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**Guidelines to Assist Rural Electric Cooperatives
to Fulfill the Requirements of Sections 201 and 210
of PURPA for Cogeneration and Small Power Production**

National Rural Electric Cooperative Association

ARGONNE NATIONAL LABORATORY
Energy and Environmental Systems Division

prepared for
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GUIDELINES TO ASSIST RURAL ELECTRIC COOPERATIVES TO
FULFILL THE REQUIREMENTS OF SECTIONS 201 AND 210 OF
PURPA FOR COGENERATION AND SMALL POWER PRODUCTION

prepared by
National Rural Electric Cooperative Association
Washington, D.C.
for
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Energy and Environmental Systems Division
under Argonne Contract 31-109-38-6183

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CHAPTER I
INTRODUCTION

The preparation of these guidelines was undertaken by NRECA in recognition of the unique problems and opportunities of rural electric systems regarding the implementation of PURPA Sections 201 and 210. The production of these guidelines was a team effort utilizing NRECA staff and consultants with significant input and strong contributions from several rural electric cooperative systems. These Guidelines were designed to assist all NRECA member systems, but particularly those in a non-regulated state environment who bear the full burden of compliance with Sections 201 and 210 of the Public Utility Regulatory Policies Act.

These Guidelines were structured to meet several anticipated uses, including use as:

- o A self-contained legal, technical and economic reference manual helpful in dealing with small power producers and cogenerators;
- o A roadmap through some of the less obvious obstacles encountered by utilities interacting with small power producers and cogenerators;
- o A starting point for those utilities who have not yet formulated specific policies and procedures, nor developed rates for purchasing power from small power producers and cogenerators;

- o A discussion vehicle to highlight key issues and increase understanding in workshop presentations to rural electric cooperatives; and
- o An evolutionary tool which can be updated to reflect changes in the law as they occur.

The chapters in these Guidelines contain both summary information, such as compliance checklists, and detailed information, such as example avoided cost rate calculations. In addition, the appendices contain more specific material, e.g. rural electric cooperative sample policy statements.

These Guidelines contain four chapters and appendices as outlined below:

- I Introduction - This chapter.
 - II Regulatory Requirements - Presents the legal background necessary to understand the legal requirements and the implications of compliance with Sections 201 and 210 of PURPA for cogeneration and small power production.
 - III Operational Considerations - Considers the technical issues of concern to a utility interconnected with a cogeneration or small power production facility.
 - IV Rate Considerations - Introduces the principles of avoided cost and demonstrates several methods for developing rates for purchases of both firm and non-firm power from cogenerators or small power producers. Discusses options for handling simultaneous buy/sell transactions.
- Appendices - Provides the text of both Sections 201 and 210 of PURPA and of the FERC rules 69 and 70 for implementing the PURPA requirements for cogeneration and small power production. Includes sample metering schemes and costs. Presents step-by-step instructions for example avoided cost calculations. Attaches samples of public hearing notices, policy statements and interconnection contracts being used by utilities. Provides a complete bibliography of useful documents listed by source of document.

CHAPTER II

REGULATORY REQUIREMENTS

This chapter of these Guidelines explains the rules which were issued by the Federal Energy Regulatory Commission in order to meet the requirements that were placed upon the Commission by the United States Congress in Section 201 and Section 210 of the Public Utility Regulatory Policies Act of 1978. The Commission's rules define the circumstances under which an electric cogenerator or small power producer gains the status of a "qualifying facility." These rules give such qualifying facilities several rights, such as the right to sell electric power to electric utilities--including rural electric cooperatives--and also the right to buy electric power from electric utilities. This chapter of these Guidelines explains the rights of such qualifying facilities in order to assist rural electric cooperatives to meet their obligations under federal law and avoid the penalties of non-compliance.

Section A of this chapter reviews the background of the law: Section 201 and Section 210 of the Public Utility Regulatory Policies Act of 1978, and Federal Energy Regulatory Commission's Order Number 69 and Order Number 70.

Section B of this chapter explains when a cogenerator or small power producer becomes a qualifying facility and thereby gains the rights granted under PURPA.

Section C of this chapter explains the rights which are granted to qualifying facilities and the obligations of such as facilities.

Section D of this chapter tabulates the specific regulatory requirements which utilities need to follow.

A. LEGAL BACKGROUND

This section of this chapter reviews the background of the Public Utility Regulatory Policies Act of 1978, Sections 201 and 210, and the Federal Energy Regulatory Commission's Order Number 69 and Order Number 70.

1: PURPA

On November 9, 1978, the 95th Congress of the United States of American enacted Public Law 95-617, called the "Public Utility Regulatory Policies Act of 1978," or "PURPA." One part of PURPA, "Title II - Certain Federal Energy Regulatory Commission and Department of Energy Authorities," contained several Sections--two of which are explained in these Guidelines: "Section 201. Definitions", and "Section 210. Cogeneration and Small Power Production." (See Appendix A.)

Section 201 amends the Federal Power Act by adding the definition of a "small power production facility" and also the definition of a "cogeneration facility." Section 210 says that the Federal Energy Regulatory Commission ("FERC") "shall prescribe ... such rules as it determines necessary to encourage cogeneration and small power production." Sections 201 and 210 also require the FERC to develop the rules to determine the circumstances under which such a cogeneration facility or small power production facility becomes

a "qualifying facility" ("QF"). Section 210 then grants several basic rights to a QF--including the right to sell electric power to utilities (including rural electric cooperatives) and also to buy electric power from those utilities in such a way as to prohibit discrimination by the utilities against the QF.

Commenting upon the objectives of PURPA Sections 201 and 210, the FERC has written:

"Prior to the enactment of PURPA, a cogeneration or small power producer seeking to establish interconnected operation with a utility faced three major obstacles. First, a utility was not generally willing to purchase the electric output or was not willing to pay an appropriate rate. Secondly, some utilities charged discriminatorily high rates for back-up service to cogenerators and small power producers. Thirdly, a cogenerator or small power producer which provided electricity to a utility's grid ran the risk of being considered an electric utility and thus being subjected to extensive State and Federal regulation. Sections 201 and 210 of PURPA are designed to remove these obstacles."1/

2: Orders -69 & 70

The FERC responded to its PURPA duties by publishing proposed rules and discussion during June, 1979. Public hearings were held in San Francisco, Chicago, and Washington during July, 1979. Subsequent public hearings were held

1/ 45 FR 17959, March 20, 1980.

in Seattle, New York, Denver, and Washington during November and December, 1979. The FERC issued revised proposed rules during January, 1980. Additional public hearings were held in February, 1980. The FERC published the final rules in two parts: Order 69 was issued on February 19, 1980 and covered the rights of a QF but did not contain the definition of a QF--the definition of a QF was in Order 70, which was issued on March 13, 1980. Taken together, Orders 69 and 70 form most of Part 292 of Chapter I, Title 18, of the Code of Federal Regulations.^{2/} The FERC published additions, revisions, and corrections to Part 292 on May 5, May 15, August 4, and September 26, 1980; and January 28, 1981. The complete Regulation 292, as of January 28, 1981, is reproduced in Appendix A of these Guidelines.

^{2/} 18 CFR Part 292.

B. QUALIFYING FACILITY

This section explains the circumstances under which a small power production facility or a cogeneration facility becomes a qualifying facility ("QF"). In general, a small power production facility is one that is no larger than 80 MegaWatts (MW). In order for a small power production facility to gain the rights of a QF, the rules require that three - quarters (3/4) of its fuel be other than oil, natural gas, and coal. In general, a cogeneration facility is one that produces both electric power and some additional useful form of energy. In order for an oil or gas fueled cogeneration facility to gain the rights of a QF, then the rules require that it meet certain energy production efficiency tests. There is no size limit upon a cogeneration facility. Any facility which meets the rules is a QF. In addition, a facility can obtain certification as a QF if it so desires.

1: SMALL POWER PRODUCTION FACILITIES

Section 292.203(a) of the rules states that a small power production facility is a QF if it meets three necessary tests simultaneously: 1) size, 2) fuel source, and 3) ownership. A logic schematic for the qualification of a small power production facility is shown in Exhibit II-1.

LOGIC SCHEMATIC FOR THE
QUALIFICATION OF A SMALL
POWER PRODUCTION FACILITY

(a) Size Criteria

The size test, given in Section 292.204(a), is that for a small power production facility to be a QF, then its total capacity, at a given site, using a given fuel, may not be more than 80 MW. Is the size to be measured gross or net of auxiliaries? The rule gives no answer.

(b) Fuel Source Criteria

The fuel source test, given in Section 292.204(b), is that at least three - quarters (more than 75%) of the input energy source must be either biomass ("any organic material not derived from fossil fuels",^{3/} such as municipal refuse, farm products, forest products, sewage treatment residue, and peat^{4/}), or waste ("by-product materials other than biomass"^{5/}, such as flare gas, pet coke, and plastics^{6/}), or renewable resources (solar, wind, hydro, and geothermal)

If additional fuels are used, then no more than 25% of the aggregate input energy source, during a calendar year, can be from non-waste conventional fossil fuels (oil, natural gas, and coal).

^{3/} Section 292.202(a).
^{4/} 45 FR 17960, March 20, 1980.
^{5/} Section 292.202(b).
^{6/} 45 FR 17960, March 20, 1980.

(c) Ownership Criteria

The ownership test, given in Section 292.206, limits the ownership control of a QF to persons other than electric utilities: an electric utility or utilities may not own a majority interest (more than 50%) in any QF.

2: COGENERATION FACILITIES

Section 292.203(b) of the rules states that a cogeneration facility is a QF if it meets four necessary tests simultaneously: 1) ownership, 2) it must not be a new diesel cogeneration facility, 3) sequential use of energy, and 4) efficiency tests--depending upon process and fuel. A logic schematic for the qualification of a cogeneration facility is shown in Exhibit II-2.

(a) Ownership Criteria

The ownership test, given in Section 292.206, is identical for both cogeneration and small power production: an electric utility or utilities may not own a majority interest (more than 50%) in any QF.

(b) New Diesel Exclusion

Diesel manufacturers have been marketing commercial buildings to install oil fueled diesel engines to run generators for electricity, and then blow the diesel's exhaust through a heat exchange to provide space heat and/or hot water

for the building. Environmentalists have warned that large scale market penetration by such cogenerators might endanger air quality.^{7/} The FERC responded by writing Section 292.203(c) of the rules which excludes a diesel cogeneration facility from gaining the rights of a QF if the facility was built after the rules (after March 13, 1980).

(c) Sequential Energy Use

PURPA Section 201(18)(A) defines a cogeneration facility as one which produces both electrical power and also other useful forms of energy (such as steam, or heat) "which are used for industrial, commercial, heating, or cooling purposes"^{8/} (Note that the "heating, or cooling purposes" can be residential.^{9/}). The FERC wrote Section 292.202(c) of the rules to require cogeneration facilities to use energy in a sequential process in order to be a QF. For example, consider a steam plant with one steam line into a turbine which drives an electric generator, and a second steam line which is used to space heat the plant during winter: such

^{7/} 45 FR 17974, March 20, 1980.
^{8/} FPA Section 3(18)(A)(ii).
^{9/} 45 FR 17960, March 20, 1980.

LOGIC SCHEMATIC FOR THE
QUALIFICATION OF A
COGENERATION FACILITY

a plant is a cogeneration facility because it does produce both electricity and useful space heat. Is such a plant a QF? Such a plant is not a QF if both steam lines come from the boiler (parallel use). Such a plant may be a QF if the input to the steam line for the space heat is the exhaust output after the turbine (sequential use).

The FERC wrote the sequential use rule in order to impose a duty of greater energy use efficiency upon a QF.

"The final rules contain an explicit requirement for the sequential use of energy in cogeneration facilities. This means that rejected heat from a power production or heating process is used in another power production or heating process. It is precisely this "cascading" use of energy in sequential process that gives rise to the energy conserving characteristic of cogeneration."^{10/}

(d) Efficiency Tests

The efficiency tests for cogeneration facilities differ according to which process sequence is employed by the facility. In general, the tests attempt to write formulas which require savings in oil or gas usage. In fact, Section 292.205(d) of the rules allows for a waiver of each particular efficiency test formula "upon a showing that the facility will produce significant energy savings" of oil and gas.

^{10/} 45 FR 17960, March 20, 1980.

The rules divide cogeneration into two classes, based upon which process is first in the sequential use of the facility's energy:

o Topping-Cycle. See Exhibit II-3. Section 292.202(d) of the rules defines a Topping-Cycle as one where the primary energy input ("A" in Exhibit II-3) is first applied to the power production process. The power production process yields both useful power ("C"), as defined in Section 292.202(g); and also reject heat for input to the thermal process (for example, process steam). The thermal process may also require supplementary firing ("B"), defined in Section 292.202(f), if the reject heat is insufficient for the needs of the thermal process. The thermal process has a useful thermal output ("D"), as defined in 292.202(h).

- Section 292.205(a)(1) requires that D be no less than 5% of C+D.

- Section 292.205(a)(2)(i)(A) requires that $100\% C + 50\% D$ must be no less than 42.5% of the oil and gas part of A+B, if the facility was built after the rules (after March 13, 1980).

TOPPING - CYCLE
COGENERATION
FACILITY

EXHIBIT II - 3

II-14

TOTAL ENERGY
INPUT = A + B

- Section 292.205 (a)(2)(i)(B) requires that 100% C + 50% D must be no less than 45% of the oil and gas part of A+B, if D is less than 15% of C+D and if the facility was built after the rules (after March 13, 1980).

o Bottoming-Cycle. See Exhibit II-4. Section 292.202(e) of the rules defines a Bottoming-Cycle as one where the primary energy input ("A" in Exhibit II-4) is first applied to the thermal process (for example, a kiln). The thermal process' reject heat is next input to the power production process. The power production process may also require supplementary firing ("B"), defined in Section 292.202(f), if the reject heat is insufficient for the needs of the power production process. The power production process has useful power output ("C"), as defined in Section 292.202(g).

- Section 292.205(b)(1) requires that C be no less than 45% of the oil and gas part of B, if the facility was built after the rules (after March 13, 1980).

o Combined-Cycle. A combined cycle electric power plant is one in which the primary energy input is first applied to the first of two power production processes; the reject heat from the first power production process, plus supplementary firing, is next applied as the input to the second power production process. Of such a facility, the FERC writes:

BOTTOMING - CYCLE
COGENERATION
FACILITY

EXHIBIT II - 4

II-16

"The Commission is of the opinion that combined-cycle electric generation plants are not cogeneration facilities, since only one form of energy is produced."11/

Thus a combined-cycle electric power plant can not be a QF--unless it is a QF by reason of being a small power production facility.

But what about a combined-cycle cogeneration plant? For example a facility with 1) a first thermal process, followed by 2) a power production process, followed by 3) a second thermal process. The rules do not seem to cover such a combined-cycle cogeneration plant.

3: PROCEDURE

If a facility meets all of the requirements of section 292.203 of the rules (all of which were explained above in these Guidelines) then that facility becomes a QF as of the time that its owner notifies the FERC. (See Section 292.207(a) of the rules.)

11/45 FR 17961, March 20, 1980.

On the other hand, if the owner of a facility so desires, then that owner may instead apply to the FERC for certification as a QF under the procedures listed in Section 292.207(b) of the rules. The FERC will then decide the facility's status. (The certification procedure would likely be used by the planner of a QF in order to obtain financing for the proposed project.)

C. RIGHTS AND OBLIGATIONS

This section explains the rights of a QF, and the mutual obligations between a utility and a QF that result from PURPA Sections 201 and 210, and the FERC's rules.

1. INTERCONNECTION

A QF has the right to interconnect with a utility. The utility has an obligation to interconnect with the QF.* (Section 292.203(c) of the rules.)

* Exception If some electric utility is exempt from regulation under Part II of the Federal Power Act, and if by reason of the interconnection with a QF that utility would lose its exemption, then that utility is excused from the obligation to interconnect with the QF. (Section 292.303(c)(2).)

The QF is obligated to pay "non-discriminatory" reasonable interconnection costs (Section 292.306). However, the costs of interconnection are:

"the reasonable costs of connection... incurred by the electric utility... to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had... instead generated an equivalent amount of electric energy."^{12/}

Thus, if a QF were located at a favorable site (e.g. near an existing substation) and if the utility had been planning a capacity expansion which involved expensive interconnection (e.g. a new transmission line) then the net difference in interconnection costs, chargeable to the QF, can be zero.

2: PARALLEL OPERATION

A QF has the right to operate his generation in parallel (synchronism) with the utility. The utility has the obligation to operate in parallel. (Section 292.303(e).) The QF has the obligation to meet reasonable standards of safety and reliability. (Section 292.308.)

^{12/} Section 292.101(b)(7).

3: BUY/SELL

A QF has the right to sell any part or all of his generation to a utility; the utility has an obligation to buy whatever power the QF may desire to sell. (Section 292.303(a).) A QF has the right to buy any part or all of his load from the utility; the utility has the obligation to sell whatever power the QF may desire to buy. (Section 292.303(b).)

Therefore, as is illustrated in Exhibit II-5, at his option, the QF may elect to exchange power on a net basis where the utility's point of metering ("M") is on the utility's side of the QF's generation ("G") and load ("L"). On the other hand, as is also shown in Exhibit II-5, at his option, the QF may elect to sell all of his generation ("G") and buy all of his load ("L") on a gross basis such that the utility's two points of metering ("M") would be as shown.

4: WHEELING

A QF can decide to interconnect and exchange power with his local utility -- he cannot be required to deal with some other non-local utility and have his power wheeled to that non-local utility by his local utility. The local utility can decide to buy the QF's power for itself -- the QF cannot require his local utility to wheel his power to some other utility.

"... this transmission can only occur with the consent of the utility to which energy or capacity from the qualifying facility is made available. Thus, no utility is forced to wheel.

But, if a QF and his local utility both agree, then they can transfer the utility's obligation to the QF onto another utility--who need not agree to the transfer of obligation (Section 292.303(d).) In this case, the local utility wheels the QF's power to the second utility. The local utility could negotiate "wheeling fees" as part of the agreement with the QF.

If, in turn, both the QF and the second utility agree, then the obligation and the power can be transferred to a third utility ... etc. Thus, if several utilities agree, the rules seem to admit the possibility of the electric output from a windmill in Arkansas being paid for by the Consolidated Edison Company in New York City.

5: ALL - REQUIREMENTS CONTRACTS

The FERC had rural electric distribution Cooperatives in mind when it wrote:

"... with regard to all-requirements rural electric cooperatives, any impairment of the obligation to obtain all of a cooperative's requirements from a generation and transmission cooperative might affect the financing ability of the generation and transmission cooperative. The commission observes that, in general, if it permitted such contractual provisions to override the obligation to purchase from qualifying facilities, these contractual devices might be used to hinder the development of cogeneration and small power production. The commission believes that the mandate of PURPA to encourage cogeneration and small power production requires that obligations

to purchase under this provision supersede contractual restrictions on a utility's ability to obtain energy or capacity from a qualifying facility. The Commission has, however, provided an alternate means by which any electric utility can meet this obligation. Under paragraph (d), if the qualifying facility consents, an all-requirements utility ... would be permitted to transmit the energy or capacity to its supplying utility."14/

That is, a QF's desire for interconnection with his distribution cooperative out ranks an all-requirements G&T contract. But if the QF and his distribution cooperative both agree, the G&T becomes obligated.

14/ 45 FR 12219, February 25, 1980.

QF'S NET BUY/SELL OPTION

QF'S GROSS BUY/SELL OPTION

On the other side of the coin, when the utility sells power to the QF, then the utility

"Shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility."^{15/}

Rates for transactions between a utility and a QF are of such importance that Chapter IV of these Guidelines are devoted to rate considerations.

D. SPECIFIC REQUIREMENTS

This section explains some of the specific requirements with which a utility must comply: public hearings, reports, data filings, and a standard rate for small QF's.

1: IMPLEMENTATION

Section 292.401 of the rules divides utilities into two implementation categories: "regulated" and "nonregulated."

^{15/} Section 292.305(a)(1)(ii).

(a) Regulated Utilities

Regulated electric utilities are those regulated by their State's regulatory authority (State Commission). By March 20, 1981, the State regulatory authorities are required to hold public hearings upon their utilities' implementation plans, and then file a report on those plans with the FERC.

(b) Non regulated Utilities

Nonregulated electric utilities are those utilities who are exempt from regulation by their State's regulatory authority (if any). ALL NONREGULATED ELECTRIC UTILITIES ARE REGULATED BY THE FERC, in so far as PURPA Sections 201 and 210 are concerned. By March 20, 1981, nonregulated utilities are required to hold a public hearing on their implementation plan, and then file a report on that plan with the FERC. Appendix E presents sample public hearing notices.

2. DATA PUBLICATIONS

In order to assist potential OF's with their cost/feasibility studies, rule Section 292.302 requires utilities to publish their cost data -- current and forecasted. This includes decremental energy costs for the next five years, capacity expansion plans for the next ten years, and forecasts of the costs for those capacity expansion plans.

Utilities with sales to end-use customers in excess of one billion kilowatt-hours per year must publish their cost data by March 20, 1981. Those with sales between 500 million and one billion kilowatt-hours must publish their cost data by May 31, 1982. Those with sales under 500 million kilowatt hours need not publish their cost data, but must provide that data upon request.

Utilities with all-requirements contracts can elect to simply republish their supplier's cost data.

