ISSUES FACING
INDUSTRIAL COGENERATORS

RATES FOR SALES AND RATES FOR
MAINTENANCE, STANDBY AND SUPPLEMENTAL POWER

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FOREWORD

Cogeneration is a process that produces both electrical or mechanical power and useful thermal heat from one fuel source. Cogeneration is not new; indeed, industrial firms have cogenerated for nearly a century. Recently, however, cogeneration has received increased attention as a means to meet future electricity needs, conserve natural gas and reduce our nation's dependence on imported oil.

This paper addresses key issues facing industrial cogenerators relating to rates for the sales of power and rates for maintenance, standby and supplemental power. These issues are complex and negotiations with utilities are often not easy. The issues are developing rapidly. As such, we view this paper as one in a series of steps that ultimately will result in an accepted body of knowledge. This paper has been prepared as an educational document to define terms, discuss underlying concepts and offer possible solutions. Hopefully, it will assist individuals not fully versed in cogeneration to better understand the complexities of these rate issues.

A companion ELCON publication (INDUSTRIAL COGENERATION: A BACKGROUND PAPER) describes how cogeneration works, why it is efficient, and existing legislated incentives intended to spur the development of cogeneration facilities. Both papers were prepared by an ELCON member company working group headed by John A. Anderson, ELCON's Senior Economist and Managing Director.

TABLE OF CONTENTS

I. INTRODUCTION

The Public Utility Regulatory Policies Act of 1978 (PURPA) requires that rates paid by utilities to "qualifying facilities" (QF's) for the purchase of cogenerated power be based on the utility's "incremental cost." PURPA defines "incremental cost" as "the cost to the electric utility which, but for the purchase from such cogenerator..., such utility would generate or purchase from another source."[1] Under the FERC rules implementing PURPA, utilities must purchase power from QF's at rates that equal each utility's full "avoided cost" unless a state regulatory authority obtains a waiver of this requirement from the FERC. The FERC rule defines avoided cost as the incremental cost to an electric utility of both electric energy and capacity which, but for the purchase from the QF, such utility would generate itself or purchase from another source.

Section II describes the conceptual framework underlying avoided cost and discusses the PURPA avoided cost requirements. A companion ELCON paper contains a more detailed discussion of these PURPA requirements.[2] We then set forth certain principles that ELCON believes should be followed as rates for purchases of cogenerated power are established. ELCON's views and position on maintenance, standby and supplemental power are contained in Section III.

There are two attachments to this paper. The first compares "economic cost" as contained in economic theory with "avoided cost" and "incremental cost" as used by utility analysts. The second reproduces the results of a state-by-state survey of rates for power purchased from QF's by state-regulated utilities.

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[1] Public Utility Regulatory Policies Act of 1978 (PURPA), Section 210(d).

[2] Industrial Cogeneration: A Background Paper, ELCON, June 1983, pages 16-24.

II. RATES FOR SALES

A CONCEPTUAL FRAMEWORK

A utility's avoided cost is the difference in total cost in meeting the system load without the cogenerator's power and the total cost of meeting the load with the cogenerator's power. The avoided energy cost includes the dollar amounts associated with fuel, variable operating and maintenance expenses, start-up and shutdown expenses, and energy losses that are avoided because of the purchase of cogenerated power. Avoided capacity cost includes the carrying cost on facilities (including reserve generation facilities) the utility does not incur because of the availability of the cogenerated power.

Utilities buy cogenerated power on either a "non-firm" or a "firm" basis. "Non-firm" power does not guarantee scheduled availability, but instead delivers power on an "as available" basis. Power provided on a "firm" basis is available to the buyer at the times covered by a commitment and in agreed upon quantities.

1. Avoided cost for non-firm power purchases - Cogenerated power supplied to a utility on a non-firm basis reduces the utility's need to generate or purchase power by approximately an equal amount.

The probability that some cogenerated power will be provided to a utility's grid at the time of system peak(s) increases with the number of cogeneration units.[3] The utility can avoid some capacity costs if it is able to rely on a proportion of the total non-firm power supply at the time of system peak(s). Capacity payments thus are justified. The likelihood that a utility can rely on non-firm cogenerated power at the time of system peak(s) increases with the number, diversity and reliability of the cogeneration units.

