

"(h) REVISION.—Each annual report of a State under section 548(a) of the National Energy Conservation Policy Act (42 U.S.C. 8258(a)) shall include the results of the survey for the State under this section.

"(i) AUTHORIZATION OF APPROPRIATIONS.—There are authorized to be appropriated to—

"(1) the Administrator to create and maintain the Registry and services authorized by this section, $1,000,000 for each of fiscal years 2008 through 2012; and

"(2) the Secretary—

"(A) to assist site or source owners and operators in determining the feasibility of projects authorized by this section, $2,000,000 for each of fiscal years 2008 through 2012; and

"(B) to provide funding for State energy office functions under this section, $5,000,000.

"SEC. 373. WASTE ENERGY RECOVERY INCENTIVE GRANT PROGRAM. 42 USC 6343.

"(a) ESTABLISHMENT.—The Secretary shall establish in the Department of Energy a waste energy recovery incentive grant program to provide incentive grants to—

"(1) owners and operators of projects that successfully produce electricity or incremental useful thermal energy from waste energy recovery;

"(2) utilities purchasing or distributing the electricity; and

"(3) States that have achieved 80 percent or more of recoverable waste heat recovery opportunities.

"(b) GRANTS TO PROJECTS AND UTILITIES.—

"(1) IN GENERAL.—The Secretary shall make grants under this section—

"(A) to the owners or operators of waste energy recovery projects; and

"(B) in the case of excess power purchased or transmitted by a electric utility, to the utility.

"(2) PROOF.—Grants may only be made under this section on receipt of proof of waste energy recovery or excess electricity generation, or both, from the project in a form prescribed by the Secretary.

"(3) EXCESS ELECTRIC ENERGY.—

"(A) IN GENERAL.—In the case of waste energy recovery, a grant under this section shall be made at the rate of $10 per megawatt hour of documented electricity produced from recoverable waste energy (or by prevention of waste energy in the case of a new facility) by the project during the first 3 calendar years of production, beginning on or after the date of enactment of the Energy Independence and Security Act of 2007.

"(B) UTILITIES.—If the project produces net excess power and an electric utility purchases or transmits the excess power, 50 percent of so much of the grant as is attributable to the net excess power shall be paid to the electric utility purchasing or transporting the net excess power.

"(4) USEFUL THERMAL ENERGY.—In the case of waste energy recovery that produces useful thermal energy that is used for a purpose different from that for which the project is principally designed, a grant under this section shall be made to the owner or operator of the waste energy recovery project at the rate of $10 for each 3,412,000 Btus of the excess thermal energy used for the different purpose.

"(c) GRANTS TO STATES.—In the case of any State that has achieved 80 percent or more of waste heat recovery opportunities identified by the Secretary under this part, the Administrator shall make a 1-time grant to the State in an amount of not more than $1,000 per megawatt of waste-heat capacity recovered (or a thermal equivalent) to support State-level programs to identify and achieve additional energy efficiency.

Regulations.

"(d) ELIGIBILITY.—The Secretary shall—

"(1) establish rules and guidelines to establish eligibility for grants under subsection (b);

"(2) publicize the availability of the grant program known to owners or operators of recoverable waste energy sources and sites listed on the Registry; and

"(3) award grants under the program on the basis of the merits of each project in recovering or preventing waste energy throughout the United States on an impartial, objective, and not unduly discriminatory basis.

"(e) LIMITATION.—The Secretary shall not award grants to any person for a combined heat and power project or a waste heat recovery project that qualifies for specific Federal tax incentives for combined heat and power or for waste heat recovery.

"(f) AUTHORIZATION OF APPROPRIATIONS.—There are authorized to be appropriated to the Secretary—

"(1) to make grants to projects and utilities under subsection (b)—

"(A) $100,000,000 for fiscal year 2008 and $200,000,000 for each of fiscal years 2009 through 2012; and

"(B) such additional amounts for fiscal year 2008 and each fiscal year thereafter as may be necessary for administration of the waste energy recovery incentive grant program; and

"(2) to make grants to States under subsection (b), $10,000,000 for each of fiscal years 2008 through 2012, to remain available until expended.

Section 374 Standard

42 USC 6344.

"SEC. 374. ADDITIONAL INCENTIVES FOR RECOVERY, USE, AND PREVENTION OF INDUSTRIAL WASTE ENERGY.

