Reference Manual and Procedures for Implementation Of the "PURPA Standards" in the Energy Policy Act of 2005

March 22, 2006

Sponsored by

American Public Power Association (APPA)
Edison Electric Institute (EEI)
National Association of Regulatory Utility Commissioners (NARUC)
National Rural Electric Cooperative Association (NRECA)

Prepared by:

Kenneth Rose and Karl Meeusen

American Public Power Association

Edison Electric Institute

NARUC
National Association of Regulatory Utility Commissioners

NRECA
A Touchstone Energy® Cooperative

Preface

This manual was prepared by Kenneth Rose, a consultant and Senior Fellow at the Institute of Public Utilities at Michigan State University, and Karl Meeusen, 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 Policy Act of 2005. 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 2005 Energy Policy Act and the Public Utility Regulatory Policies Act (PURPA) of 1978.

Table of Contents

List of Figures

Reference Manual and Procedures for Implementation of the "PURPA Standards" in the Energy Policy Act of 2005

Overview and Background of PURPA in the Energy Policy Act of 2005

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 Policy Act of 2005 (Subtitle E, "Amendments to PURPA," sections 1251, 1252, and 1254). 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. This manual is sponsored, as the 1979 manual was 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 PURPA standards. 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 the Energy Policy Act of 2005.

The manual is organized into two main sections. The first section summarizes state commission and unregulated utility requirements under the 2005 Energy Policy Act and includes background on the original and subsequent PURPA standards. The first section also covers the implementation procedures and issues that need to be considered when implementing the PURPA standards. The second section defines each of the five new standards and provides a discussion of issues that may be

[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.

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 Energy Policy Act of 2005 (EPAct) contains over 1,700 pages of wide ranging and complex legislation. The law includes provisions for energy efficiency of buildings and appliances, renewable energy, oil, natural gas, coal, and nuclear resources, the transportation sector, energy research and development, and tax incentives. The electricity title (Title XII) alone has ten subtitles dealing with reliability standards, transmission infrastructure and rate reform, repeal of the Public Utility Holding Company Act of 1935, and consumer protections. Subtitle E, "Amendments to PURPA," has four sections, three of which deal with additional PURPA Title I "federal standards" (EPAct sections 1251, 1252, and 1254). It is these three sections and implementation of these new federal standards that is covered by this manual.[2] The table of contents of the entire Energy Policy Act of 2005 and the relevant sections of Subtitle E are reproduced in Appendix A.

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 rate 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 (all six standards are listed in PURPA section 111(d)), they were (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.

[2]The fourth section of Subtitle E is section 1253, "Cogeneration and small power production purchase and sale requirements," which is not dealt with in this manual.

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)).

From this language it is clear that while state commissions and unregulated utilities are required to consider the standards, they are not required to adopt them. PURPA also states that state commissions and utilities may implement 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 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.

[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 unregulated utilities." PURPA defines a "nonregulated electric utility" as "any electric utility other than a state regulated electric utility."

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 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."

1.3 The New Standards and Requirements of the Energy Policy Act of 2005

In late July of 2005, the U.S. House of Representatives and Senate passed the Energy Policy Act of 2005. The President signed the statute into law on August 8, 2005, which is the date of enactment for purposes of the deadlines set by the law. Among the many things this complex law contains, the Energy Policy Act of 2005 adds five new federal standards to PURPA section 111(d) for state commissions and utilities to consider. The title, table of contents, and subtitle E ("Amendments to PURPA") of the Energy Policy Act of 2005 are reproduced in Appendix A of this manual. The first three additional federal standards are (11) net metering, (12) fuel diversity, and (13) fossil fuel generation efficiency (section 1251(a) of EPAct, sections 111(d)(11), (12), and (13) of PURPA, respectively). The descriptions from the 2005 law of the first three new standards are shown in Box 1.

For these three additional PURPA standards ((11) through (13)), state commissions and utilities have two years after enactment (that is, until August 8, 2007) to begin consideration of the standards or set a hearing date for the consideration (section 1251(b)(1) of EPAct, section 112(b)(3) of PURPA). State commissions and utilities have up to three years (or until August 8, 2008) to complete the consideration and make a determination on whether or not to adopt the additional standards.

The original PURPA standard requirements for failure to comply still apply, that is, if a state regulatory commission fails to meet the statutory time frame, the standards are to be considered and a determination made in the first rate proceeding three years after the law was enacted (PURPA section 112(c), as amended) if the standards are not considered in a separate hearing.

Prior state actions are grandfathered if (1) the state implemented the standard or comparable standard, (2) the state commission or 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 (section 1251(b)(3)(A) of EPAct and section 112(d) of PURPA). If these conditions are met with respect to a standard, the obligation to consider the standard is waived and no new consideration process is required.

Box 1. Section 1251 of EPAct of 2005, Additional PURPA 111(d) Standards.
(11) Net Metering.—Each electric utility shall make available upon request net metering service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term 'net metering service' means service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period.
(12) Fuel Sources.—Each electric utility shall develop a plan to minimize dependence on 1 fuel source and to ensure that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies.
(13) Fossil Fuel Generation Efficiency.—Each electric utility shall develop and implement a 10-year plan to increase the efficiency of its fossil fuel generation.

The fourth new PURPA standard in the Energy Policy Act of 2005 is (14) time-based metering and communications. This includes time-based metering and demand response programs and specifically mentions time-of-use pricing, critical peak pricing, real-time pricing and credits for customers with large loads with peak load reduction agreements (section 1252(a) of EPAct and section 111(d)(14) of PURPA). The specific language of this standard is shown in Box 2.

When determining whether or not to adopt the new standard (14, "Smart Metering"), the statute states that "each state regulatory authority shall conduct an investigation and issue a decision whether or not it is appropriate for electric utilities to provide and install time-based meters and communications devices for each of their customers" (EPAct section 1252(b)). The statute notes that such meters and devices are needed in order for customers to participate in time-based pricing and demand response programs (EPAct section 1252(b)).

Box 2. Section 1252 ("Smart Metering") of Energy Policy Act of 2005, Additional PURPA 111(d) Standard.*

(14) Time-Based Metering and Communications.—(A) Not later than 18 months after the date of enactment of this paragraph, each electric utility shall offer each of its customer classes, and provide individual customers upon customer request, a time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's costs of generating and purchasing electricity at the wholesale level. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology. . . .

*This is the opening paragraph of this standard. The second paragraph of the standard with the types of time-based rate schedules is shown in Section 6 of this manual and the entire text of all the standards are shown in Appendix A.

The compliance deadlines for this standard are different from the previous three and, unfortunately, somewhat confusing. The wording of the standard (see Box 2) provides that "not later than 18 months after the date of enactment . . . each electric utility shall offer each of its customer classes . . . a time-based rate schedule." This suggests that if the standard were adopted exactly as drafted, utilities would be required to implement certain provisions before the end of the two year decisionmaking period for the regulatory authority.[4] Of course, regulatory authorities and unregulated utilities can alter the time

[4]For electric utilities, as worded in the standard, the deadline for consideration *and*, if they decide to do so, implementation would be February 8, 2007 (section 1252(a)

period within the standard to accommodate their schedules and the practical limits of a utility program.

Section 1252(g) of the 2005 Energy Policy Act ("Time Limitations") then reverts to language that is similar to the original PURPA and what was used for the first three standards in the new law (that is, for (11) through (13)). This section states that "not later than 1 year after the enactment" state commissions and utilities[5] "shall commence the consideration . . . or set a hearing date for such consideration" and "not later than 2 years . . . shall complete the consideration, and shall make the determination." This takes the determination deadline to August 8, 2007, six months past when electric utilities were to be offering time-based schedules to customers as stated in standard (14), if the standard were adopted exactly as proposed in the amendments to PURPA.

Although confusing, the context of the language in each section clarifies the apparent ambiguity. The 18 month language is in the federal standard that states must consider, but need not adopt. The language that sets the actual statutory deadline is in EPAct section 1252(g). Thus, states and unregulated utilities have two years to make a final determination. It may seem irregular that states should have two years to decide whether or not to complete a study within 18 months of enactment, but that is a necessary conclusion of the statutory language. Of course, this is entirely achievable if a state chooses to consider the standard ahead of the deadline.

The provisions for failure to comply are the same as for the first three federal standards in the 2005 law ((11) through (13), as summarized above), that is, the standard is then considered and a determination made in the first rate proceeding three

---

of EPAct). Later in section 1252 of EPAct it states that "each State regulatory authority shall, not later than 18 months after the date of enactment . . . conduct an investigation . . . and issue a decision whether it is appropriate to implement the standards." This means that if a state commission adopts the standard as drafted with the original time frame, state commissions should conduct their investigations and issue decisions on whether to implement the standard, and have their jurisdictional utilities offering all customer classes a time-based rate schedule, also by February 8, 2007 – unless, of course, this has already occurred under a state's own initiative.

[5]Here the statute reverts back to the original PURPA language, of "each state regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility."

years after enactment (EPAct section 1252(h)). However, the grandfathering provision is similar, but with a time limit added. Prior state actions serve to waive the consideration obligation only for standard (14) if, (1) the state already implemented the standard or comparable standard, (2) the state commission or utility has conducted a proceeding considering implementation of the standard or comparable standard *within the previous three years* before enactment, or (3) the state's legislature voted on implementation of the standard or comparable standard also *within the previous three years before enactment* (EPAct section 1252(i)).

The fifth and final new PURPA standard in the 2005 Energy Policy Act is (15), interconnection standards for distributed resources, which relates to interconnection service for on-site generating facilities connected to local distribution facilities. The standard is shown in Box 3.

The deadlines for compliance are one year after enactment (August 8, 2006) state commissions and utilities are to begin consideration or set a hearing date for consideration. By two years after enactment (August 8, 2007) state commissions and utilities are to have completed their consideration and made a determination on whether or not to adopt the standard.

Again, the provisions for failure to comply and for prior state actions are the same as for the first three federal standards in the 2005 law ((11) through (13), as summarized above).

Box 3. Section 1254 ("Interconnection") of Energy Policy Act of 2005, Additional PURPA 111(d) Standard.

(15) Interconnection.—Each electric utility shall make available, upon request, interconnection service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term 'interconnection service' means service to an electric consumer under which an on-site generating facility on the consumer's premises shall be connected to the local distribution facilities. Interconnection services shall be offered based upon the standards developed by the Institute of Electrical and Electronics Engineers: IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems, as they may be amended from time to time. In addition, agreements and procedures shall be established whereby the services are offered shall promote current best practices of interconnection for distributed generation, including but not limited to practices stipulated in model codes adopted by associations of state regulatory agencies. All such agreements and procedures shall be just and reasonable, and not unduly discriminatory or preferential.

2. Implementation Procedures and Issues for the PURPA Standards

PURPA did not change the responsibility of states or unregulated utilities with respect to authority to determine electric rates. However, Title I did impose certain obligations on states commissions and unregulated 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 unregulated 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 information, not a substitute for the state or unregulated 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 unregulated utility needs to consider how the standards fit with their conditions, procedures, and prior actions. This manual is an aid to the evaluation process, not a substitute for a state- and utility-specific analysis.

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[6] 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

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

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 country."[7] 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."[8]

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.[9]

2.2 State commission and unregulated utility responsibilities and obligations

A primary responsibility for state commissions and unregulated 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 unregulated 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 unregulated 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 unregulated utilities are not prohibited

[7]Conference Committee Report, p. 69.

[8]Conference Committee Report, p. 69.

[9]Conference Committee Report, p. 70.

from modifying any standard, adopting additional standards, or more or less 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 unregulated utilities to consider and make a determination on each standard, PURPA Title I also requires state commissions and unregulated 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 unregulated 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.[10]

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"[11] 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)).

---

[10]Conference Committee Report, p. 70.

[11]This manual uses the term "unregulated utility" to refer to the same type of companies with respect to the requirements of the PURPA federal standards.

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 in 2006, retail sales data from 2004 should be used to determine if there is Title I compliance requirement (PURPA section 102(a)).[12] No further guidance is provided in the statute or in the Conference Committee Report on which utilities the requirements are to 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)). 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 unregulated 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 not release state commissions and unregulated utilities from making their own

---

[12]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.

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. 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 new PURPA standards apply 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 five of the new federal standards in EPAct. 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 standards 11, 14, and 15 (net metering, smart metering, and interconnection). 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 standards 12 and 13 (fuel diversity and fossil fuel generation efficiency). Because these utilities do not own or control generation capacity, they do not have much ability to address fuel diversity and fossil fuel generation efficiency directly. But, 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. Unfortunately, the statute is not explicit on this point.

The third category includes generation owning companies with retail customers, and total annual retail sales greater than 500,000 MWh. They would clearly be able to implement new federal standards 12 and 13 (fuel diversity and fossil fuel generation efficiency). 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 other three standards (11, 14, and 15).

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 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,[13] 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 unregulated utilities as well) cited in the report are collaborative

---

[13]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).

processes, such as a problem-solving workshop, an open technical conference, or negotiated rulemaking. These options could be used as long as it complies with the conditions specified by PURPA for a hearing. (The results from a survey from this NRRI report on what type of process 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.[14] 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 unregulated utilities when considering each standard is 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 and 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 unregulated utilities by PURPA are (as shown in Figure 2.1):

- 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 unregulated 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

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

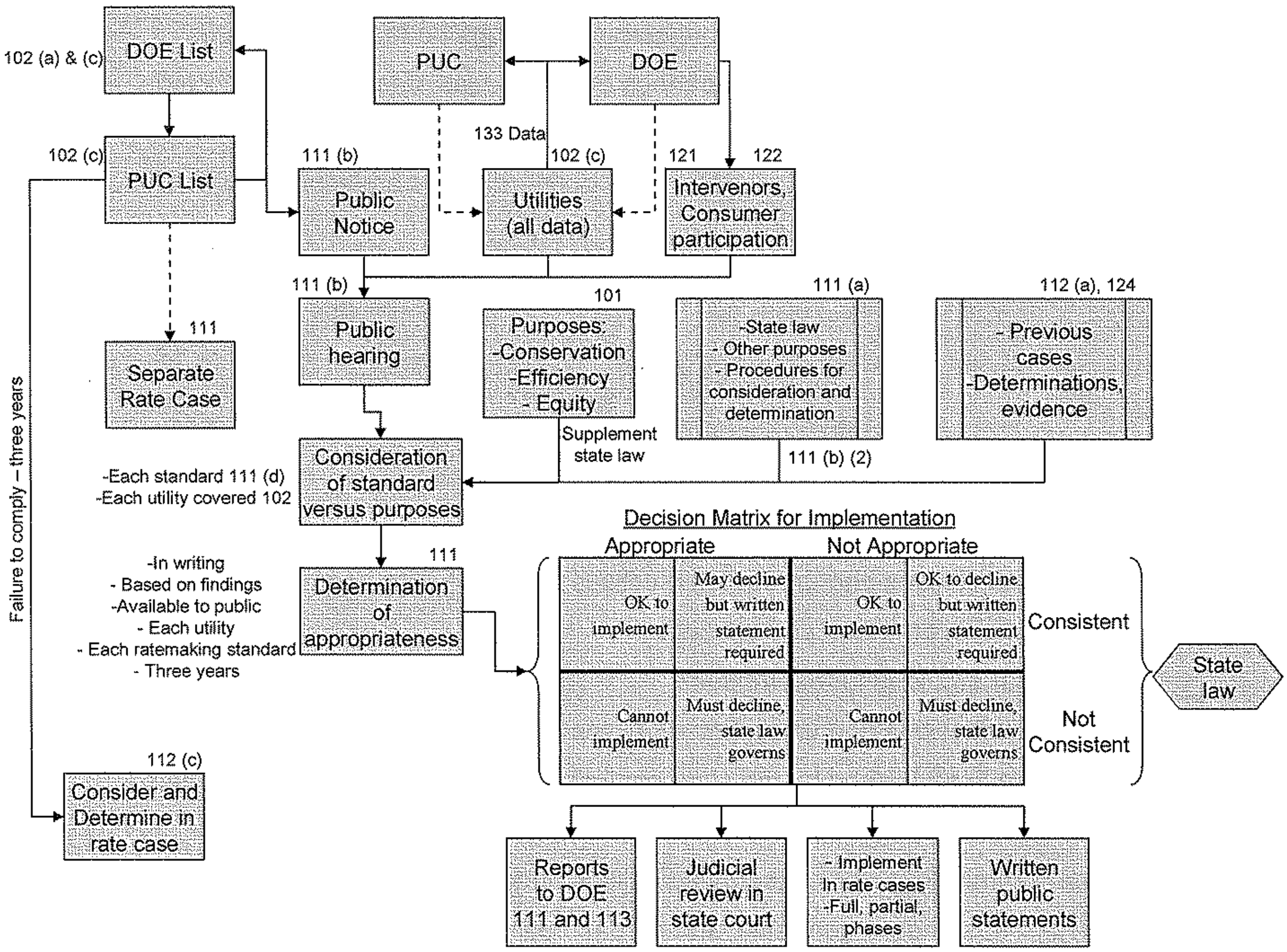


Figure 2.1. Procedures for considering PURPA 111 standards.
Source: "Reference Manual and Procedures for Implementing PURPA," 1979.

    - company-specific findings in conjunction with rate hearings

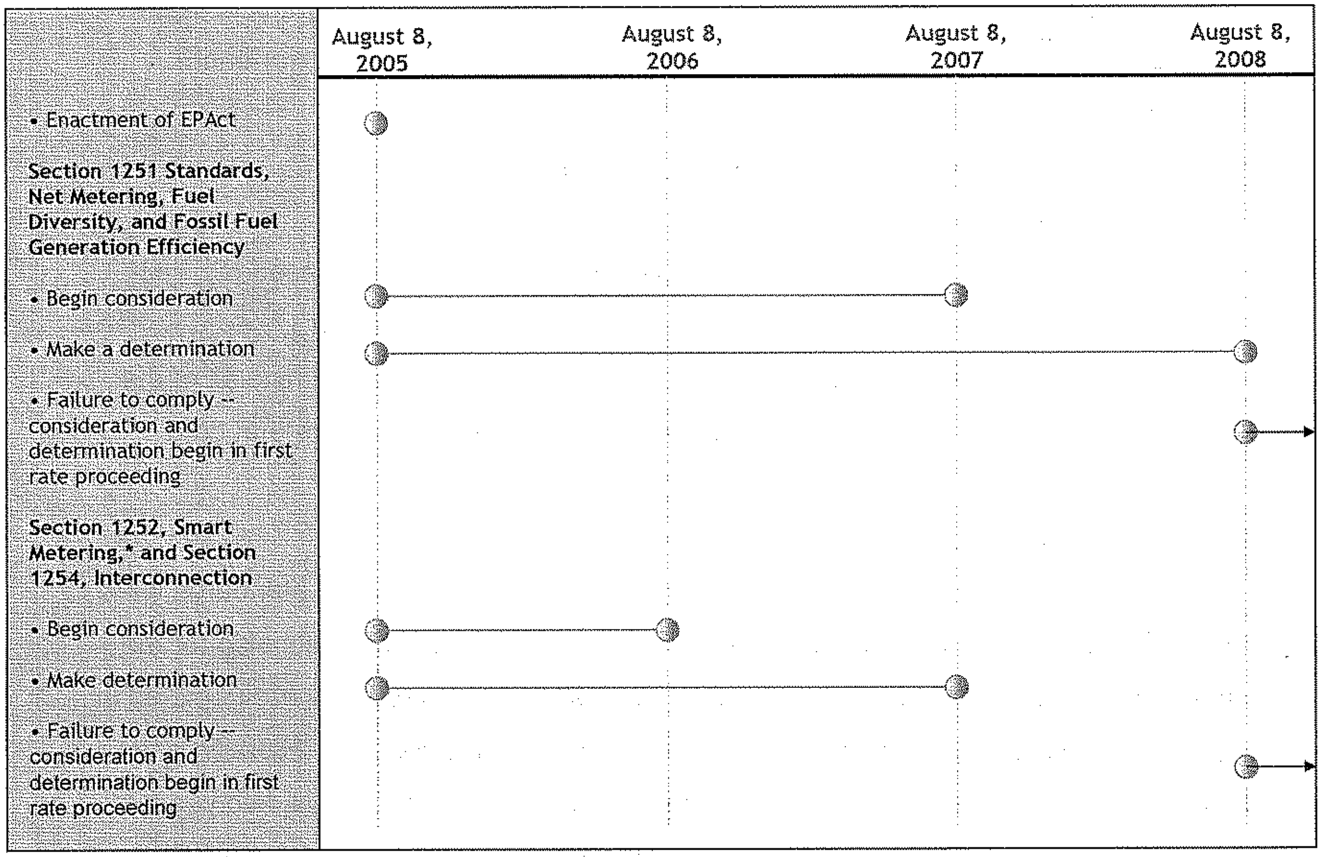
- State commissions and unregulated utilities issue public notice, or orders as appropriate under state law, of forthcoming hearings on federal standards
  - Public notice of generic hearings on the federal standards may include, depending on state law:
    - timing and description of procedural steps 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 unregulated utilities prescribe filing requirements for:
  - data, information and analysis
  - that provides for exemptions
- State commissions and unregulated utilities conduct public hearings using procedures established by the state commissions or unregulated utilities and consistent with PURPA provisions
- State commissions and unregulated 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 unregulated utility pursuant to state law
  - findings and evidence from previous hearings held
- State commissions and unregulated utilities determine appropriateness of each federal standard:
  - in writing, available to public
  - based on findings in hearing
  - for each utility (perhaps for each customer class)
  - by the deadlines prescribed in EPAct (Figure 2.2)

  - in relation to the three purposes of PURPA and other state law purposes, if identified
- State commissions and unregulated 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 (but "appropriate")
- State commissions and unregulated utilities consider and determine all of the above in "next" rate case after August 8, 2008 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. EPAct establishes time limits also for the additional federal standards. The EPAct PURPA standards time limits are depicted in Figure 2.2. The EPAct section 1251 standards, for net metering, fuel diversity, and fossil fuel generation efficiency, have the same time limitations. That is, two years to begin consideration (August 8, 2007) and three years to make a determination (August 8, 2008). EPAct section 1254, interconnection, has a one year limit to begin consideration (August 8, 2006) and a two year limit to make a determination.

EPAct section 1252, smart metering, as noted above, has a contradiction in the time limitation. In the standard's description in the statute (EPAct section 1252(a), as shown in Box 2 above), a time limit of 18 months (February 8, 2007) is given for utilities to offer each customer class time-based rate schedules and for state commissions to conduct an investigation *and* issue a decision whether or not to implement the standard. However, as noted earlier, EPAct section 1252(g), "Time Limitations," clearly amends PURPA section 112(b) and gives state commissions and unregulated utilities one year to begin consideration of this standard or set a hearing date and no later than two years after enactment to complete the consideration and make a determination on the standard (these are the dates used in Figure 2.2). As noted also, regulatory authorities



•The dates shown in the chart for the "Smart Metering" standard are from section 1252(g) of EPAct, "Time Limitations," see text for details on implementation deadlines.

Figure 2.2. Compliance deadlines for EPAct standards.

and unregulated utilities can alter the time period within the standard to accommodate their schedules and the practical limits of a utility program, as long as they follow the procedures prescribed by PURPA.

2.6 Failure to comply

If a state commission or unregulated 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 August 8, 2008 (PURPA section 112(c), EPAct sections 1251(b)(2), 1252(h), 1254(b)(2)).

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 August 8, 2008 for all five of the standards. The final outcome of any subsequent court proceedings would, of course, be uncertain.

2.7 Implementation issues

2.7.1 State Commission actions on the 1978 and 1992 PURPA standards

It may be useful to consider how state commissions implemented the 1978 and 1992 federal standards. NARUC conducted a survey of state commissions in 1982 on the PURPA activities.[15] 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 standards were to be considered in the next rate case).[16] A response was received by

---

[15]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).

[16]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.

41 of the 54 commissions and agencies[17] 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.[18] 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.[19] There were relatively few rejections of the standards, five of the six standards were rejected by the commission 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 to state commissions.[20] 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.

---

[17]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.

[18]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, were all the affected utilities were considered in a single case or rulemaking procedure.

[19]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.

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

A survey conducted by NRRI in early 1993 addressed state commission plans to consider the standards in the 1992 EPAct.[21] 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.

2.7.2 State authority

PURPA did not take the primary responsibility over electric utility rates from the states. The Title I standards impose certain obligations on state regulatory commissions and give 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.[22] Also, states may consider other purposes as well that are not specified by PURPA. State commissions and unregulated utilities are not required to take actions that conflict with state law. The legislators' intention was to preserve the discretion of state commissions and unregulated 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.[23]

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

---

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

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

[23]Conference Committee Report, p. 71.

evidence and the relationship between findings and the record of a proceeding, would be governed by state law.[24] 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.

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 unregulated 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 unregulated 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."[25] 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

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

[25] Conference Committee Report, p. 81.

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 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 unregulated 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 unregulated 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 unregulated 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 unregulated 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 unregulated 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]."[26]

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][27]

---

[26]Conference Committee Report, p. 83.

[27]Conference Committee Report, p. 83.

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 jurisdiction is limited by this section (PURPA section 123) and 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 unregulated 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[28]). 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

---

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

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 unregulated utilities have to hold hearings, make determinations, and comply with all other Title I requirements.[29] The conferees state that the enforcement authority does not provide independent authority to attack a final determination of a state commission or unregulated utility. They also note that any appeal of a final determination by a state commission or unregulated 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 unregulated utility regardless of whether the Secretary participated in the original proceeding (PURPA section 123(c)(3)). Also, this section does not prohibit the Secretary 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 (Section 124)

For four of the EPAct PURPA standards (net metering, fuel diversity, and fossil fuel generation efficiency – EPAct section 1251 and interconnection – EPAct section 1254), 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 unregulated 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 (EPAct sections 1251(b)(3)(A) and 1254(b)(3)(A)). For the smart metering standard (EPAct section 1252), the prior state action by the state commission or unregulated utility must have been conducted in a proceeding considering implementation of the standard or

[29] Conference Committee Report, p. 84.

comparable standard *within the previous three years* before enactment, or the state's legislature voted on implementation of the standard or comparable standard also within the previous three years before enactment (EPAct section 1252(i)).

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 EPAct was passed in 2005. For this reason, the law recognizes this possibility of prior or pending action by a state commission or an unregulated utility. The statute states (PURPA section 124) that proceedings by state commissions and unregulated utilities that commenced before the law was enacted (in the case of EPAct, before August 8, 2005) 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,[30] 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 unregulated 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,

[30]Conference Committee Report, p. 85.

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 noted, EPAct amended PURPA by limiting prior state action for the smart metering federal standard for state commission or unregulated utility proceedings that considered implementation of the standard or comparable standard to within the previous three years and when legislation to implement the standard or comparable standard was voted on within the previous three years. No time limit was placed on the other four standards, leaving it to the state commission's and unregulated utility's discretion to determine if the action "substantially conformed" to the Title I requirements.