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[3] We emphasize that it is the number of cogeneration units (or "shafts"), not necessarily the number of firms owning cogeneration facilities, that increases this probability.

In certain instances, non-firm power may not affect the utility's need for capacity since the utility cannot count on the availability of the power at the time of system peak(s). Under these circumstances, non-firm power may not allow the utility to avoid capacity cost and rates for such purchases should not include a capacity component.

Utilities have a mixture of generating units, each with different operating characteristics and running costs. These units are committed and dispatched by the utility according to the demand for power.

The avoided energy cost of displaced power for an economically dispatched utility with a mixture of generating units depends on many factors including: the time that the energy is displaced, the load curve, the generation mix, the availability of units, the running cost of each unit or cost of purchased energy.[4] The following diagrams illustrate the avoided cost concept as it relates to purchases of non-firm energy.

Diagram 1 illustrates the generation mix for a hypothetical utility. This utility is assumed to have 2,000 MW of 2¢/kwh nuclear, 4,000 MW of 4¢/kwh coal and 4,000 MW of 10¢/kwh oil capacity.

Diagram 2 presents a load duration curve for a hypothetical utility. The 8,760 hourly system loads are plotted in order of descending magnitude. Purchase of cogenerated power affects the utility the same as a reduction in load. Diagram 2 also illustrates the effects of purchases of both 250 MW and 1,000 MW of cogenerated power for all 8,760 hours of the year.

Diagram 3 illustrates the avoided cost concept by superimposing the generation mix and the load duration curves. In this hypothetical illustration, 1,000 MW of cogenerated power displaces only 10¢/kwh oil-fired capacity during approximately 4,800 hours of the year, both 10¢/kwh oil-fired capacity and 4¢/kwh coal-fired capacity for 2,000 hours, and 4¢/kwh coal-fired capacity during the remaining 1,960 hours. In this

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[4]Most utilities are "economically dispatched." That is, they purchase or generate power to meet their loads in the most economical manner. In general, utilities purchase power when the cost of such power is less than the running cost of all available, but unused, units.