3: STANDARD RATE

Section 292.304(c) requires each utility to provide a standard (class) rate for QF's "with a design capacity of 100 kilowatts or less." There can be a different class rate for each different supply technology. For example: one small QF rate for windmills, another small QF rate for small scale hydro. The standard rate(s) must be available by March 20, 1981.

The utility can also provide standard rates for QF's larger than 100 kw -- or deal with each larger QF on a case-by-case basis.

4: CHECKLIST

In summary, each electric utility should complete the following tasks by March 20, 1981:

- o Prepare an implementation plan on how to meet the utility's obligations to QF's.
- o Hold hearings on that implementation plan -- either before the State regulatory authority or in other public meetings.
- o File a report on the implementation plan -- either with the State regulatory authority or with the FERC.
- o Prepare a capacity expansion plan.
- o Prepare cost data -- current and forecasted -- on energy and the capacity expansion plan.
- o Publish that cost data -- or make data available upon request -- depending upon the size of your annual end-use sales.
- o Provide a standard rate for QF's under 100 kw.

6: RATES

In wholesale power interchanges between generation utilities, the buying utility computes the decremental costs which it avoided by purchasing--rather than generating--the transacted power; and the selling utility computes the incremental costs which it incurred by generating the power. The buyer's decremental avoided costs always exceed the seller's incremental incurred costs--because otherwise the buyer would have generated the power himself. The gap between the decremental avoided cost and the incremental incurred cost

is the savings achieved by the transaction. The buyer and the seller have, historically, agreed to share the savings equally--the so called "split savings" of economy transactions between utilities. Thus, both utilities are motivated to engage in power transactions.

In an effort to maximize the encouragement of small power producers and cogeneration facilities, the FERC has decided to abandon the historic tradition of the split savings. Instead, the FERC has decided to give all of the transaction savings to new qualifying facilities. Section 292.304(b)(2) holds the utility's purchase from the QF to be satisfactory when the rate for the purchase equals the utility's entire avoided cost -- including both energy and capacity avoided costs. No benefit is retained by the utility. The utility breaks even.

CHAPTER III

OPERATIONAL CONSIDERATIONS

This chapter of these Guidelines considers some of the technical issues which are of concern in the operation of a rural electric system in parallel with (connected to) a qualifying small power production or cogeneration facility. The emphasis will be on the smaller generating facilities rated at approximately 100 kW or less, which are usually connected to distribution lines and receive little individual engineering attention. Larger generating facilities for parallel operation require more detailed engineering attention and are more familiar in utility experience, and therefore will not be given detailed attention in this chapter.

This chapter is organized into the following three Sections:

- o Section A - Is an introduction to technical questions and concerns which deserve attention.
- o Section B - Gives an overview of the characteristics of the types of generation and interfacing apparatus which a qualifying facility might employ.

- o Section C- Summarizes the main concerns which an electric utility should bear in mind in assessing the possible impact of qualifying facilities on the electric system.

A. INTRODUCTION TO QUESTIONS AND CONCERNS
OF THE ELECTRIC UTILITY

The new requirements to connect dispersed, uncontrolled generators to electric distribution facilities raise complex issues and questions, each of which will require thoughtful attention. These requirements, and the related rules and regulations, require decisions that will have an impact on many aspects of electric utility planning, design and operation. Implementation is required to commence not later than March 20, 1981. Chapter II of these Guidelines has explained the PURPA legislation and the FERC rules and regulations.

The concerns in this chapter are based upon the rules that require the utility to interconnect with qualifying facilities, to purchase energy and to provide the QF with electric service (supplementary, back-up, interruptible and/or maintenance power) when requested.^{1/}

^{1/} Section 292.101(b).(8), (9), (10), (11).

To discuss the questions and operational concerns that arise as utilities begin to implement the FERC rules, it will be helpful to identify some of the key issues. In approximate order of importance, they appear to be as follows:

1: SAFETY

To avoid accidental energizing of facilities by independently owned generators, how much reliance can be placed upon isolation devices which are provided by the qualifying facility? What additional apparatus should be required for compliance with work rules and Code requirements? What additional work procedures will be required for line repairs?

2: EQUIPMENT AND LINE PROTECTION

How do we assure that line sectionalizing devices will operate correctly with the independent generators operating in various combinations? How do we assure that power system apparatus, the generators and other consumer-owned property will be adequately protected against damage under normal and abnormal conditions?

3: VOLTAGE

What is the probability of problems with voltage flicker, voltage surges and/or voltage unbalance from operation of the generators? Who pays for correction of such problems if they occur?

4: HARMONICS, DISTORTION AND INTERFERENCE

If interference problems result from operation of the QF, who is available to provide assistance? At whose expense? Should generators and converters be required to meet specific wave shape and noise objectives?

5: METERING

What metering practices can be employed to implement the rates for energy purchase and energy sales?

Other issues and concerns include standards and requirements to be met by qualifying facilities prior to parallel operation, insurance needed by the owner of the qualifying facility and the utility and the need for public information to correct misunderstanding and misinformation.

B. CHARACTERISTICS OF GENERATORS AND INTERFACING APPARATUS

A QF for small power production may utilize wind, solar, biomass, geothermal, hydroelectric or other renewable energy resources. For cogeneration, the facilities may consist of turbine driven or engine driven generators utilizing steam, waste heat or combustible gas. These facilities may be relatively predictable and constant (hydro, geothermal or waste heat from an industrial process), or as variable and unpredictable as the wind.

For any of these energy sources, the electrical apparatus feeding energy into the utility system will be one of three general types: a synchronous generator, commonly referred to as an alternator; an induction generator; or one of several descriptions of static converter to match a dc or variable frequency source to the 60 Hz utility system frequency. The differences in behavior of these "generators" are important to the electric utility.

1: GENERATORS FOR PARALLEL OPERATION

The generators used for ac power production are either induction generators, which are widely used for intermediate or smaller sized generators, and synchronous generators, which are usually referred to as alternators. Alternators are used in most of the largest capacity installations, including giant steam turbine generators. However, small alternators including permanent magnet types are also appearing in wind energy systems with rated outputs as low as 1 to 10 kw.

(a) Induction Generators.

An induction generator is like an induction motor, operated as a generator by being driven above synchronous speed. Induction generators are self-regulating in adjusting to varying torques and load conditions, and can act as motors for starting. They present a lagging reactive load to the electric system when generating as well as when acting as motors.

Induction generators, as used for parallel operation, depend on the utility system for control of speed and frequency and also for exciting current, unless capacitors are connected to provide excitation.

Induction generators have advantages over alternators in simplicity of control and start-up, and in some situations, in their ability to re-establish normal operation after electrical and mechanical transients. Also, induction generators automatically cease generating when the utility source is cut off, (unless capacitors are connected), thus reducing the possibility of hazardous voltages being produced by the isolated generator.

(b) Synchronous Generators.

Synchronous generators (alternators) must run, like electric clock motors, precisely in step with the electric system frequency. An alternator therefore requires special circuitry and controls for synchronizing before it connects to the electric utility source. Alternators can generate electricity at unity power factor or at leading power factor. Because they are self excited, they can operate independently of the central station source.

Alternators may also operate at variable speed and frequency, and this is done in some applications. The resultant variable-frequency output is then used directly in resistance loads such as heating, or rectified to charge batteries, or fed into a static converter for conversion to 60 Hz for parallel operation with a utility system

(c) Direct Current Generators

Direct current generators can be used in complete dc battery systems or, without batteries, to serve loads such as water heating which provide their own energy storage. For ac applications, dc generators (with or without batteries) are used with static inverters to serve ac loads and/or feed energy into the electric utility system. With developing technology, dc "generators" may include photovoltaic or electrochemical sources (fuel cells) as well as rotating machines.

2: STATIC CONVERTERS

The modern converter is a solid state apparatus, without moving parts, which converts ac to dc, dc to ac, or ac to ac at another voltage and frequency. This type of apparatus is usually referred to as a rectifier when used only for ac to dc conversion, or as an inverter when used for dc to ac conversion.

The converter or inverter performs an important function in matching a variable-frequency or dc source to the 60 Hz utility frequency, and by regulating power flow. However, these

benefits are bought at a price in terms of additional complexity, losses, reactive power requirements and/or quality (wave form) of the electrical output. These characteristics, and differences between types of converters, should be recognized in engineering decisions involving power production systems with or without converters and, if a converter is to be used, in specifying performance characteristics.

(a) Line Commutated Converters.

Line commutated converters are dependent on an ac source, such as the utility system, for their operation. They are not capable of operating by themselves. They require lagging reactive kvars which may be equal to or greater than the kW rating of the converter. The chopped-wave output of these converters may cause heating in motors, metering errors and electrical interference problems.

(b) Self Commutated Converters

Self commutated converters generally cost more than line commutated converters of equal capacity but are capable of producing a better output wave form, do not require a central station ac source, and can operate by themselves to supply standby power.

The term "synchronous inverter" may be applied to either a line commutated or self commutated device which is triggered by the utility source and therefore synchronizes its output with the utility.

In the section which follows, additional information will be given regarding harmonics, wave shape distortion and interference.

C. UTILITY CONCERNS WITH PARALLEL OPERATION

The many questions about wind energy systems or other consumer-owned generation, revolve mostly around the issues relating to costs and benefits. What will be incurred costs by the owner of the qualifying facility to pay for controls, protective apparatus and wiring? What amounts are necessary for the utility to spend for metering, switching and protective apparatus in order to accommodate the power producer? These amounts, to the extent that they exceed the utility's costs had they not obtained power from the QF, are chargeable to the QF. (See chapter II, Section C. 1:(b) these Guidelines.)

Another issue, less often thought of, is complexity. How does the would-be owner of a QF gain enough knowledge, about such things as wind conditions or stream flow, siting and apparatus to decide correctly about type of equipment and where and how to install it or, indeed, whether any generating system will deliver the results he expects? Can he manage the operation of a power production facility?^{2/}

^{2/} For further discussion of utility and owner-operator concerns, see Report on Problems Associated with Interconnection of Wind Generators with Rural Distribution Lines, Report on Research Project 80-2, NRECA, Washington, D.C. 1980 (not dated).

The utility, meanwhile, has its own set of problems in deciding how to operate in parallel with uncontrolled generation while maintaining standards of service in all respects, and in providing terms for purchase and sales of energy that will meet the FERC's rules. Considering these constraints, what should the costs be for the protection apparatus required?

1: SAFETY

The first concern that is usually expressed by electric utility people about dispersed generation is whether an uncontrolled generator might possibly be able to energize an isolated section of line that has been cut off from the central station source. The scenario pictured is one in which a fuse or oil circuit recloser operates to isolate a section of line on which one or several generators are operating. The combination of generator(s), line capacitance and load may be such that the generators keep operating with voltages and frequency uncontrolled. The line section could remain energized at a voltage that presents unacceptable hazards to line crews and the public, and could cause damage to utility or consumer property including generators.

The scenario could be aggravated for a three phase generator if one phase of the three phase supply line were disconnected. The generator would concentrate its output on the isolated phase, trying to maintain voltage on the faulted

phase. This phenomenon is sometimes experienced with three phase motors, but a generator has greater capability for sustained operation under these conditions.

Accidental energizing is possible with any generator that is capable of independent operation, and this includes alternators and self commutated converters which generate their own triggering signals. Induction generators can operate independently if sufficient capacitors are connected in the vicinity to provide excitation. Capacitors at an induction generator for power factor correction, or line capacitors on the isolated phase(s), may result in sustained output at a voltage and frequency determined by the circuit constants and generator speed. Line commutated converters are not regarded as capable of isolated operation, since they depend on the utility source for commutation (switching to provide ac) as well as for lagging kvars.

Commercially available wind energy systems generally have built-in protection circuitry to cause automatic shut down in response to conditions such as high or low voltage, overspeed, underspeed and frequency variations. A momentary loss of voltage, as from an automatic reclosing fuse or breaker, should result in automatic shut down. Similar features can be included in other small power production apparatus including any which employ a static converter. Unfortunately, however, independently owned apparatus can be modified or exchanged for other components, or protective apparatus can be bypassed or

defeated. For example, the owner of a QF experiencing an emergency for lack of electric power might bypass the protection circuitry in order to continue operation.

With safety involved, the utility must be conservative in requiring a disconnecting means under its control to assure isolation of the independent generator. Work rules may require visual verification or other positive assurance of disconnection before crews can work on a de-energized line, thus adding to operations and maintenance expenses.

2: EQUIPMENT AND LINE PROTECTION

Parallel generation introduces variables in distribution line protection in at least two ways. First, the coordination of fuses and other sectionalizing devices may be affected by generator contributions to fault currents. Secondly, consumer-owned generators need to be protected against abnormal power circuit conditions, including operation of utility line protective devices.

(a) Line Sectionalizing.

Line sectionalizing studies should be checked to verify correct operation of sectionalizing devices over the range of conditions that could arise with various combinations of generators operating. Small generators, with rated outputs of a few kW or less, are not likely to contribute significantly to

fault currents. However, cogeneration or small power production in higher ratings, such as tens of kW or more, may be significant in this respect.

(b) Coordination with Generator Protection

Generators in parallel with the utility system need protection against overload and against operation of sectionalizing devices which momentarily deenergize and then reenergize the line. For example, an oil circuit recloser (OCR) responds to a fault, such as a tree limb against a conductor, by deenergizing the line for approximately one-quarter to one second, and then recloses to restore service in the event the fault was temporary. This operation may be repeated up to three times, depending on the recloser setting, before the OCR goes to "lock-out", leaving the line deenergized. Such alternate connecting and disconnecting can cause damage to the generator or the driving machine such as a wind turbine.

Additional problems may arise for a three phase generator if one or two phases, but not all phases from the central station source become disconnected. In such a situation, the generator might partially energize the disconnected phases, with possible damage to utilization equipment of the owner or his neighbor, or to the generator. It is hardly feasible to

provide adequate protection in all such situations by means of apparatus on the utility facilities. To be fully effective, protection should be designed and installed as part of the power production facility.

(c) Quality of Voltage

Problems with flicker and with alternately bright and dimming lights are usually associated with varying loads and motor starting currents on the same power circuit. They may also be caused by generators with varying output. Likely sources for such problems in small power production are from wind turbine generators, since wind is apparently the most variable of the energy sources available.

Voltage surge and flicker problems can result from frequent cut in and cut out of wind turbine generators as winds reach or exceed the required velocities, or from starting currents of generators that are not self starting, or changes in the energy source (wind or sun) that cause changes in output. The severity of voltage fluctuations, and the number of consumers affected, depend on the type and design of generator as well as the size. The effects of gusting winds can be minimized with speed control devices on wind turbines. Starting currents can be reduced by use of reduced voltage starting or eliminated by using self starting turbines.

Voltage problems are related quite directly to the size of the generator as compared with the capacity of the circuit to which it is connected. The greatest effects are on the premises of the owner of the generator or others served by the same transformer. The likelihood of problems from a single QF can be minimized if the rated output is limited, for example, to 50 percent of the distribution transformer rating; or two to ten kW for a single phase unit, depending on distance from the substation; or 25 to 100 kW for three phase units with the largest allowed only in locations near the substation. However, other problems with voltage control may arise as additional QF's are connected, if the aggregate capacity of generators becomes significant compared with total load.

If the total capacity of uncontrolled generators becomes large compared with minimum load on a feeder or or substation, voltage regulators may be subject to more severe duty, requiring increased maintenance. A wider range of regulation, calling for additional line regulators may become necessary. Electric system operating conditions can vary from minimum load with all generators operating to full load with all generators off.

For reasons of voltage control and stability of operation, limitations are necessary on the maximum unit size and on the maximum total generating capacity that can be allowed on a line or substation without special analyses and possibly costly

system improvements. The total rated capacity without special study might need to be restricted, for example, to 50 percent of the line or substation minimum load. Otherwise, the connection costs might need to include the cost of increased circuit capacity or a separate circuit for the power producers. Similarly, special analysis should be required prior to commitments, for service to individual QF's larger than those mentioned above, in order to anticipate connection costs that may prove to be prohibitive.

3: HARMONICS, DISTORTION AND INTERFERENCE

Alternating current electric systems and most kinds of electrical apparatus and appliances are designed to operate with a relatively smooth, undistorted wave form. Distortions, when they occur, are in the form of harmonics or multiples of the 60 Hz fundamental frequency; for example, the third, fifth and seventh (180, 300 and 420 Hz). Excessive levels of harmonic voltages and currents such as voltage or current distortion factors exceeding 10 percent, may cause errors in watthour meter registration, excessive heating of motors and heating and possible breakdown of capacitors. Lower levels of harmonics may interfere with voice or data communication circuits or ripple-type (audio frequency) load management signals.

When interference (or inductive coordination) problems arise, the electric utility is normally considered to be the party responsible, since the interfering harmonics are flowing in its lines. Testing, analysis and corrective measures are costly and time consuming, particularly if the offending harmonics are from several sources. Although corrective actions, if required, are the responsibility of the owner of the qualifying facility, the burden of proof, of testing, analysis and negotiation, falls upon the utility. Also, it is the utility that is usually called upon for advice and assistance, or for the hard decision that the a QF causing difficulty must be shut down.

Interference from induction generators and alternators may be heard in a telephone receiver as high pitched, singing sounds, which are familiar to many who use telephones in or into rural areas. The strength of harmonics in electric line conductors depends on design as well as size of the generators, and also on the location at which they happen to be connected and whether the line is lightly or heavily loaded. Experience with motors of similar size may provide a basis for judging whether power production facilities may cause troublesome interference. However, a long, lightly loaded distribution line may be 100 times more vulnerable to interference problems, than a shorter line with more typical load density.

Static converters, inverters and rectifiers cause severe waveform distortions because of the abrupt commutating or switching action which occurs in each half cycle of the voltage wave. The voltage wave form is usually smoothed when the ac output is connected to a utility line because the capacity of the electric system is very large compared with that of the converter. However, the harmonic currents produced by the converter flow along the electric line and contribute to the power circuit "influence" which is a measure of its tendency to cause interference on nearby communication facilities. The characteristics of converters are such that the harmonics which may be produced are over the entire spectrum, from the lower order harmonic frequencies (3rd, 5th, 7th and possibly 2nd, 4th, 6th) through the full audio range and into the RF spectrum. Filtering, if required, is likely to be difficult and costly because of the presence of the lower order harmonics.

Converter output wave form can be improved at additional cost by incorporating filtering or other changes in the converter. Pulse width modulation may be incorporated, utilizing multiple pulses rather than a single pulse each half cycle to eliminate the lower order harmonics and reduce the costs of filtering. Additional information, including design objectives, is given in IEEE Standard 519-1980, IEEE Guide for Harmonic Control and Reactive Compensation of Static Power Converters.

4: METERING PRACTICES

Rates for the purchases of electric energy from a qualifying facility and rates for sales to the facility should be in accordance with the PURPA rules and FERC regulations which were described in Chapter II. Specific rate questions will be discussed in Chapter IV.

Metering requirements are determined by the needs of both the qualifying facility and the utility. The QF may wish only to sell energy; or to simultaneously sell generated energy and purchase energy (gross sales and purchases); or to sell only surplus energy and purchase supplementary energy when needed (net energy purchase or sale). Metering should be recognized as the means for obtaining data which will permit purchase and sale of energy on terms that are fair and reasonable (not discriminatory), as well as being the "cash register" for sales and purchases.

Elaborate metering, while desirable for obtaining accurate information, can result in unacceptably high connection costs for a small qualifying facility. On the other hand, when a simplified arrangement with only one or two watthour meters is used, it is important to recognize the significance of the quantities measured, and of other quantities such as load factor and power factor that are not being measured. Low load factor and low power factor tend to increase the costs of service and therefore may be significant in ratemaking.

(a) Net Energy Metering

The simplest metering connection for a consumer who is also a small power producer, is with one watthour meter connected as shown in Appendix B (Option 1). In this arrangement, the generator may supply part or all of the electrical load at the owner's service. Only the loads in excess of the generator output, including those when the generator is shut down, are supplied by the utility and registered by the watthour meter. When the generator's output is in excess of the owner's electrical load, then the surplus energy is fed back into the utility system and causes the watthour meter to rotate backward. At all times, the utility source controls the frequency, stabilizes the voltage, supplies back-up power and lagging kvars if required and accepts excess output from the generator when that is necessary.

(b) Surplus Energy Metering

To measure separately the surplus energy generated and the net kWh consumed, two meters may be connected where one measures net consumption whenever the amount used exceeds the amount generated. The other meter operates only to register the surplus energy delivered to the utility when the generator is producing electrical output that is not being used.

(c) Gross Energy Metering

For gross energy metering, two watthour meters may be connected to separately measure the kWh produced and the kWh consumed, as in Appendix B (Option 2). This arrangement provides more complete data on the electrical energy generated and consumed. Additional metering for reactive power or power factor or for time-of-day data may be added if desired.

(d) Engineered Metering

The simple watthour metering methods discussed above should be adequate for small qualifying facilities (under 100 kW), if enough data are available for establishing that the standard rates being applied are fair and nondiscriminatory. However, additional metered data may be needed even on the smaller qualifying facilities until some experience has been gained, to indicate cost-related characteristics for purposes of developing rates. On larger facilities, additional metered data are necessary for more accurate calculations of amounts paid and amounts billed to the QF.

Capacity data can be provided by indicating demand registers on watthour meters.

Reactive volt ampere hours (varhours) can be metered with a varh meter, which is a watthour meter with phase shifters.

Time-of-day data requires pulse generators on watthour and varhour meters along with a magnetic tape demand recorder, unless a more complex and costly telemetering facility is being employed.