Considerations for the Evaluation of the PURPA Standards of the Energy Policy Act of 2005

3. Net Metering

3.1. Introduction to Net Metering

3.1.1. Statement of Amendment to PURPA: Standard 11

The Energy Policy Act of 2005 amends PURPA by adding a federal standard for the consideration of net metering by states and utilities (PURPA section 111(d)(11)). The bill states:

> Each electric utility shall make available upon request net metering service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term 'net metering service' means service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period.

This section addresses issues that must be considered when determining whether or not to adopt a net metering standard. It is important to note that what follows are simply the issues and basic factual background information regarding net metering that can be considered during the evaluation of whether or not to adopt the standard, and if so, in what form. This section does not make any recommendations on the appropriateness of net metering for a given utility. The issues addressed include the definition of net metering, the relationship of net metering with the PUPRA goals, current practices such as participation, net metering approaches, and valuation of excess generation, associated costs, and environmental considerations.

3.2. Application

The definition of net metering taken for this section refers simply to the netting on a kWh-to-kWh basis of the flow of electricity from a site with consumer-owned generation to the utility against the flow of electricity from the utility to the customer. Net metering is one of several available tools for measuring and valuing generation from on-site generation or distributed generation.

It may be useful here to distinguish the term "net metering" from the term "net billing" with which it is often confused and sometimes used interchangeably. Properly used, the term "net billing" refers to a form of accounting in which dollars that a utility owes to a consumer for consumer-owned generation are netted against the dollars owed by the consumer to the utility for retail service. At the end of the billing period, if the consumer has a positive balance, then the consumer pays the balance owed. If the consumer has a negative balance, then the consumer receives a credit on the next bill from the utility, in some cases, receives payment from the utility, or the credit is zeroed out at the end of the billing period.

Net metering is best understood as a service provided with a single meter. When the customer uses more power than it generates at any moment, the dial on the meter rolls forwards, recording net positive demand. When the customer generates more power than it uses at any moment, the dial on the meter rolls backwards, erasing previously recorded customer usage. The kWh provided by the utility, therefore, are necessarily valued at the same level as kWh provided by the consumer, at least to the point where the meter rolls back to the "zero" point for the billing period.[31]

By contrast, net billing typically uses two meters or a single more sophisticated meter that can separately record flows of energy in each direction. Net billing permits the rate each party pays the other for energy to be set at a different level. Net billing also permits the meter on the customer-owned generator to be located in different places on the customer property. It can be placed at the customer property line, so that it only records the net on-site generation at any particular moment. This allows the customer to consume its own generation, reducing its retail demand on the utility and its energy sales to

[31]Net metering was first proposed as a quick and inexpensive way for utilities to fulfill PURPA's mandatory purchase obligation from smaller Qualifying Facilities. For small generators, it typically was not cost-effective to install a second meter or create additional billing functions. With net metering increasingly being used by larger generators, however, often without recognizing the significant difference in power prices between peak and off-peak periods, the impact on utilities and consumers is becoming a more significant financial issue.

the utility. Alternatively, the meter can be placed at the generator, recording all of the generator's output. Under this approach, all of the customer's demand is served by the utility and all of its output is sold to the utility.

Consideration of any previous actions taken by states or utilities with respect to this standard are discussed in sections one and two. Actions taken by the states or utilities on net metering standards will likely constitute fulfillment of the PURPA obligation.

3.2.1. Relationship to PURPA goals

This standard relates to the first and third stated purposes of PURPA, as summarized in the first and second section of this manual, that is, to encourage (1) conservation of energy supplied by electric utilities and (3) provide equitable rates for electric consumers.

Because net metering may encourage distributed generation, it is likely that net metering will permit utilities to produce less power. Some of the power that would otherwise have been produced by utilities will instead be produced by consumers. This is not to say that total energy consumption will decrease, only that less of the generation resources will come from utilities.

Rate equity concerns are probably the primary area for analysis in deciding whether or not to adopt net metering standards and if so, how to design them. Under certain circumstances, net metering can undermine the equity of retail rates. Because net metering policies provide for customer-generated kWhs to be netted on a one-for-one basis with utility-delivered kWhs, net metering policies require utilities to pay consumers the retail price for wholesale power. That means the utility is paying for services typically included in retail rates that the consumer is not providing the utility, including distribution, transmission, utility operating and maintenance expenses (O&M), utility administrative and general expenses (A&G), and sometimes taxes and public benefits charges as well. These costs will generally be recovered from other consumers on the utility's system, leading to a cost shift from customer-generators to all other consumers on the system.

In addition, simple net meters do not take into account the different value of energy at different times. If a customer-generator draws power from the utility at night when energy costs are low, and generates during the day when energy costs are high, net metering may under compensate the customer-generator for the value of its output. The same is true in reverse. If a customer-generator draws power from the utility during the day when energy costs are high, and generates at night when energy costs are low, net metering may overcompensate the customer-generator for the value of its output. Each of these would cause an inequity in the rates either of customer-generators or other consumers.

These rate equity impacts explain why the Federal Energy Regulatory Commission determined that net metering would only approximate a utility's avoided cost where, "the retail rates are marginal cost-based time-of-day rates."[32]

Net metering may have a minimal effect on efficiency goals addressed in PURPA. However, to answer that question would require a resource intensive analysis of the type of generation that the utility uses, the type of generation that would be promoted by the net metering program, and the interaction between the two. Additionally, though a net metering standard may not have a direct impact on utility operations or resource allocation, by promoting the installation of customer-owned generation to replace some utility generation, the net metering standard could have a marginal impact on the utilization of the utility's generation resources. If highly efficient customer-owned generation operates at times that permit the utility to reduce usage of less efficient generation, it could have a positive impact. If, on the other hand, inefficient customer-owned generation replaces utility-owned generation with a much lower heat rate, the effect could be negative.

As discussed below, many states and utilities that have adopted net metering plans have addressed rate equity issues by adopting limitations on one or more of: the customers entitled to net metering service, the capacity of generators or the type of generating technologies entitled to net metering service,

[32]FERC Order 69, FERC Regs. and Preambles ¶ 30,128, at 30,879 (1980).

or the total number or capacity of generators entitled to net metering service. In some cases, states and unregulated utilities have determined that adopting the very simple net metering approach for some limited consumers and some generators could prove more cost effective for the implementing utility than the cost of the metering equipment and accounting resources required to adopt other mechanisms for the measuring and valuing of customer-owned generation. Some others have concluded that, with appropriate limits, net metering would have too small an impact on other consumers' rates to merit concern. Others have adopted net metering because they have placed greater weight on other state policies than on rate issues.

The last question is the effect that net metering may have on other policies that state regulatory authorities and unregulated utilities may pursue under state law. Goals a state or utility may wish to consider as a reason for net metering standards may include, but are not limited to, reduced or shifted capital investments, environmental concerns, reliability concerns, fuel cost savings, or fuel diversity. They then may consider, in the context of the stated goals, if there are alternative options that may achieve the same goals in a more cost-efficient manner. For example, if the goal of net metering is to ensure that all local generation is connected in accord with some level of safety and security, would adopting an interconnection standard offer the same benefit at a lower cost? If the goal is to encourage renewable fuel sources, would a renewable portfolio standard or tax incentives achieve the same goals more cost effectively? The answers to these questions may differ by state and by electricity service provider.

If the state or unregulated electric utility is considering adopting net metering, it should consider the alternative designs for net metering programs adopted in different states and choose the design that best furthers the state's or unregulated utility's goals.

3.3. Implementation and plan elements

3.3.1. Regulatory/Legislative Statutes and Current practices

According to the Database of State Incentives for Renewable Energy (DSIRE),[33] 40 states and the District of Columbia have some form of net metering standard currently in place.[34] Not all net metering standards are state requirements. Some are offered by at least one major utility in the state and not required or monitored by law. Regulation and statutes regarding net metering are wide ranging and very complex. They differ by state and perhaps even by utility within a state. Current standards differ based on allowable levels of participation, qualifying resources, and treatment of net excess generation. There are no federal net metering standards.

3.3.2. Plan elements

3.3.2.1. Participation and eligibility

As noted above, states differ in what is considered acceptable participation. Many states may limit the amount of electricity, the size of the facility, or the number of consumers that can be enrolled in net metering programs. This section addresses three issues regarding allowed participation: total volume of participating generators, qualified customer sectors, and qualifying generation sources.

3.3.2.1.1. Total Participation

States may constrain the total allowable level of net generation. Usually this limit is defined in terms of service areas as opposed to statewide limits. California, for example, set the following limits:

---

[33] Described as a project of the Interstate Renewable Energy Council (IREC), funded by the U.S. Department of Energy and managed by the North Carolina Solar Center (Dsireusa.org).

[34] AL, KS, MS, MO, NE, SC, SD, TN, and WV do not have net metering standards, according to the survey.

> On a first-come-first-served basis until the total rated generating capacity used by eligible customer generators exceeds 0.5% of the electric service provider's aggregate customer peak demand.[35]

The California PUC encouraged an increase to 5 percent of total peak load, though no action has been taken on the recommendation to date.[36] Minnesota has no limit on the statewide capacity that can enroll in net metering programs. Once a participation limit is reached there is no guarantee that power produced by small on-site generators need to be credited to the consumer by power providers even if the generator meets all other requirements to be an eligible generator. However, this does not mean that the consumer cannot supply their own generation using an on-site generator, it simply means that they may receive no benefit beyond lower electric bills from reduced demand from the system.

3.3.2.1.2. Sector participation

Many states delineate what consumer sectors or producer types will be permitted to participate in net metering programs. While some states limit participation to particular sectors, like commercial or agriculture, other states permit participants from any sector. When considering what sectors should be permitted to participate in such programs, matters of generation source, potential consumer benefits, grid impacts, and connection and other costs should be considered. Some sectors may possess characteristics that make the connection process more difficult and expensive.

3.3.2.1.3. Generation Resources

Net metering can provide incentives to build on-site generation. It can also be used as an incentive to increase the use of renewable power by households or other generators. Typically, states and utilities have limited participation in net metering programs by both size of generator and by the generator fuel or energy source. With respect to size, some simply limit the size

---

[35] California SB 816 (2005)

[36] Update on Determining the Costs and Benefits of California's Net Metering System as Required by Assembly Bill 58, March 29, 2005

of an allowable unit, and many limit generators to 10 kW for residential sources while commercial providers may be permitted to generate electricity with limits as high as 100-200 kW of generation. At least part of the reason for limiting participation is system reliability. Another purpose is to ensure that the generator is sized primarily to serve the consumer's load and not for sale to the utility. With respect to fuel or energy source, many states limit net metering to renewable resources. However, this is not always the case. For example, Arkansas Code states that the Authority of Arkansas Public Service Commission:

> May expand the scope of net-metering to include additional facilities that do not use a renewable energy resource for a fuel or may increase the peak limits for individual net-metering facilities, if so doing results in desirable distribution system, environmental, or public policy benefits.[37]

Connecticut allows for sources that are non-renewable as long as the facility is licensed, properly connected to the grid, and in compliance with all of the requirements of state and federal EPA. Many states include language in the net metering laws that limit eligible generators to those that use renewable fuel sources. North Carolina states that:

> Net metering, therefore, shall be made available to a utility customer that owns and operates a solar PV, wind powered, or biomass-fueled renewable energy facility without battery storage.[38]

3.3.2.2. Approaches to net metering

If a state or utility decides to implement some form of net metering, there are several metering approaches that would allow net metering. They differ by the number of meters and installed technology. Simple net metering, dual metering, and smart metering are three of the most common approaches.

When considering what metering approach to take, a state or utility should consider the retail pricing structure (fixed or dynamic), the retail market structure (regulated or restructured), the cost of meter installation that it incurs, the ability

[37] Arkansas Code of 1987, Title 23, Subtitle 1, Chapter 18, Subchapter 6(3)
[38] NCUC Docket No. E-100, Sub 83

to install various meter types, and benefits of a given type of meter relative to the others.

Simple net metering should require very little additional investment in meters. Currently, most simple meters register flow, and are capable of netting out the incoming and outgoing electricity. This metering approach only shows the net usage and does not show total consumption for the billing period.

Smart metering allows one meter to measure and record the flow of electricity into and out of a residence. This means there are separate readings for incoming and outgoing electricity like dual metering, but all done on a single meter. A benefit of smart meters is the ability to track when and how much power is flowing in either direction (additional attributes of smart meters are discussed in Section 6). Like dual metering, smart metering will require the investment of new meter installations.

3.3.2.3. Treatment of Net Excess Generation

Existing state programs treat net excess very differently. In some states, utilities are required to pay the consumer-generators the utility's avoided cost for the net excess generation produced in each billing period. That is the same value for generation that utilities must pay qualifying facilities for generation under PURPA Section 210. In other states, consumers receive a credit for the net excess generation against future bills. In other words, the net excess generation rolls forward and is treated as if it were generated in subsequent months. It may continue to be netted against the future energy used on a kWh-by-kWh basis. Some states allow these credits to roll forward indefinitely, while others limit them to roll over for a calendar year or other fixed period. At some point, some states require the utility to "true up" or purchase credits at the avoided cost, retail price, or some other predetermined rate. Other states terminate the credits without any additional compensation to the consumer-generator. Each of these approaches provides different levels of incentives to consumer-generators. Care should be taken to identify any unintended subsidies to consumer-generators.

3.3.3. Interconnection

Utilities and regulators are also concerned with the manner in which the on-site generators are connected to the grid. Interconnection standards will be discussed in more detail in Section 7 of this manual.

3.4. Costs

Costs of meters, meter installation, and support technology, and other reasonable costs could be recovered through a use or access charge if they are considered costs of doing business and therefore the responsibility of the utility. If they are considered part of the investment by the consumer as part of the on-site generation, or accepted by unregulated utilities, the consumer-generator should bear these costs. If they are considered short-term costs that yield greater long term benefits, a case could be made for spreading these costs among all rate payers. It may be the case that the net benefit to any given consumer would be negative if they were forced to cover these costs, but the aggregate benefit to the unregulated utility could be positive even if they assumed these costs. Currently the manner in which these costs are recovered varies by state and utility.

3.4.1. Renewable Generation

Many of the states with net metering standards have language that encourages the use of renewable energy sources such as solar and wind. Some argue that the government should intervene by offering additional incentives, like tax credits, to encourage investment in renewable technologies. If encouraging the use of renewable resources is the goal, it is important to determine if the net metering standard is essential for the program to work, or if the goals could be achieved in another manner. The impact on potential consumer-generators should also be analyzed.

Many states allow utilities to take credit for the green energy that a consumer adds to the grid from renewable resources. An incentive that states may provide to utilities to increase renewable energy portfolios is to allow utilities to charge a slight premium to consumers that wish for some or all of their power to be supplied by environmentally friendly sources of electricity. Therefore, the buy-back price for this power could be the bundled rate, the avoided cost, the standard generation rate, or perhaps the "green" rate.

3.5. Additional Resources

DSIRE. "Net Metering Rules" Available at http://www.dsireusa.org/library/includes/type.cfm

Edison Electric Institute. "Net Metering Raises Policy Issues for States and Congress" Available at http://www.eei.org/industry_issues/electricity_policy/federal_legislation/netmetering.pdf

Franklin, H. Allen. Testimony on Behalf of the Edison Electric Institute Before the Senate Energy and Natural Resources Committee, Mar 27, 2003. Available at http://www.eei.org/about_EEI/advocacy_activities/Congress/2003-03-27-EEI-testimony.pdf

National Rural Electric Cooperative Association, Distributed Generation Rates Manual, http://www.nreca.org/Documents/PublicPolicy/DGRatesManual.pdf

National Rural Electric Cooperative Association. "Net Metering: An Issue Paper of the National Rural Electric Cooperative Association" is a simple explanation of the concepts and concerns that are associated with net metering. Available at http://www.nreca.org/Documents/PublicPolicy/NetMetering.pdf

Forsyth, T.L., M. Pedden, and T. Gagliano. "The Effects of Net Metering on the Use of Small-Scale Wind Systems in the United States" by, released Nov 2002. (Available at http://www.nrel.gov/docs/fy03osti/32471.pdf)

State Environmental Resource Center. "Net Billing." Available at http://www.serconline.org/netmetering/legislation.html

U.S. Department of Energy, Energy Information Administration, "Green Pricing and Net Metering Programs 2003" Available at http://www.eia.doe.gov/cneaf/solar.renewables/page/greenprice/grnprcreport.pdf

4. Fuel Diversity

4.1. Introduction to Fuel Diversity

4.1.1. Statement of amendment to PURPA: Standard 12

The Energy Policy Act of 2005 amends PURPA by adding standard 12 (PURPA section 111(d)(12)), which requires the consideration of "Fuel Sources" or fuel diversity plans by utilities. The bill states:

> Each electric utility shall develop a plan to minimize dependence on 1 fuel source and to ensure that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies.

If a state commission or unregulated utility adopts a fuel diversity standard, it must determine what this standard will be and the time horizon by which the standard must be met. The statute offers no structure or framework for the standard, leaving such issues to the state commissions and unregulated utilities to determine.

Costello (2005) defines a diverse generation portfolio as "deploying a mix of electric generation technologies with different fuel sources." This definition is used for this manual. The statute seems to imply that reliance on a single fuel source may not be the optimal way to supply electricity. This may be correct in some regions, while not in others.

This standard is closely tied to the second and third PURPA goals. That is, (2) optimize the efficiency of electric utility facilities and resources, and (3) equitable rates for electric consumers. Fuel diversity will not likely change the quantity of energy demanded, unless the fuel choices dramatically change consumers' electricity prices. However, fuel diversity standards may have a direct impact on the efficiency with which utilities operate their generation portfolio. The use of different fuel source will ultimately impact the price at which energy can be purchased. This can impact the rates paid by consumers. Equity between consumer sectors is likely to be unaffected. However, the rates paid by consumers may be altered based on the positive or negative impact that implementing a fuel diversity standard may have on the cost of producing electricity.

What follows are issues and basic factual background information that can be considered during the evaluation of the standard, and are not recommendations. This section discusses what a fuel diversity plan is, the issues that state regulatory authorities and unregulated electric utilities may wish to consider in deciding whether to adopt a fuel diversity plan, and some considerations regarding how to achieve diversity.

4.2. Considerations for Determining Whether to Adopt a Fuel Diversity Plan

There are several issues that states and utilities should consider before determining if a fuel diversity standard is appropriate for a state or utility. These issues include, but are not limited to, the following:

- What information or studies exist?
- What are the current and foreseeable generation portfolios?
- How would such a standard effect various types of risk?
- Would such a standard increase reliability?
- Would such a standard increase operational flexibility?
- Would such a standard have environmental impacts?

This section covers these considerations.

4.2.1. Integrated resource plans

When considering a fuel diversity plan many states and utilities may not be working from scratch. There have been studies conducted, for example, as part of Integrated Resource Planning (IRP) requirements, by a variety of utilities that already measure the cost effectiveness of utilizing various fuel sources to supply electricity. To the extent that the studies were conducted under conditions that are similar to current market structures and regulation, they may provide a great deal of support for utilities and states in their assessment of the cost effectiveness of a fuel diversity standard.

4.2.2. Current and foreseeable generation portfolio

Another important factor that must be reviewed is the current and future generation portfolio of a state. Generation currently in place will act as the baseline for a fuel diversity plan. The current portfolio is also an indicator of the resources that are available to a state. Additional information regarding the current and future generation capacity outlook can be found in Appendix B.

4.2.3. Potential benefits

Many of the potential benefits of fuel diversity come in the form of risk mitigation. Some of the potential benefits of fuel diversity, depending on an individual include, but are not limited to, the following:

- Mitigation of fuel price and energy price risk
- Mitigating regulatory risk associated with individual fuels
- Increased reliability
- Increased operational flexibility
- Reduced environmental impacts.

A utility's circumstances are discussed in greater detail below.

4.2.3.1. Fuel price risk mitigation

Fuel prices can fluctuate for any fuel source at any time. By employing a diverse portfolio of generation technologies and fuel sources, it may be possible to limit the level of price variations. Much like personal investment, diverse asset portfolios may offer protection from high levels of price variation. In the case of generation diversity, diversity can protect both generators and consumers from price spikes in fuel costs. At the NARUC Commissioners Summit, the benefits of fuel diversity were viewed to be that "electric utilities can manage the risk of price spikes, volatility and other undesirable effects." This section addresses several types of risks state commissions and unregulated utilities must be aware of when considering generation investments and fuel source choices.

4.2.3.1.1.1. Fuel price risk mitigation for generators

Generators that utilize only one fuel source may be subject to price variations that occur for that fuel. For example, if the price of natural gas were to be high and volatile and a utility were to utilize only natural gas generators, then the utility could see dramatic price fluctuation in the cost of production. When a generator considers fuel diversity plans, they may wish to consider the volatility of the fuel sources they utilize and then determine if diversifying will help reduce the risk associated price variation. This process should include availability of fuel sources, knowledge of the technology and ability to deploy it successfully, and correlation of fuel prices between fuels. Generators may also wish to consider how a diverse portfolio may impact their ability to bargain in contracts for fuel (may not be able to buy in bulk, but may be able to bargain one fuel for another) and the ability to substitute generation from one fuel source for another. These considerations may increase the level of efficiency of all their assets. If utilities are able to lower fuel price risk while maintaining their ability to negotiate contracts for fuel and the expertise in the fuels they use, then fuel diversity may improve a utility's ability to offer equitable rates to consumers. However, if the utility has efficiency losses in terms of contracts or output from different fuel sources, then diversity may have the opposite effect.

4.2.3.1.1.2. Fuel price risk mitigation for non-generators

Non-generators may not see a direct impact from fuel price risk, depending on the nature of their supply contracts. They may want to consider the benefits that may come from more stable or lower energy prices. Lower energy prices can then be passed on to consumers. However, if the diversity has the negative effects on generators discussed in the previous section, then any price increases will likewise be passed through.

4.2.3.1.2. Energy price mitigation risk

Fluctuations in energy prices can cause problems for buyers and sellers alike. A diverse portfolio and management of risk with judicious use of hedging may offer means to stabilize these prices.

4.2.3.1.2.1. Energy price risk mitigation for generators

Fluctuations in energy prices are a concern, albeit not a major one, for generators. Fluctuation in energy prices can reflect changes in demand, transmission congestion, or output. Investments in generation that only operates a small number of hours in a year may be unfavorable and perhaps not consistent with PURPA's resource efficiency goal. Also, as prices fluctuate, so does plant output. This may cause increased wear on generation facilities. Therefore, a generator may wish to create a diverse portfolio that is able to adjust to such changes in demand or transmission congestion within a region. (Note, for example, some industrial customers shut down when the price of electricity became extremely high and volatile during the 2000-2001 western power crises.)

4.2.3.1.2.2. Energy price risk mitigation for non-generators

In most cases, increases in energy prices are borne by the end-use consumers of the electricity. When considering the potential benefits of fuel diversity, regulators and purchasers may want to view the benefits created by generators being able to offer a more diverse portfolio of contracts or power purchase agreements in light of the cost to the consumer. Such benefits may include the ability to offer green power to end-use consumers. Regulators and purchasers should also consider the stability benefits that might result from the hedges that generators make on fuel prices. While hedging does increase the cost of power, they also mitigate price spikes and can provide some price constancy. This could, but need not, include lower energy prices on average.

Some retail and distribution only utilities face special challenges if they are bound by long term all requirements contracts with their wholesale power supplier. Some hedging and portfolio diversification options might not be available to these individual utilities. The plans of the wholesale supplier should therefore be part of any review of the subject.

4.2.3.2. Transmission system reliability

Diverse generating resources may also offer benefits in the form of increased system reliability, but each source of generation has different operational characteristics and limitations. All sources of generation are, in short, not created equal, requiring regulators and generators to evaluate each resource objectively on its merits and weaknesses. For example, flexibility is an important characteristic that many natural gas plants possess. This allows certain types of natural gas plants to increase or decrease output in real time to adjust for congestion or outages.

4.2.3.3. Operational benefits

Given the operational differences between various generation technologies, it may be beneficial to possess a variety of plants that are able to perform the different services needed to maintain grid reliability. Base-load coal plants are reliable and generally cost effective, but they are not designed to ramp up and down quickly to follow load, but a flexible gas generator could perform this function fairly easily. In emergencies, such diversity can prove very beneficial. Some plants possess other attributes that allow them to provide ancillary services to the market such as spinning reserves or black start. For example, a coal generator might not be able on short notice to come online to respond to a short-term emergency on the grid, but its ability to provide spinning reserves is substantial. Likewise, a natural gas plant may not be able to provide enough voltage support to maintain grid reliability. At different times, each generating type may be called on to provide a service to the grid. Whether it is congestion relief, spinning reserves, or any other service, some generating sources are better options for specific tasks than others. To the degree that ancillary services are needed, a diversity plan should consider the added benefit that a fuel source can provide. Investors may want to consider adding features to a generating unit to the extent that it may increase the value of the facility. By making such decisions prior to investment, a utility may be in a better position to use its assets in an efficient manner.

4.2.3.4. Environmental impact

When considering fuel diversity, choices must be made even within fuel types. Natural gas can be used in a variety of different ways. Some of the uses of natural gas produce more electricity per unit of pollution than others. Additionally, some generators that can be used to help relieve congestion might not be environmentally friendly but necessary for this specific purpose. Finally, diversity may also include the use of renewable energy sources such as hydro or wind. To the extent that these technologies are used, there are positive environmental externalities, or environmental benefits not included in the price and cost of consuming and producing power. It is important to consider what types of new technologies may be introduced and the effects (positive or negative) that each may have on the environment.

4.2.4. Potential Costs

Some of the potential costs of fuel diversity, again depending on an individual utility's circumstances, are also discussed briefly below. These include:

- Higher cost for some resources
- Political and operational challenges in developing some resources
- Lack of utility experience and expertise with the new resources

This section will discuss these potential costs in greater detail.

4.2.4.1. High resource costs

There are benefits lost when a utility uses a diverse portfolio of fuels. One of the primary sacrifices made is the loss of scale economies in purchasing fuels. Utilities will be forced to utilize multiple modes of fuel transportation and may also sacrifice the price reductions based on quantity. Furthermore, if a utility is already relying primarily on the lowest cost generation resource available in its region, adding to its fuel diversity necessarily will increase the cost of its generation portfolio because it means acquiring higher cost resources.

4.2.4.2. Political and operational challenges

4.2.4.2.1. Siting risk

Siting risk is a risk that is primarily the concern of firms, both integrated and generation only, which are seeking to expand their current generation asset portfolio. However, regulating agencies will also have an interest in this type of risk. Siting risks may make some aspects of a fuel diversity plan more difficult. For example, it would be difficult if not impossible to place a traditional coal plant in a major metropolitan area, even though that plant would help provide increased reliability, lower electricity prices, and congestion relief. Likewise, when noise is a factor, certain gas-fired plants may have to undertake mitigation in more urban settings.

In order to build a generating facility, a firm must obtain all requisite permits and approval. However, not every project will obtain full approval. Firms that are unable to get full approval may have invested a great deal of time and money into the approval process. The types of approvals that investors must obtain include zoning, environmental impact statement, grid impact, construction and interconnection approval from the regulating entity or entities with proper jurisdiction. It is often the case that homeowners and local residents do not want a generator in their back yard. The "not in my back yard" objection, or NIMBY, can derail an investment, even if that investment could provide large benefits to the grid. For this reason, the firm will need to consider issues such as the planned site's location and neighboring population, land value, environmental regulations, generation technology being considered, and interconnection.