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DIAGRAM 1

CAPACITY MIX FOR A HYPOTHETICAL UTILITY

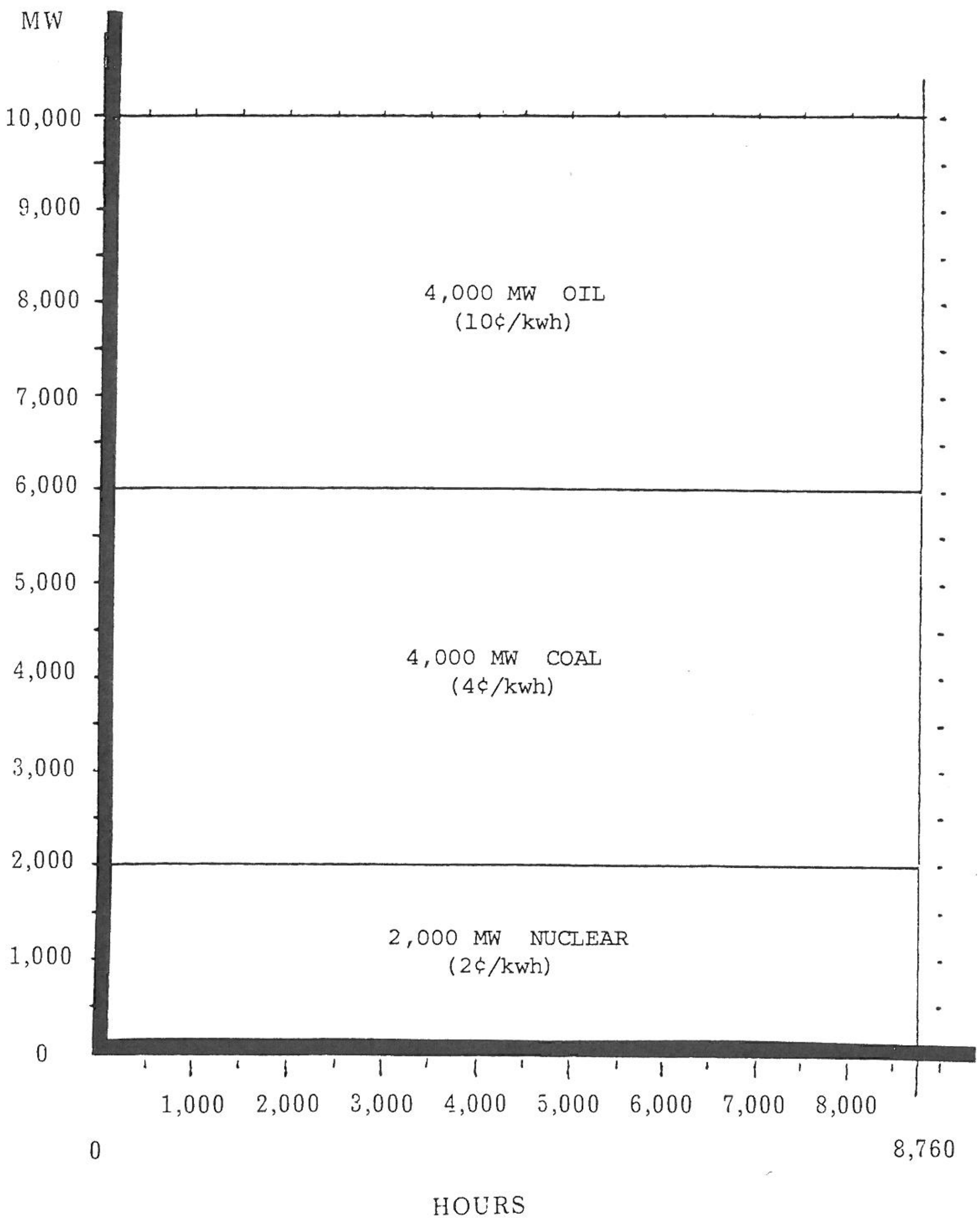


DIAGRAM 2

THE IMPACT OF COGENERATION ON A UTILITY:

Cogeneration in essence shifts a utility's load duration curve downward.