Illustrations of five different metering options that may be appropriate in various circumstances are shown in Appendix B. Estimated 1980 costs for each option and costs added because of the QF are shown in the figures. The costs do not include instrument transformers that might be used for interconnections above 240 volts and 200 amperes, nor do they allow for additional costs of three-phase metering.

CHAPTER IV
RATE CONSIDERATIONS

This chapter of these Guidelines discusses the rate considerations appropriate to the business transactions between a rural electric cooperative and a qualifying facility--small power production or cogeneration facility. This chapter is divided into the following thirteen sections:

- o Section A - Introduction
- o Section B - Principles of Avoided Cost
- o Section C - Rates Based on Avoided Costs
- o Section D - Avoided Costs for Non-Generating
Cooperatives
- o Section E - Standard Rates under 100 KW
- o Section F - Firm vs. Non-Firm Purchases from QF's
- o Section G - Calculation of Avoided Cost (Non-Firm Power)
- o Section H - Calculation of Avoided Cost (Firm Power)
- o Section I - Rates for Sales to QF's
- o Section J - Simultaneous Buy/Sell Options
- o Section K - Requirements to File Cooperative System
• Cost Data
- o Section L - Accounting Procedures
- o Section M - Contract and Wheeling Issues

A. INTRODUCTION

Cooperatives will no doubt approach rate design to meet intent of PURPA as noted by FERC in its comments published with rules 69 & 70 with their traditional desire to balance financial, economic, engineering and strategic goals. It was clearly the intent of Congress in sections 201 and 210 of PURPA that rates should not be discriminatory to the utility's current customers^{1/} nor to the qualifying facility owner^{2/}(s).

This chapter deals with the issues of rate design based on the principles of avoided costs. Rates for firm and non-firm power are discussed and examples of calculating avoided costs and other rate issues such as by/sell provisions and accounting procedures are presented.

B. PRINCIPLES OF AVOIDED COST

Avoided costs are basically the incremental costs (either additional demand or energy costs, or both) that a utility

^{1/}Section 292. 304

^{2/}Section 292.305(a)

would have to incur to generate or purchase power if there were no qualifying facilities on the system.

Energy costs are the variable costs representing the cost of fuel and a portion of the operating and maintenance expenses associated with the production of electricity. Capacity costs are the costs associated with a utility's being ready to serve a customer at any particular point in time; they consist primarily of fixed and/or capital costs of owning facilities.

Avoided costs are basically clear in theory only. The calculation of "true" avoided costs is virtually impossible because of the many assumptions, forecasts and judgements that have to be considered. Since only an estimate of "true" avoided costs is possible, the avoided cost methods presented in these guidelines should by no means preclude the development and use of other approaches.

If, by purchasing electric energy from a QF, a utility can reduce the energy production on its own system or the purchase of energy from another power supplier, the purchase rate should reflect the energy cost the utility is avoiding. If a QF offers energy of sufficient reliability and with contractual guarantees of deliverability to the utility so that it allows the utility to avoid or defer the need to construct a generating unit, or to build a smaller, less expensive plant, or to reduce the firm

power purchase from another power supplier, then the rates for such a purchase should reflect both the avoided capacity and energy costs.

Agreements between QF's and utilities will typically cover both operating and rate considerations, and be negotiated according to the specifics on a class or case-by-case basis. Payments to be made by a utility for demand and energy will only be one aspect of the total negotiations. Thus, it is not practical and advisable to prescribe a single method on which to base the utility's actual payments to a QF. As long as the payments to the QF over the term of the agreement do not exceed the utility's "true" avoided costs, other ratepayers would not be adversely affected and the agreement should be acceptable to both the parties involved and appropriate regulatory authorities.

C. RATES BASED ON AVOIDED COSTS

Rates for purchases by a utility from a QF shall be just and reasonable, non discriminatory, and in the public interest.^{3/} These conditions are met if the utility purchases the power at its avoided cost. Utilities are not required to pay more than their avoided cost. However, they

^{3/}Section 292.304(b)(2)

may pay less as agreed upon in negotiations with a QF owner or if the qualifying facility was built prior to November 9, 1978.^{4/}

There are several factors specified in the FERC rule 69 that need to be considered, to the extent practicable, in calculating avoided costs. These factors,^{5/} as shown in Exhibit IV-I, i.e., availability, dispatchability, reliability, capacity deferral, etc., are important measures in determination of firm and non-firm power purchases from a QF and the demand credits that a utility would accrue due to a QF's operation. The avoided cost provision applies even in the case where the utility purchasing power from a QF is simultaneously selling power to the QF. The utility is not required to purchase electric power (demand and energy) during any period in which, due to operation circumstances, costs would exceed those which it would incur if it did not make such purchases.^{6/} The PURPA regulations and FERC rules do not affect any existing contract between cooperatives and qualifying facilities.^{7/}

^{4/}Section 292.304(b)(1)

^{5/}Section 292.304(e)

^{6/}Section 292.304(f)(1)

^{7/}Section 292.301(b)

QUALITY OF QF POWERNON-FIRM POWER

- o As available
- o Intermittent
- o Non-Dispatchable
- o Seasonal
- o Weather Dependent
- o High Forced Outage Rate
- o Short Term Obligation
- o Peak Maintenance Schedule
- o Non-Available
 - System Emergencies
 - System Peak
- o Short Length of Period Prior to Cancellation

FIRM POWER

- o Reliable (High Capacity Factor)
- o Constant
- o Dispatchable
- o Non-Seasonable
- o Non-Weather Dependent
- o Low Forced Outage Rate
- o Long Term Obligation
- o Offpeak Maintenance Schedule
- o Available
 - System Emergencies
 - System Peak
- o Long Length of Period Prior to Cancellation

D. AVOIDED COSTS FOR NON-GENERATING COOPERATIVES

Many non-generating cooperatives are tied to an all requirements contractual obligation, some with ratchet demand rates and some with take or pay provisions. Often this means that avoided costs would reflect primarily the fuel or energy portion of the contractual rate, since the demand portion would have to be paid for whether or not the cooperative used the firm capacity reserved for it by its supplier.

This means that the avoided cost rate to non-generating cooperatives should be adjusted in most cases to a level that would equal the fuel cost, plus some variable operating and maintenance expenses related to fuel. (Some energy rates may contain demand related costs within them).

FERC felt that the avoided cost based on a wholesale rate would depend upon the reserve situation of the supplying utility. If the supplying company had sufficient reserves, there would be no market for a QF's capacity. In this case, the non-generating coop's purchase of QF power would reduce the energy purchased from a generation and transmission cooperative. This purchase would increase the revenue requirements of the generation and transmission cooperative due to lost sales. FERC indicates that the supplying G&T cooperative should be able to allocate these costs back to the distribution cooperative. Thus, the QF should receive a rate

for its power that is equal to an adjusted avoided cost which will eventually be based on a new wholesale rate from the supplier to the distribution cooperative.

If the supplying G&T Cooperative has a low reserve margin, FERC indicates that the qualifying facility could obtain an avoided cost equal to the wholesale rate, if in fact the QF is supplying both capacity and energy to the distribution cooperatives. Since wholesale rates between supplying companies and distribution cooperatives generally include a demand ratchet or a take or pay capacity payment, and would be difficult and costly to renegotiate, avoided cost will typically be calculated as the energy portion of the supplying company's wholesale rate. Time-dependent avoided costs for non-generating utilities should be based on the fuel portion and the variable operating maintenance cost portion related to fuel within the supplying company's wholesale rate.

If the agreement between the non-generating utility and the QF does not include a demand ratchet or a take or pay provision, the demand and energy avoided costs should be calculated using the methods exemplified in Sections G and H of Chapter IV. The type of contract negotiated between the supplying company and the distribution or non generating utility will weigh heavily on the determination of the avoided cost.

E. STANDARD RATES UNDER 100 KW

The FERC rules require all utilities (including cooperatives) to put into effect standard rates for QFs with a capacity of 100 KW or less.^{8/} These rates should be based on the cooperative's avoided costs. FERC indicates that the implementation of these standard rates will encourage QF's to interconnect with a utility, especially if the standard tariff is clear and simple to understand.

To fulfill this requirement, each utility should have a separate tariff or a rider to an existing tariff indicating the standard purchase rates from small power producers under 100 KW. Terms and conditions, availability, delivery of power and energy, character of service, quality of service, billing and other provisions may be incorporated within the standard requirements. However, these provisions should be unique to QF's. For example, the standard rates, if quantifiable, should reflect the supply characteristics of the particular technology (i.e., small hydro, wind, methane, solar, etc.). The various supply characteristics of the small qualifying facilities are described in Chapter III.

In addition, small power producers should have a choice among several alternative type of agreements. These alternatives are:

^{8/}Section 292.304(c)(3)(ii)

1: The QF supplies its own load with a minimum amount of power delivered to the utility. The utility stands by ready to serve the QF.

2: The QF supplies excess power to the utility.

3: The QF agrees upon a buy/sell option.

The various types of meter arrangements and interconnections are discussed in Chapter III-C and in Appendix B.

The FERC rules require that not only individual delivery of power be considered but also the aggregate delivery of power in determining avoided costs.^{9/} If several individually unreliable QF's are interconnected with a utility, their aggregate delivery of power may have a degree of reliability through diversity. Where known, the degree of aggregate reliability should be reflected in a demand credit passed on to each of the individual QF's. The determination of the aggregate value can be very complex and additional metering capability may be required. In addition, more data is needed on the performance of, for example, wind machines before a firm determination can be made that aggregate reliability is greater than individual reliability.

To avoid the complexities of determining avoided costs for small power producers, average fuel costs (because of simplicity and practicality) should be considered as a starting point for determining standard rates for QF's of 100 KW or less.

^{9/} Section 292.304(d)(v)(i)

F. FIRM VERSUS NON-FIRM PURCHASES

Sales and purchases of power by utilities can be accomplished on either a firm or non-firm basis. Power provided on a "firm" basis is available to the purchaser at all times during the period covered by the commitment. "Non-firm" power is available intermittently, and is not guaranteed and is delivered on an "as available" basis. The distinction between firm and non-firm power is paramount in determining avoided costs and hence the rates of purchase from a QF. QF's that provide power to utilities on an "as available" basis should receive payment primarily for the energy costs the utility is avoiding at the time of delivery.

If a QF provides firm power on a scheduled basis, as specified in an agreement between the utility and the QF, then avoided costs should reflect demand credits. The calculation of capacity costs avoided should take into account the utility's expansion plan for additional construction to meet projected loads.

The utility expansion plan is based on forecasts of many factors and thus introduces uncertainty into the calculation of avoided costs. Some of the key uncertainties effecting a utility's planning process are:

- o Load forecast, including price elasticity of demand
- o Financing costs and requirements

- o Capacity addition costs, and timing
- o Rate relief magnitude, and timing
- o Inflation in O&M
- o Purchased power costs
- o Fuel costs

Taking all these uncertainties into account in calculating avoided costs requires a sophisticated methodology. In most cases, the use of a simulation of utility operations or a computerized corporate model would be required and/or a probabilistic approach would be helpful. In some cases a simpler estimate using a formula to calculate the avoided costs may be adequate.

The degree of firmness of power cannot be easily defined or incorporated into a methodology and this factor will often become a pivotal negotiating point between QF owners and utilities. The factors which enter into the determination of the firmness of power were shown in Exhibit IV-1. The power a QF sells to a utility may be superior or inferior to the utility's other power sources. If a QF's power is equivalent to a utility's power, then the utility should reflect its full avoided costs including capacity credits. If the qualifying facility's power tends in value and quality more toward non-firm and intermittent, the avoided capacity costs should be proportionately reduced.

G. CALCULATIONS OF AVOIDED COST (NON-FIRM POWER)

Generating utilities under the principles of economic dispatch use the least expensive units available to follow increases in load. As a utility purchases power from a QF, it normally can avoid operating its higher cost units. The utility's incremental costs avoided at the time of purchase (the costs of generating the next energy unit) are thus the proper focus for non-firm purchases from a QF. Calculating "true" avoided costs would require an understanding of both time of day and seasonal impacts on both QF and utility generation and load.

Three methods for calculating non-firm avoided costs are presented here to demonstrate the principles involved in complying with PURPA and FERC rules 69 and 70 requirements.

1: The Energy Avoided Cost Method (EAC)

This approach is based on the actual incremental energy cost or energy-avoided cost (EAC) for "as available" energy from the QF (the cost of the next available kilowatt-hour had the QF not been in operation). Data required for this calculation should be obtained on a seasonal and/or time differentiated basis to reflect the time-related effect of fuel selection, load level and purchased energy.

Factors which impact the calculation of the energy-avoided cost include:

- (a) Fuel Cost;
- (b) Energy-related Operating and Maintenance Expenses other than Fuel Costs;
- (c) Heat Rate;
- (d) Line Losses;
- (e) Purchased Power;
- (f) Other Energy-Related Costs; and
- (g) Time Variations of (a) through (f)

If practical, the utility should determine by time period (e.g. 10:00 a.m. to 10:00 p.m. summer months) its total energy-avoided cost for several levels of assumed QF power production. The utility could use its economic dispatch model (or comparable methodology) to determine the cost by time period of the total energy furnished. Time periods should be hourly, but when appropriate, hours could be grouped to determine time of day and seasonal time periods for which energy costs can be calculated (as shown in the example in Appendix C).

Where appropriate data is available, EAC is a practical and useful method. It reflects the energy cost utilities would have incurred and translates these costs into rates to be paid the qualifying facility for power furnished. In contrast to the energy avoided costs, there are increased utility costs

associated with purchasing power from a QF. These include administrative, billing, metering, and some general costs to be recovered from the QF in some appropriate billing format. These costs could be administered to the QF at the time the utility sends the QF's electric bill for use of the utility's power as a customer charge; or the utility may show the increased costs as a deduction from revenues paid to a QF for purchases of power at energy avoided costs.

2: AVERAGE FUEL METHOD (AF)

Instead of paying the QF on the basis of an energy-avoided cost method, the utility could base the payment on its average monthly fuel costs or the energy portion of purchased power costs. This method would significantly reduce any need for special time of day metering and would reduce administrative costs since the average monthly fuel cost figure is typically one that is already calculated in the normal mode of operation as noted in Appendix C.

3: INCREMENTAL FUEL METHOD (IF)

Another method that utilities may consider in calculating an energy avoided cost is the determination of the actual cost of the incremental fuel avoided at the time of purchase from the qualifying facility. If the use of an oil fired peaker is avoided by purchase from a QF, then the cost of that oil purchased at that time, adjusted for the incremental heat rate, would produce the incremental cost of fuel in cents per KWH (as shown in Appendix C).

From the three options, the utility can make a determination (based on its characteristics, load, metering and the data available) of the method of energy avoided cost calculation best suited to its needs.

The average fuel method is by far the simplest method and the least expensive method for the utility to administer. However, the AF may overstate the value of power from the QF to the utility at various times of day or seasons because the average cost of fuel may not accurately describe the fuel cost at all times.

H. CALCULATION OF AVOIDED COST (FIRM POWER)

The methods and concepts in calculating firm power avoided costs can be very complex. The methodologies depend not only on the data available, but also on the unique characteristics of each utility and each QF. In addition, many different scenarios may be contemplated in calculating avoided costs, one of which is commonly referred to as the "worst case" approach. This approach reflects both the high capacity cost of a base load unit and the high energy avoided cost of a peaker - presenting a firm power avoided cost calculation that would be greater than the incremental costs of alternative electric power. This scenario is inappropriate for use in computing avoided costs.

Three approaches to calculating avoided costs for firm power are presented here - the Corporate Planning Method, the Expansion Plan Method and the Incremental Energy - Negotiated Demand Method.

1: CORPORATE PLANNING METHOD (CP)

The concept behind the Corporate Planning Method (CP) is easily stated, but difficult to calculate precisely. This method calculates a utility's revenue requirements two ways - with and without QF's. The difference between the revenue requirements with QF's connected versus without QF's connected represents the utility's avoided costs.

Exhibit IV-2^{10/} depicts the approach used in computing the revenue requirements:

- o Assuming no qualifying facilities and
- o Assuming a schedule of qualifying facilities (either presently connected or to be connected).

As previously noted, the CP approach requires sophisticated planning models for both generation planning and for financial planning. The product of a revenue requirements analysis is based on forecasts of a utility's load and of all other factors impacting capacity costs, energy costs, capital costs, taxes,

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Flow Diagram
Differential Revenue Requirement

financing costs and rate relief granted. In addition to the uncertainties associated with the utility's systems, there are also uncertainties associated with the prediction of the total amount of energy that will be offered by QF's within a utility's service area as a function of time. It is often difficult to compute a difference in revenue requirements (due to a QF) because many QF's are not of sufficient size to make a significant difference.

Even though it has been generally agreed by QF's and utilities alike that the CP approach is straightforward conceptually, and accurately captures the avoided cost definition, it has also been noted that QF's will have difficulty in understanding and reproducing the calculations required in this method. Often smaller utilities will lack the planning tools to accurately compute revenue requirements under the CP approach. This method is not expected to find common usage among smaller utilities.

2: EXPANSION PLAN METHOD (EP)

The use of this method requires a utility to have, or formulate, an expansion plan. The Expansion Plan Method can use data required to be filed under PURPA Sections 210 and 133, estimating the average costs of capacity and energy associated with future plant additions.

The length of the agreement for purchase of firm power from the QF by the utility affects the planning horizon for the calculation of avoided costs. If a ten year agreement is

negotiated, a ten year expansion planning horizon would be appropriate. The use of the expansion plan method is shown in Exhibit IV-3 using the results of a hypothetical generation and transmission cooperative expansion plan.

The avoided capacity costs are estimated to be the annual capital cost factor applied to the forecasted total capital cost of the ten year horizon. The capital cost factor should reflect the cooperatives fixed costs associated with its capital investment. A step-by-step procedure for calculating avoided costs using the EP method is shown in Appendix C. Avoided energy costs are calculated using the forecasted annual per unit total energy costs associated with the capacity and the 10 year kWh generation plan. This produces a per unit total avoided energy cost. Exhibit IV-3, pages 1 and 2, illustrates the use of the cooperative's expansion plan to calculate an estimate of demand and energy avoided costs.

3: INCREMENTAL ENERGY - NEGOTIATED DEMAND METHOD

There are many uncertainties associated with an expansion plan. Expansion plans may depend on complex long range financial estimates, load estimates, market analysis, population trends, and other long range analyses. Therefore, a less sophisticated method that does not depend on estimates should be considered by utilities in calculating avoided costs.

The energy avoided cost is calculated using the Energy Avoided Cost Method (EAV) as described earlier in section G of this Chapter. Any capacity credits paid by the utility in addition to the energy avoided costs could be negotiated by the utility and the qualifying facility.

CALCULATION OF AVOIDED COST

EXPANSION PLAN METHOD

<u>Date of Plant Additions</u>	<u>Installed Capacity MW</u>	<u>Capital Cost 1980 \$/KW</u>	<u>Total Cost \$ X (1,000's)</u>	<u>Energy⁽¹⁾ Cost ¢/KW</u>	<u>Capacity⁽²⁾ Factor %</u>	<u>Annual Energy Cost MWH</u>	<u>Annual Energy Cost (\$1,000's)</u>
(1)	(2)	(3)	(4) (2) X (3)	(5)	(6)	(7) (2) X (6) X 8,760	(8) (5) X (7)
1981	200	500	\$100,000	3.00	70	1,226,400	\$36,792
1982	-	-	-	-	-	-	-
1983	200	500	100,000	3.00	70	1,226,400	36,792
1984	-	-	-	-	-	-	-
1985	-	-	-	-	-	-	-
1986	300	900	270,000	2.50	80	2,102,400	52,560
1987	-	-	-	-	-	-	-
1988	-	-	-	-	-	-	-
1989	300	900	270,000	2.50	80	2,102,400	52,560
1990	-	-	-	-	-	-	-
TOTAL	1,000		\$740,000			6,657,600	\$178,704

(1) Estimated Energy Cost of Unit in Operation

(2) Should Be Adjusted for Actual or Known Values

CALCULATION OF AVOIDED COST
EXPANSION PLAN METHOD

1. Demand Avoided Cost

$\$740,000,000 \div 1,000,000 = \740 Per KW
 $\$740 \times 10\% \text{ (Annual Capital Cost Factor)} = \$74 \text{ Per KW Per Year}$
 $\$74 \div 12 = \$6.20 \text{ Per KW Per Month}$

2. Energy Avoided Cost

$\$178,704,000 \div 6,657,600,000 \text{ KWH} = 2.68\text{¢}/\text{KWH}$

The total demand and energy charge to be paid to the
qualifying facility should be:
\$6.20 Per KW and
2.68¢ Per KWH

I. RATES FOR SALES TO QFS BY COOPERATIVES

Rates to qualifying facilities should be "just and reasonable, in the public interest, and nondiscriminatory".^{11/} Section 210 of PURPA specifically addresses nondiscrimination in designing rates for sale of power to QFs. FERC, in its rules, specified the types of power to be delivered to QF's. These are:

1: Backup Power - Capacity or energy supplied by a utility to a QF during an unscheduled outage of the QF;

2: Supplementary Power - Capacity or energy supplied by a utility to a QF in addition to that which the facility generates itself;

3: Maintenance Power - Capacity or energy supplied by a cooperative to a QF during a scheduled outage of the QF facility;

4: Interruptible Power - Capacity or energy supplied by a cooperative to a QF subject to interruption under specified circumstances.