"(a) CONSIDERATION OF STANDARD.—

Deadline. Notification.

"(1) IN GENERAL.—Not later than 180 days after the receipt by a State regulatory authority (with respect to each electric utility for which the authority has ratemaking authority), or nonregulated electric utility, of a request from a project sponsor or owner or operator, the State regulatory authority or nonregulated electric utility shall—

"(A) provide public notice and conduct a hearing respecting the standard established by subsection (b); and

"(B) on the basis of the hearing, consider and make a determination whether or not it is appropriate to implement the standard to carry out the purposes of this part.

"(2) RELATIONSHIP TO STATE LAW.—For purposes of any determination under paragraph (1) and any review of the determination in any court, the purposes of this section supplement otherwise applicable State law.

"(3) NONADOPTION OF STANDARD.—Nothing in this part prohibits any State regulatory authority or nonregulated electric utility from making any determination that it is not appropriate to adopt any standard described in paragraph (1), pursuant to authority under otherwise applicable State law.

"(b) STANDARD FOR SALES OF EXCESS POWER.—For purposes of this section, the standard referred to in subsection (a) shall provide that an owner or operator of a waste energy recovery project identified on the Registry that generates net excess power shall be eligible to benefit from at least 1 of the options described in subsection (c) for disposal of the net excess power in accordance with the rate conditions and limitations described in subsection (d).

"(c) OPTIONS.—The options referred to in subsection (b) are as follows:

"(1) SALE OF NET EXCESS POWER TO UTILITY.—The electric utility shall purchase the net excess power from the owner or operator of the eligible waste energy recovery project during the operation of the project under a contract entered into for that purpose.

"(2) TRANSPORT BY UTILITY FOR DIRECT SALE TO THIRD PARTY.—The electric utility shall transmit the net excess power on behalf of the project owner or operator to up to 3 separate locations on the system of the utility for direct sale by the owner or operator to third parties at those locations.

"(3) TRANSPORT OVER PRIVATE TRANSMISSION LINES.—The State and the electric utility shall permit, and shall waive or modify such laws as would otherwise prohibit, the construction and operation of private electric wires constructed, owned, and operated by the project owner or operator, to transport the power to up to 3 purchasers within a 3-mile radius of the project, allowing the wires to use or cross public rights-of-way, without subjecting the project to regulation as a public utility, and according the wires the same treatment for safety, zoning, land use, and other legal privileges as apply or would apply to the wires of the utility, except that—

"(A) there shall be no grant of any power of eminent domain to take or cross private property for the wires; and

"(B) the wires shall be physically segregated and not interconnected with any portion of the system of the utility, except on the customer side of the revenue meter of the utility and in a manner that precludes any possible export of the electricity onto the utility system, or disruption of the system.

"(4) AGREED ON ALTERNATIVES.—The utility and the owner or operator of the project may reach agreement on any alternate arrangement and payments or rates associated with the arrangement that is mutually satisfactory and in accord with State law.

"(d) RATE CONDITIONS AND CRITERIA.—

"(1) DEFINITIONS.—In this subsection:

"(A) PER UNIT DISTRIBUTION COSTS.—The term 'per unit distribution costs' means (in kilowatt hours) the quotient obtained by dividing—

"(i) the depreciated book-value distribution system costs of a utility; by

"(ii) the volume of utility electricity sales or transmission during the previous year at the distribution level.

"(B) PER UNIT DISTRIBUTION MARGIN.—The term 'per unit distribution margin' means—

"(i) in the case of a State-regulated electric utility, a per-unit gross pretax profit equal to the product obtained by multiplying—

"(I) the State-approved percentage rate of return for the utility for distribution system assets; by

"(II) the per unit distribution costs; and

"(ii) in the case of a nonregulated utility, a per unit contribution to net revenues determined multiplying—

"(I) the percentage (but not less than 10 percent) obtained by dividing—

"(aa) the amount of any net revenue payment or contribution to the owners or subscribers of the nonregulated utility during the prior year; by

"(bb) the gross revenues of the utility during the prior year to obtain a percentage; by

"(II) the per unit distribution costs.

"(C) PER UNIT TRANSMISSION COSTS.—The term 'per unit transmission costs' means the total cost of those transmission services purchased or provided by a utility on a per-kilowatt-hour basis as included in the retail rate of the utility.