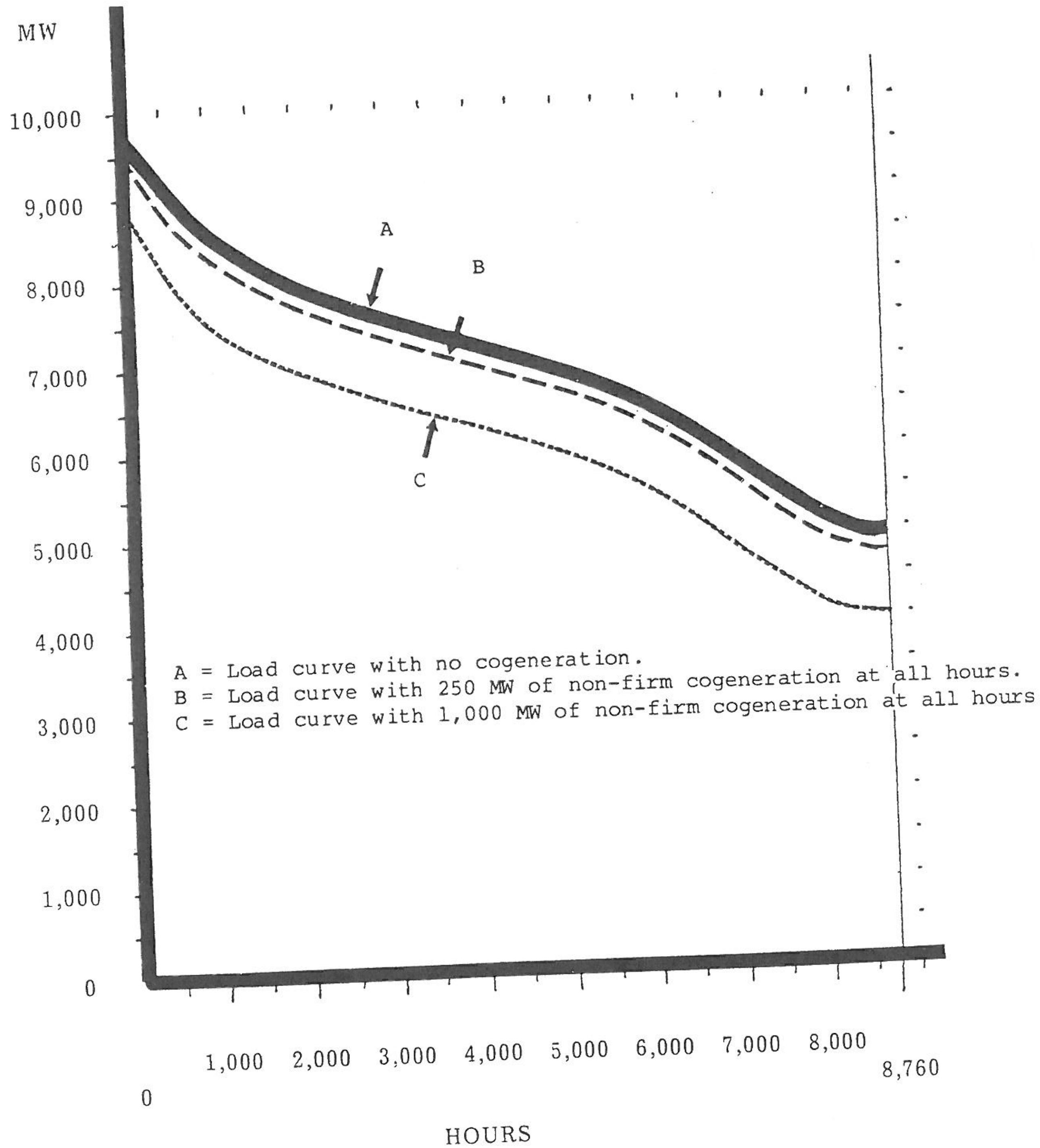
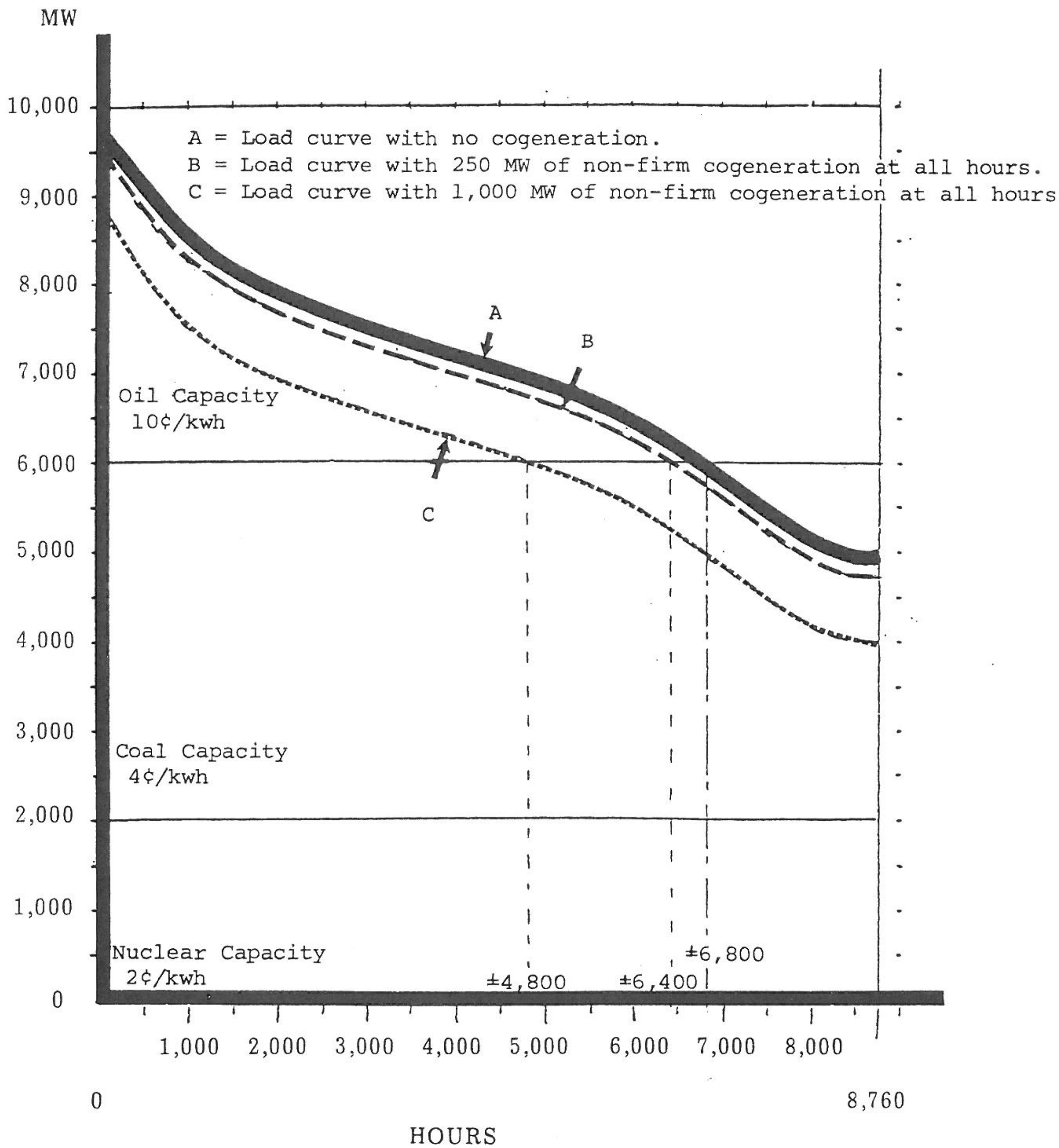