These rates are to be designed based on the cooperative's established rate-making procedures including, if applicable,

^{11/} Section 292.305 (a)

consistent system-wide costing principles and/or using rates applicable to other utility customers of similar load, cost characteristics and load factor. The regulations also specify that power sales rates shall not be based on assumptions that the QF's outages, maintenance and interruptions will occur simultaneously or during the utility system's peak unless supported by actual data. The rates must also take into account the coordination of scheduled maintenance between the QF and utility.

J. SIMULTANEOUS BUY/SELL OPTIONS

Utilities are required to purchase power from QF's at their avoided costs regardless of whether or not they are simultaneously selling power to the QF's. The QF stands to benefit from this arrangement in that it could purchase power from the utility to meet its needs at the utility's average costs and sell an equivalent block of power (produced by the QF facility) back to the utility at the higher incremental or avoided costs.

This type of arrangement gives a beneficial entitlement to a QF which it may give up in negotiating an agreement with a utility.

K. REQUIREMENTS TO FILE UTILITY SYSTEM COST DATA

Section 210 of PURPA stipulates that most utilities are required to provide certain cost data which can be used by QF's in estimating the economic feasibility of the QF and the rates the QF can receive for power sold to the utility.

Utilities (including cooperatives) with sales over 500 million KWH are required to file certain data. Companies with sales greater than 500 million kWh but less than 1 billion kWh are exempt from 1980 cost data filing but are to file data in 1982. The cooperatives with kWh sales over 500 million must file the following data:

1: The estimated avoided energy costs for the current year and the following five years for various levels of purchase from QFs. This is shown in column one of Exhibit IV-4. The levels of purchases should be stated in blocks of not more than 100 megawatts for systems with peak demand of 1,000 megawatts or more. With systems of less than 1,000 megawatts, the blocks should be stated to be not more than 10 percent of the system peak demand (Exhibit IV-5). The avoided costs are to be stated on a cents-per-kilowatt-hour basis, on a time-of-day and a seasonal basis.

2: The system's ten-year plan for addition of capacity by amount and type, capacity retirements, firm energy and capacity purchases, and the corresponding demand and energy costs.

Exhibit IV-3 illustrates the format of this plan. This expansion plan can be used in calculating avoided costs for firm power as illustrated in Section H-2.

Utilities with sales of less than 500 million kWh need to provide this data only upon the request of a QF. A distribution cooperative may supply the data of its supplying generation and transmission cooperative.

COST DATA REQUIREMENTS
 AVOIDED ENERGY COSTS
SYSTEM PEAK GREATER THAN 1,000 MW

SYSTEM PEAK 1,000 MW*

<u>Block</u>	<u>Actual 1980</u>	<u>Forecast</u>				
		<u>1981</u>	<u>1982</u>	<u>1983</u>	<u>1984</u>	<u>1985</u>
100 MW	¢/KWH	¢/KWH	¢/KWH	¢KWH	¢/KWH	¢/KWH
200 MW	¢/KWH	¢/KWH	¢/KWH	¢KWH	¢/KWH	¢/KWH
300 MW	¢/KWH	¢/KWH	¢/KWH	¢KWH	¢/KWH	¢/KWH
•	•	•	•	•	•	•
•	•	•	•	•	•	•
•	•	•	•	•	•	•
1,000 MW	¢/KWH	¢/KWH	¢/KWH	¢KWH	¢/KWH	¢/KWH

* If applicable, data should be shown by time period and season such as an on-peak period of 10:00 a.m. to 10:00 p.m. in summer and 9:00 a.m. to 9:00 p.m. in winter and all other hours categorized as off-peak periods.

COST DATA REQUIREMENTS
 AVOIDED ENERGY COSTS
SYSTEM PEAK LESS THAN 1,000 MW

SYSTEM PEAK 700 MW*

<u>Block</u>	<u>Actual 1980</u>	<u>Forecast</u>				
		<u>1981</u>	<u>1982</u>	<u>1983</u>	<u>1984</u>	<u>1985</u>
70 MW	¢/KWH	¢/KWH	¢/KWH	¢KWH	¢/KWH	¢/KWH
140 MW	¢/KWH	¢/KWH	¢/KWH	¢KWH	¢/KWH	¢/KWH
210 MW	¢/KWH	¢/KWH	¢/KWH	¢KWH	¢/KWH	¢/KWH
•	•	•	•	•	•	•
•	•	•	•	•	•	•
•	•	•	•	•	•	•
700 MW	¢/KWH	¢/KWH	¢/KWH	¢KWH	¢/KWH	¢/KWH

* If applicable, data should be shown by time period and season such as an on-peak period of 10:00 a.m. to 10:00 p.m. in summer and 9:00 a.m. to 9:00 p.m. in winter and all other hours categorized as off-peak periods.

L. ACCOUNTING PROCEDURES

There is an added analytical burden to be expected for utilities interconnecting with QF's. Certain types of cost data, as shown in Exhibit IV-5, need to be maintained in FERC accounting format. The utility accounting relating to QF's will include such items as operating and maintenance expense, plant costs, labor, material, insurance, overheads, legal, consulting services, meter reading and switching costs. The utility should maintain all transactions related to QF's using its standard FERC uniform system of accounts.

M. CONTRACT AND WHEELING ISSUES

There are several specific issues which must be considered in determining what, if anything, a utility will charge a QF interconnected to its system. It is expected that these issues, where not defined in a standard format for classes of QF types and sizes, will be determined in negotiations between the utility and individual QF's. This approach is often referred to as the "case by case" approach for dealing with QF's.

1: Contract Issues

A checklist of issues to be addressed in negotiations between utilities and QF's was developed by a task force of

UTILITY COST ITEMS COVERING OF TRANSACTIONS

<u>Potential Increased Costs Areas</u>	<u>Potential Decreased Costs Areas</u>
o Billing	o Fuel
o Administrative	o Line Losses
o Accounting	o Wheeling
o Line Losses	o Capacity Deferral
o O&M	o Smaller Capacity Increments
o Labor	o Shorter Lead Times
o Material	o Purchases Power
o Insurance	
o Overheads	
o Legal	
o Switching	
o Consulting Services	
o Avoided Costs	
o Credit and Collection	

utilities and QF's.^{12/} An expanded list of these issues and recommendations by a joint utility/QF committee of the task force is presented in Appendix F along with sample utility contracts. These contract issues fell into the following categories:

- o Plant technical considerations
- o Billing
- o Contract cancellation provisions
- o Continuity of service
- o Rights of way, permits and safety codes
- o Liability
- o Metering
- o Term of the contract

2: Wheeling Factors

In addition to the list of contract issues mentioned above, several general factors were adopted by the joint utility/QF task force for charges for wheeling a QF's power. Since FERC does not require a utility, and since wheeling can only occur with the consent of both the QF and the utility (to which energy or capacity from the QF is initially made

^{12/} Reprinted with permission from PLANERGY, Inc. from the Report of the 1980 Task Force on Cogeneration in Texas, October 1980.

available), wheeling is typically expected to be an item for negotiation between the utility and the QF. A checklist of items which are appropriate to take into account in developing a wheeling charge would include:

- o Interconnection costs associated with wheeling
- o The amount of power being wheeled
- o The duration of the wheeling
- o The load cycle
- o The location (where the power enters and leaves the system)
- o The distance power is wheeled
- o Time-of-day the wheeling service is needed (peak vs. off-peak)
- o Coverage of the investment financing costs and the utility's margin
- o Administrative and billing costs

APPENDIX A
PURPA Sections 201 & 210
And
FERC Rules 69 & 70
And Amendments

APPENDIX - A

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

Sec. 201. Definitions.

Section 3 of the Federal Power Act is amended by inserting the following before the period at the end thereof:

"(17)(A) 'small power production facility' means a facility which--

"(i) produces electric energy solely by the use, as a primary energy source, or biomass, waste, renewable resources, or any combination thereof; and

"(ii) has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), is not greater than 80 megawatts;

"(B) 'primary energy source' means the fuel or fuels used for the generation of electric energy, except that such term

does not include, as determined under rules prescribed by the Commission, in consultation with the Secretary of Energy--

"(i) the minimum amounts of fuel required for ignition, startup, testing, flame stabilization, and control uses, and

(ii) the minimum amounts of fuel required to alleviate or prevent--

"(I) unanticipated equipment outages, and

"(II) emergencies, directly affecting the public health, safety, or welfare, which would result from electric power outages;

"(C) 'qualifying small power production facility' means a small power production facility--

"(i) which the Commission determines, by rule, meets such requirements (including requirements respecting fuel use, fuel efficiency, and reliability) as the Commission may, by rule, prescribe; and

"(ii) which is owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities);

"(D) 'qualifying small power producer' means the owner or operator of a qualifying small power production facility;

"(18)(A) 'cogeneration facility' means a facility which produces--

"(i) electric energy, and

"(ii) steam or forms of useful energy (such as heat) which are used for industrial, commercial, heating, or cooling purposes;

"(B) 'qualifying cogeneration facility' means a cogeneration facility which--

"(i) the Commission determines, by rule, meets such requirements (including requirements respecting minimum size, fuel use, and efficiency) as the Commission may, by rule, prescribe; and

"(ii) is owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities);

"(C) 'qualifying cogenerator' means the owner or operator of a qualifying cogeneration facility;

"(19) 'Federal power marketing agency' means any agency or instrumentality of the United States (other than the Tennessee Valley Authority) which sells electric energy;

"(20) 'evidentiary hearings' and 'evidentiary proceeding' mean a proceeding conducted as provided in sections 554, 556, and 557 of title 5, United States Code;

"(21) 'State regulatory authority' has the same meaning as the term 'State commission,' except that in the case of an

electric utility with respect to which the Tennessee Valley Authority has ratemaking authority (as defined in section 3 of the Public Utility Regulatory Policies Act of 1978), such term means the Tennessee Valley Authority;

"(22) 'electric utility' means any person or State agency which sells electric energy; such term includes the Tennessee Valley Authority, but does not include any Federal power marketing agency".

SEC. 210 COGENERATION AND SMALL POWER PRODUCTION

(a) Cogeneration and Small Power Production Rules.--Not later than 1 year after the date of enactment of this Act, the Commission shall prescribe, and from time to time thereafter revise, such rules as it determines necessary to encourage cogeneration and small power production which rules require electric utilities to offer to--

(1) sell electric energy to qualifying cogeneration facilities and qualifying small power production facilities and

(2) purchase electric energy from such facilities. Such rules shall be prescribed, after consultation with representatives of Federal and State regulatory agencies having ratemaking authority for electric utilities, and after public notice and a reasonable opportunity for interested persons (including State and Federal agencies) to submit oral as well as written data, views, and arguments. Such rules shall include provisions respecting minimum reliability of qualifying cogeneration facilities and qualifying small power production facilities (including reliability of such facilities during emergencies) and rules respecting reliability of electric energy service to be available to such facilities from electric utilities during emergencies. Such rules may not authorize a qualifying cogeneration facility or qualifying small power production facility to make any sale for purposes other than resale.

(b) RATES FOR PURCHASES BY ELECTRIC UTILITIES.--The rules prescribed under subsection (a) shall insure that, in requiring any electric utility to offer to purchase electric energy from any qualifying cogeneration facility or qualifying small power production facility, the rates for such purchase--

(1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and

(2) shall not discriminate against qualifying cogenerators or qualifying small power producers.

No such rule prescribed under subsection (a) shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy.

(c) RATES FOR SALES BY UTILITIES--The rules prescribed under subsection (a) shall insure that, in requiring any electric utility to offer to sell electric energy to any qualifying cogeneration facility or qualifying small power production facility, the rates for such sale--

(1) shall be just and reasonable in the public interest, and

(2) shall not discriminate against the qualifying cogenerators or qualifying small power producers.

(d) DEFINITION.--For purposes of this section, the term "incremental cost of alternative electric energy" means, with respect to electric energy purchased from a qualifying cogenerator or qualifying small power producer, the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source.

(e) EXEMPTIONS--(1) Not later than 1 year after the date of enactment of this Act and from time to time thereafter, the Commission shall, after consultation with representatives of State regulatory authorities, electric utilities, owners of cogeneration facilities and owners of small power production facilities, and after public notice and reasonable opportunity

for interested persons (including State and Federal agencies) to submit oral as well as written data, views, and arguments, prescribe rules under which qualifying cogeneration facilities and qualifying small power production facilities are exempted in whole or part from the Federal Power Act, from the Public Utility Holding Company Act, from State laws and regulations respecting the rates, or respecting the financial or organizational regulation, or electric utilities, or for many combination of the foregoing, if the Commission determines such exemption is necessary to encourage cogeneration and small power production.

(2) No qualifying small power production facility which has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), exceeds 30 megawatts may be exempted under rules under paragraph (1) from any provision of law or regulation referred to in paragraph (1), except that any qualifying small power production facility which produces electric energy solely by the use of biomass as a primary energy source, may be exempted by the Commission under such rules from the Public Utility Holding Company Act and from State laws and regulations referred to in such paragraph (1).

(3) No qualifying small power production facility or qualifying cogeneration facility may be exempted under this subsection from--

(A) any State law or regulation in effect in a State pursuant to subsection (f),

(B) the provisions of section 210, 211, or 212 of the Federal Power Act or the necessary authorities for enforcement of any such provision under the Federal Power Act, or

(C) any license or permit requirement under part I of the Federal Power Act, any provision under such Act related to such a license or permit requirement, or the necessary authorities for enforcement of any such requirement.

(f) IMPLEMENTATION OF RULES FOR QUALIFYING COGENERATION AND QUALIFYING SMALL POWER PRODUCTION FACILITIES.--(1)

Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) or revised under such subsection, each State regulatory authority shall, after notice and opportunity for public hearing, implement such rule (or revised rule) for each electric utility for which it has ratemaking authority.

(2) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) or revised under such subsection, each nonregulated electric utility shall, after notice and opportunity for public hearing, implement such rule (or revised rule).

(g) JUDICIAL REVIEW AND ENFORCEMENT.--(1) Judicial review may be obtained respecting any proceeding conducted by a State

regulatory authority or nonregulated electric utility for purposes of implementing any requirement of a rule under subsection (a) in the same manner under and under the same requirements, as judicial review may be obtained under section 123 in the case of a proceeding to which section 123 applies.

(2) Any person (including the Secretary) may bring an action against any electric utility, qualifying small power producer, or qualifying cogenerator to enforce any requirement established by a State regulatory authority or nonregulated electric utility pursuant to subsection (f). Any such action shall be brought only in the manner, and under the requirements, as provided under section 123 with respect to an action to which section 123 applies.

(h) COMMISSION ENFORCEMENT.--(1) For purposes of enforcement of any rule prescribed by the Commission under subsection (a) with respect to any operations of an electric utility, a qualifying cogeneration facility or a qualifying small power production facility which are subject to the jurisdiction of the Commission under part II of the Federal Power Act, such rule shall be treated as a rule under the Federal Power Act. Nothing in subsection (g) shall apply to so much of the operations of an electric utility, a qualifying cogeneration facility or a qualifying small power production facility as are subject to the jurisdiction of the Commission under part II of the Federal power Act.

(2)(A) The Commission may enforce the requirements of subsection (f) against any State regulatory authority or nonregulated electric utility. For purposes of any such enforcement, the requirements of subsection (f)(1) shall be treated as a rule enforceable under the Federal Power Act. For

purposes of any such action, a State regulatory authority or nonregulated electric utility shall be treated as a person within the meaning of the Federal Power Act. No enforcement action may be brought by the Commission under this section other than--

(i) an action against the State regulatory authority or nonregulated electric utility for failure to comply with the requirements of subsection (f) or

(ii) an action under paragraph (1).

(B) Any electric utility, qualifying cogenerator, or qualifying small power producer may petition the Commission to enforce the requirements of subsection (f) as provided in subparagraph (A) of this paragraph. If the Commission does not initiate an enforcement action under subparagraph (A) against a State regulatory authority or nonregulated electric utility within 60 days following the date on which a petition is filed under this subparagraph with respect to such authority, the petitioner may bring an action in the appropriate United States district court to require such State regulatory authority or nonregulated electric utility to comply with such requirements, and such court may issue such injunctive or other relief as may be appropriate. The Commission may intervene as a matter of right in any such action.

(i) FEDERAL CONTRACTS--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 after the date of the enactment of this Act may contain any provision which will have the effect of preventing the implementation of any rule under this section with respect to such utility. Any provision in any such contract which has such effect shall be null and void.

(j) DEFINITIONS.--For purposes of this section, the terms "small power production facility", "qualifying small power production facility", "qualifying small power producer", "primary energy source", "cogenerator facilities", "qualifying cogeneration facility", and "qualifying cogenerator" have the respective meanings provided for such terms under section 3(17) and (18) of the Federal Power Act.

**PART 292—REGULATIONS UNDER
SECTIONS 201 AND 210 OF THE
PUBLIC UTILITY REGULATORY
POLICIES ACT OF 1978 WITH REGARD
TO SMALL POWER PRODUCTION AND
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**Authority: Public Utility Regulatory Policies
Act of 1978, Pub. L. 95-617; Natural Gas
Policy Act of 1978, Pub. L. 95-621; Department
of Energy Organization Act, Pub. L. 95-61;
E.O. 12009, 42 FR 46267.**

**Subpart F—Exemption of Qualifying Small
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**292.601 Exemption of Qualifying Facilities
from the Federal Power Act.**

**292.602 Exemption of Qualifying Facilities
From the Public Utility Holding Company**

**Act and Certain State Law and
Regulation.**

Authority: This part issued under the Public

Utility Regulatory Policies Act of 1978, 18 U.S.C. § 2601 *et seq.*, Energy Supply and Environmental Coordination Act, 15 U.S.C. § 791 *et seq.*, Federal Power Act, 16 U.S.C. § 792 *et seq.*, Department of Energy Organization Act, 42 U.S.C. § 7101 *et seq.*, E.O. 12009, 42 FR 48287.

Subpart A—General Provisions

§ 292.101 Definitions.

(a) *General rule.* Terms defined in the Public Utility Regulatory Policies Act of 1978 (PURPA) shall have the same meaning for purposes of this part as they have under PURPA, unless further defined in this part.

(b) *Definitions.* The following definitions apply for purposes of this part.

(1) "Qualifying facility" means a cogeneration facility or a small power production facility which is a qualifying facility under Subpart B of this part of the Commission's regulations.

(2) "Purchase" means the purchase of electric energy or capacity or both from a qualifying facility by an electric utility.

(3) "Sale" means the sale of electric energy or capacity or both by an electric utility to a qualifying facility.

(4) "System emergency" means a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property.

(5) "Rate" means any price, rate, charge, or classification made, demanded, observed or received with respect to the sale or purchase of electric energy or capacity, or any rule, regulation, or practice respecting any such rate, charge, or classification, and any contract pertaining to the sale or purchase of electric energy or capacity.

(6) "Avoided costs" means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.

(7) "Interconnection costs" means the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead

generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs.

(8) "Supplementary power" means electric energy or capacity supplied by an electric utility, regularly used by a qualifying facility in addition to that which the facility generates itself.

(9) "Back-up power" means electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.

(10) "Interruptible power" means electric energy or capacity supplied by an electric utility subject to interruption by the electric utility under specified conditions.

(11) "Maintenance power" means electric energy or capacity supplied by an electric utility during scheduled outages of the qualifying facility.

Subpart B—Qualifying Cogeneration and Small Power Production Facilities

§ 292.201 Scope.

This subpart applies to the criteria for and manner of becoming a qualifying small power production facility and a qualifying cogeneration facility under sections 3(17)(C) and 3(18)(B), respectively, of the Federal Power Act, as amended by section 201 of the Public Utility Regulatory Policies Act of 1978 (PURPA).

§ 292.202 Definitions.

For purposes of this subpart:

(a) "Biomass" means any organic material not derived from fossil fuels;

(b) "Waste" means by-product materials other than biomass;

(c) "Cogeneration facility" means equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes, through the sequential use of energy;

(d) "Topping-cycle cogeneration facility" means a cogeneration facility in which the energy input to the facility is first used to produce useful power output, and the reject heat from power production is then used to provide useful thermal energy;

(e) "Bottoming-cycle cogeneration facility" means a cogeneration facility in which the energy input to the system is first applied to a useful thermal energy process, and the reject heat emerging from the process is then used for power production;

(f) "Supplementary firing" means an energy input to the cogeneration facility used only in the thermal process of a topping-cycle cogeneration facility, or only in the electric generating process of a bottoming-cycle cogeneration facility:

(g) "Useful power output" of a cogeneration facility means the electric or mechanical energy made available for use, exclusive of any such energy used in the power production process:

(h) "Useful thermal energy output" of a topping-cycle cogeneration facility means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application:

(i) "Total energy output" of a topping-cycle cogeneration facility is the sum of the useful power output and useful thermal energy output:

(j) "total energy input" means the total energy of all forms supplied from external sources.

(k) "Natural gas" means either natural gas unmixed, or any mixture of natural gas and artificial gas:

(l) "Oil" means crude oil, residual fuel oil, natural gas liquids, or any refined petroleum products: and

(m) Energy input in the case of energy in the form of natural gas or oil is to be measured by the lower heating value of the natural gas or oil.

(n) "Electric utility holding company" means a holding company, as defined in section 2(a)(7) of the Public Utility Holding Company Act of 1935, 15 U.S.C. § 79b(a)(7) which owns one or more electric utilities, as defined in section 2(a)(3) of that Act, 15 U.S.C. § 79b(a)(3), but does not include any holding company which is exempt by rule or order adopted or issued pursuant to sections 3(a)(3) or 3(a)(5) of the Public Utility Holding Company Act of 1935, 15 U.S.C. § 79c(a)(3) or § 79c(a)(5).