Through the course of this process, regulatory agencies will have to consider how such an addition would allow a utility to improve its ability to achieve PURPA's stated goals, what types of benefits the generating facility provides, what types of additions are needed to the system, who opposes or supports the construction, why do they do so, who is helped and who is harmed, and what is the magnitude of each. Even if there is a strong need for additional generation to supply growing demand by a new generating facility, there are no guarantees that such an investment will be permitted.

Even if a utility is able to obtain all required permits and approvals and overcome NIMBY objections, they may have to invest millions more in legal fees and compensation to any parties that may be damaged. These are costs that investors must consider when planning additions. By properly considering all these issues, an investor may improve the chances of success.

4.2.4.2.2. Regulatory risk

The current situation across the U.S. is one of differences. One of the major differences between regions is the state of restructuring. There is still discussion as to what the next step will be, or if there will be a next step. This regulatory concern will affect a firm's assessment of any fuel diversity plan as it moves forward. The risk the proposed changes to current regulations or future unknown regulations impose are major concerns for utilities as they develop their portfolios moving into the future.

States and utilities must also be aware that some technologies have had difficulty expanding or may be limited by policies, regulations, technological development, economic feasibility, or public opinion and may not seem to be promising options for future generation expansion at the current time. This does not mean that these technologies are unimportant when considering a fuel diversity plan for the future. For example, Draper (1999) says "Coal is severely challenged on multiple fronts as an electricity generation fuel and yet must continue to be a dominant resource if the power demands of the future are to be reliably and economically met."

Regulators and power producers should keep a continuous watch on technology as it enhances the abilities of various fuel types to address consumers' needs in the future. For example, some extremely efficient natural gas plants are less capable of following load than older and somewhat less efficient ones. On the other hand, new technologies may make coal-fueled generation plants more capable of following load and with reduced emissions.

4.2.4.2.2.1. Regulatory risk for generators

Two types of regulatory risk for generators to consider are risks that the market operations could change and environmental regulation. If the market operations change, the method which generators recover the cost of their investment may also be altered. These risks may make certain types of generation less attractive. For example, where price is determined in competitive markets there are risks that over-investment in generation prevents investors from recovering the cost of investment due to lower market prices. If a carbon permitting system is implemented, then fuels that emit high levels of carbon will become relatively more expensive than those that produce low levels of carbon. When considering an investment in new generation, investors need to consider their position under various market structures and how their fuel choice would be impacted by new environmental standards.

Regulatory risk may also have an impact on a firm's ability to sell output in long-term contracts. Long-term contracts are one means for a firm to finance investment. If the terms of these contracts become disadvantageous because of change in the regulatory structure of the market, then firms may need to consider alternative means of hedging investment risk. Instability in the regulatory framework can cause suboptimal levels of investments in some types of generation. The examples in the above paragraph show why a utility may be reluctant to invest in a project that would be very valuable in one regulatory regime, but may not be beneficial in another.

4.2.4.2.3. Regulatory risk for non-generators

Non-generating entities may also face uncertainty from market changes. Many states that opened retail electricity to competition are coming to the end of price freezes or discounts. These new market conditions may attract new entry, price shift, or load shift. Some changes may also make those who purchase power more hesitant to engage in long term sales contracts, as they may make long term contracts risky and less attractive; and, in turn, may make long term resource investments less attractive. Though the market may change in favorable ways for purchasers, there is still a fair level of risk involved.

4.2.4.3. Lack of experience

Costello also cites a loss of "learning-by-doing." This phenomenon comes from specializing in a certain production method. The more a utility generates from a fuel source, the more efficient it may become at producing. This would be analogous to utilizing the firm's comparative advantage in generating. A diverse portfolio may require a utility to become a "jack of all trades, and master of none." Learning-by-doing may also create externalities that a utility would not capture. For example, a utility learns a new technology, and then other utilities learn from this utility without having to invest in the research and development of the technology. The goal of diverse portfolios would be to overcome this loss through savings gained in reduced price variations of any particular fuel or the ability to switch to another fuel option that may provide cost savings.

4.2.5. General

There is no defined ideal diversity level for a region. Each region, in considering what would constitute an optimal portfolio, may wish to do so based on the assets of the region, recognizing that the optimal portfolio will likely change over time.

The 2005 NARUC summit yielded comments regarding regional differences in what would constitute an optimally diverse portfolio. A report from the summit states that a "state with significant hydro-based generation, for instance, may have different issues than one with a heavy reliance on natural-gas-fired electricity generators. The goal of fuel diversity is to ensure price stability and fuel availability by reducing reliance on a single, or a small number, of fuel sources.... Electricity generators use wind or coal or natural gas where it is economically advantageous and this may differ by region."[39]

A cost benefit analysis would need primarily to consider the comparative costs of different generation resources and the incremental cost of increasing the diversity of the utility's fuel resources. Depending on the resources the utility currently uses and the other resources available to that utility within the time frame covered by a fuel diversity plan, it may be that increasing fuel diversity would cost the utility less than continued reliance on the same fuel(s) the utility uses today.

4.3. Achieving diversity

Given the environmental externalities, the regulatory uncertainty, and price uncertainty, many organizations support funding or subsidies for utilities for achieving fuel diversity. EEI (2005) states that "[f]ederal and state energy and tax policies should promote fuel diversity and further development of renewable energy, energy efficiency improvements, nuclear energy, and clean coal technologies."[40] While NARUC adds "[r]esearch and development of all potential alternative fuels for generation should be promoted including nuclear, clean coal, carbon sequestration, wind and even ocean tides."[41]

---

[39] NARUC The State of Regulation: A Preview of Key Issues Facing Commissions in 2005 Proceedings of the Commissioners-Only Summit, New Orleans, Louisiana, Jan. 16-18, 2005
http://www.nrri.ohio-state.edu/dspace/bitstream/2068/845/1/05-01.pdf

[40] Available at
http://www.eei.org/about_EEI/advocacy_activities/Federal_Energy_Regulatory_Commission/050314ComerFercAffiliate.pdf

[41] NARUC The State of Regulation: A Preview of Key Issues Facing Commissions in 2005 Proceedings of the Commissioners-Only Summit, New Orleans, Louisiana, Jan. 16-18, 2005
http://www.nrri.ohio-state.edu/dspace/bitstream/2068/845/1/05-01.pdf

If a standard is implemented, state commissioners and unregulated utilities may wish to consider addressing matters of congestion, market power, environmental improvement, price stability, and grid reliability. However, Costello (2005) notes that "[f]uel diversity per se should not be perceived as an end, but only as a means that has the capability to generate benefits less costly than other alternatives to achieve the same objectives." He also states that multi-objective planning and power acquisition should be the reasons for advocating various technologies. In other words, diversity should not be encouraged for diversity's sake, but as a means to achieve a particular goal.

Achieving greater diversity may allow utilities to reduce volatility in the price of fuels and electricity, but these benefits may come at the expense of economies of scale. Fuel diversity can allow a firm to improve its operational efficiency through fuel switching or it may lose efficiency through the benefits gained from specialization. Regulators must consider how these tradeoffs affect the utilities in the state, as well as the resources and technologies available in the state, when considering whether a fuel diversity standard is in the best interest of the state, the utility, and the consumers. Regulators and other concerned persons should allow utilities a degree of flexibility to develop suitable plans for fuel diversity.

4.3.1. Environment and renewable portfolio standards

A diverse generation portfolio may force firms into using generation technology that they may not have ordinarily used. This may include generators that have positive environmental effects. However, the expansion will not be limited to environmentally friendly technologies. This section will provide only a cursory look at the environmental issues with regards to fuel diversity plans.

4.3.1.1. Renewable Portfolio Standards (RPS)

Many environmental benefits that may be obtained through implementing fuel diversity are external to energy markets. This means firms investing in renewable generation will not receive every benefit of their investment.

Therefore, regulators may take a role in subsidizing such investments. Costello (2005) states that "[f]inancial incentives from the government may be justified for developing technologies."

Many states have instituted requirements that utilities provide a portion of their electricity by renewable resources. The current status of RPS in the U.S. can be found at DSIRE.[42] Currently, 19 states have RPS standards and two more have set RPS goals. The portion of a utility's portfolio that will be required to be renewable differs from state to state. Some states seek renewables as a certain percentage of generation, while others set a capacity objective. There may be additional market benefits to consumers from renewable generation. Wiser (2005) says that increased use of renewable energy to displace natural gas generation will push natural gas prices down.[43]

Renewable portfolio standards offer the regional benefit of improved environmental quality, but states must be careful in the manner in which they require and enforce these standards. Graves et al. (2004) offers the following warning:

> Some utilities now face obligations to supply a double-digit percentage of their power from renewables by as early as 2010. State policy makers may determine that this is socially beneficial, but they should consider the means to achieve it carefully, including regulatory assurances that the ratepayers will be fully responsible for the cost (which may involve subsidies).

RPS may be adopted for reasons other than environmental benefits. When considering the use or implementation of RPS, regulators or legislators may wish to consider the benefits that may come from subsidizing new technology development, the sustainability of certain renewable technologies,

---

[42] Information on RPS can be found at http://www.dsireusa.org/searchby/searchtype.cfm?&CurrentPageID=2 then selecting 'Portfolio Standards/Set Asides."

[43] Testimony Prepared for a Hearing on Power Generation Resource Incentives & Diversity Standards Senate Committee on Energy and Natural Resources Tuesday, March 8, 2005, 2:30 PM. Available at http://www-library.lbl.gov/docs/LBNL/572/68/PDF/LBNL-57268.pdf

and the local effect of smaller generation units. Some RPS may simply be a way of subsidizing a new technology. This may not be the objective of the RPS, but it is important to consider that, in implementing some RPSs, this is in fact what may be happening. Wiser (2000, p16) adds "Some state RPSs contain a single general renewables purchase requirement (e.g., Maine and Texas); the lowest-cost eligible renewable resources will obtain the majority of support under these policies."

If such RPS are in place, investors in generation must give them proper consideration. The use and implementation of such standards may have objectives that differ from those of fuel diversity. However, these objectives need not be mutually exclusive. If a state wishes to adopt an RPS, generators and regulators have to consider carefully how to meet the standard and the correct levels for various resources. A utility may be forced to make an investment in a renewable generator or series of generators instead of investing in a large baseload generator. Renewable resources are generally smaller than fossil fuel plants, but can cost more per kWh generated to construct. This can impair a utility's ability to meet the rate equity goal of PURPA, while encouraging conservation of fossil fuel resources (if it replaces fossil generation) though not necessarily reduced energy consumption (unless increased prices produce demand reductions). It should also be noted the renewable energy sources may have negative environmental and other impacts. For example, dams can adversely impact marine life in a river, or the use of biomass can lead to unsustainable forestry practices. Overdependence on natural gas generation could cause socially unacceptable high prices for heating and cooking and could increase national reliance on foreign supplies.

4.4. Additional Resources

Costello, Ken. "A Perspective on Fuel Diversity," *The Electricity Journal*, Volume 18, Issue 4, May, 2005. pp. 28-47.

Edison Electric Institute. "Different Regions of the Country Rely on Different Fuel Mixes to Generate Electricity" 2005. Available at http://www.eei.org/industry_issues/energy_infrastructure/fuel_diversity/diversity_map.pdf

Edison Electric Institute. "Electricity Net Generation at Electric Utilities, 1960-1999" http://www.eei.org/industry_issues/energy_infrastructure/fuel_diversity/history_timeline.pdf

Edison Electric Institute. "Fuel Diversity: Key to Affordable and Reliable Electricity," March 2003. Available at http://www.eei.org/industry_issues/energy_infrastructure/fuel_diversity/FuelDiversity.pdf

Federal Energy Regulatory Commision, Office of Market Oversight and Investigations. "State of the Markets Report: Assessment of Energy Markets for the Period January 1, 2002 through June 30, 2003," January 2004, DOCKET MO4-2-000. Available at http://www.ferc.gov/legal/maj-ord-reg/land-docs/som-2003.pdf#xml=http://search.atomz.com/search/pdfhelper.tk?sp-o=2,100000,0

Graves, Frank C., James A. Read, and Joseph B. Wharton. "Resource Planning and Procurement In Evolving Electricity Markets," January 31, 2004. Available at http://www.eei.org/industry_issues/electricity_policy/state_and_local_policies/resource_procurement_prudence/nonav_resource_procurement_prudence/ResourcePlanningProcurement.pdf

Humphreys, H. Bret. and Katherine T McClain. "Reducing the Impacts of Energy Price Volatility Through Dynamic Portfolio Selection," *Energy Journal*, 1998, Vol. 19, Issue 3.

United States Department of Energy. "The Annual Energy Outlook," December 2004. Available at http://www.eia.doe.gov/oiaf/aeo/download.html

Wiser, Ryan, Kevin Porter, and Steve Clemmer. "Emerging Markets for Renewable Energy: The Role of State Policies during Restructuring," *Energy Journal*, January/February 2000 Vol. 13, Issue 1, 13-24.

5. Fossil Fuel Generation Efficiency

5.1 Statement of amendment to PURPA: Standard 13

The Energy Policy Act of 2005 amends PURPA by adding standard 13, the fossil fuel generation efficiency standard (PURPA section 111(d)(13)). This is the briefest of the five new PURPA standards, but it is also very specific. The entire standard in the statute is one sentence long, which reads:

> Each electric utility shall develop and implement a 10-year plan to increase the efficiency of its fossil fuel generation.

If a state commission decided to adopt the standard, the task then would fall to its jurisdictional utilities to develop a ten-year plan to improve fossil fuel generation efficiency. Unregulated utilities will have to decide whether or not to develop the ten-year plan for themselves.

The definition of efficiency is taken to mean the energy efficiency of the fossil fuel generation facilities owned or operated by a utility. This is typically measured by the heat rate: the amount of energy needed to produce one kWh of electricity, measured in Btu/kWh. Increasing the plant's efficiency is the ability to generate a kWh of electricity using less fuel than before the improvement (or generating more kWh for the same amount of fuel used), or lowering the heat rate.

This standard is closely tied to the second stated purpose of PURPA, as summarized in the first and second sections of this manual, that is, to optimize the efficiency of electric utility facilities and resources. The direct intent of this standard is to have each electric utility develop and implement ten-year plans to increase the efficiency of its fossil fuel generation, which would at least optimize the efficiency of electric utility fossil fuel generation facilities. It is reasonable to infer that Congress also intended this standard to be implemented if it would lead to the conservation of energy by electric utilities as well, the first PURPA purpose.[44] But, an analysis would have to be made to ascertain whether increasing the efficiency of its fossil-fuel generation also leads to an increase in the efficiency of all the generation resources the utility owns or controls.[45]

The effect of this standard on the third PURPA purpose, to encourage equitable rates for electric consumers, would depend on the outcome of a benefit/cost analysis. Such an analysis would determine whether the benefits of such a plan, such as lowering future operating and capital cost, would outweigh the expected costs, such as the additional expenses and investment costs incurred to increase efficiency. While efficiency improvements would not necessarily directly affect rate allocation among the customer classes, any net cost or net savings may be a net cost or net benefit to the utility's customers as well.

It is important to note that this discussion is simply identifying issues and basic factual background information that can be considered during the evaluation of whether or not to adopt the standard and does not include any recommendations. This section also does not make any recommendations on adoption of any additional standards or practices in use by other utilities or state agencies. The next sections identify which states and utilities this standard may apply to, how a plan may be structured, and issues to consider when developing and considering a plan to increase the efficiency of its fossil fuel generation facilities.

5.2 Application

When evaluating whether or not to adopt this federal standard, the first question to ask is whether a particular state-regulated utility or unregulated utility

[44]The first purpose of PURPA, conservation of energy supplied by electric utilities, implies conservation by consumers. Clearly, the general goal of PURPA was the conservation of energy resources used overall, however.
[45]Assuming a utility has a mix of resources that are used for generation, it is possible that by increasing the efficiency of fossil plants, the efficiency of non-fossil generation facilities decreases, for example by lowering the capacity factors at nuclear plants. This overall impact should be studied when considering efficiency-improving options.

is in a position practically to be able to implement the standard. A state commission may find that it cannot practically consider the standard or that efforts to implement this standard would be inconsistent with state law because it does not have jurisdiction over any power plants in the state or the state no longer regulates existing generation facilities after restructuring. However, some restructured states may find that they still have authority to consider and implement this standard under state law. Similarly, unregulated utilities may find that they do not own or control generation facilities and thus, that they cannot implement the standard.

If it is determined this standard can, practically, be implemented by a utility at issue, then the state commission or unregulated utility may consider whether a comparable plan has already been developed and implemented or is being considered. If so, then it has to be determined whether the prior state or unregulated utility action is comparable to the PURPA standard, the process used to develop the action was comparable to the PURPA-mandated procedures, and thus whether the prior action qualifies for grandfathering under EPAct. If a grandfathered plan does not exist, consideration then turns to whether it would be appropriate under the PURPA goals and applicable state law for the electric utility at issue to implement the standard or a comparable standard.

A state commission may find that while it has the authority, such a standard is unnecessary because there is sufficient competitive pressure to induce generation owners to increase plant efficiency. Others may find that while competition may drive generation owners to increase efficiency at the plants they own, this may not consider all options and all generation facilities in the state or how the plants are operated in a competitive environment over a long period. Other commissions may find that existing regulation may also be sufficient, such as state mandated or utility initiated Integrated Resource Plans.

If it is decided to require or develop utility plans to increase fossil fuel generation efficiency, then attention can be turned to how such a plan could be developed and what it should contain.

5.2.1 Plan elements and development issues

The basic elements of a plan to increase the efficiency of fossil fuel generation facilities are (1) a determination of the options that can be considered, (2) an evaluation of those options, and (3) an outline of the procedures to implement the plan. Options may range from repowering a generation unit or units to changing maintenance procedures to retrofitting new technology. The options considered should take into account the particular situation the utility's generation facilities are in, including the age of the generation facilities, recent upgrades, and maintenance history. Options should consider all operations of the facility including turbine, boiler, fuel handling and quality, and environmental control equipment. The plan should consider expected retirement of existing facilities and the construction of new ones.

The evaluation should examine costs and benefits of each option or combination of options and determine the overall cost effectiveness of each plan as compared with alternative plans. All the alternative plans or scenarios should focus specifically on how fossil fuel generation efficiency will be improved. Costs would include additional plant and equipment expenditures, additional training for plant operators, and operating costs from any plant improvements. The potential benefits to utilities are lower operating costs, fuel cost savings, and savings on other operating and maintenance costs. These savings could improve competitiveness of the generator in the wholesale market and, for regulated or public utilities, this could also mean savings to the company's customers.

An important benefit to society as a whole is the environmental benefit from reduced air emissions and water discharges, as well as the reduced environmental compliance costs for utilities (from fewer pollution permits that are required or the benefit to revenue from the sale of excess permits, for example). However, this benefit must be weighed against the possibility that upgrades to the facility may cause substantial additional cost from additional environmental requirements (that is, new source performance standards). Another important factor to consider in the evaluation and development of a plan is the impact on reliability. The options considered should include any operational changes or availability of the generation plants, either from the efficiency improvement itself or during the implementation period.

Finally, implementation of the plan should consider a timeframe to achieve the results. The standard calls for consideration of a ten-year plan, but state commissions and utilities may develop timeframes that best suit their individual situations. The more complex the plan, the more likely it will require multiple phases to reach full implementation. Contingency or alternative plans should be devised in the event the implementation of the original plan cannot be completed as expected.

5.3 Additional Resources

The potential savings to a utility for existing fossil power plants may not be trivial. The Electric Power Research Institute (EPRI) cited a 1983 utility survey of 129 fossil generation units and reported a mean heat-rate improvement of more than 400 Btu/kWh. EPRI notes that "for a typical 500-MW fossil-fueled power plant, a 400 Btu/kWh reduction in heat rate translates into $4 million in annual fuel savings."[46]

EPRI developed a reference manual on heat rate improvement that provides tools for utilities to increase fossil fuel generation efficiency. The EPRI document is described as a "manual . . . designed to be used by electric utilities as a training tool and reference book for heat rate engineers." The topics covered by the document include: heat rate basics, fossil steam station components, elements of a thermal performance monitoring program, and heat rate improvement programs. The following is a link to a web page with more information on the reference manual EPRI developed on heat rate improvement:[47]

---

[46]This is from information on EPRI's web site for its *Heat Rate Improvement Reference Manual*, which is described in more detail in the text.
[47]Link to information on EPRI report: *Heat Rate Improvement Reference Manual*, EPRI, Palo Alto, CA: 1998. TR-109546.

http://www.epri.com/OrderableitemDesc.asp?product_id=TR%2D109546&targetnid=106&value=99T067.0&marketnid=2&oitype=1&searchdate=1/1/1998
The web page includes an abstract and a link to the document. EPRI members can download the document at no charge. Non-eligible entities can purchase the report for $1500. This reference manual supplements EPRI's Heat Rate Improvement Guidelines, published in May of 1986 (EPRI report CS-4554).

6. Smart Metering

6.1. Introduction to Smart Metering

6.1.1. Statement of Amendment to PURPA: Standard 14

The Energy Policy Act of 2005 amends PURPA by adding Standard 14 (PURPA section 111(d)(14)), which requires the consideration of time-based metering and communications. The bill states:

> (A) Not later than 18 months after the date of enactment of this paragraph, each electric utility shall offer each of its customer classes, and provide individual customers upon customer request, a time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's costs of generating and purchasing electricity at the wholesale level. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.
> (B) The types of time-based rate schedules that may be offered under the schedule referred to in subparagraph (A) include, among others--
>
> > (i) time-of-use pricing whereby electricity prices are set for a specific time period on an advance or forward basis, typically not changing more often than twice a year, based on the utility's cost of generating and/or purchasing such electricity at the wholesale level for the benefit of the consumer. Prices paid for energy consumed during these periods shall be pre-established and known to consumers in advance of such consumption, allowing them to vary their demand and usage in response to such prices and manage their energy costs by shifting usage to a lower cost period or reducing their consumption overall;
> > (ii) critical peak pricing whereby time-of-use prices are in effect except for certain peak days, when prices may reflect the costs of generating and/or purchasing electricity at the wholesale level and when consumers may receive additional discounts for reducing peak period energy consumption;
> > (iii) real-time pricing whereby electricity prices are set for a specific time period on an advanced or forward basis, reflecting the utility's cost of generating and/or purchasing electricity at the wholesale level, and may change as often as hourly; and
> > (iv) credits for consumers with large loads who enter into pre-established peak load reduction agreements that reduce a utility's planned capacity obligations.

In this discussion the term "time-based rates" will be used to refer to any pricing structure that allows for prices to vary based on the time of consumption. The statute list three forms of time-based rates. The definition of each is the broad definition as cited in the statute. The following is a brief restatement of these definitions and short description of each of these time-based rates, as well as average cost pricing:

- Time-of-use pricing (TOU) – price is usually broken into two or three time blocks based on typical demand levels (peak, intermediate, and off-peak). These prices are fixed for a predetermined period. Prices are highest during the highest period of demand and lowest in the lowest period of demand. Typically, price is higher than the utility's average cost during the peak time block and lower during off-peak.
- Critical peak pricing (CPP) – This method is similar to TOU in about 95 percent or more hours every year. However, it allows the utility to increase peak prices to a substantially higher level during a predetermined number of extreme peak hours. Any load shift or forgone usage in the critical hours should reduce demand during hours when the reduced demand is most valuable and provides the greatest benefits.
- Real time prices (RTP) – Prices are provided in real time or near real time. This means consumers could receive notification of rate changes from one hour to one day prior to use. RTP requires the consumer to monitor both prices and use in much greater detail. Prices are uncertain, and therefore open the consumer to the greatest price risk. Peak periods will have higher rates than off-peak. There is no necessary correlation between RTP peak or off-peak with the utility's average cost of production. RTP peak (off-peak) prices, though typically higher (lower) than the utility's average cost, need not be.

The fourth definition in the statute, credits for consumers with large loads who enter into pre-established peak load reduction agreements that reduce a utility's planned capacity obligations, specifically refers to consumer credits to allow a utility to reduce planned capacity needs. This section of the manual focuses on the smart metering and time-based rates (the first three definitions), and does not address this fourth definition.

This standard is closely tied to the first two stated purposes of PURPA, as summarized in the first and second sections of this manual, that is, to encourage (1) conservation of energy supplied by electric utilities and (2) optimize the efficiency of electric utility facilities and resources. The goal of the statute is to allow consumers to pay prices that more accurately reflect the cost of providing the service. Time-based rates, if designed properly, are intended to provide price signals to consumers so they can make decisions on when or whether to use electricity, for consumers on the time-based rates. Reductions in peak demand can lead to reduced transmission congestion, possibly allowing lower cost imports to enter the market. Reductions in peak demand may also permit more expensive generators to run less often, and may also reduce the need for the addition of peaking capacity.

This section of the manual covers issues related to smart metering and time-based rates. It is important to note that what follows are simply issues and basic factual background information that can be considered during the evaluation of whether or not to adopt the standard and does not include any recommendations. This section also does not make any recommendations on what type of rate structure should be used, what costs should be included in rates, or what types of technology investments should be made. These issues include decision authority, the benefits and costs that must be considered when trying to determine if time-based rates are appropriate, and options that exist for states and utilities if they decide that time-based rates are a beneficial tool. This section also provides several case studies as examples of current practices or attempts at time-based rate programs.

6.2. Application

Of the five standards covered in this manual, issues and questions surrounding time-based rates are perhaps the most complex and encompassing. State commissions and unregulated electric utilities considering smart metering standards need to consider:

- That each type of time-based rate is different and may not work the same for all consumer sectors
- That if one type of time-based rate does not work, it does not mean that none of them will work
- Most of the benefits of time-based rates will be realized only if consumers respond to price signals and change their consumption patterns
- Many of the goals of time-based rates are interconnected. Goals may work in ways that are positive, negative, or undetermined with others.
- Time-based rates may only be appropriate for certain consumer sectors or utilities in some locations and the end decision may be that time-based rates are appropriate for some sectors or utilities but not for others.

The first question that must be answered is who has the authority to make the determination of the appropriateness of a time based rate pricing program. If the state commission adopts time based rates, then they must also determine what load serving entities under their jurisdiction are covered under the program. The state may also defer to individual utilities to make the determination if time-based rates are appropriate and, if so, how they can be implemented in a cost effective manner. The state or utility judging the costs and benefits of time-based rates may consider whether the program will leave consumer bills higher than they are currently. If bills increase, then it could be argued that average cost pricing provides more equitable rates. Increased bills could also lead to problems sustaining a time-based rate program over time.

The questions that states and utilities should ask, which follow, should be asked of each of the time-based rates separately. *This is a very important point.* Different time-based rates may be appropriate for different utilities and different consumer sectors within a utility. The fact that a decision was reached to reject RTP as an appropriate tool does not mean that TOU will also be inappropriate. Each method must be evaluated separately. Additionally, the questions must be asked separately for each market sector. For example, TOU must be considered separately for residential consumers and industrial consumers. Each pricing structure should be considered as an alternative means of achieving a desired goal within a sector. This process breaks down into the following matrix:

Sector/Time-based rate	TOU	CPP	RTP
Residential			
Commercial			
Industrial			

Each block within this matrix is a separate consideration. This implies that a state or utility may find that a different rate structure is appropriate for different sectors. There is no limitation that prohibits such practices in the statute. Current practices support differentiation of sectors by the different types of rates paid. For example, industrial customers may pay TOU while residential customers may retain average cost pricing.