DIAGRAM 3

AN ILLUSTRATION OF THE AVOIDED ENERGY COST CONCEPT FOR NON-FIRM PURCHASES:

The costs that are avoided depend upon timing, loads and the generation mix.



example, the addition of cogenerated power to the utility's grid thus allows the utility to avoid costs ranging between 10¢/kwh to 4¢/kwh.

Diagram 3 illustrates several characteristics of avoided cost. First, avoided running cost may vary by the time of purchase. In the hypothetical example described above, the avoided running cost is 10¢/kwh in those hours when oil is displaced, but 4¢/kwh in those hours when coal is displaced. Thus, the addition of 1,000 MW of cogenerated power in any hour that results in the displacement of 10¢/kwh oil (illustrated over the range of 0 through approximately 4,800 hours in this simplified example) allows the utility to avoid $100,000 in running costs for that hour.[5] Alternatively, the addition of 1,000 MW of cogenerated power in any hour that results in the displacement of 4¢/kwh coal (approximately hours 6,800 through 8,760) allows the utility to avoid $40,000 in running costs for that hour. Actually, there are many avoided running costs for a utility with many generating units.

Second, changes in any one of many factors (assumed in the hypothetical discussion to be constant) may change the avoided cost for any hour. For example, changes in the generation mix, load curve, cost of fuel or cost of purchased power may change the entire set of avoided costs.

Third, changes in purchases of cogenerated power may affect the avoided running costs for any hour. For example, the addition of 250 MW of cogenerated power for one hour during the 6,400th hour allows the utility to avoid $25,000. The avoided cost for 250 MW of cogenerated power at that hour thus averages 10¢/kwh since the cogenerator displaces all oil capacity. However, 1,000 MW of cogenerated power supplied to the utility's grid for one hour during the 6,400th hour allows the utility to

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[5] The total avoided costs are calculated as follows: 1,000 MW for one hour allows the utility to avoid the generation of 1,000 mwh or 1,000,000 kwh of electric energy. A reduction of 1,000,000 kwh of 10¢/kwh energy saves the utility $100,000.

avoid $55,000.[6] The avoided cost for 1,000 MW of cogenerated power at that hour thus averages 5.5¢/kwh ($55,000 ÷ 1,000,000 kwh) since the cogenerator displaces 250 MW of 10¢/kwh oil capacity and 750 MW of 4¢/kwh coal capacity.

In theory, avoided non-firm energy cost is an unambiguous concept. However, in practice, a rigorous calculation is very complex.

A utility's real-time dispatch control system can be used to (a) calculate the total hourly cost of production when the cogenerator actually delivers energy and (b) simulate the cost as though the cogenerator did not deliver the energy. The difference between these total costs is the utility's avoided non-firm energy cost.