§ 292.203 General requirements for qualification.

(a) *Small power production facilities.* A small power production facility is a qualifying facility if it:

- (1) Meets the maximum size criteria specified in § 292.204(a);
- (2) Meets the fuel use criteria specified in § 292.204(b); and
- (3) Meets the ownership criteria specified in § 292.206.

(b) *Cogeneration facilities.* (1) Unless excluded under paragraph (c), a cogeneration facility is a qualifying facility if it:

(i) Meets any applicable operating and efficiency standards specified in § 292.205 (a) and (b); and

(ii) Meets the ownership criteria specified in § 292.206.

(2) For purposes of qualification of a cogeneration facility for exemption from incremental pricing, a cogeneration facility must qualify under § 292.205(c).

(c) *Interim exclusion.* (1) Pending further Commission action, any cogeneration facility which is a new diesel cogeneration facility may not be a qualifying facility.

(2) A new diesel cogeneration facility is a cogeneration facility:

(i) Which derives its useful power output from a diesel engine, and

(ii) The installation of which began on or after March 13, 1980.

(3) Pending further Commission action, any cogeneration facility which is a new dual-fuel cogeneration facility which seeks to obtain qualifying status must follow the procedures set forth in § 292.207(b) of this section.

(4) A new dual-fuel cogeneration facility is a cogeneration facility:

(i) which derives its useful power output from an internal combustion piston engine capable of changing automatically between gas and oil operation, and

(ii) the installation of which began on or after May 15, 1980.

§ 292.204 Criteria for qualifying small power production facilities.

(a) *Size of the facility.*—(1) *Maximum size.* The power production capacity of the facility for which qualification is sought, together with the capacity of any other facilities which use the same energy resource, are owned by the same person, and are located at the same site, may not exceed 80 megawatts.

(2) *Method of calculation.* (i) For purposes of this paragraph, facilities are considered to be located at the same site as the facility for which qualification is sought if they are located within one mile of the facility for which qualification is sought and, for hydroelectric facilities, if they use water from the same impoundment for power generation.

(ii) For purposes of making the determination in clause (i), the distance

between facilities shall be measured from the electrical generating equipment of a facility.

(3) *Waiver.* The Commission may modify the application of subparagraph (2) for good cause.

(b) *Fuel use.* (1)(i) The primary energy source of the facility must be biomass, waste, renewable resources, or any combination thereof, and more than 75 percent of the total energy input must be from these sources. . . .

(ii) Any primary energy source which, on the basis of its energy content, is 50 percent or more biomass shall be considered biomass.

(2) Use of oil, natural gas, and coal by a facility may not, in the aggregate, exceed 25 percent of the total energy input of the facility during any calendar year period.

§ 292.205 Criteria for qualifying cogeneration facilities.

(a) *Operating and efficiency standards for topping-cycle facilities—*

(1) *Operating standard.* For any topping-cycle cogeneration facility, the useful thermal energy output of the facility must, during any calendar year period, be no less than 5 percent of the total energy output.

(2) *Efficiency standard.* (i) For any topping-cycle cogeneration facility for which any of the energy input is natural gas or oil, and the installation of which began on or after March 13, 1980, the useful power output of the facility plus one-half the useful thermal energy output, during any calendar year period, must:

(A) Subject to paragraph (a)(2)(i)(B) of this section be no less than 42.5 percent of the total energy input of natural gas and oil to the facility; or

(B) If the useful thermal energy output is less than 15 percent of the total energy output of the facility, be no less than 45 percent of the total energy input of natural gas and oil to the facility.

(ii) For any topping-cycle cogeneration facility not subject to paragraph (a)(2)(i) of this section there is no efficiency standard.

(b) *Efficiency standards for bottoming-cycle facilities.* (1) For any bottoming-cycle cogeneration facility for which any of the energy input as supplementary firing is natural gas or oil, and the installation of which began on or after March 13, 1980, the useful power output of the facility must, during any calendar year period, be no less than 45 percent of the energy input of natural gas and oil for supplementary firing.

(2) For any bottoming-cycle cogeneration facility not covered by subparagraph (1) of this paragraph, there is no efficiency standard.

(c) *Exemption from incremental pricing.* (1) Natural gas used in any topping-cycle cogeneration facility is eligible for an exemption from incremental pricing under Title II of the Natural Gas Policy Act of 1978 (NGPA), and Part 282 of the Commission's rules if:

(i) The facility meets the operating and efficiency standards under paragraphs (a)(1) and (2)(i) of this section and is a qualifying facility under § 292.203(b)(1); or

(ii) The facility is a qualifying facility under Subpart E of this part.

(2) Natural gas used in any bottoming cycle cogeneration facility, not subject to an exemption from incremental pricing under Subpart E of this part, is eligible for an exemption under Title II of the NGPA and Part 282 of the Commission's rules to the extent that reject heat emerging from the useful thermal energy process is made available for use for power production.

(3) Nothing in this subpart affects any exemption provided under Subpart E of this part.

(4) Natural gas used for supplementary firing in any cogeneration facility is not eligible under this part for exemption from incremental pricing.

(d) *Waiver.* The Commission may waive any of the requirements of paragraphs (a), (b) and (c) of this section upon a showing that the facility will produce significant energy savings.

§ 292.206 Ownership criteria.

(a) *General rule.* A cogeneration facility or small power production facility may not be owned by a person primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities).

(b) *Ownership test.* For purposes of this section, a cogeneration or small power production facility shall be considered to be owned by a person primarily engaged in the generation or sale of electric power, if more than 50 percent of the equity interest in the facility is held by an electric utility or utilities, or by an electric utility holding company, or companies, or any combination thereof. If a wholly or partially owned subsidiary of an electric utility or electric utility holding company has an ownership interest in a facility, the subsidiary's ownership interest shall be considered as ownership by an electric utility or electric utility holding company.

(c) *Exceptions.* For purposes of this section a company shall not be considered to be an "electric utility" company if it:

(1) Is a subsidiary of an electric utility holding company which is exempt by rule or order adopted or issued pursuant to section 3(a)(3) or 3(a)(5) of the Public Utility Holding Company Act of 1935, 15 U.S.C. 79c(a)(3), 79c(a)(5); or

(2) Is declared not to be an electric utility company by rule or order of the Securities and Exchange Commission pursuant to section 2(a)(3)(A) of the Public Utility Holding Company Act of 1935, 15 U.S.C. 79b(a)(3)(A).

§ 292.207 Procedures for obtaining qualifying status.

(a) *Qualification.* (1) A small power production facility or cogeneration facility which meets the criteria for qualification set forth in § 292.203 is a qualifying facility.

(2) The owner or operator of any facility qualifying under this paragraph shall furnish notice to the Commission providing the information set forth in paragraph (b)(2)(i) through (iv) of this section.

(b) *Optional procedure—*(1) *Application for Commission certification.* Pursuant to the provisions of this paragraph, the owner or operator of the facility may file with this Commission an application for Commission certification that the facility is a qualifying facility.

(2) *General contents of application.* The application shall contain the following information:

(i) The name and address of the applicant and location of the facility;

(ii) A brief description of the facility, including a statement indicating whether such facility is a small power production facility or a cogeneration facility;

(iii) The primary energy source used or to be used by the facility;

(iv) The power production capacity of the facility; and

(v) The percentage of ownership by any electric utility or by any ~~separate~~ utility holding company, or by any person owned by either.

(3) *Additional application requirements for small power production facilities.* An application by a small power producer for Commission certification shall contain the following additional information:

(i) The location of the facility in relation to any other small power production facilities located within one mile of the facility, owned by the applicant which use the same energy source; and

(ii) Information identifying any planned usage of natural gas, oil or coal.

(4) *Additional application requirements for cogeneration facilities.*

An application by a cogenerator for Commission certification shall contain the following additional information:

(i) A description of the cogeneration system, including whether the facility is a topping or bottoming cycle and sufficient information to determine that any applicable requirements under § 292.205 will be met; and

(ii) The date installation of the facility began or will begin.

(5) *Commission action.* Within 90 days of the filing of an application, the Commission shall issue an order granting or denying the application, tolling the time for issuance of an order, or setting the matter for hearing. Any order denying certification shall identify

the specific requirements which were not met. If no order is issued within 90 days of the filing of the complete application, it shall be deemed to have been granted.

(6) *Notice.* (i) Applications for certification filed under this paragraph shall include a copy of a notice of the request for certification for publication in the Federal Register. The notice shall state the applicant's name, the date of the application, and a brief description of the facility for which qualification is sought. This description shall include:

(A) A statement indicating whether such facility is a small power production facility or a cogeneration facility;

(B) The primary energy source used or to be used by the facility;

(C) The power production capacity of the facility; and

(D) The location of the facility.

(ii) The notice shall be in the following form:

(Name of Applicant)

Docket No. QF-

**Notice of Application for Commission
Certification of Qualifying Status of a (Small
Power Production) (Cogeneration) Facility**

On (date application was filed), (name and address of applicant) filed with the Federal Energy Regulatory Commission an application to be certified as a qualifying (small power production) (cogeneration) facility pursuant to § 292.207 of the Commission's rules.

[Brief description of the facility].

Any person desiring to be heard or objecting to the granting of qualifying status should file a petition to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, in accordance with §§ 1.8 and 1.10 of the Commission's Rules of Practice and Procedure. All such petitions or protests must be filed within 30 days after the date of publication of this notice and must be served on the applicant. Protests will be considered by the Commission in determining the appropriate action to be taken but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a petition to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

(c) *Notice requirements for facilities of 500 kW or more.* An electric utility is not required to purchase electric energy from a facility with a design capacity of 500 kW or more until 90 days after the facility notifies the utility that it is a qualifying facility, or 90 days after the facility has applied to the Commission under paragraph (b) of this section.

(d) *Revocation of qualifying status.* (1) The Commission may revoke the qualifying status of a qualifying facility which has been certified under this section if such facility fails to comply with any of the statements contained in its application for Commission certification.

(2) Prior to undertaking any substantial alteration or modification of a qualifying facility which has been certified under this section, a small power producer or cogenerator may apply to the Commission for a determination that the proposed alteration or modification will not result in a revocation of qualifying status.

**Subpart C—Arrangements Between
Electric Utilities and Qualifying
Cogeneration and Small Power
Production Facilities Under Section
210 of the Public Utility Regulatory
Policies Act of 1978**

§ 292.301 Scope.

(a) *Applicability.* This subpart applies to the regulation of sales and purchases between qualifying facilities and electric utilities.

(b) *Negotiated rates or terms.* Nothing in this subpart:

(1) Limits the authority of any electric utility or any qualifying facility to agree to a rate for any purchase, or terms or conditions relating to any purchase, which differ from the rate or terms or conditions which would otherwise be required by this subpart; or

(2) Affects the validity of any contract entered into between a qualifying facility and an electric utility for any purchase.

§ 292.302 Availability of electric utility system cost data.

(a) *Applicability.* (1) Except as provided in paragraph (a)(2) of this section, paragraph (b) applies to each electric utility, in any calendar 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.

(2) Each utility having total sales of electric energy for purposes other than

resale of less than one billion kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding year, shall not be subject to the provisions of this section until May 31, 1982.

(b) *General rule.* To make available data from which avoided costs may be derived, not later than November 1, 1980, May 31, 1982, and not less often than every two years thereafter, each regulated electric utility described in paragraph (a) of this section shall provide to its State regulatory authority, and shall maintain for public inspection, and each nonregulated electric utility described in paragraph (a) of this section shall maintain for public inspection, the following data:

(1) The estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of not more than 100 megawatts for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than 10 percent of the system peak demand for systems of less than 1000 megawatts. The avoided costs shall be stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the next 5 years;

(2) The electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding 10 years; and

(3) The estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases.

(c) Special rule for small electric utilities.

(1) Each electric utility (other than any electric utility to which paragraph (b) of this section applies) shall, upon request:

(i) Provide comparable data to that required under paragraph (b) of this section to enable qualifying facilities to estimate the electric utility's avoided costs for periods described in paragraph (b) of this section; or

(ii) With regard to an electric utility which is legally obligated to obtain all its requirements for electric energy and capacity from another electric utility, provide the data of its supplying utility and the rates at which it currently purchases such energy and capacity.

(2) If any such electric utility fails to provide such information on request, the qualifying facility may apply to the State regulatory authority (which has ratemaking authority over the electric utility) or the Commission for an order requiring that the information be provided.

(d) Substitution of alternative method.

(1) After public notice in the area served by the electric utility, and after opportunity for public comment, any State regulatory authority may require (with respect to any electric utility over which it has ratemaking authority), or any non-regulated electric utility may provide, data different than those which are otherwise required by this section if it determines that avoided costs can be derived from such data.

(2) Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated utility which requires such different data shall notify the Commission within 30 days of making such determination.

(e) State Review. (1) Any data submitted by an electric utility under this section shall be subject to review by the State regulatory authority which has ratemaking authority over such electric utility.

(2) In any such review, the electric utility has the burden of coming forward with justification for its data.

§ 292.303 Electric utility obligations under this subpart.

(a) Obligation to purchase from qualifying facilities. Each electric utility shall purchase, in accordance with § 292.304, any energy and capacity which is made available from a qualifying facility:

(1) Directly to the electric utility; or

(2) Indirectly to the electric utility in accordance with paragraph (d) of this section.

(b) Obligation to sell to qualifying facilities. Each electric utility shall sell to any qualifying facility, in accordance with § 292.305, any energy and capacity requested by the qualifying facility.

(c) Obligation to interconnect. (1) Subject to paragraph (c)(2) of this section, any electric utility shall make such interconnections with any qualifying facility as may be necessary to accomplish purchases or sales under this subpart. The obligation to pay for any interconnection costs shall be determined in accordance with § 292.306.

(2) No electric utility is required to interconnect with any qualifying facility if, solely by reason of purchases or sales

over the interconnection, the electric utility would become subject to regulation as a public utility under Part II of the Federal Power Act.

(d) *Transmission to other electric utilities.* If a qualifying facility agrees, an electric utility which would otherwise be obligated to purchase energy or capacity from such qualifying facility may transmit the energy or capacity to any other electric utility. Any electric utility to which such energy or capacity is transmitted shall purchase such energy or capacity under this subpart as if the qualifying facility were supplying energy or capacity directly to such electric utility. The rate for purchase by the electric utility to which such energy is transmitted shall be adjusted up or down to reflect line losses pursuant to § 292.304(e)(4) and shall not include any charges for transmission.

(e) *Parallel operation.* Each electric utility shall offer to operate in parallel with a qualifying facility, provided that the qualifying facility complies with any applicable standards established in accordance with § 292.308.

§ 292.304 Rates for purchases.

(a) *Rates for purchases.* (1) Rates for purchases shall:

- (i) Be just and reasonable to the electric consumer of the electric utility and in the public interest; and
- (ii) Not discriminate against qualifying cogeneration and small power production facilities.

(2) Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases.

(b) *Relationship to avoided costs.* (1) For purposes of this paragraph, "new capacity" means any purchase from capacity of a qualifying facility, construction of which was commenced on or after November 9, 1978.

(2) Subject to paragraph (b)(3) of this section, a rate for purchases satisfies the requirements of paragraph (a) of this section if the rate equals the avoided costs determined after consideration of the factors set forth in paragraph (e) of this section.

(3) A rate for purchases (other than from new capacity) may be less than the avoided cost if the State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or the nonregulated electric utility determines that a lower rate is consistent with paragraph (a) of this section, and is sufficient to encourage cogeneration and small power production.

(4) Rates for purchases from new capacity shall be in accordance with paragraph (b)(2) of this section.

regardless of whether the electric utility making such purchases is simultaneously making sales to the qualifying facility.

(5) In the case in which the rates for purchases are based upon estimates of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for such purchases do not violate this subpart if the rates for such purchases differ from avoided costs at the time of delivery.

(c) *Standard rates for purchases.* (1) There shall be put into effect (with respect to each electric utility) standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less.

(2) There may be put into effect standard rates for purchases from qualifying facilities with a design capacity of more than 100 kilowatts.

(3) The standard rates for purchases under this paragraph:

(i) Shall be consistent with paragraphs (a) and (e) of this section; and

(ii) May differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

(d) *Purchases "as available" or pursuant to a legally enforceable obligation.* Each qualifying facility shall have the option either:

(1) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or

(2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:

(i) The avoided costs calculated at the time of delivery; or

(ii) The avoided costs calculated at the time the obligation is incurred.

(e) *Factors affecting rates for purchases.* In determining avoided costs, the following factors shall, to the extent practicable, be taken into account:

(1) The data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data;

(2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

(i) The ability of the utility to dispatch the qualifying facility;

(ii) The expected or demonstrated reliability of the qualifying facility;

(iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

(iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

(vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

(3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

(f) Periods during which purchases not required.

(1) Any electric utility which gives notice pursuant to paragraph (f)(2) of this section will not be required to purchase electric energy or capacity during any period during which, due to operational circumstances, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself.

(2) Any electric utility seeking to invoke paragraph (f)(1) of this section must notify, in accordance with applicable State law or regulation, each affected qualifying facility in time for the qualifying facility to cease the delivery of energy or capacity to the electric utility.

(3) Any electric utility which fails to comply with the provisions of paragraph (f)(2) of this section will be required to pay the same rate for such purchase of energy or capacity as would be required had the period described in paragraph (f)(1) of this section not occurred.

(4) A claim by an electric utility that such a period has occurred or will occur is subject to such verification by its State regulatory authority as the State

regulatory authority determines necessary or appropriate, either before or after the occurrence.

§ 292.305 Rates for sales.

(a) *General rules.* (1) Rates for sales:

(i) Shall be just and reasonable and in the public interest; and

(ii) Shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility.

(2) Rates for sales which are based on accurate data and consistent systemwide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics.

(b) *Additional Services to be Provided to Qualifying Facilities.* (1) Upon request of a qualifying facility, each electric utility shall provide:

(i) Supplementary power;

(ii) Back-up power;

(iii) Maintenance power; and

(iv) Interruptible power.

(2) The State regulatory authority (with respect to any electric utility over which it has ratemaking authority) and the Commission (with respect to any nonregulated electric utility) may waive any requirement of paragraph (b)(1) of this section if, after notice in the area served by the electric utility and after opportunity for public comment, the electric utility demonstrates and the State regulatory authority or the Commission, as the case may be, finds that compliance with such requirement will:

(i) Impair the electric utility's ability to render adequate service to its customers; or

(ii) Place an undue burden on the electric utility.

(c) *Rates for sales of back-up and maintenance power.* The rate for sales of back-up power or maintenance power:

(1) shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and

(2) shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.

§ 292.306 Interconnection costs.

(a) *Obligation to pay.* Each qualifying facility shall be obligated to pay any interconnection costs which the State

regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may assess against the qualifying facility on a nondiscriminatory basis with respect to other customers with similar load characteristics.

(b) *Reimbursement of interconnection costs.* Each State regulatory authority (with respect to any electric utility over which it has ratemaking authority) and nonregulated utility shall determine the manner for payments of interconnection costs, which may include reimbursement over a reasonable period of time.

§ 292.307 System emergencies.

(a) *Qualifying facility obligation to provide power during system emergencies.* A qualifying facility shall be required to provide energy or capacity to an electric utility during a system emergency only to the extent:

(1) Provided by agreement between such qualifying facility and electric utility; or

(2) Ordered under section 202(c) of the Federal Power Act.

(b) *Discontinuance of purchases and sales during system emergencies.* During any system emergency, an electric utility may discontinue:

(1) Purchases from a qualifying facility if such purchases would contribute to such emergency; and

(2) Sales to a qualifying facility, provided that such discontinuance is on a nondiscriminatory basis.

§ 292.308 Standards for operating reliability.

Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may establish reasonable standards to ensure system safety and reliability of interconnected operations. Such standards may be recommended by any electric utility, any qualifying facility, or any other person. If any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility establishes such standards, it shall specify the need for such standards on the basis of system safety and reliability.

Subpart D—Implementation

§ 292.401 Implementation by State regulatory authorities and nonregulated electric utilities.

(a) *State regulatory authorities.* Not later than one year after these rules take effect, each State regulatory authority shall, after notice and an opportunity for public hearing, commence

implementation of Subpart C (other than § 292.302 thereof). Such implementation may consist of the issuance of regulations, an undertaking to resolve disputes between qualifying facilities and electric utilities arising under Subpart C, or any other action reasonably designed to implement such subpart (other than § 292.302 thereof).

(b) *Nonregulated electric utilities.* Not later than one year after these rules take effect, each nonregulated electric utility shall, after notice and an opportunity for public hearing, commence implementation of Subpart C (other than § 292.302 thereof). Such implementation may consist of the issuance of regulations, an undertaking to comply with Subpart C, or any other action reasonably designed to implement such subpart (other than § 292.302 thereof).

(c) *Reporting requirement.* Not later than one year after these rules take effect, each State regulatory authority and nonregulated electric utility shall file with the Commission a report describing the manner in which it will implement Subpart C (other than § 292.302 thereof).

§ 292.402 Implementation of certain reporting requirements.

Any electric utility which fails to comply with the requirements of § 292.302(b) shall be subject to the same penalties to which it may be subjected for failure to comply with the requirements of the Commission's regulations issued under section 133 of PURPA.