Next states or utilities must determine what goals they hope to achieve though the use of time-based rates. Goals of time-based rates may include, but are not limited to

- Reduced total demand,
- Reduced peak load demand,
- Mitigated price spikes,
- Mitigated market power,
- Increased reliability,
- More efficient use of current capacity,
- Lower consumer bills,
- Lower energy price, or
- Reduced emissions.

When considering which objective is the primary goal, it is important to consider the potential interactions with other outcomes of pursuing that goal. For example, peak load consumption could go down. However load shifting to off-peak periods could lead to an increase in utilization of base load generators, which in turn can lead to an increase in emissions (if off-peak power is fossil fueled).

Once the goal is defined, states or utilities should also consider what other options are available to achieve the desired goal. If the goal is to reduce peak demand, then consideration must be given to traditional demand side management, demand charges, and other load control tools. If the goal is to reduce energy prices, then consideration may be given to fuel diversity and capacity planning. Again, if these goals are being looked at using RTP, then consideration should be given to how cost effective it would be versus CPP or TOU.

Utilities must be aware of their load portfolio. It is important to understand what types of consumers are present in the market. If load is made up of consumers that are willing and able to adjust their load, then there is more potential than with unresponsive load. This means that sector composition (percent residential vs. percent commercial vs. percent industrial, etc), the willingness of each sector to accept price risk, and the level of risk they are willing to accept, will determine the price responsiveness overall. Generally speaking, residential consumers have a preference for lower risk. Large commercial and industrial consumers tend to be the most responsive to dynamic prices. Large industrial consumers may have more options to curtail load and may also have the benefit of on-site generation. Industrial consumers may see benefits from time-based rates even if load is not reduced, but shifted to off-peak times.

The gain in economic efficiency also differs between the time-based rate types. Farrow (2002) states that the benefits of TOU pricing captures only 14 percent of the efficiency gains that could be captured by RTP. Since CPP is somewhat of a hybrid of TOU and RTP, it is reasonable to assume that the benefits will also fall between TOU and RTP. However, O'Sheasy (2002) says that time-based rates are probably appropriate for less than 1 percent of all customers, but these customers make up 35 percent of the demand.

6.3. Benefits to consider

The benefits of a time-based rate program may vary across utilities, municipalities, cooperatives, consumer sectors and the various time-based rates. The benefits may include the following:

- Mitigated price spikes in the cost of power purchased in wholesale markets
- Mitigated market power, which limits the ability of a single supplier or group of suppliers from sustaining prices higher than they would be in a competitive market
- Increased reliability
- Environmental benefits from reduced total consumption
- Reduced energy prices and/or lower consumer bills
- Reduced operational costs for utilities

These benefits are only realized if consumers significantly reduce their demand in response to price signals. Analysis must be done to determine if these benefits can be attained in a more cost effective manner using alternative means. Even small reductions of consumption in peak period can reduce price spikes, reduce market power, and increase reliability in peak periods. Some of these benefits work in accord with others, while the interaction with others is undetermined. For example, reduction in peak load demand can mitigate potential market power through reduced congestion. The reduced congestion also could have the benefit of lowering peak price over time by allowing less expensive imports to supply the power needs of an area. Congestion on transmission lines can lead to increased risk of line outages. As peak load demand is reduced reliability generally increases. This means fewer outages and increased reliability.

If the overall use of electricity decreases then levels of emissions from fossil fuel-generated electricity may also decrease, creating positive externalities to load reduction. However, if large industrial consumers have on-site generation that they use to respond to high prices, this could be less environmentally friendly (higher emissions per kWh produced) than the utility-owned generator, then there are potential negative externalities. The environmental impact of small generators may be negligible to any single region, but the potential overall impact should be considered. Additionally, load shift to off-peak hours can mean that consumption may actually increase in total or that coal generation is used to serve a greater portion of load when the load is shifted from peak to off peak. These shifts could lead to increased emissions levels.

6.4. Costs to consider

Along with any of the benefits that can potentially come from time-based rates, there are costs that need to be considered. Costs that should be considered include, but are not limited to:

- Investments in meters and other infrastructure, added administrative costs
- Technology and data collection upgrades
- Support for technology and data analysis,
- Consumer education and customer service and
- Costs to consumers in the form of inconvenience, price risk, or production interruption.

Before implementing a real time pricing program it is also important to determine who will bear the costs. These costs may vary across utility and consumer sectors based on levels of participation, population density, geographic region covered, and the time-based rate being considered.

Traditional meters do not possess the level of technical sophistication required to implement time-based rates. Therefore meters must be retro fitted or replaced with more sophisticated meters that are able to gauge the time that electricity is consumed. There will be additional installation costs for new meters. These costs can depend on the meter technology, method used to roll out the new meters, population density, and meters per site. Sites with multiple meters or sites that are close together can be done quickly relative to sites that have single meters or sites that are more dispersed. Installation fees may be lower in urban areas than rural areas. If there are efficiency gains from a uniform rollout, then these gains should be weighed against the cost of installing meters that will not be used for real time pricing (consumers that opt out of the programs). Beyond the cost of meters, utilities may also be forced to invest in additional infrastructure depending on the communication and data collection technology they select. For example, if the utilities select cellular technology, they may be required to build cell towers to transmit the signal. Costs of such investments may be lower per consumer in urban areas than in rural areas.

States and utilities also need to consider the administrative cost that will be required to support and promote a time-based rate program. Costs of processing data may increase due to increased volume of data, but the price of data collection may decrease due to automatic meter reading (if such technology is adopted -- and had not been previously installed by the utility) sending the data directly to the computer.

States and utilities will also have to educate and inform consumers. This is for the benefit of all parties, but the cost of doing so should be considered. Utilities may also have to have the capability to deliver data to consumers via interactive internet services so that consumers can track electricity prices. There may also be a need for increased customer service to respond to problems

Residential consumers will generally face costs that are different from others they are familiar with in the electricity industry. The consumers may be exposed to greater price risk under time-based rates. Consumers are exposed to the most price risk under RTP, then CPP, and finally TOU. These risks can be mitigated by altering consumption behavior. In order for time-based rates to be successful, consumers will need to monitor and change their behavior in response to the prices that are given. This increased monitoring by consumers will almost certainly create inconvenience costs. The inconvenience could be a matter of the consumer not being able to do what they want when they want (turning on the air conditioner during the middle of the day on a day off from work) or being forced to do what they want when they don't want to do it (i.e. running the dishwasher in the middle of the night as they try to sleep). If time-based rates provide consumers benefits in the form of cost savings, then they require this savings to exceed any cost they have incurred from inconvenience. If consumers view the inconvenience to be too great, time-based rates may not be sustainable.

Industrial or commercial consumers may face costs from restrictions on their output. During extreme price spikes, some industrial consumers may shut down production when the cost of energy as an input to their process makes their output relatively expensive compared to their competitors. This would require shutting down machinery and sending the work force home. Commercial consumers may be forced to turn off air conditioning which may lead to worker discomfort and loss of productivity or dissatisfied clientele.

The indirect costs described above (that is, inconvenience to residential customers, worker discomfort, etc.) will affect customer acceptance of and response to new time-based rate designs. This effect on customer price-responsiveness should be considered in the evaluation of benefits of time-based rates.

Other issues that should be considered when judging the appropriateness of time-based rates include:

- Load serving entities with generation will be forced to consider how their generating units will be affected by reduced demand. They will also need to determine how this portfolio fits with the changing demand. They must decide if their portfolio is still the optimal means for providing power to their consumers or if they should seek contracts from other suppliers.
- For generators to determine their long run position, they should consider how their asset portfolio, total output, and the price they receive for the output are affected.
- If load is shifted from peak to off peak, this may cause prices in off-peak hours to increase slightly. Any price reduction in peak prices

should be measured against increases in off-peak hours from load shift.

The benefits and costs of each type of time-based rate for each consumer sector can be used to determine whether or not time-based rates are appropriate for a state or utility. It is a minimal requirement that the benefits of achieving goals should outweigh the costs. Beyond this, it is also important that these goals are reached using the most cost effective tool. The ability to trade lower peak demand for additional generation should be a factor when determining the reliability benefits of time-based rates. If it is not possible to site new generation or transmission, then perhaps some sort of demand reduction can offer similar benefits. It is also important to consider that no class or sector is subsidizing another class or sector. Consideration may be given also to each sector's impact (in aggregate) in terms of benefits or losses.

When attempting to determine what, if any, time-based rate plan is appropriate, the costs and benefits listed above should be considered along with any location specific issues by all parties involved. It is not clear if any single party benefits more from time-based rates than another in the long run. As discussed above, consumers can benefit from low prices, but potentially with greater inconvenience. Producers may benefit through more efficient use of current generation, but they may receive lower prices for that generation. Load serving entities without generation may benefit from being able to fully capture cost of acquiring electricity in wholesale markets and receive accurate value for the electricity sold.

Ultimately, consumers on time-based rate plans will have greater control over their bills and can benefit through direct response to prices. Those that are not on dynamic pricing may also receive lower costs from retailers' ability to provide lower prices to all consumers. However, decreases in revenues to generators may lead to a decrease in investment or forgone entry by new competitors.[48]

---

[48] Ruff (2002) warns that generators will regain their position in the market, which may actually be more concentrated. He says prices may actually be more

If a state or utility determines that time-based rates are appropriate then the specific details of the program must be developed. These details include: what metering technology to use, what communication technology to use, how to enroll consumers, what tariff is appropriate, and how consumers can hedge against price risks.

6.5. Implementation

Development of a time-based rate programs requires a great deal of consideration of technology. Such programs will require utilities to invest in meters, data collection and handling tools, communications devices, other infrastructure, and supporting technologies. Currently, there are numerous options for each of these technologies, each of which has different associated costs and advantages. If costs are to be recovered as part of the time-based rates, then there must be an explicit statement of the manner in which cost of such investments are covered and by which parties. If the cost is covered through the use of an additional charge to consumers, then the amount of the charge and the manner in which the consumer is billed must be determined. Options for addressing metering costs include allowing the utility to include an additional connection fee for the meter, including the costs in rate base in the next rate case, or having the utility absorb the costs in the short run, provided the utility can actually recover the metering costs from the expected long-run savings. Considerations should be made for the cost of implementing a given technology as well as the benefits in terms of cost savings and maintenance.

First, utilities using time-based rates must determine which meter technology to employ. Meters can collect and provide data in several ways. Meters can be selected based on the level of data required and the frequency at which it is required. RTP may require meters that register data at all times, while TOU may require meters that only measure consumption for two or three time

---

volatile in the long run and that consumers will not benefit at the cost of producers. He states that "when making policy for the future, the best bet is that consumers will pay all costs in a long run … and suppliers … will rationally plan for and respond to an increase in demand response."

periods. Though traditional meters are not currently able to support time-based rates, they can be retrofitted to accommodate various rates. Prior to the California Statewide Pricing Pilot (SPP) Program (discussed in greater detail at the end of this section) a survey was conducted which contained detailed information regarding minimum requirements for metering and communication systems to implement various time-based rate programs.[49] Appendix C contains a reproduction of tables 7-1 and 7-2 from that report.

Smart meters can register the time during which consumption or supply took place, and thus can facilitate time-based rates. Smart meters can be utilized in a variety of different ways that can improve communication and demand response through active monitoring and data collection.

Once the utility decides on a meter technology, it must decide what communication technology to use to collect the data. Data collection can be conducted in numerous ways. Automated Meter Reading (AMR) technology allows utilities to send signals from the meter to the base and collect data without human interaction. Manual meter reading can be performed with technology such as scanners and automatic downloads to a hand-held computer. Manual and automated meter reading are both capable of functioning with TOU, CPP, and RTP.

Communication technology can also be used to notify consumers of price fluctuations. This can be done by telephone, beeper, internet, or through the use of signals to enabling devices. Enabling devices are small instruments that can be attached to most major appliances in the consumers' homes, such as an air conditioner or water heater, which allow the utility to send a signal that reduces the demand of the appliance during peak periods. These communication systems can be closed (only read on-site), one way (out to consumers only or in from consumers only) or two way (in from and out to consumers). More complex

[49] "Proposed Pilot Projects and Market Research to Assess the Potential for Deployment of Dynamic Tariffs for Residential and Small Commercial Customers." Available at http://www.energy.ca.gov/demandresponse/documents/working_group_documents/2002-12-10_WG3_REPORT.PDF

systems have higher installation and maintenance costs, but the more advanced systems may also allow for faster data processing and response.

Various enrollment strategies can be utilized. Each enrollment plan can have different impacts on consumers and utilities. Depending on the fashion in which enrollment is handled; the burden of action can shift from consumers to providers. Enrollment can be mandatory, voluntary, or by default.

- Mandatory enrollment – This requires all consumers in the selected sectors to participate in time-based rates programs. There are no other rate plan options available to the consumer. Economic and political feasibility must be considered. It is likely that such an approach will not garner a great deal of support.
- Voluntary enrollment – This allows the consumer to opt into a time-based rate program. A concern with voluntary enrollment is that only those that are interested in attempting to change their usage patterns will enroll, creating a self-selection bias or that it might attract consumers that already have most of their demand in off-peak periods (Center for Energy, Economic & Environmental Policy, 2005) or other customers who had higher rates then they would have under a time differentiated pricing scheme. These consumers would see lower bills, but would provide no additional benefits to the system. These types of biases prevent consumers form seeing the full benefit of the program as they will continue to subsidize those that are not reducing demand.
- Default enrollment – This enrolls consumers automatically, but gives the consumer the ability to opt out of the program. This process may not be well received by all consumers as it may force them to take actions they may feel are unnecessary. The benefit of this method is that consumers may attempt to alter their demands before opting out. However, if this does not happen, the same problems may exist as with voluntary enrollment. That is, customers will self-select into the rate category that lowers their own costs without changing their behavior.

A smooth transition into these approaches can be implemented through the use of simultaneous billing over several months. A consumer with a smart meter would receive two bills: one that shows charges using the old rate and another that shows the charges using time-based pricing. Eventually this billing method will stop and the enrollment approach will take place.

Another important issue that must be determined is the form of rate structure. If TOU or CPP are chosen, then the difference between peak and off-peak pricing may be the difference between success and failure of a program. If prices are too low in peak periods, then consumers may not alter behavior; if they are too high, then consumers may not want to participate in the program. If CPP is the selected tool, then a decision on how many critical periods can be called in a year can have similar effects.

States and utilities must also decide what costs are to be included in the rates. There are different methods that retailers have used in dynamic pricing plans. Two methods are the two part tariff and a consumer base line (CBL) with protection contracts. The two part tariff typically consists of a component for transmission and distribution,[50] which is fixed or based relative to a consumer's portion of peak load, and another component for energy that would vary based on time. The CBL is a type of two part tariff with the first part of the tariff based on the historic demand or otherwise negotiated demand level, and a second part based on use relative to the CBL. If the consumer goes over the CBL, they are exposed to market prices. If they are under the CBL, they receive a credit.[51]

---

[50] These charges are often referred to as demand charges. Demand charges for large industrial consumers may also contain a generation fee. Borenstein (2001) argues that demand charges attempt to distribute the costs of a common good and do so in an improper manner. He claims that generators and investments are a common good to produce peak and off-peak electricity and that the demand charges attempt to allocate costs of the common good into each category. Boisvert and Neenan (2003) say that the two part tariff is not what economists had in mind and that they "seem to affect customers' willingness to participate and to adjust electricity use in response to price change."

[51] Agreements can be set up to determine the rates at which the credits are exchanged for over-use, often called "contracts for differences." Borenstein (2005) shows how these contracts can reduce wealth transfer for consumers.

When determining which option works best, regulators and utilities may want to consider the difference between utilities and consumers, how a baseline would be established, and what costs can be included in these prices.

6.5.1. Price Risks

Because dynamic pricing methods attempt to tie consumer rates to wholesale prices, consumers may fear increased bills. Though this may be a greater concern with RTP than with TOU and CPP, consumer perception should be the key concern. It is feasible that products or contracts can be introduced that will allow consumers to balance their risk, however, these products are not currently in place. If contracts for risk hedging become available, it is important that they be easy for residential consumers to understand. Mechanisms similar to average cost pricing could be offered to certain consumer sectors. However, utilities and regulators should recognize that these types of products – if mandated – will, by their inherent design, blunt the effect of time-sensitive pricing to retail customers.

Consumers also face risks of price discrimination with time-based rates. Current practice allows for difference between sectors. However, with time-based rates, prices should not differ within a sector. This is an equity concern. Additionally, the impact of time-based rates on low income households should be considered.

6.6. Current Practices

6.6.1. Dynamic Prices – Case Studies

Several case studies have been performed on the few large programs in the U.S. with active and large enrollments. What follows are the results of selected studies. These studies offer levels of demand response, price elasticities, successes and shortcomings. They differ based on regulatory structure of the state, customer type participation, pricing method used, and size. For more information and greater detail, a citation is provided for each report.

6.6.1.1. US Survey

Barbose, Goldman, and Neenan (2004)[52] conducted a survey of utilities that offered some form of RTP. What follows are some of the important findings and conclusions of this survey. At the time of the survey, 70 firms offered some type of RTP pricing, of which 43 were surveyed. The primary reasons cited for utilities offering such programs fell primarily into one of two categories: increase customer satisfaction and loyalty, and reduction of peak demand. Many of the utilities surveyed focused on efforts of large industrial customers. One third of the program required participants to have a peak demand greater than one MW. This essentially eliminates residential participation in these programs. Only three utilities had over 100 participants or 500 MW of demand. This accounted for 80 percent of all participation, while 30 percent of the programs had zero participation. Many of the utilities claim to not actively market, promote, or educate consumers about these programs. Many of the participants, particularly the most responsive, had some sort of on-site generation. Barbose et al found there was little quantitative analysis on actual demand response to RTP. From the information they found, in programs with ten or more participants, between 20 to 60 percent of the participants responded at prices of $0.20/kWh, while other participants did not respond until prices reached $0.80/kWh. Of the participants responding, the most common means of reducing load were "primitive methods" such as load shifting or using on-site generation. Only two utilities saw reductions of greater than 100 MW and only one saw reductions greater than one percent of its total peak demand. Currently, utilities are seeing overall participation decrease. Over half of the programs have lost a quarter of their participation and only two have seen participation increase.[53] They also found that 30 percent of the utilities are in the process of phasing out RTP programs. Barbose et al. offer several policy implications from this study. This report also

[52] Available at http://certs.lbl.gov/PDF/54238.pdf
[53] It is not clear what whether these increases occurred as part of the California RTP pilot or if they occurred independently.

offers greater detail on the specific utilities that participated in the survey. The appendix of the Barbose et al.report contains a brief case study of each.

6.6.1.2. Georgia Power

The Georgia Power Company (GPC) has been operating a real time pricing market for large industrial and commercial customers. The demand response can be as much as five percent of GPC's total load. The program offers day-ahead and hour-ahead notification of the RTP. There is a $155/month charge for customers over 1,000 kW and $175/month for those smaller than 1000 kW for day-ahead participants. The fee is $850/month for the hour-ahead and is only available to consumers larger than 5,000 kW. Braithwait and O'Sheasy (2002) provide a study detailing response rates and price elasticities of the enrolled customers. At the time of the Braithwait and O'Sheasy article, the GPC program was eight years old and had over 1,600 enrolled customers totaling over 500 MW of subscribed demand. GPC uses a two part tariff with a consumer baseline (CBL) based on historic use. The first part of the tariff is set up as a fixed fee based on standard tariff prices, which in turn is based on their CBL. The second part of the tariff is calculated based on deviations from the CBL. Braithwait and O'Sheasy say "[C]ustomers effectively pay hourly prices for all of their energy consumption, but receive a financial hedge against volatile prices in the form of a *contract for differences*, or a 'swap' contract, in which they are guaranteed to pay no more than their standard tariff for their CBL." This means when the consumer under-consumes relative to their CBL, they have an agreement that credits the lesser consumption, and this credit can be traded for times when the consumer over-consumes. Charges and credits are granted at the utility's marginal cost. When the consumer is over their CBL, they are subject to full RTP price; however, GPL offers products to insure against extreme price fluctuations.

Braithwait and O'Sheasy studied the effects of price spikes during the summer of 1999. The objective was to determine the response rates of various types of consumers with RTP when faced with these spikes. Previous to the 1999 spikes, prices for RTP consumers in peak hours averaged $0.20/kWh to

$0.40/kWh. The prices in 1999 averaged $0.40/kWh to $0.50/kWh. This provided data on new and more extreme price levels. The consumer response was found using the difference between an expected load, or what the authors refer to as a "reference load," and the actual load. The overall response of large industrial consumers in the hour-ahead market was 30 percent for moderate priced days (average price between $0.20/kWh to $0.35/kWh), and up to 60 percent on high priced days (average price greater than $0.35/kWh). Braithwait and O'Sheasy equate the later to approximately 250 MW of load relief. The large industrial consumers in the day-ahead market offered a reduction of 10 percent in moderate price days (average price greater than $0.28/kWh to $0.35/kWh), and 25 percent on high priced days (average price greater than $0.35/kWh). This response was estimated to be approximately 500 MW of relief. Elasticities also varied by consumer group and price. The level of response varied by price and increased as price increased. Most of the additional response came from industrial customers. They also found that consumers with on-site generation were the most price responsive. The percent of customers responding to RTP ranged from 40 percent for smaller commercial customers to 80 percent of large industrials with on-site generation.

6.6.1.3. Niagara Mohawk

In October 1998, Niagara Mohawk Power Company (NMPC) offered an RTP program to large industrial and commercial customers. Their program recovered transmission and distribution charges through demand charges, while the electricity portion of the bill was indexed to the day-ahead prices in NYISO. Hopper et al conducted two survey studies (2004[54] and 2005[55]) of the level of price response and strategies used to achieve these responses. The following section details the finding of these two studies.

The NMPC program was unique in that it was the first program to make RTP the default service and not a voluntary opt-in program. Customers were

---

[54] Available at http://eetd.lbl.gov/ea/EMS/reports/NMPC_LBNL_54761.pdf
[55] Available at http://eetd.lbl.gov/EA/EMP/reports/57128_app.pdf

given two options. They could take RTP (Option 1) or sign up for a TOU based fixed rate contract (Option 2). The program was offered separately from any NYISO demand response programs, but customers could sign up for both independently. Both studies found consumers to be generally happy with the program. Though many consumers were not hedged, a fair number were. They primarily used a physical supply contract with flat or TOU rates. Hopper et al state that "hedging options were limited."

Hopper (2004) found that the overall price response was "modest overall, but individual customer response is extremely variable." Of the respondents, 51 percent were unable to curtail use, 30 percent choose to forgo use, and 15 percent shifted load. Hopper (2004) found the substitution elasticity to be 0.14 on average. The elasticity was highest for government and educational facilities (0.30), then industrial (0.11), and last was commercial (0.00). Hopper (2005) finds that manufacturing consumers are fairly price responsive. However, they say that individual manufactures are either extremely responsive or not responsive at all. Hopper (2004) also found that at a reference price of $0.50/kWh demand response would be approximately 100 MW. Industrial consumers were more responsive to the NYISO programs than they were to the RTP. Specifically, consumers with on-site generation were more responsive than those without, though the difference was not statistically significant in this study. On average, peak prices were significantly higher, but the off-peak volatility was lower.

Response methods were "low tech" methods to reduce load. Generally limiting discretionary use was used to reduce load more than shifting. Hopper (2004) states that 90 percent of the curtailing potential is achieved at $0.50/kWh. One counterintuitive finding was that investment in enabling technology actually yielded less responsive demand. However, Hopper states that though enabling technology may not be necessary for short term price response, it may be needed to sustain the response. Hopper (2005) states that long period of hot weather and high prices could lead to fatigue.

In the end, Hopper (2004) concludes by saying:

> [S]ubjecting customers to wholesale market variability is not sufficient to realize their full demand response potential. DR programs that target payments to specific market conditions that arise after day-ahead prices have been posted provide supplemental load curtailments that produce significant benefits. The debate should not be focused on the choice between these designs, but on how to use both to best advantage.

Hopper (2005) states that the goals of RTP and ISO DSB programs enhance the overall load reduction and need to be considered together.

The barriers to response in the market were too little time of notice, inadequate incentives, and production risks. Hopper (2005) claims that policymakers "should expect that about half of large customers cannot or may have no intention of becoming affirmatively price responsive, regardless of whether alternatives to day-ahead pricing are available to them." In addition, while consumers have been generally happy with RTP using a day-ahead index, many would opt out of the program if prices were indexed to the hour-ahead prices. This is similar to the results found in New Jersey where 84 percent of customers switched out of the program.

6.6.1.4. California

Following the California Energy Crisis of 2001, regulators and legislators authorized a pilot study to test the level of demand response using various dynamic pricing schemes on residential and small industrial and commercial consumers. The study was conducted from July 2003 through December 2004. The results were analyzed and summarized by Charles River Associates (CRA, 2005). This section will highlight some of the important findings from this study.

The Statewide Pricing Pilot (SPP) was run with the three main investor-owned utilities: Pacific Gas & Electric (PG&E), SoCal Edison (SCE), and San Diego Gas & Electric (SDG&E), and the two regulatory commissions. The program was funded by the state of California and had 2,500 participants. The program utilized three types of pricing including one type of TOU and 2 types of

CPP. CPP-F had fixed critical peak period and day ahead notification, while CPP-V had variable peak critical periods and day-of notification. CPP-V consumers were also given the option of an enabling device free of charge. CPP-V was only run in the SDG&E service area. An information only study was also run to see if consumers would reduce peak load use without price signals. There was limited success in 2003, but these reductions were lost by 2004. CRA concludes that load response is not sustainable in the absence of price signals.

The statewide reduction of peak period load for residential customers under CPP-F was 13 percent. This reduction differed from the cooler north (7.6 percent) to the warmer south (15.8 percent). The level of reductions was consistent across summers. The impact on critical days was greater in the summer months than in non-summer months. Households with central air conditioners were more responsive than those without. Reductions continued at higher prices but at a decreasing rate. CRA asserts that much of this response is attributable to reduced use of air conditioners. TOU saw reductions in 2003, but these reductions disappeared in 2004. CRA warns that the sample for TOU size is small, and any statistical significance is limited. However, they also state that if the results are accurate, then the prices tested did not yield sustainable results. The CPP-V participants were broken into two tracks. Track A was chosen from consumers with average summer demand of greater than 600 kW. The sample population had a high rate of air conditioning saturation and was given the option of free enabling technology (about two thirds accepted). Track C participants of a previous run smart metering pilot, therefore they all had smart meters. Track A participants showed a reduction of peak load of 16 percent, while Track C reductions were 27 percent. CRA attributes about two thirds of Track C's reduction to enabling technology.