In the event that a utility does not have the capabilities to calculate avoided energy costs as described above, reasonable estimates can be made. However, estimates of avoided cost require many assumptions and judgements. Extreme care must be made to minimize the error associated with such avoided energy cost estimates.

2. Avoided cost for firm power purchases - Firm power purchases require cogenerators to provide power on a scheduled basis under contract. Purchasing firm cogenerated power may allow a utility to postpone or avoid (1) construction of additional capacity, (2) long-term firm bulk power purchases or (3) unit purchase transactions. Purchases of firm power allows the utility to avoid both capacity and energy costs required to meet both on-line and reserve generation needs. Avoided cost for firm power purchases is the sum of the capacity and energy costs that the utility can avoid with the cogenerator's commitment.

Firm energy payments should be linked to firm capacity payments. The energy cost that is avoided when a plant is cancelled or postponed is the (average) energy cost related to the capacity of that cancelled or postponed plant -- not the energy cost of the most expensive or any other

[6] This avoided cost figure is calculated as follows: 250,000 kwh x $0.10/kwh + 750,000 kwh x $0.04/kwh = $55,000.

operating unit. For example, if a coal-fired base load unit is identified as the unit that will be avoided, both firm capacity and energy payments should be based on costs associated with the installation and operation of that coal-fired unit. In this example, a relatively high firm capacity payment would be linked with a firm energy payment based on the projected energy cost of that coal-fired unit. In such a situation, firm energy payments may be less than non-firm energy payments. Alternatively, if a gas-fired base load unit is identified as the unit that will be avoided, both firm capacity and energy payments should be based on costs associated with that gas-fired unit. Thus, a low firm capacity payment would be linked with a high firm energy payment.

The linkage of firm capacity and energy payments is similar to that experienced by utilities when they negotiate unit sales. If the utility anticipates that it will be buying power on a constant basis, it may arrange a unit purchase, whereby it pays a capacity charge for the right to take power from a given generating unit and pays an energy charge related to the running cost of that particular unit.

The time of unit completion is an important consideration in determining the total avoided cost. A utility could be energy short without the purchases from cogenerators and could delay the completion of a coal-fired unit because of such purchases. In this case, under a firm contract, the cogenerator would be entitled to a capacity payment linked to the dollar savings associated with the postponement.[7] Conceptually, the firm energy payment would be based on the utility's avoided cost of producing energy from all units (using a method such as that described on pages 7-8), up until the time that the coal unit would have been completed and operating. At that time, the firm energy payment would be linked to the energy costs of the coal unit.

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[7] This statement assumes that the utility's costs would be decreased by a delay of the completion of a unit. If it is demonstrated that a cogenerator does not allow the utility to avoid capital costs for this unit, the cogenerator should not receive a capacity payment associated with this unit.

In some instances, the linkage can be quantified in an acceptable manner utilizing the utility's planning models and reasonable assumptions.

However, in other cases the implementation of this conceptual linkage can be very difficult for several reasons. First, capital and operating and maintenance (O&M) costs for units to be built in the future must be estimated. Estimates of future capital and O&M costs may be subject to error and debate. Second, sometimes it is difficult to directly attribute the cancellation of a particular utility unit to the addition of a cogenerator to the grid although the value of firm capacity and energy may be established at the cost of an avoided unit. Third, utility generating units often operate at substantially different capacity factors than cogeneration facilities. For example, base load utility generating units often operate at 65 to 75 percent capacity factors while cogeneration facilities may operate at capacity factors greater than 90 percent. Under such conditions, it would be incorrect to assume that firm energy from a cogeneration facility will displace only energy from one particular utility generation unit. Indeed, under such circumstances, cogeneration capacity may produce more energy (and thus avoid greater running costs) than utility generating units with the same rated capacity.

Difficulties such as these underscore the need for arms-length negotiations of contracts between cogenerators and utilities. Contracts should account for the site-specific characteristics of the cogenerator and the utility and thus are best conducted on a case-by-case basis. Each contract must clearly set forth all terms and conditions including (but not limited to) firm capacity and energy payments both before and after the time at which the parties agree that an avoided unit of capacity would have been operational. State regulatory authorities should resolve situations where cogenerators and utilities cannot agree.