§ 292.403 Waivers.

(a) *State regulatory authority and nonregulated electric utility waivers.* Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may, after public notice in the area served by the electric utility, apply for a waiver from the application of any of the requirements of Subpart C (other than § 292.302 thereof).

(b) *Commission action.* The Commission will grant such a waiver only if an applicant under paragraph (a) of this section demonstrates that compliance with any of the requirements of Subpart C is not necessary to encourage cogeneration and small power production and is not otherwise required under section 210 of PURPA.

**Subpart E—Qualification of
Cogeneration Facilities for
Incremental Pricing Exemption**

§ 292.501 Scope.

This subpart defines qualifying cogeneration facilities for the sole purpose of establishing an interim exemption from incremental pricing under the Natural Gas Policy Act of 1978.

**§ 292.502 Qualifying requirements for
cogeneration facilities.**

(a) *Definition of qualifying cogeneration facility.* For purposes of Title II of the Natural Gas Policy Act of 1978 (NGPA), and Subpart B of Part 282 of the Commission's rules, the term "qualifying cogeneration facility" means a cogeneration facility which:

- (1) Was in existence on November 1, 1978;
- (2) Used natural gas as a fuel on or prior to that date;
- (3) Produces electric energy and another form of useful energy (such as heat or steam), used for industrial, commercial, heating or cooling purposes, through the sequential use of energy; and
- (4) Meets the efficiency standards set forth in this section.

(b) *Definitions.* For purposes of this subpart:

(1) "Cogeneration facility" means equipment used to produce electric energy and another form of useful energy (such as heat or steam), used for industrial, commercial heating or cooling purposes, through the sequential use of energy;

(2) "Useful thermal energy output" of a cogeneration facility means the heat made available for use in an industrial process or for use as space or water heating;

(3) "Useful power output" of a cogeneration facility means the electrical or mechanical energy made available for use, exclusive of any used solely in the power production process;

(4) "Total energy input" means the total energy of all forms supplied from external sources to the cogeneration facility. In the case of energy in the form of fossil fuel, the energy input is to be measured by the lower heating value of such fuel;

(5) "Working fluid energy input" to a cogeneration facility means the enthalpy of steam leaving a boiler minus that of the feed water, when the steam is subsequently used in a topping cycle;

(6) "Overall energy efficiency" means the ratio of the sum of all useful thermal and power outputs to the total energy input of the cogeneration facility, measured by means of actual data or estimates. Any energy used exclusively in the thermal process of a topping-cycle (supplementary firing) facility shall not be included as energy output or energy input for the purpose of determining the cogeneration facility's overall energy efficiency;

(7) "Internal energy efficiency" means the ratio of the sum of all useful thermal and power outputs to the working fluid energy input, measured by means of actual data or estimates. Any energy used exclusively in the thermal process of a topping-cycle (supplementary firing) facility shall not be included as energy output or energy input for the purpose of determining the cogeneration facility's internal energy efficiency;

(8) A "topping-cycle cogeneration facility" means a cogeneration facility in which the energy input to the facility is first used to produce power, and the waste heat from power production is then used to provide useful heat;

(9) A "bottoming-cycle cogeneration facility" means a cogeneration facility in which the energy input to the system is first applied to a useful heating process, and the residual heat emerging from the

process is used then for power production; and

(10) "Supplementary firing" means natural gas used only in the thermal process of a topping-cycle cogeneration facility, or only in the electric generating process of a bottoming-cycle cogeneration facility.

(c) *Efficiency standards for topping-cycle facilities.* For topping-cycle cogeneration facilities using natural gas, with or without any other fuels, the following efficiency standard applies:

(1) The facility's overall energy efficiency must be not less than 0.55, or

(2) The internal energy efficiency of the facility must be not less than 0.70.

(d) *Efficiency standards for bottoming-cycle facilities.* For bottoming-cycle cogeneration facilities, there is no efficiency standard for qualification.

(e) *Eligibility.* In order to obtain qualifying status under the interim rule, a cogeneration facility must:

(1) Have been in existence on November 1, 1979, and

(2) Have used natural gas as an energy input on or prior to November 1, 1979.

(f) *Waiver.* The Commission may waive any of the provisions of this subpart if it determines that such waiver is necessary to encourage cogeneration.

(g) *Limitations of benefits of interim qualification.* Obtaining qualifying status for purpose of this interim rule does not:

(1) Constitute qualifying status for purposes of section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), or

(2) Assure that a facility will be a qualifying facility under the Commission's final rules implementing section 201 of PURPA or Title II of the NGPA.

§ 292.503 Procedures for obtaining qualifying status.

(a) In order to be a qualifying facility for purposes of exemption from incremental pricing, a facility must meet the standards set forth in § 292.502.

(b) If a cogeneration facility meets the standards set forth in § 292.502, the owner or operator of the facility may file an executed exemption affidavit that the facility is a qualifying cogeneration facility, pursuant to the procedures set forth in § 282.204 of the Commission's rules.

FOR FURTHER INFORMATION, CONTACT THE SECRETARY OF THE COMMISSION
CALLING CODE 646-271-61

Subpart F—Exemption of Qualifying Small Power Production Facilities and Cogeneration Facilities from Certain Federal and State Laws and Regulations

§ 292.601 Exemption to qualifying facilities from the Federal Power Act.

(a) *Applicability.* This section applies to:

- (1) qualifying cogeneration facilities; and
- (2) qualifying small power production facilities which have a power production capacity which does not exceed 30 megawatts.

(b) *General rule.* Any qualifying facility described in paragraph (a) shall be exempt from all sections of the Federal Power Act, except:

- (1) Sections 1-18, and 21-30;
- (2) Sections 202(c), 210, 211, and 212;
- (3) Sections 305(c); and
- (4) Any necessary enforcement provision of Part III with regard to the sections listed in paragraphs (b) (1), (2) and (3) of this section.

§ 292.602 Exemption to qualifying facilities from the Public Utility Holding Company Act and certain State law and regulation.

(a) *Applicability.* This section applies to any qualifying facility described in § 292.601(a), and to any qualifying small power production facility with a power production capacity over 30 megawatts if such facility produces electric energy solely by the use of biomass as a primary energy source.

(b) *Exemption from the Public Utility Holding Company Act of 1935.* A qualifying facility described in paragraph (a) shall not be considered to be an "electric utility company" as defined in section 2(a)(3) of the Public Utility Holding Company Act of 1935, 15 U.S.C. 79b(a)(3).

(c) *Exemption from certain State law and regulation.*

(1) Any qualifying facility shall be exempted (except as provided in paragraph (c)(2)) of this section from State law or regulation respecting:

- (i) The rates of electric utilities; and
- (ii) The financial and organizational regulation of electric utilities.

(2) A qualifying facility may not be exempted from State law and regulation implementing Subpart C.

(3) Upon request of a State regulatory authority or nonregulated electric utility, the Commission may consider a limitation on the exemptions specified in subparagraph (1).

(4) Upon request of any person, the Commission may determine whether a qualifying facility is exempt from a particular State law or regulation.

(FR Doc. 80-3720 Filed 2-22-80; 8:45 am)

BILLING CODE 6450-65-01

APPENDIX B
Metering Schematics
And Costs

7.0 EXHIBITS

METERING OPTIONS

All metering options (including simultaneous) assume single-phase metering without demand indicators. Estimated 1980 "plug-in" costs are for purposes of "order of magnitude" only. Three-phase metering will probably be more costly. Costs do not include instrument transformers that will be required for interconnections rated above 600 volts or above 200 amps.

Option 1

Simplest, assumes rate for billing is the same as the rate for buy back.

Costs:	Meter	\$ 25
	Labor	<u>58</u>
	Total	\$ 83

Option 2

Needed if rate for billing is different than the rate for buy back.

Costs:	Meter	\$ 72
	Labor	<u>77</u>
	Total	\$149

EXHIBIT 1

METERING OPTIONS

Option 3

This option is for metering varhours for billing.

Costs:	Meters	\$ 62
	Phase Shifter	280
	Labor	<u>160</u>
	Total	\$502

Option 4

For metering varhours, or determining average power factor, and also gives option of different rates for billing and buy back.

Costs:	Meters	\$111
	Phase Shifter	280
	Labor	<u>200</u>
	Total	\$591

EXHIBIT 2

METERING OPTIONS

Option 5

Provides the same metering as Option 4 but has time of day capabilities.

Costs:	Meters	\$ 135
	Phase Shifter	280
	Magnetic Tape	750
	Labor	450
	Total	<u>\$1615</u>

SIMULTANEOUS METERING OPTIONS

Option A

Assumes QF load and QF generation are on separate service laterals.

Costs:	Meters	\$ 50
	Labor	77
	Total	<u>\$127</u>

EXHIBIT 3

Option B

Meters net average power factor of QF generation

Costs:	Meters	\$ 75
	Phase Shifter	280
	Labor	200
	Total	\$555

Option C

Time-of-day metering. Permits determination of both VARS generated and those required by QF generator. Also, separately meters power factor of load.

Costs:	Meters	\$ 192
	(2) Phase Shifters	560
	(2) Magnetic Tapes	1500
	Labor	630
	Total	\$2882

EXHIBIT 4

APPENDIX C
Instructions For
Sample Avoided
Cost Calculations

APPENDIX C

Step by Step Instructions for Avoided Cost Calculation.

1. The Energy Avoided Cost Method (EAC)

System lambda or incremental fuel data can be obtained from dispatch computer models for each hour of the year.

As a utility's generation increases to meet its load, typically its incremental power costs also increase:

<u>KW</u>	<u>Incremental Cost (¢/KWH)</u>
⋮	⋮
1001	1.0
1002	1.0
1003	1.1
1004	1.2
⋮	⋮
Average 1.1	

This cost data, since it would be available for each hour, could be calculated by time-of-day or season simply by averaging the incremental costs over these periods.

The average of the incremental cost over the time period or season the utility would purchase power from a QF would be the energy avoided cost (EAC).

2. Average Fuel Method (AF)

In the normal mode of operation, utilities maintain records of fuel costs and megawatt hours generated during the year. This data can be obtained from the FERC uniform system of accounts or the utilities operating reports. The quotient of the total annual fuel costs and the MWH generated results in the average fuel cost in ¢/KWH.

3. Incremental Fuel Method (IF)

The incremental fuel method is rather straightforward. If the fuel of the avoided unit (as a result of purchases from a QF) is oil, coal or gas, then the avoided cost can be calculated as follows:

$$\begin{aligned} \text{Cost of Fuel of Plant} \times \text{Heat Rate} &= \text{Energy Avoided Cost} \\ \text{i.e. } \text{\$/BTU} \times \text{BTU's/KWH} &= \text{\$/KWH} \end{aligned}$$

4. Expansion Plan Method

Exhibit IV - 3 page 1 of 2

- (1) Column 1 indicates the planning horizon to be studied or covered in an agreement by a utility and a QF.
- (2) Column 2 indicates the capacity additions by year within the planning horizon. These capacity additions obtained from the Planning Department should cover all base, intermediate, and peaking units that are planned to be built. These capacity additions should be summarized over the number of years in the expansion plan.
- (3) Column 3 indicates the per unit installed capacity cost of each new generating unit. These figures in \$/KW of installed capacity should be based on present day dollars (levelized).
- (4) Column 4 indicates the total cost of each installed generating unit by years and then summarized over the number of years in the planning horizon.
- (5) Column 5 indicates the per-unit cost of energy generated by each corresponding new plant addition in the planning horizon. This data could be obtained from the fuel cost forecasting section.

4. Expansion Plan Method (cont.)

- (6) Column 6 indicates the expected capacity factor of each new unit coming on line.
- (7) Column 7 indicates the total megawatt-hours generated by each new plant. This figure is obtained by multiplying the installed capacity times the capacity factor times the number of hours in a year (8760). The MWH should be summed over the planning horizon.
- (8) Column 8 indicates the total energy cost expended by year by each new unit coming on line. This figure is obtained by multiplying the per unit energy cost by the total annual megawatt-hours. The total energy costs should be summed over the planning horizon.

Exhibit IV - 3 page 2 of 2

- (1) The calculation of the demand avoided cost can be obtained from the expansion plan data.

A. The overall expansion plan capacity per unit cost should be obtained. The total cost of capacity divided by the installed capacity results in this figure.

$$\$740,000,000 \div 1,000,000\text{KW} = \$740 \text{ per KW}$$

B. The annual carrying costs of these added new units need to be calculated. This is obtained by multiplying \$740 per KW by the cooperative's annual capital or carrying cost factor. In this instance 10% is used as an example only.

$$\$740 \text{ per KW} \times .10 = \$74 \text{ per KW per year}$$

C. The annual carrying cost should be adjusted to a monthly billing figure. i.e. divided by 12.

$$\$74 \text{ per KW per year} \div 12 = \$6.20 \text{ per KW per month}$$

4. Expansion Plan Method (cont.)

Exhibit IV - 3 page 2 of 2

- (2) The calculation of the energy avoided cost can be obtained from the expansion plan data. This can be calculated by dividing the total expansion plan energy cost by the total annual megawatt-hours.

$$\$178,704,000 \times 100 \div 6,657,600,000 \text{ KWH} = 2.68\text{¢/KWH}$$

- (3) The total avoided cost is then calculated by applying \$6.20 per KW per month to the demand supplied by the QF and 2.68¢ per KWH to the energy supplied by the QF.

APPENDIX D

Sample of Public
Hearing Notices

PUBLIC HEARING
AGENDA

1. Purpose and Rules of the Meeting.
2. Overview of PURPA & FERC Orders 69 & 70.
3. Overview of Plan.
4. Service Rules & Regulations..
5. Service Agreement.
6. Avoided Cost.
7. Rate Schedule.
8. Questions and Comments from the Public.

LEGAL NOTICE

NOTICE OF PUBLIC HEARING

by

Purpose:

To take public comment concerning 's proposed plan for implementing federal requirements relating to the purchase of electric power and energy from qualifying small power producers and cogenerators.

Required by:

The Public Utility Regulatory Policies Act of 1978 (PURPA), Section 210; 16 USCS 824a-3; and Implementing Regulations of the Federal Energy Regulatory Commission, 18 CFR Part 292, (Docket No. RM79-55, Order Number 69).

(The Public Utility Regulatory Policies Act of 1978, Section 201, 16 USCS 796; and Regulations of the Federal Energy Regulatory Commission, 18 CFR Part 292, (Docket No. RM79-54, Order No. 70) provide additional information regarding Small Power Production and Cogeneration Qualifying Status.)

Date: February 9, 1981

Time: 1:30 PM

Location: Board of Directors Room

Summary: is a public power district, rural electric distribution system serving approximately 3,700 consumer members in all or parts of the counties of Cheyenne, Deuel, Morrill and Garden. is developing a plan to comply with the federal requirements referenced above. The plan will address the terms and conditions of obligation to purchase electric power and energy from qualifying small power producers and cogenerators, its methods for establishing rates for purchase and for providing supplementary, interruptible, maintenance and backup power. Consideration also will be given to costs of interconnection, obligations during system emergencies and standards for safety and system reliability. Comments are invited from interested persons and the comments will be considered in making final determinations regarding the proposed plan.

Supporting information will be available to review from headquarters office during regular business hours on or after January 26, 1981.

The final implementation plan adopted through this procedure may be modified

at a later date by reason of new information and public input.

Public Comment and Hearing Procedure:

Written comments are encouraged and will be considered if they are received on or before February 13, 1981.

Parties who wish to make oral comment at the hearing should notify the contact person specified in this notice on or before February 4, 1981. Written copies of statements will be appreciated.

Oral comments may be limited to 10 minutes. Further opportunity to comment may be allowed as time permits.

Final Implementation Plan:

final implementation plan as submitted to the Federal Energy Regulatory Commission will be available after March 20, 1981.

Contact:

Written comments, request to participate in the hearing, and requests for further information should be directed to:

Staff Assistant

SAMPLE PUBLIC NOTICE

_____ ELECTRIC COOPERATIVE, CENTRAL ELECTRIC POWER COOPERATIVE and ASSOCIATED ELECTRIC COOPERATIVE jointly announce that a public hearing will be held at _____ (location) at _____ (time) on _____ (date), 1981, to provide information regarding the operation, connection and rates to be paid to small power producers and cogenerators desiring to connect to the Cooperative facilities. This public hearing is being held in accordance with Section 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA).

The _____ Electric Cooperative, Central Electric Power Cooperative and Associated Electric Cooperative hereby make public offer to purchase the electrical output of all small power producers and cogenerators, as defined in the PURPA regulations, desiring to connect to the Cooperative facilities.

by _____ ELECTRIC COOPERATIVE

(address)

CENTRAL ELECTRIC POWER COOPERATIVE
Post Office Box 269
Jefferson City, MO 65102

ASSOCIATED ELECTRIC COOPERATIVE
Post Office Box 754
Springfield, MO 65801

APPENDIX E

Samples of Utility Policy Statements

PROPOSED POLICY FOR COOPERATIVE PURCHASE OF POWER AND ENERGY FROM
SMALL POWER PRODUCERS AND COGENERATORS IN COMPLIANCE WITH THE
PUBLIC UTILITY REGULATORY PRACTICES ACT (PURPA) OF 1978

The Cooperative will purchase at its "avoided costs" power and energy from qualifying facilities in accordance with Sections 201 and 210 of PURPA. The Cooperative will also sell power and energy to the qualifying facility as it may require. The Cooperative will sell the qualifying facility its needs over and above its generating capabilities or, at the qualifying facility's option, will purchase 100% of its generation output and sell to the qualifying facility 100% of its needs.

The Cooperative will base "avoided costs" on that portion of its wholesale power cost which, by virtue of the purchase from the qualifying facility, it now avoids.

Energy cost avoidance will equal the wholesale cost of energy on a one-for-one basis.

Firm capacity cost avoidance will equal the wholesale cost of firm capacity on a one-for-one basis for all capacity the qualifying facility can provide on an equally firm basis as the Cooperative's wholesale power supplier. Non-firm or intermittent capacity will not qualify for payment.

Power and energy sales to the qualifying facility shall be made at standard rates.

PURPA provides that the other Cooperative members shall not subsidize the qualifying facility. Thus, all costs including engineering, construction, material and related expenses are to be paid by the Small Power Producers and Cogenerators.

The Cooperative and the other Cooperative members are to be held harmless from all acts or omissions on the part of the qualifying facility. The qualifying facility will be required to carry adequate insurance and will be required to reimburse the Cooperative for its additional insurance premiums which may be caused by the connection of the qualifying facility.

The PURPA regulations also mandate that service to other Cooperative members shall not be degraded because of the presence or connection of the qualifying facility. The qualifying facility shall construct, operate and maintain its facilities or cause them to be constructed, operated and maintained, in a manner conforming to all existing safety codes, regulations and best operating practices. Failure to comply shall be cause for disconnection of the qualifying facility.

Future costs or system improvements which may become necessary by reason of the continued connection of additional qualifying facilities to a Cooperative facility shall be shared by all qualifying facilities that contribute to the need for the improvement to the Cooperative facility. The sharing of costs shall be prorated on a capacity basis at the time the cost is incurred.

Each connection of Small Power Producer and Cogenerator to the Cooperative's radial distribution system will require individual engineering analysis. The Cooperative encourages prospective Small Power Producers and Cogenerators to

employ qualified engineering firms in the design of the interconnecting facilities and in the design of modifications, if any, to the Cooperative system to accommodate the addition of generation. The Cooperative will provide all system data for use by the engineer, including line characteristics, substation capacities, sectionalizing schemes and voltage regulation programs. The design of the interconnecting facilities and system modifications shall incorporate apparatus and devices compatible with those existing on the Cooperative system and compatible with facilities other Small Power Producers and Cogenerators connect to the Cooperative system. The design shall incorporate features that will permit construction, operation and maintenance of the facility without disruption or degradation of service to the consumers served by the Cooperative. The Cooperative is prepared to provide the design and construction service referred to herein on a cost reimbursable basis. However, the Small Power Producers and Cogenerators are encouraged to employ independent firms for this service.

Metering of KW and KWH quantities shall be provided by "in" and "out" meters as appropriate. Based on readings of these meters, the Cooperative will monthly render a statement showing in necessary detail the purchase by the Cooperative, the sales by the Cooperative and the net monies owed by the Cooperative or due to the Cooperative.

The Cooperative will maintain an accurate and complete accounting of all expenses related to the application and connection of each Small Power Producer and Cogenerator and shall promptly bill the Small Power Producer or Cogenerator for all related expenses. Related expense shall include but not be limited to labor, materials, insurances, overheads, legal services, consulting services, meter reading, switching costs, mileage and equipment costs.

The Cooperative and the Small Power Producer or Cogenerator shall enter into a written agreement setting forth in necessary detail the manner in which the Cooperative shall purchase and sell power and energy to the Small Power Producer or Cogenerator, the facilities to be constructed, the character of service, the planned mode of operation and maintenance of the facilities. The agreement shall also detail the rate, billing and payment arrangements for power and energy transactions, the billing and payment procedures for Cooperative expenses related to the Small Power Producer or Cogenerator and other items that are a necessary part of the agreement.

MAJOR STEPS REQUIRED TO IMPLEMENT PURPA SECTION 210

1. Inform public

Place a noticable ad in a newspaper or newspapers of general circulation in the service area informing the public of the Cooperative's offer to buy power from qualifying facilities and notice of a public hearing. A similar noticable ad should be placed in the Cooperative's newsletter. The State-wide newspaper should run a news article designed to inform members of the program and to alert them of the upcoming public hearings in their particular area.