The commercial and industrial (C&I) study was run only in SCE using CPP-V (using Track A and C as above) and TOU. Consumers were broken down based on size. In CPP-V Track A, small C&I reduced peak period demand by 6 percent, while large C&I reduced peak period demand by 9 percent. CPP-V Track C had small C&I consumer reduce peak load demand by just over 14 percent and large consumers reduced peak load demand by almost 14 percent, with 80 percent of this being attributable to enabling technology. TOU participants saw no reduction for small C&I in 2003, but saw reductions of 7 percent in 2004. Large C&I had reductions of 4 percent in 2003 and 8.6 percent in 2004. However, due to small sample size, CRA advises that these results be viewed cautiously.

As part of the pilot, annual analysis was also performed. These reports, as well as the one summarized above and many other reports on demand response in general can be found at http://www.energy.ca.gov/demandresponse/documents/index.html#metering

6.6.1.5. Puget Sound Electric

In 2001, Puget Sound Electric (PSE) introduced a TOU retail pilot program. The program enrolled 600,000 customers in the first six months. However, PSE terminated the program in July of 2003. In a report filed with Washington Utilities and Transportation Commission (WUTC), PSE terminated the program due to a negative cost benefit assessment.[56] Using a "Cost-Effectiveness Model," Charles Rivers Associates determined that the program was not sustainable. Approximately 90 percent of consumers saw higher bills in the first six months of enrollment, and 10 percent then opted out of the program.[57] It was determined that consumers were paying more under TOU rates then they would have under flat rates. The WUTC staff report that "excluding PSE's program costs, there are net benefits." The report speculates drought in the northwest U.S. and poor rate structure to be among the reasons for failure. The program did show load reduction of about 5 percent. The WUTC staff feels there are still potential benefits from CPP that may warrant additional consideration.

---

[56] The filing is available at http://www.wutc.wa.gov/webimage.nsf/0/c8c53dde0bdefc8088256d1f0067e8f1/$FILE/Time-of-Use%20Compliance%20filing%20.pdf

[57] http://www.newsdata.com/enernet/conweb/conweb83.html

6.6.1.6. Others

The above case studies are only a sample of the total case studies available. They have been selected as a sample of recent case studies. However, there are numerous case studies that offer additional insight into the results of empirical studies of dynamic pricing schemes. Barbose et al (2005)[58] offers a comparative study of eight RTP programs.[59] In this study, the authors lay out the regulatory structure and the basic program features. They also offer several policy implications. Farrow (2002) briefly covers programs in Oregon and San Diego and provides additional research on GPC. Chung, Lam, and Hamilton (2002) also provide research on programs in Washington and Oregon as well as British Columbia. In 1984, the Journal of Econometrics released an entire issue dedicated to studies of the dynamic pricing of electricity. In this journal, Aigner (1984) summarizes ten studies (many of which are contained in the same issue) on TOU pricing.

6.7. Additional Resources

Borenstein, Severin. "Frequently Asked Questions about Implementing Real-Time Electricity Pricing in California for Summer 2001," March 2001. Available at http://www.iasa.ca/ED_documents_various/Borenstein03.pdf

Borenstein, Severin. "Wealth Transfers from Implementing Real-Time Retail Electricity Pricing," August 2005. Available at http://www.ucei.berkeley.edu/PDF/csemwp147.pdf

Borenstein, Severin, Jaske, Michael, and Rosenfeld, Arthur, "Dynamic Pricing, Advanced Metering, and Demand Response in Electricity Markets," October 2002. Available at http://repositories.cdlib.org/cgi/viewcontent.cgi?article=1005&context=ucei/csem

California Energy Commission, documents related to the Demand Response Proceeding:

[58] Available at http://eetd.lbl.gov/EA/EMP/reports/57661.pdf

[59] This study cover programs in New Jersey, Maryland, Pennsylvania, New York, Illinois, Ohio, Oregon, and Georgia.

http://www.energy.ca.gov/demandresponse/documents/index.html#metering

Commission for Energy Regulation, "Electricity Tariff Structure Review: International Comparisons," CER/04/101, March 9, 2004. Available at http://www.cer.ie/cerdocs/cer04101.pdf

Holland, Stephen and Erin T. Mansur. "Is Real-Time Pricing Green?: The Environmental Impacts of Electricity Demand Variance" UCEI Working Paper August 2004. Available at http://www.ucei.berkeley.edu/PDF/csemwp136.pdf

Huntington, Hillard G. "Market Based U.S. Electricity Prices: A Multi-Model Evaluation," in *Electricity Pricing in Transition,* Edited by Ahmad Faruqui and B. Kelly Eakin, Boston, Dordecht/London: Kluwer Academic Publishers, 2002.

Irwin, Sharon and Waeckerlin, Eric, "Demand Response Program Summary," http://www.westgov.org/wieb/meetings/crepcfall2002/briefing%20materials/dr_VI.pdf

PJM Interconnection Market Monitoring Unit. "2004 State of the Market Report," March 2005. Available at http://www.pjm.com/markets/market-monitor/som.html

Ruff, Larry. "Economic Principles of Demand Response in Electricity," October 2002a. Available at http://www.ksg.harvard.edu/hepg/Papers/Ruff_economic_principles_demand_response_eei_10-02.pdf

Ruff, Larry. "Demand Response: Reality Versus 'Resource'," *The Electricity Journal*, Volume 15, Issue 10, December, 2002b. pp. 10-23.

U.S. Department of Energy, "Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005," February 2006. Available at http://www.electricity.doe.gov/documents/congress_1252d.pdf

7. Interconnection

7.1. Introduction to interconnection

7.1.1. Statement of Amendment to PURPA: Standard 15

The Energy Policy Act of 2005 amends PURPA by adding Standard 15 (section 111(d)(15) of PURPA), which requires the consideration of interconnection standards. The bill states:

> Each electric utility shall make available, upon request, interconnection service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term `interconnection service' means service to an electric consumer under which an on-site generating facility on the consumer's premises shall be connected to the local distribution facilities. Interconnection services shall be offered based upon the standards developed by the Institute of Electrical and Electronics Engineers: IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems, as they may be amended from time to time. In addition, agreements and procedures shall be established whereby the services are offered shall promote current best practices of interconnection for distributed generation, including but not limited to practices stipulated in model codes adopted by associations of state regulatory agencies. All such agreements and procedures shall be just and reasonable, and not unduly discriminatory or preferential.

This section of the manual will address issues that regulators and unregulated utilities may consider when determining whether to implement interconnection standards. It is important to note that what follows are simply issues and basic factual background information that can be considered during the evaluation of whether or not to adopt the standard and does not include any recommendations. This section also does not make any recommendations on whether to adopt any standard or practice in use by other agencies. This section discusses briefly what the Institute of Electrical and Electronics Engineers (IEEE) Standard 1547 (hereafter 1547) is,[60] what interconnection standards offer different parties, some current practices and procedures, and issues regarding the terms of the interconnection agreement.

---

[60] The IEEE standards can be purchased at http://shop.ieee.org/ieeestore/Default.aspx

7.2. IEEE 1547

IEEE 1547 is a creation of a massive collaboration between engineers, regulators, utilities, and numerous other industry experts. The collaboration is still on going. For this reason the language of the EPAct is intentionally flexible. The EPAct standard states that the interconnection shall follow 1547 as it is updated and amended. On-site generation that is interconnected to a utility system must meet the technical standards incorporated in 1547 to ensure that the addition of their generation to a utility's system will not have negative impacts on safety, power quality, or reliability.

IEEE 1547 provides tools "to help utilities tap surplus electricity form alternative sources..."[61] The guidelines established in 1547 are designed to protect all parties connected to the grid. This includes utility workers conducting routine maintenance, consumers' homes in the event of a power surge, and the grid as a whole to prevent overloading. These standards are designed to facilitate "small" generating resources, defined generally as resources smaller than 10 MVA aggregate capacity, in obtaining access to the grid in a manner that protect the grid from these small resources.

The standards of 1547 aim to "provide the minimum functional technical requirements universally needed to help ensure a technically sound interconnection," but additional tests and requirements may be required under certain local conditions.[62] Currently 1547 has six additions (1547.1 - 1547.6) that may expand 1547, but are not yet part of the final 1547 standard.[63] The standards established in 1547 will be reviewed and amended to maintain an effective standard.

7.2.1. Interconnection benefits

Basso and Friedman (2003) offers several benefits that small local resources, or distributed resources (DR) may offer for the future. They state that

---

[61] Available at http://www.nrel.gov/docs/fy03osti/34882.pdf
[62] Basso and Deblasio, Available at http://www.nrel.gov/docs/fy03osti/34882.pdf
[63] An outline of these standards is available at http://grouper.ieee.org/groups/scc21/dr_shared/

DR offers "options for utilities that range from a physical hedge against purchased power to alternatives to transmission and distribution system upgrades or construction." They project that DR will account for 10 percent of new capacity addition over the next twenty years. They believe that the lack of such interconnection standards has acted as a real barrier to widespread use of DR technologies. Other potential benefits to the grid noted by Basso and Friedman include, but are not limited to, reduced electric line loss; grid/EPS investment deferment and improved grid/EPS asset utilization; improved reliability; ancillary services such as voltage support or stability, VARs, contingency reserves, and black start capability. Other benefits that consumers may receive, under appropriate circumstances, include clean energy, lower-cost electricity, reduced price volatility, and greater reliability and power quality. Kropski et al. state that "these technologies can provide increased efficiency, availability, and reliability; better power quality; and a variety of economic and power system benefits."

7.3. Process and other practices

There are guidelines that currently exist that make use of the standards in 1547. These practices include National Association of Regulated Utility Commissioners (NARUC) in the "Model Interconnection Procedures and Agreement for Small Distributed Generation Resources,"[64] the Nation Rural Electric Cooperative Association's (NRECA) "Distributed Generation Interconnection Toolkit,"[65] and FERC's "Small Generator Interconnection Rule."[66] These procedures and agreements govern concerns such as liability, costs allocation, study procedures and timing, dispute resolution, and many other issues that may arise when attempting to interconnect a local generator to the grid.

---

[64] Available at http://files.harc.edu/Sites/GulfCoastCHP/Publications/ModelInterconnectionProcedures.pdf

[65] Available at http://nreca.org/PublicPolicy/dgtoolkit.htm

[66] Available at http://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp

7.3.1. Application process

The application process is different for each the standards. NRECA, NARUC, and FERC all propose slightly different standards, but the procedures for receiving approval for interconnection are roughly the same for all standards. Figure 7.1 is taken from NRECA's "Business and Contract Guide for Distributed Generation (DG) Interconnection (p5)."[67] This document provides an overview of the process for NRECA.

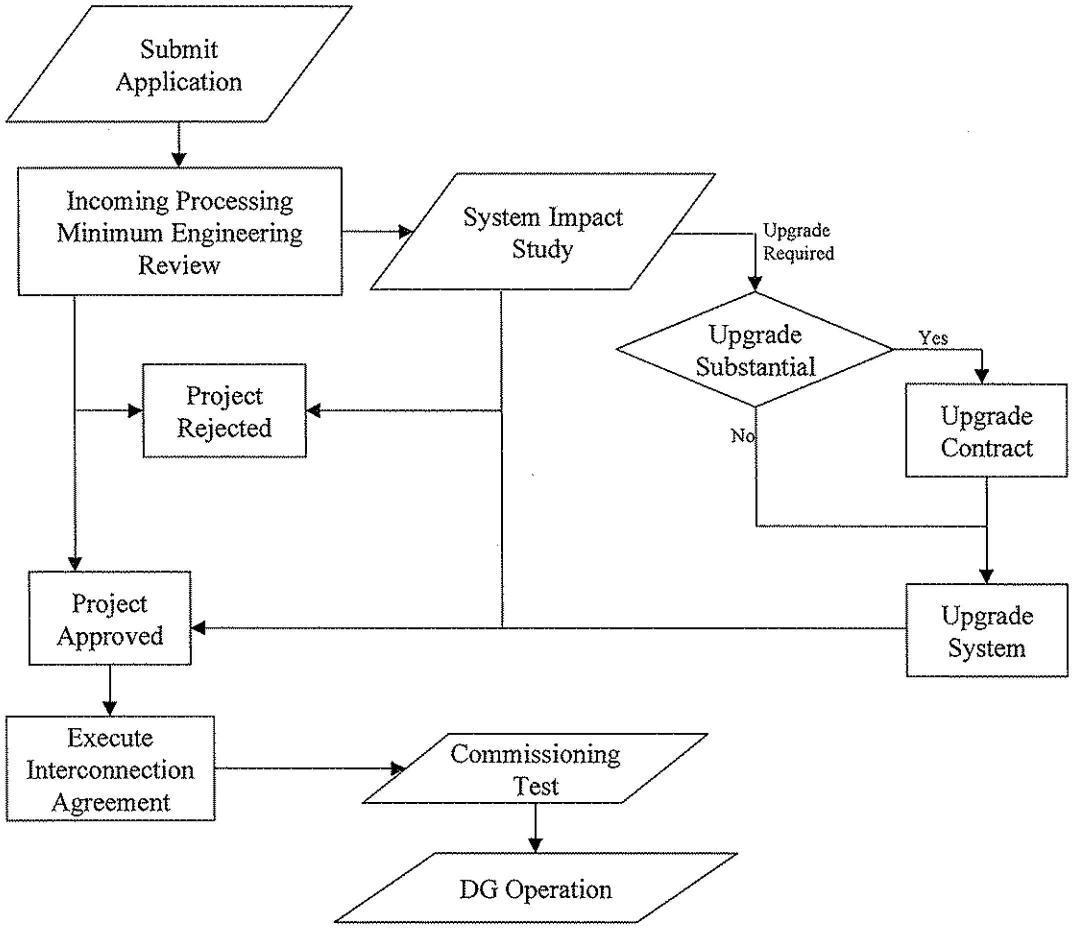


Figure 7.1. The NRECA application process for DG.

[67] Available at http://nreca.org/PublicPolicy/dgtoolkit.htm

Typically, generators must also include in these application procedures system studies, interconnect studies, any other relevant information regarding the generator and equipment, screens that check the circuit, generator size, aggregate of distributed resources on the grid, and various other technical requirements. There may be multiple screens. A DG Unit can be approved for interconnection on a case by case evaluation.

7.4. Terms of interconnection

The NARUC's Model Interconnection Procedures and Agreement for Small Distributed Generation Resources offers a sample agreement for interconnection. This document (which follows the application forms and a flow chart of the overall process) details the responsibilities of parties, liabilities, indemnifications, insurance, and terms of disconnection and severability.

As the Model Interconnection Procedures and Agreement for Small Distributed Generation Resources states, interconnection practices "shall be just and reasonable, and not unduly discriminatory or preferential." This may imply a need for regularity in certain terms from customer to customer, while other terms may differ based on the site specific characteristic. However, most current interconnection agreements allow for the utility to recover the reasonable costs that they incur while providing interconnection services. These costs can include labor, interconnection studies, overhead, meter installation, and any other required equipment. These terms supports PURPA's third goal to encourage fair and equitable rates.

7.5. Additional Resources

Federal Energy Regulatory Commission, "Standard Interconnection Agreements & Procedures for Small Generators: current as of Order No. 2006-A," (70 FR 71760), November 30, 2005. Available at http://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp

National Rural Electric Cooperative Association, DG Toolkit. Available at http://www.nreca.org/PublicPolicy/ElectricIndustry/dgtoolkit.htm

National Association of Regulated Utility Commissioners, "Model Interconnection Procedures and Agreement for Small Distributed Generation Resources," October 2003. Available at http://files.harc.edu/Sites/GulfCoastCHP/Publications/ModelInterconnectionProcedures.pdf

Edison Electric Institute, "Standardized Procedures For Interconnecting Small Generators, Advanced Notice Of Proposed Rulemaking: Comments of Edison Electric Institute," FERC Docket RM02-12-000, December 20, 2002. Available at http://www.eei.org/about_EEI/advocacy_activities/Federal_Energy_Regulatory_Commission/122002CommentsRM02-12.pdf

Congressional Budget Office, "Prospects for Distributed Electricity Generation," September 2003. Available at http://www.cbo.gov/showdoc.cfm?index=4552&sequence=0

Harris, Louis, "Thorny Details," Electric Perspectives, March/April 2001. Available at http://www.eei.org/magazine/editorial_content/nonav_stories/2001-03-01-thorny.htm

Additional Resources

Net Metering

DSIRE. "Net Metering Rules." Available at http://www.dsireusa.org/library/includes/type.cfm

Edison Electric Institute. "Net Metering Raises Policy Issues for States and Congress." Available at http://www.eei.org/industry_issues/electricity_policy/federal_legislation/netmetering.pdf

Franklin, H. Allen. Testimony on Behalf of the Edison Electric Institute Before the Senate Energy and Natural Resources Committee, Mar 27, 2003. Available at http://www.eei.org/about_EEI/advocacy_activities/Congress/2003-03-27-EEI-testimony.pdf

National Rural Electric Cooperative Association. "Net Metering: An Issue Paper of the National Rural Electric Cooperative Association" is a simple explanation of the concepts and concerns that are associated with net metering. Available at http://www.nreca.org/nreca/Policy/Regulatory/Documents/NetMetering.pdf

U.S. Department of Energy, Energy Information Administration, "Green Pricing and Net Metering Programs 2003." Available at http://www.eia.doe.gov/cneaf/solar.renewables/page/greenprice/grnprcreport.pdf

U.S. EPA. "Glossary of Green Power Terms." Available at http://www.epa.gov/greenpower/whatis/glossary.htm

Fuel Diversity

Costello, Ken. "A Perspective on Fuel Diversity," *The Electricity Journal*, Volume 18, Issue 4, May, 2005. pp. 28-47.

Edison Electric Institute. "Different Regions of the Country Rely on Different Fuel Mixes to Generate Electricity," 2005. Available at http://www.eei.org/industry_issues/energy_infrastructure/fuel_diversity/diversity_map.pdf

Edison Electric Institute. "Electricity Net Generation at Electric Utilities, 1960-1999." Available at http://www.eei.org/industry_issues/energy_infrastructure/fuel_diversity/history_timeline.pdf

Edison Electric Institute. "Fuel Diversity: Key to Affordable and Reliable Electricity," March 2003. Available at http://www.eei.org/industry_issues/energy_infrastructure/fuel_diversity/FuelDiversity.pdf

Federal Energy Regulatory Commision, Office of Market Oversight and Investigations. "State of the Markets Report: Assessment of Energy Markets for the Period January 1, 2002 through June 30, 2003," January 2004, DOCKET MO4-2-000. Available at http://www.ferc.gov/legal/maj-ord-reg/land-docs/som-2003.pdf#xml=http://search.atomz.com/search/pdfhelper.tk?sp-o=2,100000,0

Graves, Frank C., James A. Read, and Joseph B. Wharton. "Resource Planning and Procurement In Evolving Electricity Markets," January 31, 2004. Available at http://www.eei.org/industry_issues/electricity_policy/state_and_local_policies/resource_procurement_prudence/nonav_resource_procurement_prudence/ResourcePlanningProcurement.pdf

Humphreys, H. Bret. and Katherine T McClain. "Reducing the Impacts of Energy Price Volatility Through Dynamic Portfolio Selection," *Energy Journal*, 1998, Vol. 19, Issue 3.

United States Department of Energy. "The Annual Energy Outlook," December 2004. Available at http://www.eia.doe.gov/oiaf/aeo/download.html

Smart Metering/Time Base Rates

Aigner, Dennis J. "The Welfare Econometrics of Peak Load Pricing for Electricity," *Journal of Econometrics* Volume 26 (1984), 1-15.

Barbose, Galen, Charles Goldman, and Bernie Neenan. "A Survey of Utility Experience with Real Time Pricing," June 2004. Available at http://certs.lbl.gov/PDF/54238.pdf

Barbose, G., C. Goldman, R. Bharvirkar, N. Hopper, M. Ting, and B. Neenan,. "Real Time Pricing as a Default or Optional Service for C&I Customers: A Comparative Analysis of Eight Case Studies," LBNL-57661. August 2005. Available at http://drrc.lbl.gov/pubs/57661.pdf

Black, Jason W. and Marija Ilic. "Survey of Technologies and Cost Estimates for Residential Electricity Services," 2001. Available at http://mit.edu/ilic/www/papers_pdf/surveyoftechnologies.pdf

Boisvert, R.N. and B.F. Neenan, "Social Welfare Implications of Demand Response Programs in Competitive Electricity Markets," LBNL-52530. August 2003. Available at http://eetd.lbl.gov/EA/EMP/reports/LBNL-52530.pdf

Borenstein, Severin. "Frequently Asked Questions about Implementing Real-Time Electricity Pricing in California for Summer 2001," March 2001. Available at http://www.iasa.ca/ED_documents_various/Borenstein03.pdf

Borenstein, Severin. "Wealth Transfers from Implementing Real-Time Retail Electricity Pricing," August 2005. Available at http://www.ucei.berkeley.edu/PDF/csemwp147.pdf

Braithwait, Steven and Mike O'Sheasy. "RTP Customer Demand Response: Empirical Evidence of How Much To Expect," found in *Electricity Pricing in Transition,* Edited by Ahmad Faruqui and B. Kelly Eakin, Boston, Dordecht/London: Kluwer Academic Publishers, 2002.

Charles River Associates. "Impact Evaluation of the California Statewide Pricing Pilot," March 16 2005. Avialable at http://www.energy.ca.gov/demandresponse/documents/group3_final_reports/2005-03-24_SPP_FINAL_REP.PDF

Chung, Allen, Jeff Lam, and William E. Hamilton. "Innovative Retail Pricing: A Pacific Northwest Case Study," found in *Electricity Pricing in Transition,* Edited by Ahmad Faruqui and B. Kelly Eakin, Boston, Dordecht/London: Kluwer Academic Publishers, 2002.

Christiansen Associates "Evaluation of California's Real-Time Energy Metering (RTEM) Program," August 2005. Available at http://www.energy.ca.gov/2005publications/CEC-400-2005-021/CEC-400-2005-021.PDF

Costello, Ken. "An Observation on Real-Time Pricing: Why Practice Lags Theory," *The Electricity Journal* Volume: 17, Issue: 1, January - February, 2004. pp. 21-25.

Edison Electric Institute. "EEI Member and Non-Member Residential/Commercial/Industrial Efficiency and Demand Response Programs for 2005/2006" Updated on December 8, 2005. Available at http://www.eei.org/industry_issues/retail_services_and_delivery/wise_energy_use/programs_and_incentives/progs.pdf

Farrow, Elizabeth. "Energy Modeling Forum Conference: Retail Participation in Competitive Power Markets," found in *Electricity Pricing in Transition,* Edited by Ahmad Faruqui and B. Kelly Eakin, Boston, Dordecht/London: Kluwer Academic Publishers, 2002.

Faruqui, Ahmad and Stephen George. "Quantifying Customer Response to Dynamic Pricing," *The Electricity Journal* Volume: 18, Issue: 4, May, 2005. pp. 53-63.

Federal Energy Regulatory Commision, Office of Market Oversight and Investigations. "State of the Markets Report: Assessment of Energy Markets for the Period January 1, 2002 through June 30, 2003," January 2004, DOCKET MO4-2-000. Available at http://www.ferc.gov/legal/maj-ord-reg/land-docs/som-2003.pdf#xml=http://search.atomz.com/search/pdfhelper.tk?sp-o=2,100000,0

Goldman, C., N. Hopper, R. Bharvirkar, B. Neenan, R. Boisvert, P. Cappers, D. Pratt, and K. Butkins. "Customer Strategies for Responding to Day-Ahead Market Hourly Electricity Pricing," August 2005. Available at http://drrc.lbl.gov/pubs/57128.pdf

Goldman, C., N. Hopper, O. Sezgen, M. Moezzi and R. Bharvirkar, B. Neenan, R. Boisvert, P. Cappers, and D. Pratt. "Customer Response to Day-ahead Wholesale Market Electricity Prices: Case Study of RTP Program Experience in New York," June 2004. Available at http://drrc.lbl.gov/pubs/NMPC_LBNL_54761.pdf

Hirst, Eric. "Barriers to Price Responsive Demand in Wholesale Electricity Markets," June 2002. Available at http://www.ksg.harvard.edu/hepg/Papers/Hirst_Barriers_PRD_6-02.pdf

Hirst, Eric and Brendan Kirby. "Retail-Load Participation in Competitive Wholesale Electricity Markets," January 2001. Available at http://www.eei.org/industry_issues/retail_services_and_delivery/wise_energy_use/demand_response/retail_load.pdf

Holland, Stephen and Erin T. Mansur. "Is Real-Time Pricing Green?: The Environmental Impacts of Electricity Demand Variance" UCEI Working Paper August 2004. Available at http://www.ucei.berkeley.edu/PDF/csemwp136.pdf

Huntington, Hillard G. "Market Based U.S. Electricity Prices: A Multi-Model Evaluation," in *Electricity Pricing in Transition,* Edited by Ahmad Faruqui and B. Kelly Eakin, Boston, Dordecht/London: Kluwer Academic Publishers, 2002.

Kelly, John. "The Problem with Cost Allocation: The Heart of the Matter," *Public Power*, March-April 2004

Kelly, John. "The Right Costs, The Right Rates" *Public Power*, Nov-Dec 2004. Available at http://www.appanet.org/newsletters/ppmagazinedetailarchive.cfm?ItemNumber=10684

Mimno, Gerald. "All about time-of-use metering," *Metering International*, 2002, Issue 3. Available at http://www.metering.com/archive/023/22_1.htm

New York State Energy Research and Development Authority. "A Primer on SmartMetering," Fall 2003. Available at http://www.nyserda.org/programs/pdfs/meteringprimer.pdf

O'Sheasy, Michael T. "Demand Response: Not Just Rhetoric, Itcan Truly be the Silver Bullet," The Electricity Journal, Volume: 16, Issue: 10, December, 2003. pp. 48-60.

O'Sheasy, Michael T. "Is Real Time Pricing a Panacea? If So, Why Isn't It More Widespread?" The Electricity Journal,Volume: 15, Issue: 10, December, 2002. pp. 24-34.

PJM Interconnection Market Monitoring Unit. "2004 State of the Market Report," March 2005. Available at http://www.pjm.com/markets/market-monitor/som.html

Ruff, Larry. "Economic Principles of Demand Response in Electricity," October 2002a. Available at http://www.ksg.harvard.edu/hepg/Papers/Ruff_economic_principles_demand_response_eei_10-02.pdf

Ruff, Larry. "Demand Response: Reality Versus 'Resource'," *The Electricity Journal*, Volume 15, Issue 10, December, 2002b. pp. 10-23.