"(2) OPTIONS.—The options described in paragraphs (1) and (2) in subsection (c) shall be offered under purchase and transport rate conditions that reflect the rate components defined under paragraph (1) as applicable under the circumstances described in paragraph (3).

"(3) APPLICABLE RATES.—

"(A) RATES APPLICABLE TO SALE OF NET EXCESS POWER.—

"(i) IN GENERAL.—Sales made by a project owner or operator of a facility under the option described in subsection (c)(1) shall be paid for on a per kilowatt hour basis that shall equal the full undiscounted retail rate paid to the utility for power purchased by the facility minus per unit distribution costs, that applies to the type of utility purchasing the power.

"(ii) VOLTAGES EXCEEDING 25 KILOVOLTS.—If the net excess power is made available for purchase at voltages that must be transformed to or from voltages exceeding 25 kilovolts to be available for resale by the utility, the purchase price shall further be reduced by per unit transmission costs.

"(B) RATES APPLICABLE TO TRANSPORT BY UTILITY FOR DIRECT SALE TO THIRD PARTIES.—

"(i) IN GENERAL.—Transportation by utilities of power on behalf of the owner or operator of a project under the option described in subsection (c)(2) shall incur a transportation rate that shall equal the per unit distribution costs and per unit distribution margin, that applies to the type of utility transporting the power.

"(ii) VOLTAGES EXCEEDING 25 KILOVOLTS.—If the net excess power is made available for transportation at voltages that must be transformed to or from voltages exceeding 25 kilovolts to be transported to the designated third-party purchasers, the transport rate shall further be increased by per unit transmission costs.

"(iii) STATES WITH COMPETITIVE RETAIL MARKETS FOR ELECTRICITY.—In a State with a competitive retail market for electricity, the applicable transportation rate for similar transportation shall be applied in lieu of any rate calculated under this paragraph.

"(4) LIMITATIONS.—

"(A) IN GENERAL.—Any rate established for sale or transportation under this section shall—

"(i) be modified over time with changes in the underlying costs or rates of the electric utility; and

"(ii) reflect the same time-sensitivity and billing periods as are established in the retail sales or transportation rates offered by the utility.

"(B) LIMITATION.—No utility shall be required to purchase or transport a quantity of net excess power under this section that exceeds the available capacity of the wires, meter, or other equipment of the electric utility serving the site unless the owner or operator of the project agrees to pay necessary and reasonable upgrade costs.

"(e) PROCEDURAL REQUIREMENTS FOR CONSIDERATION AND DETERMINATION.—

"(1) PUBLIC NOTICE AND HEARING.—

"(A) IN GENERAL.—The consideration referred to in subsection (a) shall be made after public notice and hearing.

"(B) ADMINISTRATION.—The determination referred to in subsection (a) shall be—

"(i) in writing;

"(ii) based on findings included in the determination and on the evidence presented at the hearing; and

"(iii) available to the public.

"(2) INTERVENTION BY ADMINISTRATOR.—The Administrator may intervene as a matter of right in a proceeding conducted under this section—

"(A) to calculate—

"(i) the energy and emissions likely to be saved by electing to adopt 1 or more of the options; and "(ii) the costs and benefits to ratepayers and the utility; and

"(B) to advocate for the waste-energy recovery opportunity.

"(3) PROCEDURES.—

"(A) IN GENERAL.—Except as otherwise provided in paragraphs (1) and (2), the procedures for the consideration and determination referred to in subsection (a) shall be the procedures established by the State regulatory authority or the nonregulated electric utility.

"(B) MULTIPLE PROJECTS.—If there is more than 1 project seeking consideration simultaneously in connection with the same utility, the proceeding may encompass all such projects, if full attention is paid to individual circumstances and merits and an individual judgment is reached with respect to each project.

"(f) IMPLEMENTATION.—

"(1) IN GENERAL.—The State regulatory authority (with respect to each electric utility for which the authority has ratemaking authority) or nonregulated electric utility may, to the extent consistent with otherwise applicable State law—

"(A) implement the standard determined under this section; or

"(B) decline to implement any such standard.

"(2) NONIMPLEMENTATION OF STANDARD.—

"(A) IN GENERAL.—If a State regulatory authority (with respect to each electric utility for which the authority has ratemaking authority) or nonregulated electric utility declines to implement any standard established by this section, the authority or nonregulated electric utility shall state in writing the reasons for declining to implement the standard.

"(B) AVAILABILITY TO PUBLIC.—The statement of reasons shall be available to the public.