THE PURPA AVOIDED COST MANDATE

The FERC's rule implementing PURPA requires utilities to purchase electricity from new QF's at a rate that equals each utility's full "avoided cost" unless a state regulatory authority obtains a waiver from the FERC demonstrating that a lower rate is just and reasonable, nondiscriminatory and sufficient to encourage cogeneration.[8] The FERC defines avoided cost the same as PURPA's "incremental cost of alternative energy." The rule requires utilities to establish standard rates for purchases from QF's of 100 kw or less.

If a QF offers energy of sufficient reliability to permit the purchasing utility to avoid the construction of a generating unit, then the FERC rule requires that the rates for purchase from the qualifying facility must be based upon the avoided capital cost of the new facility, as well as the avoided energy cost.

The FERC rule lists several factors which may be taken into account in calculating avoided cost. These factors include the duration of the obligation, termination notice requirement and sanctions for noncompliance, the expected reliability of the qualifying facility, the ability of the utility to dispatch the qualifying facility, and the extent to which scheduled outages of the qualifying facility can be coordinated with scheduled outages of the utility's facilities.

State regulatory authorities are required to implement a cogeneration (and small power production) program that conforms with the FERC rule. The specifics of each state's rules differ substantially, although most offer fixed rate tariffs for QF's of 100 kw or less, as required by the FERC rule. Most states also have formulated either a generic avoided cost rate or a methodology for calculating avoided cost on a case-by-case basis for QF's larger than 100 kw.

A survey of state actions regarding rates for purchase of QF power was published by the Office of Technology Assessment (OTA), Congress of the United States.[9] Although the numerical values are now somewhat

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[8]Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of PURPA, Final Rule, Federal Energy Regulatory Commission, 45 Federal Register 12214, February 25, 1980. A more detailed discussion of the PURPA mandate and the FERC rule implementing PURPA is contained in a companion ELCON paper titled: "Industrial Cogeneration, A Background Paper."

[9]Industrial and Commercial Cogeneration, Congress of the United States, Office of Technology Assessment, OTA-E-192, February 1983, pages 86-89, herein referred to as the "OTA Report."

dated, the summary results are reproduced as an attachment to this paper as an illustration of the wide differences in rates that exist between the states. The OTA concludes that the state PUC's "have taken full advantage of the procedural latitude allowed by the FERC rules, using rulemaking, adjudication, and dispute resolution to establish rates and operating criteria."[10] These procedures have resulted in a wide diversity in state approaches to PURPA, as well as in the rates established thereunder.

ELCON POSITION

ELCON proposes that certain principles should be followed in establishing rates for purchases of cogenerated power.

1. The establishment of contracts setting forth pricing structures for avoided energy and capacity purchases should allow arm's length negotiations between the utility and a cogenerator.

Financiers often require a long-term contract setting forth the terms and conditions of the agreement reached between the utility and a cogenerator prior to committing the resources required to finance the construction of the facility. In establishing the contract, care must be taken to account for the characteristics of the specific cogenerator and the utility. These specific characteristics are best evaluated on a case-by-case basis, even when an approved tariff is in existence.

Neither the utility nor the cogenerator should have its bargaining power restricted with "split-the-savings," "percentage of avoided cost" or other such rules. The specific rate should be agreed upon between the parties and subject to state regulatory approval. State regulatory authorities should resolve situations where QF's and utilities cannot agree.

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[10] Ibid., page 86.

2. <u>All cogenerators selling non-firm energy at one point in time to a utility should receive a payment based on the same methodology for calculating avoided energy costs. The actual payment to individual cogenerators could be different due to differences in delivery characteristics, etc.</u>

All kilowatt-hours of non-firm cogenerated power supplied to a utility's grid at one point in time are of equal value. This is because the loss of power from any individual cogenerator would affect the utility the same as the loss of a similar amount of power from any other cogenerator. All other things equal, all cogenerators selling non-firm power at one point in time should receive the same rate.

Power from one cogenerator may be more or less valuable to the utility than power from another cogenerator and the costs of serving cogenerators may differ. For example, line losses may make a kilowatt-hour produced at a distant cogenerator of less value than a kilowatt-hour produced at a near cogenerator. Additionally, the costs incurred by a utility in serving cogenerators at different voltage levels may differ.