Rosenstock, Steve. "Final Results of the EEI/PLMA 2003 Demand Response Benchmarking Survey" April, 2004. Available at http://www.eei.org/industry_issues/retail_services_and_delivery/wise_energy_use/demand_response/DemandResponseSurvey2004.pdf

Siddiqui, Afzal S., Emily S. Bartholomew, and Chris Marnay. "Empirical Analysis of the Spot Market Implications of Price-Responsive Demand," August 2005. Available at http://eetd.lbl.gov/ea/ems/reports/58747.pdf

U.S. Department of Energy, "Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005," February 2006. Available at http://www.electricity.doe.gov/documents/congress_1252d.pdf

Interconnection

Basso, Thomas and N. Richard Friedman. "IEEE 1547 National Standard for Interconnecting Distributed Generation: How Could It Help My Facility?" November 2003, NREL/JA-560-34875. Available at http://www.nrel.gov/docs/fy04osti/34875.pdf

Basso, Thomas S. and Richard DeBlasio. "IEEE 1547 Series of Standards: Interconnection Issues," September 2003, NREL/JA-560-34882. Available at http://www.nrel.gov/docs/fy03osti/34882.pdf

Congressional Budget Office. "Prospects for Distributed Electricity Generation," September 2003. Available at http://www.cbo.gov/showdoc.cfm?index=4552&sequence=0

Edison Electric Institute. "Standardized Procedures For Interconnecting Small Generators, Advanced Notice Of Proposed Rulemaking: Comments of Edison Electric Institute," FERC Docket RM02-12-000, December 20, 2002. Available at http://www.eei.org/about_EEI/advocacy_activities/Federal_Energy_Regulatory_Commission/122002CommentsRM02-12.pdf

Federal Energy Regulatory Commission. "Standard Interconnection Agreements & Procedures for Small Generators: current as of Order No. 2006-A," (70 FR 71760), November 30, 2005. Available at http://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp

Harris, Louis. "Thorny Details," Electric Perspectives, March/April 2001. Available at http://www.eei.org/magazine/editorial_content/nonav_stories/2001-03-01-thorny.htm

Kroposki, Benjamin, Thomas Basso, and Richard DeBlasio. "Interconnection Testing of Distributed Resources: Preprint". NREL/CP-560-35569. Golden, CO: National Renewable Energy Laboratory. February 2004. Available at http://www.nrel.gov/docs/fy04osti/35569.pdf

National Association of Regulatory Utility Commissioners. "Model Interconnection Procedures and Agreement for Small Distributed Generation Resources," October 2003. Available at http://www.naruc.org/associations/1773/files/dgiaip_oct03.pdf

National Rural Electric Cooperative Association. DG Toolkit. Available at http://nreca.org/PublicPolicy/dgtoolkit.htm

National Association of Regulated Utility Commissioners. "Model Interconnection Procedures and Agreement for Small Distributed Generation Resources," October 2003. Available at http://files.harc.edu/Sites/GulfCoastCHP/Publications/ModelInterconnectionProcedures.pdf

Appendix A
Excerpts of the Energy Policy Act of 2005

H. R. 6

One Hundred Ninth Congress of the United States of America

AT THE FIRST SESSION

Begun and held at the City of Washington on Tuesday, the fourth day of January, two thousand and five

An Act

To ensure jobs for our future with secure, affordable, and reliable energy.

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

SECTION 1. SHORT TITLE; TABLE OF CONTENTS.

(a) SHORT TITLE.—This Act may be cited as the "Energy Policy Act of 2005".

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

TITLE XII—ELECTRICITY

Subtitle E—Amendments to PURPA

SEC. 1251. NET METERING AND ADDITIONAL STANDARDS.

(a) ADOPTION OF STANDARDS.—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:

"(11) NET METERING.—Each electric utility shall make available upon request net metering service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term 'net metering service' means service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period.

"(12) FUEL SOURCES.—Each electric utility shall develop a plan to minimize dependence on 1 fuel source and to ensure that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies.

"(13) FOSSIL FUEL GENERATION EFFICIENCY.—Each electric utility shall develop and implement a 10-year plan to increase the efficiency of its fossil fuel generation.".

(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 at the end the following:

"(3)(A) Not later than 2 years 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 electric utility shall commence the consideration referred to in section 111, or set a hearing date for such consideration, with respect to each standard established by paragraphs (11) through (13) of section 111(d).

"(B) Not later than 3 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 (11) through (13) 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 at the end the following: "In the case of each standard established by paragraphs (11) through (13) 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 (11) through (13).".

(3) PRIOR STATE ACTIONS.—

(A) IN GENERAL.—Section 112 of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2622) is amended by adding at the end the following:

"(d) PRIOR STATE ACTIONS.—Subsections (b) and (c) of this section shall not apply to the standards established by paragraphs (11) through (13) of section 111(d) in the case of any electric utility in a State if, before the enactment of this subsection—

"(1) the State has implemented for such utility the standard concerned (or a comparable standard);

"(2) the State regulatory authority for such State or relevant nonregulated electric utility has conducted a proceeding to consider implementation of the standard concerned (or a comparable standard) for such utility; or

"(3) the State legislature has voted on the implementation of such standard (or a comparable standard) for such utility.".

(B) CROSS REFERENCE.—Section 124 of such Act (16 U.S.C. 2634) is amended by adding the following at the end thereof: "In the case of each standard established by paragraphs (11) through (13) 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 (11) through (13).".

SEC. 1252. SMART METERING.

(a) IN GENERAL.—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:

"(14) TIME-BASED METERING AND COMMUNICATIONS.—(A) Not later than 18 months after the date of enactment of this paragraph, each electric utility shall offer each of its customer classes, and provide individual customers upon customer request, a time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's costs of generating and purchasing electricity at the wholesale level. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.

"(B) The types of time-based rate schedules that may be offered under the schedule referred to in subparagraph (A) include, among others—

"(i) time-of-use pricing whereby electricity prices are set for a specific time period on an advance or forward basis, typically not changing more often than twice a year, based on the utility's cost of generating and/or purchasing such electricity at the wholesale level for the benefit of the consumer. Prices paid for energy consumed during these periods shall be pre-established and known to consumers in advance of such consumption, allowing them to vary their demand and usage in response to such prices and manage their energy costs by shifting usage to a lower cost period or reducing their consumption overall;

"(ii) critical peak pricing whereby time-of-use prices are in effect except for certain peak days, when prices may reflect the costs of generating and/or purchasing electricity at the wholesale level and when consumers may receive additional discounts for reducing peak period energy consumption;

"(iii) real-time pricing whereby electricity prices are set for a specific time period on an advanced or forward basis, reflecting the utility's cost of generating and/or purchasing electricity at the wholesale level, and may change as often as hourly; and

"(iv) credits for consumers with large loads who enter into pre-established peak load reduction agreements that reduce a utility's planned capacity obligations.

"(C) Each electric utility subject to subparagraph (A) shall provide each customer requesting a time-based rate with a time-based meter capable of enabling the utility and customer to offer and receive such rate, respectively.

"(D) For purposes of implementing this paragraph, any reference contained in this section to the date of enactment of the Public Utility Regulatory Policies Act of 1978 shall be deemed to be a reference to the date of enactment of this paragraph.

"(E) In a State that permits third-party marketers to sell electric energy to retail electric consumers, such consumers shall be entitled to receive the same time-based metering and communications device and service as a retail electric consumer of the electric utility.

"(F) Notwithstanding subsections (b) and (c) of section 112, each State regulatory authority shall, not later than 18 months after the date of enactment of this paragraph conduct an investigation in accordance with section 115(i) and issue a decision whether it is appropriate to implement the standards set out in subparagraphs (A) and (C).".

(b) STATE INVESTIGATION OF DEMAND RESPONSE AND TIME-BASED METERING.—Section 115 of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2625) is amended as follows:

(1) By inserting in subsection (b) after the phrase "the standard for time-of-day rates established by section 111(d)(3)" the following: "and the standard for time-based metering and communications established by section 111(d)(14)".

(2) By inserting in subsection (b) after the phrase "are likely to exceed the metering" the following: "and communications".

(3) By adding at the end the following:

"(i) TIME-BASED METERING AND COMMUNICATIONS.—In making a determination with respect to the standard established by section 111(d)(14), the investigation requirement of section 111(d)(14)(F) shall be as follows: Each State regulatory authority shall conduct an investigation and issue a decision whether or not it is appropriate for electric utilities to provide and install time-based meters and communications devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other demand response programs.".

(c) FEDERAL ASSISTANCE ON DEMAND RESPONSE.—Section 132(a) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2642(a)) is amended by striking "and" at the end of paragraph (3), striking the period at the end of paragraph (4) and inserting "; and", and by adding the following at the end thereof:

"(5) technologies, techniques, and rate-making methods related to advanced metering and communications and the use of these technologies, techniques and methods in demand response programs.".

(d) FEDERAL GUIDANCE.—Section 132 of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2642) is amended by adding the following at the end thereof:

"(d) DEMAND RESPONSE.—The Secretary shall be responsible for—

"(1) educating consumers on the availability, advantages, and benefits of advanced metering and communications technologies, including the funding of demonstration or pilot projects;

"(2) working with States, utilities, other energy providers and advanced metering and communications experts to identify and address barriers to the adoption of demand response programs; and

"(3) not later than 180 days after the date of enactment of the Energy Policy Act of 2005, providing Congress with a report that identifies and quantifies the national benefits of demand response and makes a recommendation on achieving specific levels of such benefits by January 1, 2007.".

(e) DEMAND RESPONSE AND REGIONAL COORDINATION.—

(1) IN GENERAL.—It is the policy of the United States to encourage States to coordinate, on a regional basis, State energy policies to provide reliable and affordable demand response services to the public.

(2) TECHNICAL ASSISTANCE.—The Secretary shall provide technical assistance to States and regional organizations formed by two or more States to assist them in—

(A) identifying the areas with the greatest demand response potential;

(B) identifying and resolving problems in transmission and distribution networks, including through the use of demand response;

(C) developing plans and programs to use demand response to respond to peak demand or emergency needs; and

(D) identifying specific measures consumers can take to participate in these demand response programs.

(3) REPORT.—Not later than 1 year after the date of enactment of the Energy Policy Act of 2005, the Commission shall prepare and publish an annual report, by appropriate region, that assesses demand response resources, including those available from all consumer classes, and which identifies and reviews—

(A) saturation and penetration rate of advanced meters and communications technologies, devices and systems;

(B) existing demand response programs and time-based rate programs;

(C) the annual resource contribution of demand resources;

(D) the potential for demand response as a quantifiable, reliable resource for regional planning purposes;

(E) steps taken to ensure that, in regional transmission planning and operations, demand resources are provided equitable treatment as a quantifiable, reliable resource relative to the resource obligations of any load-serving entity, transmission provider, or transmitting party; and

(F) regulatory barriers to improve customer participation in demand response, peak reduction and critical period pricing programs.

(f) FEDERAL ENCOURAGEMENT OF DEMAND RESPONSE DEVICES.—It is the policy of the United States that time-based pricing and other forms of demand response, whereby electricity customers are provided with electricity price signals and the ability to benefit by responding to them, shall be encouraged, the deployment of such technology and devices that enable electricity customers to participate in such pricing and demand response systems shall be facilitated, and unnecessary barriers to demand response participation in energy, capacity and ancillary service markets shall be eliminated. It is further the policy of the United States that the benefits of such demand response that accrue to those not deploying such technology and devices, but who are part of the same regional electricity entity, shall be recognized.

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

"(4)(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 electric utility shall commence the consideration referred to in section 111, or set a hearing date for such consideration, with respect to the standard established by paragraph (14) of section 111(d).

"(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 the standard established by paragraph (14) of section 111(d).".

(h) 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 at the end the following:

"In the case of the standard established by paragraph (14) 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 paragraph (14).".

(i) PRIOR STATE ACTIONS REGARDING SMART METERING STANDARDS.—

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

"(e) PRIOR STATE ACTIONS.—Subsections (b) and (c) of this section shall not apply to the standard established by paragraph (14) of section 111(d) in the case of any electric utility in a State if, before the enactment of this subsection—

"(1) the State has implemented for such utility the standard concerned (or a comparable standard);

"(2) the State regulatory authority for such State or relevant nonregulated electric utility has conducted a proceeding to consider implementation of the standard concerned (or a comparable standard) for such utility within the previous 3 years; or

"(3) the State legislature has voted on the implementation of such standard (or a comparable standard) for such utility within the previous 3 years.".

(2) CROSS REFERENCE.—Section 124 of such Act (16 U.S.C. 2634) is amended by adding the following at the end thereof: "In the case of the standard established by paragraph (14) 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 paragraph (14).".

SEC. 1253. COGENERATION AND SMALL POWER PRODUCTION PURCHASE AND SALE REQUIREMENTS.

(a) TERMINATION OF MANDATORY PURCHASE AND SALE REQUIREMENTS.—Section 210 of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 824a–3) is amended by adding at the end the following:

"(m) TERMINATION OF MANDATORY PURCHASE AND SALE REQUIREMENTS.—

"(1) OBLIGATION TO PURCHASE.—After the date of enactment of this subsection, no electric utility shall be required to enter into a new contract or obligation to purchase electric energy from a qualifying cogeneration facility or a qualifying small power production facility under this section if the Commission finds that the qualifying cogeneration facility or qualifying small power production facility has nondiscriminatory access to—

"(A)(i) independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy; and (ii) wholesale markets for long-term sales of capacity and electric energy; or

"(B)(i) transmission and interconnection services that are provided by a Commission-approved regional transmission entity and administered pursuant to an open access transmission tariff that affords nondiscriminatory treatment to all customers; and (ii) competitive wholesale markets that provide a meaningful opportunity to sell capacity, including long-term and short-term sales; and electric energy, including long-term, short-term and real-time sales, to buyers other than the utility to which the qualifying facility is interconnected. In determining whether a meaningful opportunity to sell exists, the Commission shall consider, among other factors, evidence of transactions within the relevant market; or

"(C) wholesale markets for the sale of capacity and electric energy that are, at a minimum, of comparable competitive quality as markets described in subparagraphs (A) and (B).

"(2) REVISED PURCHASE AND SALE OBLIGATION FOR NEW FACILITIES.—(A) After the date of enactment of this subsection, no electric utility shall be required pursuant to this section to enter into a new contract or obligation to purchase from or sell electric energy to a facility that is not an existing qualifying cogeneration facility unless the facility meets the criteria for qualifying cogeneration facilities established by the Commission pursuant to the rulemaking required by subsection (n).

"(B) For the purposes of this paragraph, the term 'existing qualifying cogeneration facility' means a facility that—

"(i) was a qualifying cogeneration facility on the date of enactment of subsection (m); or

"(ii) had filed with the Commission a notice of self-certification, self recertification or an application for Commission certification under 18 CFR 292.207 prior to the date on which the Commission issues the final rule required by subsection (n).

"(3) COMMISSION REVIEW.—Any electric utility may file an application with the Commission for relief from the mandatory purchase obligation pursuant to this subsection on a service territory-wide basis. Such application shall set forth the factual basis upon which relief is requested and describe why the conditions set forth in subparagraph (A), (B), or (C) of paragraph (1) of this subsection have been met. After notice, including sufficient notice to potentially affected qualifying cogeneration facilities and qualifying small power production facilities, and an opportunity for comment, the Commission shall make a final determination within 90 days of such application regarding whether the conditions set forth in subparagraph (A), (B), or (C) of paragraph (1) have been met.

"(4) REINSTATEMENT OF OBLIGATION TO PURCHASE.—At any time after the Commission makes a finding under paragraph (3) relieving an electric utility of its obligation to purchase electric energy, a qualifying cogeneration facility, a qualifying small power production facility, a State agency, or any other affected person may apply to the Commission for an order reinstating the electric utility's obligation to purchase electric energy under this section. Such application shall set forth the factual basis upon which the application is based and describe why the conditions set forth in subparagraph (A), (B), or (C) of paragraph (1) of this subsection are no longer met. After notice, including sufficient notice to potentially affected utilities, and opportunity for comment, the Commission shall issue an order within 90 days of such application reinstating the electric utility's obligation to purchase electric energy under this section if the Commission finds that the conditions set forth in subparagraphs (A), (B) or (C) of paragraph (1) which relieved the obligation to purchase, are no longer met.

"(5) OBLIGATION TO SELL.—After the date of enactment of this subsection, no electric utility shall be required to enter into a new contract or obligation to sell electric energy to a qualifying cogeneration facility or a qualifying small power production facility under this section if the Commission finds that—

"(A) competing retail electric suppliers are willing and able to sell and deliver electric energy to the qualifying cogeneration facility or qualifying small power production facility; and

"(B) the electric utility is not required by State law to sell electric energy in its service territory.

"(6) NO EFFECT ON EXISTING RIGHTS AND REMEDIES.—Nothing in this subsection affects the rights or remedies of any party under any contract or obligation, in effect or pending approval before the appropriate State regulatory authority or non-regulated electric utility on the date of enactment of this subsection, to purchase electric energy or capacity from or to sell electric energy or capacity to a qualifying cogeneration facility or qualifying small power production facility under this Act (including the right to recover costs of purchasing electric energy or capacity).

"(7) RECOVERY OF COSTS.—(A) The Commission shall issue and enforce such regulations as are necessary to ensure that an electric utility that purchases electric energy or capacity from a qualifying cogeneration facility or qualifying small power production facility in accordance with any legally enforceable obligation entered into or imposed under this section recovers all prudently incurred costs associated with the purchase.

"(B) A regulation under subparagraph (A) shall be enforceable in accordance with the provisions of law applicable to enforcement of regulations under the Federal Power Act (16 U.S.C. 791a et seq.).

"(n) RULEMAKING FOR NEW QUALIFYING FACILITIES.—(1)(A) Not later than 180 days after the date of enactment of this section, the Commission shall issue a rule revising the criteria in 18 CFR 292.205 for new qualifying cogeneration facilities seeking to sell electric energy pursuant to section 210 of this Act to ensure—

"(i) that the thermal energy output of a new qualifying cogeneration facility is used in a productive and beneficial manner;

"(ii) the electrical, thermal, and chemical output of the cogeneration facility is used fundamentally for industrial, commercial, or institutional purposes and is not intended fundamentally for sale to an electric utility, taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as State laws applicable to sales of electric energy from a qualifying facility to its host facility; and "(iii) continuing progress in the development of efficient electric energy generating technology.

"(B) The rule issued pursuant to paragraph (1)(A) of this subsection shall be applicable only to facilities that seek to sell electric energy pursuant to section 210 of this Act. For all other purposes, except as specifically provided in subsection (m)(2)(A), qualifying facility status shall be determined in accordance with the rules and regulations of this Act.

"(2) Notwithstanding rule revisions under paragraph (1), the Commission's criteria for qualifying cogeneration facilities in effect prior to the date on which the Commission issues the final rule required by paragraph (1) shall continue to apply to any cogeneration facility that—

"(A) was a qualifying cogeneration facility on the date of enactment of subsection (m), or

"(B) had filed with the Commission a notice of self-certification, self-recertification or an application for Commission certification under 18 CFR 292.207 prior to the date on which the Commission issues the final rule required by paragraph (1).".

(b) ELIMINATION OF OWNERSHIP LIMITATIONS.—

(1) QUALIFYING SMALL POWER PRODUCTION FACILITY.—Section 3(17)(C) of the Federal Power Act (16 U.S.C. 796(17)(C)) is amended to read as follows:

"(C) 'qualifying small power production facility' means a small power production facility that the Commission determines, by rule, meets such requirements (including requirements respecting fuel use, fuel efficiency, and reliability) as the Commission may, by rule, prescribe;".

(2) QUALIFYING COGENERATION FACILITY.—Section 3(18)(B) of the Federal Power Act (16 U.S.C. 796(18)(B)) is amended to read as follows:

"(B) 'qualifying cogeneration facility' means a cogeneration facility that the Commission determines, by rule, meets such requirements (including requirements respecting minimum size, fuel use, and fuel efficiency) as the Commission may, by rule, prescribe;".

SEC. 1254. INTERCONNECTION.

(a) ADOPTION OF STANDARDS.—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:

"(15) INTERCONNECTION.—Each electric utility shall make available, upon request, interconnection service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term 'interconnection service' means service to an electric consumer under which an on-site generating facility on the consumer's premises shall be connected to the local distribution facilities. Interconnection services shall be offered based upon the standards developed by the Institute of Electrical and Electronics Engineers: IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems, as they may be amended from time to time. In addition, agreements and procedures shall be established whereby the services are offered shall promote current best practices of interconnection for distributed generation, including but not limited to practices stipulated in model codes adopted by associations of state regulatory agencies. All such agreements and procedures shall be just and reasonable, and not unduly discriminatory or preferential.".

(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 at the end the following:

"(5)(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 standard established by paragraph (15) of section 111(d).

"(B) Not later than two years after the date of the enactment of the 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 paragraph (15) of section 111(d).".

(2) FAILURE TO COMPLY.—Section 112(d) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2622(c)) is amended by adding at the end the following: "In the case of the standard established by paragraph (15), 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 paragraph (15).".

(3) PRIOR STATE ACTIONS.—

(A) IN GENERAL.—Section 112 of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2622) is amended by adding at the end the following:

"(f) PRIOR STATE ACTIONS.—Subsections (b) and (c) of this section shall not apply to the standard established by paragraph (15) of section 111(d) in the case of any electric utility in a State if, before the enactment of this subsection—

"(1) the State has implemented for such utility the standard concerned (or a comparable standard);

"(2) the State regulatory authority for such State or relevant nonregulated electric utility has conducted a proceeding to consider implementation of the standard concerned (or a comparable standard) for such utility; or

"(3) the State legislature has voted on the implementation of such standard (or a comparable standard) for such utility.".

(B) CROSS REFERENCE.—Section 124 of such Act (16 U.S.C. 2634) is amended by adding the following at the end thereof: "In the case of each standard established by paragraph (15) of section 111(d), the reference contained in this subsection to the date of enactment of the Act shall be deemed to be a reference to the date of enactment of paragraph (15).".

Appendix B
Current U.S. Generation Capacity

The current U.S. electric generation portfolio appears to have a wide spectrum of generation source. According to the Edison Electric Institute, 50 percent of the total available generation in the U.S. is coal generation.[1] Nuclear (20 percent), natural gas (19 percent), hydroelectric (7 percent), other renewables (3 percent), and oil (2 percent) make up the balance of the generation capacity. The reasons for this variation include regulatory differences between regions, transmission limitation, or geographic dispersion may make interaction between two regions insignificant. When diversity is considered at a regional level, however, trends begin to appear within regions and the level of diversity in the individual regions may not be a great as these figures show.[2] Regional difference may be of interest for several reasons. For example, in the Midwest 70 percent of the total generation is coal fired.[3] The mountain region and the west north central region are 64 percent and 77 percent coal respectively. The west, south central and Pacific regions have relatively high natural gas concentrations. The Pacific region also has a high hydroelectric concentration (44 percent) while no other region tops 10 percent hydro.

Natural gas was the preferred fuel source through much of the 1990s. Prices of natural gas were low and forecasted to stay low. Even recently much of the new generation additions are gas fired. Between January 2002 and June 2003 96% of all capacity additions, or almost 82 GW, of the new generation was gas fired.[4]

---

[1] http://www.eei.org/industry_issues/energy_infrastructure/fuel_diversity/FuelDiversity.pdf

[2] Information on individual states is available at http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html

[3] http://www.eei.org/industry_issues/energy_infrastructure/fuel_diversity/diversity_map.pdf

[4] http://www.ferc.gov/legal/maj-ord-reg/land-docs/som-2003.pdf#xml=http://search.atomz.com/search/pdfhelper.tk?sp-o=2,100000,0

Current planned additions

The generation portfolio described above is just a snapshot in time. Generation additions and retirements happen frequently. Even long term maintenance (projects that cause plants to be decommissioned for months at a time) can have dramatic impacts on the generation portfolio of a region. Table B.1 shows the planned generation capacity additions for the U.S.[5] Table B.2 shows the capacity additions and retirements by fuel source.

As noted, most recent capacity additions have been natural gas-fired generation. Rising natural gas prices and increased price volatility have not yet spurred more diverse investment. However, additional time may be needed to allow for project planning for large investments in other types of generating plants. Another reason natural gas plants have boomed recently is the fact that they are relatively inexpensive to build and site. The Annual Energy Outlook, DOE (2005)[6] forecasts capacity additions in the Southeast and the West will be substantially more diverse than in the other regions, where most additions are projected to be natural gas-fired capacity. The report states "[a]lmost all additions of coal-fired and renewable capacity are expected to be in these two areas."

---

[5] Information for individual states can be found at http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html
[6] Available at http://www.eia.doe.gov/oiaf/aeo/download.html

Table B.1. Planned Nameplate Capacity Additions from New Generators, by Energy Source, 2005 through 2009 (Megawatts) Energy Source

Fuel Source	2005	2006	2007	2008	2009
Coal	573	450	2,064	1,879	8,122
Petroleum	432	441	186	--	8
Natural Gas	15,216	12,499	16,013	9,895	5,451
Dual Fired	4,916	1,924	5,236	2,649	1,860
Other Gases	159	--	340	580	--
Nuclear	--	--	--	--	--
Hydroelectric Conventional	32	8	3	4	--
Other Renewables	2,519	294	126	147	1
Pumped Storage	--	--	--	--	--
Other	--	--	--	--	--
Total	**23,846**	**15,616**	**23,967**	**15,153**	**15,441**

Source: U.S. Department of Energy, Energy Information Administration. Available at http://www.eia.doe.gov/cneaf/electricity/epa/epat2p4.html

Table B.2. Capacity Additions, Retirements and Changes by Energy Source, 2004 (Megawatts)

	Generator Additions				Generator Retirements				Updates and Revisions		
Fuel Type	Number of Generators	Generator Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Number of generators	Generator Name-plate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Generator Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)
Coal	4	617	553	553	13	623	543	543	-543	-8	117
Petroleum	62	244	224	224	45	725	630	677	-2,514	-2,321	-2,231
Natural Gas	110	18,305	15,345	16,730	62	1,263	1,130	1,222	618	1,595	1,517
Dual Fired	47	5,565	4,776	5,166	90	4,975	4,844	4,996	1,786	944	1,196
Other Gases	--	--	--	--	3	66	60	60	318	362	336
Nuclear	--	--	--	--	--	--	--	--	145	419	485
Hydro	9	72	70	69	9	116	115	115	390	-765	-450
Other Renewable	24	450	445	440	18	60	54	52	248	172	89
Other	--	--	--	--	--	--	--	--	51	62	76
Total	**256**	**25,253**	**21,413**	**23,183**	**240**	**7,829**	**7,377**	**7,666**	**499**	**459**	**1,133**

Source: U.S. Department of Energy, Energy Information Administration. Available at http://www.eia.doe.gov/cneaf/electricity/epa/epat2p6.html

Appendix C: Metering/Measuring Requirements by Tariff Type

Tariff or Rate Treatment	Metering and Measurement Requirements	Data Type	Data Collection Frequency	Data Frequency		Minimum Data Available	Comments
				Audit Function	Enhanced Communication		
Time of use	Usage during predetermined time bins (see note1)	KWh read by bin	Minimum: Predetermined bins monthly Recommended : predetermined bins, daily	Minimum : Monthly	Minimum: Daily Recommended: hourly so customer usage patterns can be changed if necessary	billing entity, utility and customer	Flexibility to change the tariff is a technology dependent issue, see note 2.TOU meter would require field visits to reprogram meter for tariff changes.
Real Time Pricing (one or two part)	Usage coincident with market price or system changes. Recommend: Hourly updates issue at 15 minutes before the hour	KWh read per hourly interval with associated rate in effect	Hourly	Minimum : Monthly	Minimum: Daily Recommended: hourly so customer usage patterns can be changed if necessary	billing entity, utility & customer messaging system	Rate in effect must accompany usage to account for loss of price change data at end use point and conflicts in billing.
Critical Peak Pricing (both CPP-F and CPP-V)	Usage during CP Period	KWh read by period	Hourly	Minimum : Monthly	Minimum: Daily Recommended: hourly so cust. usage patterns can be changed if necessary	billing entity, utility & customer messaging system	Need ability to change CP period daily. Helpful to have positive verification it was received and acted upon at every end point
Demand Bidding	Demand available to be controlled (pre) And actually controlled (post)	KWh during control period	Hourly	Minimum : Monthly	Minimum: Daily Recommended: Hourly	billing entity, utility, customer & demand bidder's systems	
Emergency Demand Bidding and Control	Demand available to be controlled (pre) And actually controlled (post)	KWh during control period & KW upon request	Hourly	Minimum : Monthly	15 seconds (ISO standard for aggregated load)	billing entity, utility, customer & demand bidder's systems	

Appendix C (continued): Message or Communication System Requirements by Tariff Type

Tariff or Rate Treatment	Communication Requirements	Messaging Type	Message Frequency (see notes 7, 9)	Access Method (see note 9)
Time of use	Billing usage by bin	Bill, online , or email access	Monthly (via Bill) *Recommended:* Daily.	*Minimum:* Monthly (via Bill) *Recommended:* Available online or via electronic email/messaging
Real Time Pricing (one or two part)	Whether Critical Peak Price is activated—send information to customer or their designee Critical peak price time, level and duration	Signal to display device (fax, email, website)	*Minimum:* Hourly information (or to match market) sent 1 day ahead *Recommended:* display price data and a start and stop time for the price point. The price should be known enough in advance to make the decision	Electronically by both customers and their designees AND via monthly summary bill.
Critical Peak Pricing	Usage during CP Period	Mass media, online access, or signal to display device (fax, pager, website)	*Minimum:* Day ahead	Electronically by both customers and their designees AND via monthly summary bill.
Demand Bidding	Demand available to be controlled (pre) And actually controlled (post) Status of control action	Signal to display device (fax email, website)	Periodically (to match bid profile and control action) *Recommended:* Day ahead	Control entity, ISO or utility: pre-control kW available, post-control kW captured
Emergency Demand Bidding and Control	Controlling entity, utility and ISO: Demand available to be controlled (pre) And actually controlled (post) Customer: control action status, override status	Signal to display device (pager, fax, email)	Hourly Data (to match market) *Recommended:* Day ahead	Control entity, ISO or utility: pre-control kW available, post-control kW captured

Source: "Proposed Pilot Projects and Market Research to Assess the Potential for Deployment of Dynamic Tariffs for Residential and Small Commercial Customers." California Energy Commission. Available at: http://www.energy.ca.gov/demandresponse/documents/working_group_documents/2002-12-10_WG3_REPORT.PDF

Appendix D
Conformed Copy of PURPA – Title I
by Skadden, Arps

PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978[1]

AN ACT To suspend until the close of June 30, 1980, the duty on certain doxorubicin hydrochloride antibiotics.