2. Offer to purchase

An offer to purchase power from qualifying facilities should be made in the notice and at the public hearing.

3. Establish rate for 100 KW and below

A rate shall be established for purchases of power and energy from qualifying facilities of 100 KW and below. The public must have this rate available to them in order to evaluate the economics of providing power and energy to the Cooperative.

4. Public hearing

A public hearing to be held in the headquarters city should provide the details of the PURPA regulations to the public. The news media should be aware of the meeting and the PURPA program and should be invited to attend the public hearing. A fairly accurate record should be made of the hearing with specifics regarding commentors and their comments. Each person attending should be asked to register upon entering the meeting room. The public meeting should be held in the evening and an adequate meeting place selected that will accommodate a larger than anticipated attendance. The major items to be covered during the public meeting should include:

- a. Indicate which Cooperatives are jointly having the meeting.
- b. Inform the attendees that a record of the proceedings is being made.
- c. Provide a definition of small power producers and cogenerators.
- d. Explain the basics of the PURPA regulations and its requirements.

- e. State the Cooperative policy designed to implement the PURPA regulations.
- f. Provide the rate for 100 KW and below qualifying facilities.
- g. Make the offer to buy and sell power and energy from the qualifying facilities.
- h. Provide a question and answer period.

5. Report

Each Cooperative must submit a report to the Federal Energy Regulatory Commission (FERC) detailing how the guidelines have been complied with by March 20, 1981.

INTERIM RECOMMENDATIONS FOR INTERCONNECTING
SMALL POWER PRODUCERS

February 9, 1981

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL ELECTRIFICATION ADMINISTRATION
ENERGY MANAGEMENT & UTILIZATION DIVISION

INTERIM INTERCONNECTION RECOMMENDATIONS
POLICY

A. General

1. For the safety of electric supply system personnel and the general public, no generation should be paralleled with an electric system without the prior knowledge and written approval of the cooperative.
2. A member desiring to install generation derived primarily from supplemental energy should formally notify the cooperative in writing of this intention. Included with the notification should be a complete set of electrical diagrams, a site plan showing the location of the facilities, a complete listing of the electrical parameters associated with the generator power conditioning equipment, a description of the protective functions of the facilities including hardware; a range of settings and fuse characteristics, maximum power rating and expected kWh production from the generator. Any information on the expected use of the generator as it pertains to its end use, seasonal availability patterns, wind regime average monthly data, or solar insolation patterns that would be helpful in preparing load curves should also be provided.
3. The cooperative should estimate the required modifications or additions to the distribution system that are necessary to interconnect the member-owned generation. FERC regulation, 18 CFR 292 Part C, allows for billing of the small power producer for any interconnection costs. A method for repayment should be determined if the cooperative is not under a state commission jurisdiction. It is also important to include in the interconnection agreement provisions for the members installation of future modifications and additions as may be required with large penetrations of small power producers. Such future costs might include equipment for harmonic filtering, complex utility relaying schemes, power factor correction, and System Control And Data Acquisition (SCADA) Systems.
4. The electrical facility should be designed and installed in accordance with applicable portions of the latest edition of the National Electrical Safety Code (NESC) & The National Electrical Code (NEC), as appropriate.
5. The cooperative should inspect the installation prior to energization and any deficiencies noted by the inspection should be corrected prior to energization. This inspection by the cooperative should not relieve the owner of any liability.
6. No modifications or revision to the member's installation should be made without prior notification and approval by the cooperative.
7. Because of the numerous liability issues that are involved with the interconnection of member-owned generation, the member should be instructed to have his insurance company submit proof of the purchase of liability insurance coverage to the cooperative with renewal policies being provided annually.

B. Technical

1. No induction generators larger than 10 kW should be permitted on single phase secondary services without the cooperative first performing the necessary studies to insure that adequate and reliable service to all members may still be maintained due to possible phase unbalances and voltage flicker.
2. The electrical arrangement of the member's service should be in accordance with the attached diagram. The member consumer should furnish the following equipment:
 - (a) One or two load break disconnect switches depending on whether the unit is capable of operating isolated from the utility system. For force-commutated inverters and synchronous machines, both a utility disconnect switch and a generator disconnect switch should be supplied so that the responsibility for synchronizing the member's generator is removed from the cooperative's lineman as well as remove the cooperative of the liability of operating the member's equipment. (See comment number C. 3 for further explanation).

Induction generators and line-commutated inverters are capable of self excitation when isolated from the utility system and connected to small loads which possess a leading power factor. In the most likely case where self-excitation of the member's generation is highly improbable due to system configuration, the utility disconnect switches may be omitted. Due to frequent modifications of distribution systems, it is recommended that the cooperative's err on the conservative or safety side when establishing its' interconnection policies. Disconnect switches should have load interrupting capability and provision for padlocking.

For small size generators, the utility may prefer to utilize the transformer primary cutout, rather than installing a disconnect switch, as the means of disconnecting or isolating the member's generator. This method of isolation should not be used for a multi tap transformer secondary since this may effect service to other members.

- (b) The cooperative should determine which metering configuration (discussed in Section III) will be best for the energy technology and the size of the unit being considered. If the cooperative has no preference, it is REA's recommendation that two watt-hour meters be furnished which are unidirectional. One meter would read energy delivered to the member by the cooperative and the other will read excess energy supplied by the member to the cooperative.

It may be instrumental in the installation of the first few installations of each technology that time-of-day metering be used. The information obtained from this form of metering will provide valuable data for determining rates and avoided costs as specified by PURPA.

- (c) To ensure safety to utility personnel against self excitation of induction machines and synchronous machines, provision for grounding the incoming line at the member transformer should be made.
3. The member's system shall be equipped and constructed such that it will automatically disconnect from a de-energized or faulted utility line.

Minimum protection requirements will vary on different generator configurations and distribution system characteristics, however; the following protective functions should be supplied:

- (a) Overcurrent protection should be set as low as feasible, allowing for machine inrush characteristics. Three phase generators which can act as a ground source to the utility system should be equipped with a sensitive ground overcurrent relay when practical.
- (b) Over-under voltage protection and frequency protection functions should be supplied on generators which have the capability for isolated operation. The intent of requiring this protection is to prevent damage to the appliances of other members on the same distribution line and to connected distribution system equipment. These protective functions are expected to be supplied on synchronous machines and self-commutated inverters. Induction generator systems which have frequency protection are the exception to the norm.
- 4. The member should provide a generation facility which is self protected from normal, abnormal, and system emergency conditions and carry adequate liability insurance to protect against accidental damage to adjacent members due to miss operation of equipment. The cooperative should be absolved from any liability for damages to the member's facility.
- 5. The small power producer should not introduce harmonics into the cooperative's power system that are excessive enough to affect other members. ANSI C50-1936 requires that allowable distortion measured at the member's meter not exceed 10 percent. Present industry practice for inverter equipment is to limit total harmonic distortion to less than 5%. Since the most economical inverter on the market exceeds all these limits, an imposition of a harmonic content limit on a member's generator now, would most likely stifle efforts to install supplemental energy sources. In order to encourage the installation of member's generation facilities, it is recommended that interconnection agreements specify that any interference to the electrical or communications systems (to include telephone, radio, television, carrier, etc.) resulting from the member's equipment, will be grounds for termination of the interconnection until the member corrects the condition in its' facilities to the satisfaction of the cooperative.
- 6. The member should be advised that in the long term, the cooperative may have to install a communication channel and remote terminal equipment for the purpose of supervisory control and data acquisition or to complete a protective relaying system. The cooperative should further advise that the cost of the communications equipment and any necessary modifications to the member's equipment may be the responsibility of the member. This requirement should be included in the initial interconnection contract.

C. Operational

- 1. If the cooperative determines that it is necessary to do work on the customer's premises, an inspection of the work area and consumers generating facility should be made by cooperative personnel to determine that the machine is inoperative. If hazardous working conditions are detected,

the member should be required to correct the unsafe condition before the work will be performed.

2. The cooperative should reserve the right to interrupt the small power producer when deemed necessary by the cooperative due to system emergencies or unsafe operating conditions.
3. Cooperative personnel should not assume responsibility for synchronizing member-owned generation to the utility system frequency. Restoration of electric service to a customer's load panel will be made by closing the utility disconnect switch only after the member's generator disconnect switch has been opened. The customer should have complete control of the generator disconnect except during the restoration procedure. No padlocks or other locking devices may be placed on the generator disconnect switch or on facilities which may restrict access to the switch. The utility disconnect switch should be placed on the utility side of the meter and should have a load interrupting rating equivalent to the rating of the service. The utility disconnect switch should not at any time be operated by the member and shall be locked with a padlock or locking device. The cooperative should furnish laminated plastic escutcheons for attachment to the generator and utility disconnect switches to designate their function and the type and size of the member's generator.
4. The cooperative should adequately mark the location of member-owned generation by attaching caution signs for the benefit of operating personnel at the member's transformer location and at the point where the spur or lateral joins the main feeder.
5. The cooperative should issue revised circuit maps of the feeder when member-owned generation facilities are energized. Substation one-line diagrams should also be updated to indicate the number and aggregate rating of generators on a feeder. Feeders which have member-owned generation should bear the same type of caution sign as employed on the distribution line.
6. In accordance with Occupational Safety and Health Act (OSHA) requirements, all power sources should be removed from a feeder and grounded prior to commencing work on a line section. This means that each member-owned generating system will have to be disconnected and the feeder grounded at a point between the work area and the member-owned generator.

RECOMMENDED ELECTRICAL ARRANGEMENT

RECOMMENDED ELECTRICAL ARRANGEMENT II

REFERENCES

1. Professor Gerald L. Park, "Summary of Interface Issues Arising when Intermittent Customer-Owned Sources are Connected to Utility Distribution Systems"; Michigan State University.
2. Systems Control Inc., "Operation of Small Wind Turbines on a Distribution System", Palo Alto, California 94304.
3. Donald Bain, "Metering, Coincidence, and Diversity Reliability of Small Power Producers", Oregon Department of Energy.

APPENDIX F
Samples of
Interconnection
Contracts

EXHIBIT III-7

**LIST OF CONTRACT ISSUES TO BE ADDRESSED IN
NEGOTIATIONS BETWEEN UTILITIES AND QUALIFYING FACILITIES**

EXHIBIT III-7

AN INITIAL LIST OF CONTRACT ISSUES
TO BE ADDRESSED IN NEGOTIATIONS BETWEEN
UTILITIES AND QUALIFYING FACILITIES

Contract Issues

Committee Recommendations

Plant

- 1) What appropriate ownership configurations are available regarding the generating equipment; generating plant facilities; interconnections and metering equipment; piping facilities for steam; etc.?

No limitations on ownership arrangements other than state and federal law. The contract should include a clause stating that the facility warrants that it is a qualifying facility.

The contract should clearly define the "point of interconnection."

The contract should specify the ownership arrangements for various parts of the facility. For instance, a substation might be built by the utility or by the industry with utility specifications.

- 2) What are the technical specifications for expected outputs of electric power of the system?

Verification that a facility does qualify for the benefits of the FERC rules should be left to the FERC. It is the responsibility of the qualifying facility to be certified.

The contract should include specific technical specifications and performance standards including but not limited to: standard voltage, current, kva, kvar, kw, expected range of frequencies, and harmonic distortion.

- 3) Who is responsible for operation and maintenance of specific aspects of the system?

The contract should specify responsibility for O&M on the interconnected QF. In this context, the owner should provide for his own protection in an emergency situation. However, the contract should give the utility the right to approve the interconnected equipment from the standpoint of system safety and reliability. If this brings up liability questions, then these too should be answered in the contract and its negotiations.

4) How and when will routine maintenance work be scheduled?

This question should be addressed in a QF-utility contract.

5) Who will provide for insurance on the various parts of the system?

It was generally agreed that this was not a serious issue except perhaps in the area of worker's compensation in the event of certain accidents. Generally, the owner of the QF is responsible for maintenance, insurance and taxes on its facility.

6) Under what arrangements will supplementary power and/or back-up power be provided to the cogenerator?

For agreements other than simultaneous buy-sell arrangements, provisions and conditions for making available supplementary, back-up, maintenance, or interruptible power should be spelled out in the contract. PURPA requires that these forms of power be offered, and it defines them as follows:

"Supplementary power" means electric energy or capacity supplied by an electric utility, regularly used by a qualifying facility in addition to that which the facility generates itself.

"Back-up power" means electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.

"Interruptible power" means electric energy or capacity supplied by an electric utility subject to interruption by the electric utility under specified conditions.

"Maintenance power" means electric energy or capacity supplied by an electric utility during scheduled outages of the qualifying facility.

Billing

1) What is the appropriate way to measure and bill for electricity being bought and sold?

Generally, billing will occur by normal billing period. This question should be addressed in a QF-utility contract. A simultaneous buy-sell arrangement will require at least two meters. Time of day metering should be specified if appropriate.

Contract Cancellation

- 1) Under what conditions can the contract be voided?

Conditions for contract cancellation are an important part of any QF-utility contract. The Committee felt that the conditions would probably be different for each situation but recognized also that the conditions set out would be a determinant of any avoided-capacity cost payments the QF might receive from the utility. The Committee avoided getting into the question of what conditions should qualify a facility for capacity credits. The Committee stressed that situations voiding a QF-utility contract should be specified in the contract.

The Committee did discuss some general areas where conditions should be specified in the contract including:

- o Financial stability of the cogenerator or small power producer, (may require a bonding clause); and
- o Range of allowable load changes or production changes.

- 2) What is required of the parties in the event of contract cancellation?

The contract must address the problem of non-performance of the parties, including penalties. As a principle, if the utility hasn't spent extra money, it should not penalize the QF. However, "there should be appropriate penalties for cancellation or non-performance" and these should be specified in a contract.

Continuity of Service

- 1) Under what conditions is one of the parties not liable for interruptions in the contracted service?

Contracts should contain provisions which are compatible with Section 292.304(f)(1-4). Cogenerators and small power producers whose power purchase requirements cease should be treated in the same manner as the procedure for the class of customer to which they belong.

Rights of Way, Permits, Safety Codes

- 1) What rights of way are guaranteed to the utility for interconnection purposes?

The contract should consider incorporating terms to cover rights of way, permits and safety codes. The contract should require that a QF is expected to operate with mutually agreed upon safety codes and standards. The utility has rights of way which are basically the same as for any customer.

Liability

- 1) Who is liable for damages and losses to property and persons that may occur at different points in the system?

Each party is liable for anything up to its point of interconnection or anything attributable to its facility.

Metering

- 1) Who purchases, installs and maintains metering equipment?

The contract should specify that the QF is responsible for any additional costs of metering over and above regular metering costs.

The contract should specify arrangements for payment of metering equipment.

- 2) What rights does the other party have to test the meter?

The contract should include provisions for adequate access, testing, reading, etc.

The utility should be responsible for normal metering. A simultaneous buy-sell arrangement will require at least two meters and the extra costs should be borne by the QF. Also, the reliability of the extra meters needs to be verified and checked periodically.

Term of the Contract

- 1) Contract effective-date; length of contract; provisions for renewal?

Generally, contracts go into effect when signed. Rates go into effect at the time of operation.

ELECTRIC SERVICE AGREEMENT
MEMBER OWNED GENERATION FACILITIES

THIS AGREEMENT, made this _____ day of _____, 19____, by and between

(hereinafter called the "COOPERATIVE") and

(hereinafter called "MEMBER").

WITNESSETH:

WHEREAS, the MEMBER has indicated a desire to install electric generating facilities described on the attached Schedule A on his property located at _____; and

WHEREAS, the Member Owned Generating Facilities (hereinafter called Qualifying Facilities or QF) will utilize renewable resources as fuel and/or produce two forms of energy simultaneously and otherwise meet the qualification standards established by the Federal Energy Regulatory Commission (FERC); and

WHEREAS, the MEMBER wishes to generate electric energy for his own uses and sell any excess energy to the COOPERATIVE; and

WHEREAS, the COOPERATIVE, consistent with its policy of encouraging innovation in the energy field, is willing to interconnect and operate in parallel with the MEMBER Owned Qualifying Facilities and to furnish parallel electric service to the MEMBER for the operation of his generating facilities;

NOW, THEREFORE, the COOPERATIVE and the MEMBER agree as follows:

1. The COOPERATIVE shall furnish electric service and supply the energy requirements of the MEMBER which are not supplied by the QF in accordance with the rate schedules applicable to the MEMBER'S class of service.
2. The COOPERATIVE shall purchase all power and energy made available by the MEMBER on the terms and conditions of Option ____ of Rate Schedule PG, which is attached and is a part of this Agreement, and any revisions approved by the COOPERATIVE'S Board of Directors. The rate which the COOPERATIVE shall pay for the power and energy shall be based on the COOPERATIVE's avoided cost, as determined solely by the COOPERATIVE.
3. The installation and operation of the QF shall be in accordance with the terms and conditions of the applicable rate schedule and rules, regulations and policies of the COOPERATIVE which from time to time may be modified or adopted by the Board of Directors of the COOPERATIVE.

ELECTRIC SERVICE AGREEMENT
(CONTINUED)

4. Prior to the installation of the QF, the MEMBER shall submit his plans and specifications for the facilities to the COOPERATIVE for its review to assure compliance with the COOPERATIVE'S rules, regulations and bylaws. Such review shall not be construed as permission to operate the facilities without written authorization from the COOPERATIVE after inspection of the completed facilities as hereinafter provided.
5. Prior to interconnection of the QF, the MEMBER shall notify the COOPERATIVE and the COOPERATIVE shall inspect the facilities for compliance with the rules, regulations and bylaws. The COOPERATIVE shall inspect and test the operation of the QF to assure the safety of its employees, and the satisfactory operation of the QF in parallel with the COOPERATIVE'S system before authorizing the operation of the facilities. Such inspection by the COOPERATIVE shall not relieve the MEMBER from his responsibility to install, operate, and maintain the facility in a safe and satisfactory manner.
6. The MEMBER shall reimburse the COOPERATIVE for the COOPERATIVE'S cost of providing additional facilities or modifying existing facilities including metering required to interconnect with the QF. Payment shall be due within 30 days of receipt of a statement thereof from the COOPERATIVE.
7. The COOPERATIVE may at any time install or modify its equipment as it deems necessary to insure the safety of its employees and the satisfactory operation of its system, and/or the accuracy of its meter as a result of the operation of the QF. The MEMBER shall reimburse the COOPERATIVE for the cost of such installation or modification within 30 days of receipt of a statement thereof from the COOPERATIVE.
8. Authorized COOPERATIVE employees shall have the right to enter upon the MEMBER'S property at any time for the purpose of inspecting QF and making additional tests to ensure the continued safe operation of the QF and the accuracy of the meter. Such inspections shall not relieve the MEMBER from his obligation to install, operate, and maintain the facility in a safe and satisfactory manner.
9. If, in the sole judgment of the COOPERATIVE, the MEMBER has failed to maintain the QF in satisfactory operating condition, the COOPERATIVE may notify the MEMBER to disconnect the facilities from the COOPERATIVE system. In the event the MEMBER fails to immediately comply with such notice, the COOPERATIVE may discontinue service to the MEMBER until the QF is disconnected or restored to satisfactory operating condition.

PSE
12/12/80

ELECTRIC SERVICE AGREEMENT
(CONTINUED)

10. The MEMBER shall have the sole responsibility for the safety and electrical protection of his facilities, irrespective of the condition of the COOPERATIVE'S facilities.
11. The MEMBER shall protect, idemnify and hold harmless the COOPERATIVE and its officers, agents and employees from any and all claims, demands, suits, liability and expense (including attorneys fees) by reason of any injury to or death of any person or damage to any property caused by or resulting from the QF.
12. The MEMBER shall procure and maintain the following types of insurance in the amounts stated:
 - A) General liability insurance in the amount of \$1,000,000 per occurrence or greater.
 - B) Property loss insurance in the amount of \$250,000 or greater.

Each year the MEMBER shall provide the COOPERATIVE with proof of insurance and shall notify the COOPERATIVE upon termination or modification of the insurance coverage.

13. This Agreement shall become effective immediately upon the executive hereof and shall continue in effect until terminated by either party upon thirty (30) days written notice given to the other party. Termination shall require permanent disconnection of the facilities.

IN WITNESS WHEREOF, the parties have caused this Agreement to be duly executed as of the day and year first above written.

Attest:

COOPERATIVE

By _____
(President, Manager)

Attest:

MEMBER

By _____

PSE
12/12/80

ELECTRICITY SERVICE & PURCHASE AGREEMENT

THIS AGREEMENT, dated this _____ day of _____,
19____, by and between _____, hereinafter
referred to as _____, and _____,
hereinafter referred to as "Customer",

W I T N E S S E T H :

WHEREAS, Customer has notified Consumers that Customer intends to install or has installed facilities on Customer's property for the purpose of generating electric energy to reduce or eliminate Customer's dependence on outside sources for Customer's own electricity needs, or to create surplus electricity for sale; and

WHEREAS, prior to December, 1980; Consumers service schedule has made provision only for electric service without any other source of electric supply, and no provision has been made for the purchase of electricity from its small service customers; and

WHEREAS, Consumers now desires to change the foregoing policies, in favor of policies which encourage the development of small power production facilities; and

WHEREAS, the parties desire to contract between themselves to provide for the achievement of their aforesaid mutual goals in a harmonious, mutually beneficial and safety conscious manner,

NOW, THEREFORE, in consideration of the covenants and

conditions herein contained, the parties hereto agree as follows:

1. Consumers Service. Consumers shall make available facilities to provide _____ phase, _____ volt electric service to be used for _____ at (location) _____, described as follows:

Such electric service shall be furnished at one point of delivery and metering on Customer's premises.