"(C) ANNUAL REPORT.—The Administrator shall include in an annual report submitted to Congress a description of the lost opportunities for waste-heat recovery from the project described in subparagraph (A), specifically identifying the utility and stating the quantity of lost energy and emissions savings calculated.

"(D) NEW PETITION.—If a State regulatory authority (with respect to each electric utility for which the authority has ratemaking authority) or nonregulated electric utility declines to implement the standard established by this section, the project sponsor may submit a new petition under this section with respect to the project at any time after the date that is 2 years after the date on which the State regulatory authority or nonregulated utility declined to implement the standard.

Appendix D
2007 NARUC AMI Resolution

Resolution to Remove Regulatory Barriers To the Broad Implementation of Advanced Metering Infrastructure

WHEREAS, The Energy Policy Act of 2005 amended the State ratemaking provisions of the Public Utilities Regulatory Policies Act of 1978 (PURPA) to require every State regulatory commission to consider and determine whether to adopt a new standard with regard to advanced metering infrastructure (AMI); *and*

WHEREAS, Advanced metering, as defined by Federal Energy Regulatory Commission (FERC), refers to a metering system that records customer consumption hourly or more frequently and that provides daily or more frequent transmittal of measurements over a communication network to a central collection point; *and*

WHEREAS, The implementation of dynamic pricing, which is facilitated by AMI, can afford consumers the opportunity to better manage their energy consumption and electricity costs through the practice of demand response strategies; *and*

WHEREAS, Effective price-responsive demand requires not only deployment of AMI to a material portion of a utility's load, but also implementation of dynamic price structures that reveal to consumers the value of controlling their consumption at specific times; *and*

WHEREAS, AMI deployment offers numerous potential benefits to consumers, both participants and non-participants, including:

- greater customer control over consumption and electric bills;
- improved metering accuracy and customer service;
- potential for reduced prices during peak periods for all consumers;
- reduced price volatility;
- reduced outage duration; and,
- expedited service initiation and restoration; *and*

WHEREAS, The use of AMI may afford significant utility operational cost savings and other benefits, including:

- automation of meter reading;
- outage detection;
- remote connection/disconnection;
- reduced energy theft;
- improved outage restoration;
- improved load research;
- more optimal transformer sizing;
- reduced demand during times of system stress;
- decreased T&D system congestion; and,
- reduced reliance on inefficient peaking generators; *and*

WHEREAS, Sound AMI planning and deployment requires the identification and consideration of tangible and intangible costs and benefits to a utility system and its customers; *and*

WHEREAS, Cost-effective AMI may be a critical component of the intelligent grid of the future that will provide many benefits to utilities and consumers; *and*

WHEREAS, It is important that AMI allow the free and unimpeded flow and exchange of data and communications to empower the greatest range of technology and customer options to be deployed; *and*

WHEREAS, The deployment of cost-effective AMI technology may require the removal and disposition of existing meters that are not fully depreciated and may require replacement of, or significant modification to, existing meter reading, communications, and customer billing and information infrastructure; *and*

WHEREAS, Regulated utilities may be discouraged from pursuing demand response opportunities by the prospect of diminished sales and revenues; *now, therefore, be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners, convened at its February 2007 Winter Meetings in Washington, D.C., recommends that commissions seeking to facilitate deployment of cost-effective AMI technologies consider the following regulatory options:

- pursue an AMI business case analysis, in conjunction with each regulated utility, in order to identify an optimal, cost-effective strategy for deployment of AMI that takes into account both tangible and intangible benefits;
- adopt ratemaking policies that provide utilities with appropriate incentives for reliance upon demand-side resources;
- provide for timely cost recovery of prudently incurred AMI expenditures, including accelerated recovery of investment in existing metering infrastructure, in order to provide cash flow to help finance new AMI deployment; and,
- provide depreciation lives for AMI that take into account the speed and nature of change in metering technology; *and be it further*

RESOLVED, That the Federal tax code with regard to depreciable lives for AMI investments should be amended to reflect the speed and nature of change in metering technology; *and be it further*

RESOLVED, That NARUC supports movement toward an appropriate level of open architecture and interoperability of AMI to enable cost-effective investments, avoid obsolescence, and increase innovations in technology products.

Sponsored by the Committee on Energy Resources and Environment
Adopted by NARUC Board of Directors February 21, 2007