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

SECTION 1. SHORT TITLE AND TABLE OF CONTENTS.

(a) SHORT TITLE.—This Act may be cited as the "Public Utility Regulatory Policies Act of 1978".

(b) TABLE OF CONTENTS. —

[1]This Act was enacted on November 9, 1978 as Public Law 95-617 (92 Stat. 3117) and appears generally in 16 U.S.C. 2601 and following. Various provisions appear elsewhere in the United States Code.

TITLE II—CERTAIN FEDERAL ENERGY REGULATORY COMMISSION AND DEPARTMENT OF ENERGY AUTHORITIES

TITLE III—RETAIL POLICIES FOR NATURAL GAS UTILITIES

TITLE IV—SMALL HYDROELECTRIC POWER PROJECTS

TITLE V—CRUDE OIL TRANSPORTATION SYSTEMS

TITLE VI—MISCELLANEOUS PROVISIONS

SEC. 2. FINDINGS.

The Congress finds that the protection of the public health, safety, and welfare, the preservation of national security, and the proper exercise of congressional authority under the Constitution to regulate interstate commerce require—

(1) a program providing for increased conservation of electric energy, increased efficiency in the use of facilities and resources by electric utilities, and equitable retail rates for electric consumers,

(2) a program to improve the wholesale distribution of electric energy, the reliability of electric service, the procedures concerning consideration of wholesale rate applications before the Federal Energy Regulatory Commission, the participation of the public in matters before the Commission, and to provide other measures with respect to the regulation of the wholesale sale of electric energy,

(3) a program to provide for the expeditious development of hydroelectric potential at existing small dams to provide needed hydroelectric power,

(4) a program for the conservation of natural gas while insuring that rates to natural gas consumers are equitable,

(5) a program to encourage the development of crude oil transportation systems, and

(6) the establishment of certain other authorities as provided in title VI of this Act.

(16 U.S.C. 2601)

SEC. 3. DEFINITIONS.

As used in this Act, except as otherwise specifically provided—

(1) The term "antitrust laws" includes the Sherman Antitrust Act (15 U.S.C. 1 and following), the Clayton Act (15 U.S.C. 12 and following), the Federal Trade Commission Act (15 U.S.C. 14 and following), the Wilson Tariff Act (15 U.S.C. 8 and 9), and the Act of June 19, 1936, chapter 592 (15 U.S.C. 13, 13a, 13b, and 21A).

(2) The term "class" means, with respect to electric consumers, any group of such consumers who have similar characteristics of electric energy use.

(3) The term "Commission" means the Federal Energy Regulatory Commission.

(4) The term "electric utility" means any person, State agency, or Federal agency, which sells electric energy.

(5) The term "electric consumer" means any person, State agency, or Federal agency, to which electric energy is sold other than for purposes of resale.

(6) The term "evidentiary hearing" means—

(A) in the case of a State agency, a proceeding which (i) is open to the public, (ii) includes notice to participants and an opportunity for such participants to present direct and rebuttal evidence and to cross-examine witnesses, (iii) includes a written decision, based upon evidence appearing in a written record of the proceeding, and (iv) is subject to judicial review.

(B) in the case of a Federal agency, a proceeding conducted as provided in sections 554, 556, and 557 of title 5, United States Code; and

(C) in the case of a proceeding conducted by any entity other than a State or Federal agency, a proceeding which conforms, to the extent appropriate, with the requirements of subparagraph (A).

(7) The term "Federal agency" means an executive agency (as defined in section 105 of title 5 of the United States Code).

(8) The term "load management technique" means any technique (other than a time-of-day or seasonal rate) to reduce the maximum kilowatt demand on the electric utility, including ripple or radio control mechanisms, and other types of interruptible electric service, energy storage devices, and load-limiting devices.

(9) The term "nonregulated electric utility" means any electric utility other than a State regulated electric utility.

(10) The term "rate" means (A) any price, rate, charge, or classification made, demanded, observed, or received with respect to sale of electric energy by an electric utility to an electric consumer, (B) any rule, regulation, or practice respecting any such rate, charge, or classification, and (C) any contract pertaining to the sale of electric energy to an electric consumer.

(11) The term "ratemaking authority" means authority to fix, modify, approve, or disapprove rates.

(12) The term "rate schedule" means the designation of the rates which an electric utility charges for electric energy.

(13) The term "sale" when used with respect to electric energy includes any exchange of electric energy.

(14) The term "Secretary" means the Secretary of Energy.

(15) The term "State" means a State, the District of Columbia, and Puerto Rico.

(16) The term "State agency" means a State, political subdivision thereof, and any agency or instrumentality of either.

(17) The term "State regulatory authority" means any State agency which has ratemaking authority with respect to the sale of electric energy by any electric utility (other than such State agency), and in the case of an electric utility with respect to which the Tennessee Valley Authority has ratemaking authority, such term means the Tennessee Valley Authority.

(18) The term "State regulated electric utility" means any electric utility with respect to which a State regulatory authority has ratemaking authority.

(19) The term "integrated resource planning" means, in the case of an electric utility, a planning and selection process for new energy resources that evaluates the fifty range of alternatives, including new generating capacity, power purchases, energy conservation and efficiency, cogeneration and district heating and cooling applications, and renewable energy resources, in order to provide adequate and reliable service to its electric customers at the lowest system cost. The process shall take into account necessary features for system operation, such as diversity, reliability, dispatchability, and other factors of risks; shall take into account the ability to verify energy savings

achieved through energy conservation and efficiency and the projected durability of such savings measured over time; and shall treat demand and supply resources on a consistent and integrated basis.

(20) The term "system cost" means all direct and quantifiable net costs for an energy resource over its available life, including the cost of production, distribution, transportation, utilization, waste management, and environmental compliance.

(21) The term "demand side management" includes load management techniques.

(16 U.S.C. 2602)

SEC. 4. RELATIONSHIP TO ANTITRUST LAWS.

Nothing in this Act or in any amendment made by this Act affects—

(1) the applicability of the antitrust laws to any electric utility or gas utility (as defined in section 302), or

(2) any authority of the Secretary or of the Commission under any other provision of law (including the Federal Power Act and the Natural Gas Act) respecting unfair methods of competition or anticompetitive acts or practices.

(16 U.S.C. 2603)

TITLE I—RETAIL REGULATORY POLICIES FOR ELECTRIC UTILITIES

Subtitle A—General Provisions

SEC. 101. PURPOSES.

The purposes of this title are to encourage—

(1) conservation of energy supplied by electric utilities;

(2) the optimization of the efficiency of use of facilities and resources by electric utilities; and

(3) equitable rates to electric consumers.

(16 U.S.C. 2611)

SEC. 102. COVERAGE.

(a) VOLUME OF TOTAL RETAIL SALES.—This title applies to each utility in any calendar year, and to each proceeding relating to each electric utility in such year, if the total sales of electric energy by such utility for purposes other than resale exceeded 500 million kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding calendar year.

(b) EXCLUSION OF WHOLESALE SALES.—The requirements of this title do not apply to the operations of an electric utility, or to proceedings respecting such operations, to the extent that such operations or proceedings relate to sales of electric energy for purposes of resale.

(c) LIST OF COVERED UTILITIES.—Before the beginning of each calendar year, the Secretary shall publish a list identifying each electric utility to which this title applies during such calendar year. Promptly after publication of such list each State regulatory authority shall notify the Secretary of each electric utility on the list for which such State regulatory authority has ratemaking authority.

(16 U.S.C. 2612)

SEC. 103. FEDERAL CONTRACTS.

Notwithstanding the limitation contained in section 102(b), no contract between a Federal agency and any electric utility for the sale of electric energy by such Federal agency for resale which is entered into or renewed after the date of the enactment of this Act may contain any provision which will have the effect of preventing the implementation of any requirement of subtitle B or C. Any provision in any such contract which has such effect shall be null and void.

(16 U.S.C. 2613)

Subtitle B—Standards For Electric Utilities

SEC. 111. CONSIDERATION AND DETERMINATION RESPECTING CERTAIN RATEMAKING STANDARDS.

(a) CONSIDERATION AND DETERMINATION.—Each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility shall consider each standard established by subsection (d) and make a determination concerning whether or not it is appropriate to implement such standard to carry out the purposes of this title. For purposes of such consideration and determination in accordance with subsections (b) and (c), and for purposes of any review of such consideration and determination in any court in accordance with section 123, the purposes of this title supplement otherwise applicable State law. 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, pursuant to its authority under otherwise applicable State law.

(b) PROCEDURAL REQUIREMENTS FOR CONSIDERATION AND DETERMINATION.—(1) The consideration referred to in subsection (a) shall be made after public notice and hearing. The determination referred to in subsection (a) shall be—

(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.

(2) Except as otherwise provided in paragraph (1), in the second sentence of section 112(a), and in sections 121 and 122, the procedures for the consideration and determination referred to in subsection (a) shall be those established by the State regulatory authority or the nonregulated electric utility.

(c) IMPLEMENTATION.—(1) The State regulatory authority (with respect to each electric utility for which it has ratemaking authority) or nonregulated electric utility may, to the extent consistent with otherwise applicable State law—

(A) implement any such standard determined under subsection (a) to be appropriate to carry out the purposes of this title, or

(B) decline to implement any such standard.

(2) If a State regulatory authority (with respect to each electric utility for which it has ratemaking authority) or nonregulated electric utility declines to implement any standard established by

subsection (d) which is determined under subsection (a) to be appropriate to carry out the purposes of this title, such authority or non-regulated electric utility shall state in writing the reasons therefor. Such statement of reasons shall be available to the public.

(3)[1] If a State regulatory authority implements a standard established by subsection (d)(7) or (8), such authority shall—

(A) consider the impact that implementation of such standard would have on small businesses engaged in the design, sale, supply, installation or servicing of energy conservation, energy efficiency or other demand side management measures, and

(B) implement such standard so as to assure that utility actions would not provide such utilities with unfair competitive advantages over such small businesses.

(d) ESTABLISHMENT.—The following Federal standards are hereby established:

(1) COST OF SERVICE.—Rates charged by any electric utility for providing electric service to each class of electric consumers shall be designed, to the maximum extent practicable, to reflect the cost of providing electric service to such class, as determined under section 115(a).

(2) DECLINING BLOCK RATES.—The energy component of a rate, or the amount attributable to the energy component in a rate, charged by any electric utility for providing electric service during any period to any class of electric consumers may not decrease as kilowatt-hour consumption by such class increases during such period except to the extent that such utility demonstrates that the costs to such utility of providing electric service to such class, which costs are attributable to such energy component, decrease as such consumption increases during such period.

(3) TIME-OF-DAY RATES.—The rates charged by any electric utility for providing electric service to such class of electric consumers shall be on a time-of-day basis which reflects the costs of providing electric service to such class of electric consumers at different times of the day unless such rates are not cost-effective with respect to such class, as determined under section 115(b).

(4) SEASONAL RATES.—The rates charged by an electric utility for providing electric service to each class of electric consumers shall be on a seasonal basis which reflects the costs of providing service to each class of consumers at different sea sons of the year to the extent that such costs vary seasonally for such utility.

(5) INTERRUPTIBLE RATES.—Each electric utility shall offer each industrial and commercial electric consumer an interruptible rate which reflects the cost of providing interruptible service to the class of which such consumer is a member.

(6) LOAD MANAGEMENT TECHNIQUES.—Each electric utility shall offer to its electric consumers such load

[1] Indentation so in law; Public Law 102-486, sec. 111(b), 106 Stat. 2795.

management techniques as the State regulatory authority (or the nonregulated electric utility) has determined will—

(A) be practicable and cost-effective, as determined under section 115(c),

(B) be reliable, and

(C) provide useful energy or capacity management advantages to the electric utility.

(7) INTEGRATED RESOURCE PLANNING.—Each electric utility shall employ integrated resource planning. All plans or filings before a State regulatory authority to meet the requirements of this paragraph must be updated on a regular basis, must provide the opportunity for public participation and comment, and contain a requirement that the plan be implemented.

(8) INVESTMENTS IN CONSERVATION AND DEMAND MANAGEMENT.—The rates allowed to be charged by a State regulated electric utility shall be such that the utility's investment in and expenditures for energy conservation, energy efficiency resources, and other demand side management measures are at least as profitable, giving appropriate consideration to income lost from reduced sales due to investments in and expenditures for conservation and efficiency, as its investments in and expenditures for the construction of new generation, transmission, and distribution equipment. Such energy conservation, energy efficiency resources and other demand side management measures shall be appropriately monitored and evaluated.

(9) ENERGY EFFICIENCY INVESTMENTS IN POWER GENERATION AND SUPPLY.—The rates charged by any electric utility shall be such that the utility is encouraged to make investments in, and expenditures for, all cost-effective improvements in the energy efficiency of power generation, transmission and distribution. In considering regulatory changes to achieve the objectives of this paragraph, State regulatory authorities and nonregulated electric utilities shall consider the disincentives caused by existing ratemaking policies, and practices, and consider incentives that would encourage better maintenance, and investment in more efficient power generation, transmission and distribution equipment.

(10)[1] 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.—

(A) To the extent that a State regulatory authority requires or allows electric utilities for which it has rate-making authority to consider the purchase of long-term wholesale power supplies as a means of meeting electric demand, such authority shall perform a general evaluation of:

[1] Section 712 of the Energy Policy Act of 1992 (P.L. 102-486) instructed that section 111 of the Public Utility Regulatory Policies Act of 1978 is amended by inserting this paragraph (10) after paragraph (9). The amendment probably should have been made to section 111(d) as shown in the text.

(i) the potential for increases or decreases in the costs of capital for such utilities, and any resulting increases or decreases in the retail rates paid by electric consumers, that may result from purchases of long-term wholesale power supplies in lieu of the construction of new generation facilities by such utilities;

(ii) whether the use by exempt wholesale generators (as defined in section 32 of the Public Utility Holding Company Act of 1935) of capital structures which employ proportionally greater amounts of debt than the capital structures of such utilities threatens reliability or provides an unfair advantage for exempt wholesale generators over such utilities;

(iii) whether to implement procedures for the advance approval or disapproval of the purchase of a particular long-term wholesale power supply; and

(iv) whether to require as a condition for the approval of the purchase of power that there be reasonable assurances of fuel supply adequacy.

(B) For purposes of implementing the provisions of this paragraph, any reference contained in this section to the date of enactment of the Public Utility Regulatory Policies Act of 1978 shall be deemed to be a reference to the date of enactment of this paragraph.

(C) Notwithstanding any other provision of Federal law, nothing in this paragraph shall prevent a State regulatory authority from taking such action, including action with respect to the allowable capital structure of exempt wholesale generators, as such State regulatory authority may determine to be in the public interest as a result of performing evaluations under the standards of subparagraph (A).

(D) Notwithstanding section 124 and paragraphs (1) and (2) of section 112(a), each State regulatory authority shall consider and make a determination concerning the standards of subparagraph (A) in accordance with the requirements of subsections (a) and (b) of this section, without regard to any proceedings commenced prior to the enactment of this paragraph.

(E) Notwithstanding subsections (b) and (c) of section 112, each State regulatory authority shall consider and make a determination concerning whether it is appropriate to implement the standards set out in subparagraph (A) not later than one year after the date of enactment of this paragraph.

<u>(11) NET METERING.–Each electric utility shall make available upon request net metering service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term 'net metering service' means service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period.</u>

<u>(12) FUEL SOURCES.–Each electric utility shall develop a plan to minimize dependence on 1 fuel source and to ensure</u>

that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies.

(13) Fossil FUEL GENERATION EFFICIENCY.–Each electric utility shall develop and implement a 10-year plan to increase the efficiency of its fossil fuel generation.

(14) TIME-BASED METERING AND COMMUNICATIONS.–(A) Not later than 18 months after the date of enactment of this paragraph, each electric utility shall offer each of its customer classes, and provide individual customers upon customer request, a time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's costs of generating and purchasing electricity at the wholesale level. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.

(B) The types of time-based rate schedules that may be offered under the schedule referred to in subparagraph (A) include, among others–

(i) time-of-use pricing whereby electricity prices are set for a specific time period on an advance or forward basis, typically not changing more often than twice a year, based on the utility's cost of generating and/or purchasing such electricity at the wholesale level for the benefit of the consumer. Prices paid for energy consumed during these periods shall be pre-established and known to consumers in advance of such consumption, allowing them to vary their demand and usage in response to such prices and manage their energy costs by shifting usage to a lower cost period or reducing their consumption overall;

(ii) critical peak pricing whereby time-of-use prices are in effect except for certain peak days, when prices may reflect the costs of generating and/or purchasing electricity at the wholesale level and when consumers may receive additional discounts for reducing peak period energy consumption;

(iii) real-time pricing whereby electricity prices are set for a specific time period on an advanced or forward basis, reflecting the utility's cost of generating and/or purchasing electricity at the wholesale level, and may change as often as hourly; and

(iv) credits for consumers with large loads who enter into pre-established peak load reduction agreements that reduce a utility's planned capacity obligations.

(C) Each electric utility subject to subparagraph (A) shall provide each customer requesting a time-based rate with a time-based meter capable of enabling the utility and customer to offer and receive such rate, respectively.

(D) For purposes of implementing this paragraph, any reference contained in this section to the date of enactment of the Public Utility Regulatory Policies Act of 1978 shall be deemed to be a reference to the date of enactment of this paragraph.

(E) In a State that permits third-party marketers to sell electric energy to retail electric consumers, such consumers shall be entitled to receive the same time-based metering and communications device and service as a retail electric consumer of the electric utility.

(F) Notwithstanding subsections (b) and (c) of section 112, each State regulatory authority shall, not later than 18 months after the date of enactment of this paragraph conduct an investigation in accordance with section 115(i) and issue a decision whether it is appropriate to implement the standards set out in subparagraphs (A) and (C).

(15) INTERCONNECTION.--Each electric utility shall make available, upon request, interconnection service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term 'interconnection service' means service to an electric consumer under which an on-site generating facility on the consumer's premises shall be connected to the local distribution facilities. Interconnection services shall be offered based upon the standards developed by the Institute of Electrical and Electronics Engineers; IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems, as they may be amended from time to time. In addition, agreements and procedures shall be established whereby the services are offered shall promote current best practices of interconnection for distributed generation, including but not limited to practices stipulated in model codes adopted by associations of state regulatory agencies. All such agreements and procedures shall be just and reasonable, and not unduly discriminatory or preferential.

(16 U.S.C. 2621)

SEC. 112. OBLIGATIONS TO CONSIDER AND DETERMINE.

(a) REQUEST FOR CONSIDERATION AND DETERMINATION.—Each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility may undertake the consideration and make the determination referred to in section 111 with respect to any standard established by section 111(d) in any proceeding respecting the rates of the electric utility. Any participant or intervenor (including an intervenor referred to in section 121) in such a proceeding may request, and shall obtain, such consideration and determination in such proceeding. In undertaking such consideration and making such determination in any such proceeding with respect to the application to any electric utility of any standard established by section 111(d), a State regulatory authority (with respect to an electric utility for which it has ratemaking authority) or nonregulated electric utility may take into account in such proceeding—

(1) any appropriate prior determination with respect to such standard—

(A) which is made in a proceeding which takes place after the date of the enactment of this Act, or

(B) which was made before such date (or is made in a proceeding pending on such date) and complies, as provided in section 124, with the requirements of this title; and

(2) the evidence upon which such prior determination was based (if such evidence is referenced in such proceeding).

(b) TIME LIMITATIONS.—(1) Not later than 2 years after the date of the enactment of this Act (or after the enactment of the Comprehensive National Energy Policy Act in the case of standards under paragraphs (7), (8), and (9) of section 111(d)), each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility shall commence the consideration referred to in section 111, or set a hearing date for such consideration, with respect to each standard established by section 111(d).

(2) Not later than three years after the date of the enactment of this Act (or after the enactment of the Comprehensive National Energy Policy Act in the case of standards under paragraphs (7), (8), and (9) of section 111(d)), 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 section 111(d).

(3) (A) Not later than 2 years 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 electric utility shall commence the consideration referred to in section 111, or set a hearing date for such consideration, with respect to each standard established by paragraphs (11) through (13) of section 111(d).

(B) Not later than 3 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 (11) through (13) of section 111(d).

(4) (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 electric utility shall commence the consideration referred to in section 111, or set a hearing date for such consideration, with respect to the standard established by paragraph (14) of section 111(d).

(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 the standard established by paragraph (14) of section 111(d).

(5) (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 such consideration, with respect to the standard established by paragraph (15) of section 111(d).

(B) Not later than two 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 paragraph (15) of section 111(d).

(c) FAILURE TO COMPLY.—Each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility shall undertake the consideration, and make the determination, referred to in section 111 with respect to each standard established by section 111(d) in the first rate proceeding commenced after the date three years after the date of enactment of this Act respecting the rates of such utility if such State regulatory authority or nonregulated electric utility has not, before such date, complied with subsection (b)(2) with respect to such standard. In the case of each standard established by paragraphs (11) through (13) 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 (11) through (13). In the case of the standard established by paragraph (14) 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 paragraph (14). In the case of the standard established by paragraph (15), 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 paragraph (15).

(d) PRIOR STATE ACTIONS.–Subsections (b) and (c) of this section shall not apply to the standards established by paragraphs (11) through (13) of section 111(d) in the case of any electric utility in a State if, before the enactment of this subsection–

(1) the State has implemented for such utility the standard concerned (or a comparable standard);

(2) the State regulatory authority for such State or relevant nonregulated electric utility has conducted a proceeding to consider implementation of the standard concerned (or a comparable standard) for such utility; or

(3) the State legislature has voted on the implementation of such standard (or a comparable standard) for such utility.

(e) Prior STATE ACTIONS.–Subsections (b) and (c) of this section shall not apply to the standard established by paragraph (14) of section 111(d) in the case of any electric utility in a State if, before the enactment of this subsection–

(1) the State has implemented for such utility the standard concerned (or a comparable standard);

(2) the State regulatory authority for such State or relevant nonregulated electric utility has conducted a proceeding to consider implementation of the standard concerned (or a comparable standard) for such utility within the previous 3 years; or

(3) the State legislature has voted on the implementation of such standard (or a comparable standard) for such utility within the previous 3 years.

(f) PRIOR STATE ACTIONS.–Subsections (b) and (c) of this section shall not apply to the standard established by paragraph (15) of section 111(d) in the case of any electric utility in a State if, before the enactment of this subsection–

(1) the State has implemented for such utility the standard concerned (or a comparable standard);

(2) the State regulatory authority for such State or relevant nonregulated electric utility has conducted a proceeding to consider implementation of the standard concerned (or a comparable standard) for such utility; or

(3) the State legislature has voted on the implementation of such standard (or a comparable standard) for such utility.

(16 U.S.C. 2622)

SEC. 113. ADOPTION OF CERTAIN STANDARDS.

(a) ADOPTION OF STANDARDS.—Not later than two years after the date of the enactment of this Act, each State regulatory authority (with respect to each electric utility for which it has ratemakingauthority), and each nonregulated electric utility, shall provide public notice and conduct a hearing respecting the standards estab-lished by subsection (b) and, on the basis of such hearing, shall—

(1) adopt the standards established by subsection (b) (other than paragraph (4) thereof), if, and to the extent, such authority or nonregulated electric utility determines that such adoption is appropriate to carry out the purposes of this title, is otherwise appropriate, and is consistent with otherwise applicable State law, and

(2) adopt the standard established by subsection (b)(4) if, and to the extent, such authority or nonregulated electric utility determines that such adoption is appropriate and consistent with otherwise applicable State law.

For purposes of any determination under paragraphs (1) or (2) and any review of such determination in any court in accordance with section 123, the purposes of this title supplement otherwise applicable State law. Nothing in this subsection prohibits any State regulatory authority or nonregulated electric utility from making any determination that it is not appropriate to adopt any such standard, pursuant to its authority under otherwise applicable State law.

(b) ESTABLISHMENT.—The following Federal standards are hereby established:

(1) MASTER METERING.—To the extent determined appropriate under section 115(d), master metering of electric service in the case of new buildings shall be prohibited or restricted to the extent necessary to carry out the purposes of this title.