2. Service Rates. Customer shall receive and pay for service furnished hereunder in accordance with the applicable rate schedule in effect for electric service customers in like circumstances and effective superseding rate schedules of Consumers.

3. Meters. An interconnection shall be provided at Customer's expense on the source side of the Customer's service meter to measure the total output of the Customer's generation facilities. At its expense, Customer shall provide three meter bases for Consumers' meters to measure kilowatt hours in, kilowatt hours out, and reactive kilovolt amperes in. For installations where maximum reactive kilovolt ampere demand is less than 5.0 kvar, no meter for measuring reactive kilovolt amperes in shall be required.

4. Purchase Rates. Consumers shall receive and pay for all separately metered kilowatt hours of Customer generation

in accordance with the applicable rate schedule in effect, which shall be based on actual or projected "avoided costs" of Consumers, and effective superseding rate schedules.

5. Hold Harmless. Customer agrees to protect, indemnify and hold harmless Consumers, its directors, officers, employees, agents, and their representatives against and from any and all loss, claims, actions, or suits, including costs and attorneys' fees, both at trial and on appeal, for or on account of injury to, bodily or otherwise, or death, of any person, or damage to or destruction of property belonging to Consumers or others, resulting from, or arising out of, any operations or interconnection hereunder, excepting only such injury or death as may be caused solely by the fault or negligence of Consumers its directors, officers, employees or agents.

6. Safety Disconnect. Customer shall furnish and install a load break disconnect safety switch on the Customer's side of the metering. If the Customer's generation unit is capable of isolated operation from Consumers system, Customer shall furnish and install two such switches. The disconnect switch(es) shall be located adjacent to Consumers' meters and shall be of the visible break type in a metal enclosure which can be secured in an open position by a Consumers padlock. Consumers shall have the right to lock such switch(es) open whenever, in the sole judgment of Consumers, (1) it is necessary to maintain safe electrical operating conditions, or (2) Customer's facilities adversely affect Consumers'

system or the electric or telephone service of another customer or member of Consumers, or (3) there is a system emergency or are abnormal conditions existing.

7. Installation. Except only for metering, Customer shall own, maintain and be solely responsible for all facilities on the Customer side of the single point of delivery specified by Consumers. Customer's system, including interconnecting equipment, shall meet the requirements of and be inspected and approved by the State electrical inspector and any other public authority having jurisdiction before any connection is made to Consumers' system. The Customer's facility shall be designed and installed in accordance with the applicable portions of the National Electrical Safety Code and the National Electrical Code. Customer shall provide all necessary wiring to locate the generation metering adjacent to Consumers' service meter. Customer shall submit equipment specifications, design drawings and protection arrangements to Consumers for review and approval prior to installation. Prior to initial energization of the customer's generating system, inspection and/or tests will be jointly performed by both the customer and designated Company personnel to verify the proper operation of the generator and related equipment.

8. System Outages. Customer shall furnish, install, operate and maintain in good order and repair, and without cost to Consumers, all facilities required for the safe operation of Customer's generation in parallel with Consumers' system. These facilities shall include, but not be limited

to, equipment necessary to automatically establish and maintain synchronism with Consumers system, and circuit breaker protection which will automatically disconnect Customer's generating equipment from Consumers system in the event of overload or of an outage of Consumers system. The automatic separation of the systems is for the protection of Consumers personnel and the Customer's generator. Customer's generation system output to Consumers lines must at all times operate with a frequency variance of not more than five percent (5%) and a voltage variance of not more than ten percent (10%).

9. Self Protected Facility. Customer's generation facility shall be designed, installed and maintained to be self protected from normal, abnormal and system emergency conditions. Self protection features and mechanisms shall provide protective functions in accordance with the rules and regulations of Consumers and such additional protective functions as may be required by Consumers in the exercise of its sole, but reasonable, judgment given the particular generator configuration and distribution system characteristics applicable to Customer's facility. Customer shall make no modification of Customer's facility (1) which shall result in any non-compliance with this agreement, or (2) without prior notification to, and approval by, Consumers.

10. Access. Authorized Consumers employees shall have the right to enter upon Customer's property for the purpose

of operating or inspecting the disconnect and metering and making tests concerning output and operation and the accuracy of its meters, but such inspections or any Consumers review, approval, test, or authorization to connect or otherwise shall not relieve Customer from his obligation to install and maintain the facilities in satisfactory operating condition and in accordance with the terms and provisions of this agreement. Such entry onto the Customer's property may be without notice (1) in case of emergency and (2) additionally, on one occasion per month for inspection of meters. Otherwise, Consumers shall give Customer not less than 4 hours notice, which may be verbal by telephone, of its intention to enter upon Customers property. If Customer erects or maintains locked gates or barriers, Customer shall furnish a means to allow Consumers to install its own padlock which, when opened, will allow free access by vehicle to Customer's premises.

11. Rules & Regulations. Purchase and supply of electricity hereunder and the terms and provisions of this agreement shall be subject to the rates, rules and regulations of Consumers now in effect, and as may be changed from time to time by superceding schedules, rules and regulations. Customer shall be bound by all subsequent changes in rate schedules and those changes in rules and regulations which are reasonably consistent with this agreement. Customer has been provided a copy of the rate schedules, rules and regulations currently in effect, and hereby receipts therefor.

12. Liability Insurance. The parties are entering into an agreement governing the conduct of a new business relationship in the area of electrical energy resources and which may involve potential liabilities and consequences not yet known or demonstrated. It is anticipated that Consumers and other utilities will be entering into a number of such agreements in the future. If it develops in the electric utility industry that material losses or liabilities are incurred by electric utilities, including Consumers, as a result of the activities contemplated by this agreement, then Consumers shall have the right, upon 60 days written notice to Customer, to require Customer (at Customer's expense) to obtain and maintain liability insurance covering Customer's generation activities and equipment, naming Consumers as an additional insured, with liability limits to be determined by Consumers as in its reasonable judgment will be appropriate given the experience of the industry in similar circumstances. In the interest of non-discrimination, Consumers shall not require such insurance of this Customer, unless the same requirement is invoked for all customers, participating in agreements of this nature with Consumers, insofar as Consumers may have the right to invoke such requirement. The fact that Consumers may not have experienced any loss in respect to this particular Customer shall not prevent Consumers from exercising its rights to require insurance under this paragraph.

13. Future Costs. Customer shall pay at a future date the share of costs, attributable to Customer's facility, for

equipment as may become necessary or desirable by reason of numerous penetrations of Consumers system by small power producers in the future. Reference in this regard is made to Service Rule No. 48 of Consumers.

14. Clarification. In Paragraph 6 hereinabove, it is provided that Consumers has the right to disconnect Customer's generation facilities in the event that Customer has failed to maintain Customer's generating facilities in satisfactory operating condition, etc. This in no way places any obligation upon Consumers to inspect Customer's generating facilities or to in any way whatsoever participate or assist in the maintenance of said facilities, or to effect such disconnection. In Paragraph 7 hereinabove, and elsewhere, there are provisions for inspection and approval of Customer's facility by Consumers. This in no way relieves Customer from its obligations under this agreement, nor does it impose any obligation upon Consumers to properly inspect or approve Customer's facility, nor warrant the facility's safety or compliance with this agreement. Consumers makes no representations concerning, and expressly disclaims any expertise or specialized knowledge relating to the particular type of generation employed by the customer or the equipment associated with such generation.

15. Termination. Either party may terminate this agreement after 60 days written notice to the other. The parties have made provision for the termination hereof, in part, because it is difficult to anticipate the practicalities and consequences to be encountered in carrying this new form

of relationship between the parties into actual practice. As experience in this field is achieved, a party to this agreement may feel that one or more provisions in this agreement are not realistic, practical or prudent, as an element governing the relationship herein contemplated. Or, for the same reasons, a party may deem it appropriate that further agreements or provisions be included. In the event that any such concern of a party could not be resolved through the mutual assent of both parties, then the party with such concern would be entitled to terminate this agreement, after the appropriate notice, leaving the parties to negotiate whatever agreement that may be subsequently reached by and between them. The foregoing is only one illustration of the reason for making provision, as the parties have done in the first sentence of this paragraph, for unilateral termination hereof, after notice, with or without cause. Such illustration shall not be construed as a limitation upon such provision.

16. Breach. In the event of a breach of this agreement by either party, the aggrieved party may elect to immediately terminate this agreement. This remedy shall be cumulative, in addition to any other remedy provided at law or in equity. This agreement is not severable, that is, if any part or portion hereof is determined by a Court of competent jurisdiction to be unenforceable, then the entire agreement shall become void, and each party shall be responsible for their own costs, losses and expenses incurred prior to such determination.

17. Litigation. In the event either of the parties

hereto institutes suit or action to procure any remedy for any breach hereof, the party prevailing shall recover from the other such sums for attorney's fees in such suit or action, and on any appeal therefrom, as the Court shall adjudge reasonable.

18. Assignment. This agreement and all of the terms and provisions hereof shall be binding upon and inure to the benefit of the respective successors and assigns of the parties hereto, save that no assignment hereof shall be effective without the written consent of Consumers being first obtained.

IN WITNESS WHEREOF, Consumers and Customer have caused this agreement to be executed in duplicate as of the day and year first above written.

CUSTOMER

CONSUMERS POWER, INC.

By _____
Title _____

AGREEMENT FOR PARALLEL OPERATION OF QUALIFYING
COGENERATION OR SMALL POWER PRODUCTION FACILITIES
OF 100 KILOWATTS OR LESS CAPACITY

THIS AGREEMENT, made this _____ day of _____, 19____, between _____, a non-profit corporation organized under the laws of the State of Ohio, with its principal office located at _____, Ohio (hereinafter called the "Cooperative"); and _____, (hereinafter called the "Consumer"), with a residence, farm, or place of business located at _____, Ohio.

WITNESSETH:

WHEREAS, the Cooperative is a rural electric company engaged in the distribution and sale of electric power and energy at retail to its patrons in the State of Ohio; and

WHEREAS, the Consumer desires to install certain qualifying facilities, as defined in the Cooperative's Operational Policy relating to qualifying cogeneration and small power production facilities and as described in Exhibit A hereto (hereinafter called "qualifying facilities"), on the Consumer's property for the purpose of generating electric energy and wishes to operate these qualifying facilities in parallel with the secondary or low voltage electric service facilities of the Cooperative; and

WHEREAS, the Cooperative desires to comply with the requirements of the Public Utility Regulatory Policies Act of 1978 and all governmental regulations lawfully promulgated thereunder (PURPA) and to encourage the development of qualifying cogeneration and small power production facilities which will conserve oil, natural gas, coal, and other non-renewable resources and, to this end, is willing

to interconnect and operate its electric facilities in parallel with the qualifying facilities of the Consumer on the following terms and conditions;

NOW, THEREFORE, the parties hereto, each in consideration of the premises and the covenants herein contained, mutually agree as follows:

ARTICLE I

TERM

This Agreement shall continue in effect for a period of one year from the date hereof, and shall continue thereafter until either party gives the other at least 60 days prior written notice of any intent to terminate this Agreement.

ARTICLE II

INTERCONNECTION

The Cooperative agrees to interconnect and operate in parallel its electric system with the qualifying facilities of the Consumer and the Consumer agrees to interconnect its qualifying facilities with the electric system of the Cooperative on the terms and subject to the conditions herein contained.

Exhibit A attached hereto and incorporated herein by reference lists the component parts constituting the qualifying facilities which shall be provided by the Consumer, including generating equipment, and specifies the electrical capacity, voltage ratings, and manufacturer's nameplate data for each component part of such qualifying facilities.

Exhibit B attached hereto and incorporated herein by reference lists the facilities to be used in the interconnection between the Cooperative's electric system and the Consumer's qualifying facilities and the location, electrical capacity voltage rating, and ownership of each component part thereof.

The Consumer shall pay for all costs associated with any addition or alteration to the Cooperative's electric system incurred by the Cooperative in the establishment and operation of the interconnection herein contemplated, or any additions or alterations to the Cooperative's electric system, required for metering of power and energy purchased by the Cooperative from the Consumer and for the safe and reliable operation of the Consumer's qualifying facilities in parallel with the Cooperative's electric system. Where additions or alterations to the Cooperative's electric system are required during the term hereof due to the collective presence of the Consumer's qualifying facilities and one or more other consumer-owned qualifying facilities operating in parallel with the Cooperative's electric system, the costs of such additions or alterations shall be shared by the Consumer and the consumer-owners of such other qualifying facilities on such equitable basis as the Cooperative shall in its sole judgment determine.

The Consumer shall make all payments initially required under this Article II prior to the connection of its qualifying facilities to the electric system of the Cooperative as herein contemplated. Any additional payments required hereunder shall be made within 30 days of a statement therefor from the Cooperative.

The Cooperative's rules and regulations relating to qualifying facilities as they now exist or may hereafter be amended are hereby incorporated by reference into this Agreement as if contained herein. The Cooperative's obligations hereunder are expressly made conditional upon Consumer's compliance at all times with all the terms of this Agreement, including all the aforementioned rules and regulations. A copy of such rules and regulations will be supplied to the Consumer by the Cooperative upon request.

ARTICLE III

SALE AND PURCHASE OF POWER AND ENERGY

Section 1: The Cooperative shall sell electric power and energy to the Consumer under the same rate schedule applicable to sales to its other consumers with similar load and other cost-related characteristics. Any such sales shall be subject to the terms and conditions of the Cooperative's applicable rate schedule, as they now exist or may be amended from time to time in the future. Such rate schedule may be amended from time to time by the Cooperative, however, the initial and subsequent rates for sales to the Consumer shall not unreasonably discriminate against the Consumer in comparison to rates for sales to other consumers of the Cooperative with similar load and other cost-related characteristics. Any such sales by the Cooperative to the Consumer shall be subject to and in accordance with the terms and conditions of all rules, regulations and policies of the Cooperative relating to sales by the Cooperative generally.

Section 2: The Cooperative shall purchase electric energy and the associated capacity from the Consumer's qualifying facilities which the Consumer makes available for sale after it supplies its own electric requirements, such purchase to be made upon the terms and conditions set forth in the Cooperative's applicable rate schedule for purchases from qualifying cogeneration and small power production facilities as it now exists or may be amended from time to time in the future. The applicable rate schedule in effect at the date hereof is attached hereto and incorporated herein by reference. Such rate schedule may be amended in the future, however, the payment made by the Cooperative to the Consumer thereunder shall at all times be at least equal to the costs of the Cooperative avoided by its purchases from the Cooperative, as determined by the Cooperative, as Exhibit C.

ARTICLE IV

LIABILITY

Section 1: The Consumer shall provide such liability insurance coverage as the Cooperative may in its sole judgment require, and the Consumer shall provide such proof of this coverage as may be requested by the Cooperative. Review or testing of the Consumer's facilities by the Cooperative does not constitute any assumption of liability by the Cooperative for the lawful, safe and reliable operation thereof.

Section 2: If the Consumer violates or fails to comply with any term or provision of this Agreement, including any rule, regulation or rate schedule referred to herein, the Cooperative may require immediate termination of parallel operation and the Member shall be liable for any losses, damages or injuries resulting therefrom. Upon the occurrence of any such violation or failure by the Consumer, the Cooperative shall have the right to terminate this Agreement. Delay or waiver by the Cooperative of any such violation or failure shall not constitute a waiver of any further violation or waiver.

ARTICLE V

GENERAL PROVISIONS

Section 1: This Agreement shall be binding on the parties and their successors or assigns; provided, however, that this Agreement shall not be assigned by the Patron without the prior written consent of the Cooperative.

Section 2: Any payments, notices, demands, or requests required or authorized by this Agreement shall be deemed properly given if mailed postage prepaid to:

General Manager
Cooperative
Address

or Consumer
Address

as appropriate. The designation of the persons to be notified, or the address thereof, may be changed by notice in writing by one party to the other.

This Agreement contains all the agreements of the parties relating to the interconnection, purchase and sales herein contemplated and no other agreement or understanding relating hereto shall be binding on the parties, unless set forth in writing as an amendment hereto.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be duly executed as of the day and year first above written.

(Cooperative)

By _____

By _____
(Consumer)

(Witness)

THE STATE CORPORATION COMMISSION OF KANSAS

Index No.

SCHEDULE PGC-79

The Leavenworth-Jefferson Electric Cooperative, Inc.

(Name of Issuing Utility)

Replacing Schedule Initial Sheet

Entire Service Area

(Territory to which schedule is applicable)

which was filed

No supplement or separate understanding
shall modify the tariff as shown hereon.

Sheet 1 of 3 Sheets

PARALLEL GENERATION CONTRACT SERVICEAVAILABLE

Electric service is available under this schedule at points on the Cooperative's existing distribution facilities located within its service area.

APPLICABLE

To a Residential or General Service Customer who contracts for service supplied at one point of delivery where part or all of the electrical requirements of the Customer can be supplied from a source or sources other than the Cooperative, and where such sources are connected for parallel operation of the Customer's system with the system of the Cooperative. Customer sources may include but are not limited to windmills, water wheels, solar conversion and geothermal devices.

This schedule is not applicable to breakdown, standby, or resale electric service.

CHARACTER OF SERVICE

Alternating current, 60 cycles, at the voltage and phase of the Cooperative's established secondary distribution system most available to the service location.

NET MONTHLY BILLRate

For capacity and energy supplied by Cooperative to Customer, the applicable rate shall apply.

For energy supplied by Customer to Cooperative, the rate shall be:

2.937¢ per KWH for all KWH plus the Cooperative's applicable Energy Cost Adjustment.

Commission File Number

Issued	December	28	1979	FILED THE STATE CORPORATION COMMISSION OF KANSAS By _____ Secretary
	Month	Day	Year	
Effective	January	1	1980	
	Month	Day	Year	
By	President			
	Signature of Officer			

THE STATE CORPORATION COMMISSION OF KANSAS

Index No.

SCHEDULE PGC-79

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Sheet 2 of 3 Sheets

NET MONTHLY BILL - ContinuedMinimum

The applicable Customer Charge plus \$0.75 for each KW over 5 KW of the highest Billing Capacity established during the twelve months ending currently, plus applicable adjustments and surcharges. When a special transformer installation is necessary for the benefit of the Customer, or to protect the quality of service to other Customers, such minimum shall be not less than \$0.75 per KVA of required transformer capacity.

PAYMENT

Monthly bills will be rendered NET, payable within fifteen days of the date of the bill, and will become delinquent thereafter. Two percent shall be added to the net amount on the date the bill becomes delinquent as stated thereon.

OTHER TERMS AND CONDITIONS

1. The Cooperative will supply, own, and maintain all necessary meters and associated equipment utilized for billing. In addition, and for purposes of monitoring customer generation and load, the Cooperative may install at its expense, load research metering. The Customer shall supply, at no expense to the Cooperative, a suitable location for meters and associated equipment used for billing and for load research.
2. The Cooperative shall have the right to require the customer, at certain times and as electrical operating conditions warrant, to limit the production of electrical energy from the generating facility to an amount no greater than the load at the customer's facility of which the generating facility is a part.
3. The customer shall furnish, install, operate, and maintain in good order and repair, and without cost to the Cooperative, such relays, locks and seals, breakers, automatic synchronizer, and

Commission File Number

Issued	December	28	1979
	Month	Day	Year
Effective	January	1	1980
	Month	Day	Year
By	President		
	Signature of Officer Title		

FILED

THE STATE CORPORATION COMMISSION
OF KANSAS

By Secretary

THE STATE CORPORATION COMMISSION OF KANSAS

LLJ No.

SCHEDULE PGC-79

The Leavenworth-Jefferson Electric Cooperative, Inc.

(Name of Issuing Utility)

Replacing Schedule Initial Sheet

Entire Service Area

(Territory to which schedule is applicable)

which was filed

No supplement or separate understanding shall modify the terms as shown hereon.

Sheet 3 of 3 Sheets

other control and protective apparatus as shall be designated by the Cooperative as being required as suitable for the operation of the generator in parallel with the Cooperative's system. In addition, the Cooperative will install, own, and maintain a disconnecting device located near the electric meter or meters. Interconnection facilities shall be accessible at all times to Cooperative personnel.

The Customer may be required to reimburse the Cooperative for any equipment or facilities required as a result of the installation by the Customer of generation in parallel with the Cooperative's service.

The Customer shall notify the Cooperative prior to the initial energizing and start-up testing of the Customer-owned generator, and the Cooperative shall have the right to have a representative present at said test.

4. The Cooperative requires a special contract for conditions related to technical and safety aspects of parallel generation.
5. This schedule is not applicable where the Customer's maximum capacity exceeds 50 KW.
6. Individual motor units rated at more than five horsepower shall be three phase (when three phase service is supplied), unless otherwise agreed upon prior to installation.
7. Individual motor units rated at 10 horsepower or more shall have starting equipment satisfactory to the Cooperative.
8. Service hereunder is subject to the Cooperative's Rules and Regulations on file with the State Corporation Commission of the State of Kansas.

Commission File Number

Issued December 28 1979
 Month Day Year
 Effective January 1 1980
 Month Day Year
 By *Andrew L. Dempsey* President
 Signature of Officer Title

FILED
 THE STATE CORPORATION COMMISSION
 OF KANSAS
 By _____ Secretary

APPENDIX G
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Reference
Documents

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