(2) AUTOMATIC ADJUSTMENT CLAUSES.—No electric utility may increase any rate pursuant to an automatic adjustment clause unless such clause meets the requirements of section 115(e).

(3) INFORMATION TO CONSUMERS.—Each electric utility shall transmit to each of its electric consumers information regarding rate schedules in accordance with the requirements of section 115(f).

(4) PROCEDURES FOR TERMINATION OF ELECTRIC SERVICE.—No electric utility may terminate electric service to

any electric consumer except pursuant to procedures described in section 115(g).

(5) ADVERTISING.—No electric utility may recover from any person other than the shareholders (or other owners) of such utility any direct or indirect expenditure by such utility for promotional or political advertising as defined in section 115(h).

(c) PROCEDURAL REQUIREMENTS.—Each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility, within the two-year period specified in subsection (a), shall (1) adopt, pursuant to subsection (a), each of the standards established by subsection (b) or, (2) with respect to any such standard which is not adopted, such authority or nonregulated electric utility shall state in writing that it has determined not to adopt such standard, together with the reasons for such determination. Such statement of reasons shall be available to the public.

(16 U.S.C. 2623)

SEC. 114. LIFELINE RATES.

(a) LOWER RATES.—No provision of this title prohibits a State regulatory authority (with respect to an electric utility for which it has ratemaking authority) or a nonregulated electric utility from fixing, approving, or allowing to go into effect a rate for essential needs (as defined by the State regulatory authority or by the nonregulated electric utility, as the case may be) of residential electric consumers which is lower than a rate under the standard referred to in section 111(d)(l).

(b) DETERMINATION.—If any State regulated electric utility or nonregulated electric utility does not have a lower rate as described in subsection (a) in effect two years after the date of the enactment of this Act, the State regulatory authority having ratemaking authority with respect to such State regulated electric utility or the nonregulated electric utility, as the case may be, shall determine, after an evidentiary hearing, whether such a rate should be implemented by such utility.

(c) PRIOR PROCEEDINGS.—Section 124 shall not apply to the requirements of this section.

(16 U.S.C. 2624)

SEC. 115. SPECIAL RULES FOR STANDARDS.

(a) COST OF SERVICE.—In undertaking the consideration and making the determination under section 111 with respect to the standard concerning cost of service established by section 111(d)(l), the costs of providing electric service to each class of electric consumers shall, to the maximum extent practicable, be determined on the basis of methods prescribed by the State regulatory authority (in the case of a State regulated electric utility) or by the electric utility (in the case of a nonregulated electric utility). Such methods shall to the maximum extent practicable—

(1) permit identification of differences in cost-incurrence, for each such class of electric consumers, attributable to daily and seasonal time of use of service and

(2) permit identification of differences in cost-incurrence attributable to differences in customer demand, and energy

components of cost. In prescribing such methods, such State regulatory authority or nonregulated electric utility shall take into account the extent to which total costs to an electric utility are likely to change if—

(A) additional capacity is added to meet peak demand relative to base demand; and

(B) additional kilowatt-hours of electric energy are delivered to electric consumers.

(b) TIME-OF-DAY RATES.—In undertaking the consideration and making the determination required under section 111 with respect to the standard for time-of-day rates established by section 111(d)(3) and the standard for time-based metering and communications established by section 111(d)(14), a time-of-day rate charged by an electric utility for providing electric service to each class of electric consumers shall be determined to be cost-effective with respect to each such class if the long-run benefits of such rate to the electric utility and its electricconsumers in the class concerned are likely to exceed the metering and communications costs and other costs associated with the use of such rates.

(c) LOAD MANAGEMENT TECHNIQUES.—In undertaking the consideration and making the determination required under section 111 with respect to the standard for load management techniques established by section 111(d)(6), a load management technique shall be determined, by the State regulatory authority or nonregulated electric utility, to be cost-effective if—

(1) such technique is likely to reduce maximum kilowatt demand on the electric utility, and

(2) the long-run cost-savings to the utility of such reduction are likely to exceed the long-run costs to the utility associated with implementation of such technique.

(d) MASTER METERING.—Separate metering shall be determined appropriate for any new building for purposes of section 113(b)(1) if—

(1) there is more than one unit in such building,

(2) the occupant of each such unit has control over a portion of the electric energy used in such unit, and

(3) with respect to such portion of electric energy used in such unit, the long-run benefits to the electric consumers in such building exceed the costs of purchasing and installing separate meters in such building.

(e) AUTOMATIC ADJUSTMENT CLAUSES.—(1) An automatic adjustment clause of an electric utility meets the requirements of this subsection if—

(A) such clause is determined, not less often than every four years, by the State regulatory authority (with respect to an electric utility for which it has ratemaking authority) or by the electric utility (in the case of a nonregulated electric utility), after an evidentiary hearing, to provide incentives for efficient use of resources (including incentives for economical purchase and use of fuel and electric energy) by such electric utility, and

(B) such clause is reviewed not less often than every two years, in the manner described in paragraph (2), by the State regulatory authority having ratemaking authority with respect to such utility (or by the electric utility in the case of a nonregulated electric utility), to insure the maximum economies in those operations and purchases which affect the rates to which such clause applies.

(2) In making a review under subparagraph (B) of paragraph (1) with respect to an electric utility, the reviewing authority shall examine and, if appropriate, cause to be audited the practices of such electric utility relating to costs subject to an automatic adjustment clause, and shall require such reports as may be necessary to carry out such review (including a disclosure of any ownership or corporate relationship between such electric utility and the seller to such utility of fuel, electric energy, or other items).

(3) As used in this subsection and section 113(b), the term "automatic adjustment clause" means a provision of a rate schedule which provides for increases or decreases (or both), without prior hearing, in rates reflecting increases or decreases (or both) in costs incurred by an electric utility. Such term does not include an interim, rate which takes effect subject to a later determination of the appropriate amount of the rate.

(f) INFORMATION TO CONSUMERS.—(1) For purposes of the standard for information to consumers established by section 113(b)(3), each electric utility shall transmit to each of its electric consumers a clear and concise explanation of the existing rate schedule and any rate schedule applied for (or proposed by a non-regulated electric utility) applicable to such consumer. Such statement shall be transmitted to each such consumer—

(A) not later than sixty days after the date of commencement of service to such consumer or ninety days after the standard established by section 113(b)(3) is adopted with respect to such electric utility, whichever last occurs, and

(B) not later than thirty days (sixty days in the case of an electric utility which uses a bimonthly billing system) after such utility's application for any change in a rate schedule applicable to such consumer (or proposal of such a change in the case of a nonregulated utility).

(2) For purposes of the standard for information to consumers established by section 113(b)(3), each electric utility shall transmit to each of its electric consumers not less frequently than once each year—

(A) a clear and concise summary of the existing rate schedules applicable to each of the major classes of its electric consumers for which there is a separate rate, and

(B) an identification of any classes whose rates are not summarized.

Such summary may be transmitted together with such consumer's billing or in such other manner as the State regulatory authority or non-regulated electric utility deems appropriate.

(3) For purposes of the standard for information to consumers established by section 113(b)(3), each electric utility, on request of an electric consumer of such utility, shall transmit to such consumer a clear and concise statement of the actual consumption (or degree-day adjusted consumption) of electric energy by such consumer for each billing period during the prior year (unless such consumption data is not reasonably ascertainable by the utility).

(g) PROCEDURES FOR TERMINATION OF ELECTRIC SERVICE.—The procedures for termination of service referred to in section 113(b)(4) are procedures prescribed by the State regulatory authority (with respect to electric utilities for which it has ratemaking authority) or by the nonregulated electric utility which provide that—

(1) no electric service to an electric consumer may be terminated unless reasonable prior notice (including notice of rights and remedies) is given to such consumer and such consumer has a reasonable opportunity to dispute the reasons for such termination, and

(2) during any period when termination of service to an electric consumer would be especially dangerous to health, as determined by the State regulatory authority (with respect to an electric utility for which it has ratemaking authority) or nonregulated electric utility, and such consumer establishes that—

(A) he is unable to pay for such service in accordance with the requirements of the utility's billing, or

(B) he is able to pay for such service but only in installments,

such service may not be terminated.

Such procedures shall take into account the need to include reasonable provisions for elderly and handicapped consumers.

(h) ADVERTISING.—(1) For purposes of this section and section 113(b)(5)—

(A) The term "advertising" means the commercial use, by an electric utility, of any media, including newspaper, printed matter, radio, and television, in order to transmit a message to a substantial number of members of the public or to such utility's electric consumers.

(B) The term "political advertising" means any advertising for the purpose of influencing public opinion with respect to legislative, administrative, or electoral matters, or with respect to any controversial issue of public importance.

(C) The term "promotional advertising" means any advertising for the purpose of encouraging any person to select or use the service or additional service of an electric utility or the selection or installation of any appliance or equipment designed to use such utility's service.

(2) For purposes of this subsection and section 113(b)(5), the terms "political advertising" and "promotional advertising" do not include—

(A) advertising which informs electric consumers how they can conserve energy or can reduce peak demand for electric energy,

(B) advertising required by law or regulation, including advertising required under part 1 of title II of the National Energy Conservation Policy Act,

(C) advertising regarding service interruptions, safety measures, or emergency conditions,

(D) advertising concerning employment opportunities with such utility,

(E) advertising which promotes the use of energy efficient appliances, equipment or services, or

(F) any explanation or justification of existing or proposed rate schedules, or notifications of hearings thereon.

(i) TIME-BASED METERING AND COMMUNICATIONS.–In making a determination with respect to the standard established by section 111(d)(14), the investigation requirement of section 111(d)(14)(F) shall be as follows: Each State regulatory authority shall conduct an investigation and issue a decision whether or not it is appropriate for electric utilities to provide and install time-based meters and communications devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other demand response programs.

(16 U.S.C. 2625)

SEC. 116. REPORTS RESPECTING STANDARDS.

(a) STATE AUTHORITIES AND NONREGULATED UTILITIES.—Not later than one year after the date of the enactment of this Act and annually thereafter for ten years, each State regulatory authority (with respect to each State regulated electric utility for which it has ratemaking authority), and each nonregulated electric utility, shall report to the Secretary, in such manner as the Secretary shall prescribe, respecting its consideration of the standards established by sections 111(d) and 113(b). Such report shall include a summary of the determinations made and actions taken with respect to each such standard on a utility-by-utility basis.

(b) SECRETARY.—Not later than eighteen months after the date of the enactment of this Act and annually thereafter for ten years the Secretary shall submit a report to the President and the Congress containing—

(1) a summary of the reports submitted under subsection (a),

(2) his analysis of such reports, and

(3) his actions under this title, and his recommendations for such further Federal actions, including any legislation, regarding retail electric utility rates (and other practices) as may be necessary to carry out the purposes of this title.

(16 U.S.C. 2626)

SEC. 117. RELATIONSHIP TO STATE LAW.

(a) REVENUE AND RATE OF RETURN.—Nothing in this title shall authorize or require the recovery by an electric utility of revenues, or of a rate of return, in excess of, or less than, the amount of revenues or the rate of return determined to be lawful under any other provision of law.

(b) STATE AUTHORITY.—Nothing in this title prohibits any State regulatory authority or nonregulated electric utility from adopting, pursuant to State law, any standard or rule affecting electric utilities which is different from any standard established by this subtitle.

(c) FEDERAL AGENCIES.—With respect to any electric utility which is a Federal agency, and with respect to the Tennessee Valley Authority when it is treated as a State regulatory authority as provided in section 3(17), any reference in section 111 or 113 to State law shall be treated as a reference to Federal law.

(16 U.S.C. 2627)

Subtitle C–Intervention and Judicial Review

SEC. 121. INTERVENTION IN PROCEEDINGS.

(a) AUTHORITY TO INTERVENE AND PARTICIPATE.—In order to initiate and participate in the consideration of one or more of the standards established by subtitle B or other concepts which contribute to the achievement of the purposes of this title, the Secretary, any affected electric utility, or any electric consumer of an affected electric utility may intervene and participate as a matter of right in any ratemaking proceeding or other appropriate regulatory proceeding relating to rates or rate design which is conducted by a State regulatory authority (with respect to an electric utility for which it has ratemaking authority) or by a nonregulated electric utility.

(b) ACCESS TO INFORMATION.—Any intervenor or participant in a proceeding described in subsection (a) shall have access to information available to other parties to the proceeding if such information is relevant to the issues to which his intervention or participation in such proceeding relates. Such information may be obtained through reasonable rules relating to discovery of information prescribed by the State regulatory authority (in the case of proceedings concerning electric utilities for which it has ratemaking authority) or by the nonregulated electric utility (in the case a proceeding conducted by a nonregulated electric utility).

(c) EFFECTIVE DATE; PROCEDURES.—Any intervention or participation under this section, mi any proceeding commenced before the date of the enactment of this Act but not completed before such date, shall be permitted under this section only to the extent such intervention or participation is timely under otherwise applicable law.

(16 U.S.C. 2631)

SEC. 122. CONSUMER REPRESENTATION.

(a) COMPENSATION FOR COSTS OF PARTICIPATION OR INTERVENTION.—(1) If no alternative means for assuring representation of electric consumers is adopted in accordance with subsection (b) and if an electric consumer of an electric utility substantially contributed to the approval, in whole or in part, of a position advocated by such consumer in a proceeding concerning such utility, and relating to any standard set forth in subtitle B, such utility shall be liable to compensate such consumer (pursuant to paragraph (2)) for reasonable attorneys' fees, expert witness fees, and other reasonable costs incurred in preparation and advocacy of such position in such proceeding (including fees and costs of obtaining judicial review of any determination made in such proceeding with respect to such position).

(2) A consumer entitled to fees and costs under paragraph (1) may collect such fees and costs from an electric utility by bringing a civil action in any State court of competent jurisdiction, unless the State regulatory authority (in the case of a proceeding concerning a State regulated electric utility) or nonregulated electric utility (in the case of a proceeding concerning such nonregulated electric utility) has adopted a reasonable procedure pursuant to which such authority or nonregulated electric utility—

(A) determines the amount of such fees and costs, and

(B) includes an award of such fees and costs in its order in the proceeding.

(3) The procedure adopted by such State regulatory authority or nonregulated utility under paragraph (2) may include a preliminary proceeding to require that—

(A) as a condition of receiving compensation under such procedure such consumer demonstrate that, but for the ability to receive such award, participation or intervention in such proceeding may be a significant financial hardship for such consumer, and

(B) persons with the same or similar interests have a common legal representative in the proceeding as a condition to receiving compensation.

(b) ALTERNATIVE MEANS.—Compensation shall not be required under subsection (a) if the State, the State regulatory authority (in the case of a proceeding concerning a State regulated electric utility), or the nonregulated electric utility (in the case of a proceeding concerning such nonregulated electric utility) has provided an alternative means for providing adequate compensation to persons—

(1) who have, or represent, an interest—

(A) which would not otherwise be adequately represented in the proceeding, and

(B) representation of which is necessary for a fair determination in the proceeding, and

(2) who are, or represent an interest which is, unable to effectively participate or intervene in the proceeding because such persons cannot afford to pay reasonable attorneys' fees, expert witness fees, and other reasonable costs of preparing for, and participating or intervening in, such proceeding (including fees and costs of obtaining judicial review of such proceeding).

(c) TRANSCRIPTS.—The State regulatory authority or nonregulated electric utility, as the case may be, shall make transcripts of the proceeding available, at cost of reproduction, to parties or intervenors in any ratemaking proceeding, or other regulatory proceeding relating to rates or rate design, before a State regulatory authority or nonregulated electric utility.

(d) FEDERAL AGENCIES.—Any claim under this section against any Federal agency shall be subject to the availability of appropriated finds.

(e) RIGHTS UNDER OTHER AUTHORITY.—Nothing in this section affects or restricts any rights of any participant or intervenor in any proceeding under any other applicable law or rule of law.

(16 U.S.C. 2632)

SEC. 123. JUDICIAL REVIEW AND ENFORCEMENT.

(a) LIMITATION OF FEDERAL JURISDICTION.—Notwithstanding any other provision of law, no court of the United States shall have jurisdiction over any action arising under any provision of subtitle A or B or of this subtitle except for—

(1) an action over which a court of the United States has jurisdiction under subsection (b) or (c)(2); and

(2) review of any action in the Supreme Court of the United States in accordance with sections 1257 and 1258 of title 28 of the United States Code.

(b) ENFORCEMENT OF INTERVENTION RIGHT.—(1) The Secretary may bring an action in any appropriate court of the United States to enforce his right to intervene and participate under section 121(a), and such court shall have jurisdiction to grant appropriate relief.

(2) If any electric utility or electric consumer having a right to intervene under section 121(a) is denied such right by any State court, such electric utility or electric consumer may bring an action in the appropriate United States district court to require the State regulatory authority or nonregulated electric utility to permit such intervention and participation, and such court shall have jurisdiction to grant appropriate relief.

(3) Nothing in this subsection prohibits any person bringing any action under this subsection in a court of the United States from seeking review and enforcement at any time in any State court of any rights he may have with respect to any motion to intervene or participate in any proceeding.

(c) REVIEW AND ENFORCEMENT.—(l) Any person (including the Secretary) may obtain review of any determination made under subtitle A or B or under this subtitle with respect to any electric utility (other than a utility which is a Federal agency) in the appropriate State court if such person (or the Secretary) intervened or otherwise participated in the original proceeding or if State law otherwise permits such review. Any person (including the Secretary) may bring an action to enforce the requirements of this title in the appropriate State court, except that no such action may be brought in a State court with respect to a utility which is a Federal agency. Such review or action in a State court shall be pursuant to any applicable State procedures.

(2) Any person (including the Secretary) may obtain review in the appropriate court of the United States of any determination made under subtitle A or B or this subtitle by a Federal agency if such person (or the Secretary) intervened or otherwise participated in the original proceeding or if otherwise applicable law permits such review. Such court shall have jurisdiction to grant appropriate relief. Any person (including the Secretary) may bring an action to enforce the requirements of subtitle A or B or this subtitle with respect to any Federal agency in the appropriate court of the United States and such court shall have jurisdiction to grant appropriate relief.

(3) In addition to his authority to obtain review under paragraph (1) or (2), the Secretary may also participate as an amicus curiae in any review by any court of an action arising under the provisions of subtitle A or B or this subtitle.

(d) OTHER AUTHORITY OF THE SECRETARY.—Nothing in this section prohibits the Secretary from—

(1) intervening and participating in any proceeding, or

(2) intervening and participating in any review by any court of any action

under section 204 of the Energy Conservation and Production Act.

(16 U.S.C. 2633)

SEC. 124. PRIOR AND PENDING PROCEEDINGS.

For purposes of subtitle A and B, and this subtitle, proceedings commenced by State regulatory authorities (with respect to electric utilities for which it has ratemaking authority) and nonregulated electric utilities before the date of the enactment of this Act and actions taken before such date in such proceedings shall be treated as complying with the requirements of subtitles A and B, and this subtitle if such proceedings and actions, substantially conform to such requirements. For purposes of subtitles A and B, and this subtitle, any such proceeding or action commenced before the date of enactment of this Act, but not completed before such date, shall comply with the requirements of subtitles A and B, and this subtitle, to the maximum extent practicable, with respect to so much of such proceeding or action as takes place after such date, except as otherwise provided in section 121(c). In the case of each standard established by paragraphs (11) through (13) 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 (11) through (13). In the case of the standard established by paragraph (14) 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 paragraph (14). In the case of each standard established by paragraph (15) of section 111(d), the reference contained in this subsection to the date of enactment of the Act shall be deemed to be a reference to the date of enactment of paragraph (15).

(16 U.S.C. 2634)

Subtitle D—Administrative Provisions

SEC. 131. VOLUNTARY GUIDELINES.

The Secretary may prescribe voluntary guidelines respecting the standards established by sections 111(d) and 113(b). Such guidelines may, not expand the scope or legal effect of such standards or establish additional standards respecting electric utility rates.

(16 U.S.C. 2641)

SEC. 132. RESPONSIBILITIES OF SECRETARY OF ENERGY.

(a) AUTHORITY.—The Secretary may periodically notify the State regulatory authorities, and electric utilities identified pursuant to section 102(c)—

(1) load management techniques and the results of studies and experiments concerning load management techniques;

(2) developments and innovations in electric utility rate making throughout the United States, including the results of studies and experiments in rate structure and rate reform;

(3) methods for determining cost of service;

(4) any other data or Information which the Secretary determines would assist such authorities and utilities in carrying out the provisions of this title; and

(5) technologies, techniques, and rate-making methods related to advanced metering and communications and the use of these technologies, techniques and methods in demand response programs.

Deleted: and

Deleted: .

(b) TECHNICAL ASSISTANCE.—The Secretary may provide such technical assistance as he determines appropriate to assist the State regulatory authorities in carrying out their responsibilities under subtitle B and as is requested by any State regulatory authority relating to the standards established by subtitle B.

(c) APPROPRIATIONS.—There are authorized to be appropriated to carry out the purposes of subsection (b) not to exceed $1,000,000 for each of the fiscal years 1979 and 1980.

(d) DEMAND RESPONSE.–The Secretary shall be responsible for–

(1) educating consumers on the availability, advantages, and benefits of advanced metering and communications technologies, including the funding of demonstration or pilot projects;

(2) working with States, utilities, other energy providers and advanced metering and communications experts to identify and address barriers to the adoption of demand response programs; and

(3) not later than 180 days after the date of enactment of the Energy Policy Act of 2005, providing Congress with a report that identifies and quantifies the national benefits of demand response and makes a recommendation on achieving specific levels of such benefits by January 1, 2007.

(e) DEMAND RESPONSE AND REGIONAL COORDINATION.–

(1) IN GENERAL.–It is the policy of the United States to encourage States to coordinate, on a regional basis, State energy policies to provide reliable and affordable demand response services to the public.

(2) TECHNICAL ASSISTANCE.–The Secretary shall provide technical assistance to States and regional organizations formed by two or more States to assist them in–

(A) identifying the areas with the greatest demand response potential;

(B) identifying and resolving problems in transmission and distribution networks, including through the use of demand response;

(C) developing plans and programs to use demand response to respond to peak demand or emergency needs; and

(D) identifying specific measures consumers can take to participate in these demand response programs.

(3) REPORT.–Not later than 1 year after the date of enactment of the Energy Policy Act of 2005, the Commission shall prepare and publish an annual report, by appropriate region, that assesses demand response resources, including those available from all consumer classes, and which identifies and reviews–

(A) saturation and penetration rate of advanced meters and communications technologies, devices and systems;

(B) existing demand response programs and time-based rate programs;

(C) the annual resource contribution of demand resources;

(D) the potential for demand response as a quantifiable, reliable resource for regional planning purposes;

(E) steps taken to ensure that, in regional transmission planning and operations, demand resources are provided equitable treatment as a quantifiable, reliable resource relative to the resource obligations of any load-serving entity, transmission provider, or transmitting party; and

(F) regulatory barriers to improved customer participation in demand response, peak reduction and critical period pricing programs.

(f) FEDERAL ENCOURAGEMENT OF DEMAND RESPONSE DEVICES.–It is the policy of the United States that time-based pricing and other forms of demand response, whereby electricity customers are provided with electricity price signals and the ability to benefit by responding to them, shall be encouraged, the deployment of such technology and devices that enable electricity customers to participate in such pricing and demand response systems shall be facilitated, and unnecessary barriers to demand response participation in energy, capacity and ancillary service markets shall be eliminated. It is further the policy of the United States that the benefits of such demand response that accrue to those not deploying such technology and devices, but who are part of the same regional electricity entity, shall be recognized.

(16 U.S.C. 2642)

SEC. 133. GATHERING INFORMATION ON COSTS OF SERVICE.

(a) INFORMATION REQUIRED TO BE GATHERED.—Each electric utility shall periodically gather information under such rules (promulgated by the Commission) as the Commission determines necessary to allow determination of the costs associated with providing electric service. For purposes of this section, and for purposes of any consideration and determination respecting the standard established by section 111(d)(2), such costs shall be separated, to the maximum extent practicable, into the following components: customer cost component, demand cost component, and energy cost component. Rules under this subsection shall include requirements for the gathering of the following information with respect to each electric utility—

(1) the costs of serving each electric consumer class, including costs of serving different consumption patterns within such class, based on voltage level, time of use, and other appropriate factors;

(2) daily kilowatt demand load curves for all electric consumer classes combined representative of daily and seasonal differences in demand, and daily kilowatt demand load curves for each electric consumer class for which there is a separate rate, representative of daily and seasonal differences in demand;

(3) annual capital, operating, and maintenance costs—

(A) for transmission and distribution services, and

(B) for each type of generating unit; and

(4) costs of purchased power, including representative daily and seasonal differences in the amount of such costs.

Such rules shall provide that information required to be gathered under this section shall be presented in such categories and such detail as may be necessary to carry out the purposes of this section.

(b) COMMISSION RULES.—The Commission shall, within 180 days after the date of enactment of this Act, by rule, prescribe the methods, procedure, and format to be used by electric utilities in gathering the information described in this section. Such rules may provide for the exemption by the Commission of an electric utility or class of electric utilities from gathering all or part of such information, in cases where such utility or utilities show and the Commission finds, after public notice and opportunity for the presentation of written data, views, and arguments, that gathering such information is not likely to carry out the purposes of this section. The Commission shall periodically review such findings and may revise such rules.

(c) FILING AND PUBLICATION.—Not later than two years after the date of enactment of this Act, and periodically, but not less frequently than every two years thereafter, each electric utility shall file with—

(1) the Commission, and

(2) any State regulatory authority which has ratemaking authority for such utility,

the information gathered pursuant to this section and make such information available to the public in such form and manner as the Commission shall prescribe. In addition, at the time of application for, or proposal of, any rate increase, each electric utility shall make such information available to the public in such form and manner as the Commission shall prescribe. The two-year period after the date of the enactment specified in this subsection may be extended by the Commission for a reasonable additional period in the case of any electric utility for good cause shown.

(d) ENFORCEMENT.—For purposes of enforcement, any violation of a requirement of this section shall be treated as a violation of a provision of the Energy Supply and Environmental Coordination Act of 1974 enforceable under section 12 of such Act (notwithstanding any expiration date in such Act) except that in applying the provisions of such section 12 any reference to the Federal Energy Administrator shall be treated as a reference to the Commission.

(16 U.S.C. 2643)

SEC. 134. RELATIONSHIP TO OTHER AUTHORITY.

Nothing in this title shall be construed to limit or affect any authority of the Secretary or the Commission under any other provision of law.

(16 U.S.C. 2644)

Subtitle E—State Utility Regulatory Assistance

SEC. 141. GRANTS TO CARRY OUT TITLES I AND III

[Amends section 207 of the Energy Conservation and Production Act.]

SEC. 142. AUTHORIZATIONS.

[Amends title II of the Energy Conservation and Production Act.]

SEC. 143. CONFORMING AMENDMENTS.

(a) ADMINISTRATOR.—Title II of the Energy Conservation and Production Act is amended by striking out "Administrator" in each place it appears and substituting "Secretary". Section 202(l) of the Energy Conservation and Production Act is amended to read as follows:

"(b) DEFINITION.—

"(1) The term 'Secretary' means the Secretary of Energy".