To the extent that factors such as these are shown to affect the costs of cogenerated power, cogenerators should receive different rates for sales of cogenerated power. However, if differences in value or costs are not demonstrated, all cogenerators selling non-firm power at one point in time should receive the same price.

3. <u>Capacity payments for purchases of non-firm power are warranted if the utility avoids capacity costs. Payments for purchases of non-firm cogenerated power should involve energy payments only if it is demonstrated that the purchases do not allow the utility to avoid capacity costs.</u>

Utilities often assert that since non-firm (or "as available") cogenerated power may not be available at the time of system peak and thus cannot result in an avoidance of capacity costs, sales of such power should involve energy payments only.

When there are a large number of cogeneration facilities, there is a high probability that some cogenerated capacity can be relied upon at the time of system peak. Thus, more than likely purchases of cogenerated power allow the utility to avoid capacity costs and a capacity payment to cogenerators is justified. The FERC recently issued a ruling consistent with this position. Specifically, the FERC ruled that Middle South Utilities should pay for the capacity value of purchases from QF's unless the utility can demonstrate clearly why no capacity payment is appropriate.[11] The likelihood that a utility could rely on non-firm cogenerated power at the time of system peak increases with the number, diversity and reliability of the cogenerators. Documentation of cost avoidance must be conducted on a utility-by-utility basis. Different capacity payments should not be made to cogenerators supplying similar quantities of energy at the same point in time.

4. <u>Purchases of cogenerated energy should include payments for avoided fuel, variable operating and maintenance expenses, start-up and shutdown expenses and energy losses that are avoided because of the purchase of cogenerated power</u>.

5. <u>Capacity payments should be paid for purchases of firm power</u>.

The rate for purchase should be based on the avoided capacity and energy costs if a cogenerator offers energy of sufficient reliability and with sufficient legally enforceable guarantees of deliverability to permit the purchasing electric utility to (a) avoid or delay the construction of a generating unit, (b) build a smaller, less expensive plant or (c) reduce firm power purchases from another utility.

6. <u>If a performance standard is imposed by a utility on a cogenerator, the standard should be no more stringent than the performance of the utility's units</u>.

Reasonable contractual performance standards may be appropriate when capacity payments are to be paid. Cogenerators should not be

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[11] <u>Middle South Utilities v. Arkansas and Louisiana</u>, FERC Dockets ER81 and EL81-12, September 30, 1983.

required to meet more stringent performance standards than the utility units that are displaced.

If capacity and energy payments are made and if a penalty factor is applied for non-performance, then a premium should be paid if the performance standard is exceeded. The payment of a premium should reflect the fact that highly reliable power is worth more than less reliable power. A premium should not be paid that is in excess of costs that are avoided by the utility.

7. <u>The method selected to calculate avoided costs should be rigorous and must be carefully monitored to be certain that it is producing reasonable estimates.</u>

The degree of sophistication in the calculation of avoided energy costs depends on the amount of the cogeneration energy relative to system load, the computing capabilities of the utility and the desired level of accuracy.

Utilities should be required to make relevant data and methodologies available to all interested parties. The appropriate state regulatory authorities should use their authority to ensure that all necessary information is available. Additionally, the regulatory authority should be the final arbiter of any disputes arising from negotiations between the parties.

III. RATES FOR MAINTENANCE, STANDBY AND SUPPLEMENTAL POWER

Industrial cogenerators may require electricity from utilities to provide power when the cogeneration facility is not operating or to supplement the power production of the cogeneration facility. Cogenerators requiring power from utilities can negotiate either "simultaneous buy/sell" agreements or individual contracts for their specific power requirements.

Under a simultaneous buy/sell agreement, a utility buys all of the power generated by the cogenerator and sells power to the cogenerator to meet all of its electrical needs.

Industrial cogenerators operating under other than simultaneous buy/sell agreements are usually interested in purchasing maintenance, standby or supplemental power. A discussion of each of these power needs follows a brief review of the PURPA provisions relating to each.

PURPA REQUIREMENTS

PURPA Section 210 requires the Federal Energy Regulatory Commission (FERC) to prescribe rules relating to power sales by utilities to cogenerators. These rules are intended to encourage cogeneration and require electric utilities to sell electric energy to QF's. PURPA states that the FERC rules are to ensure that the rates charged for such power sales shall (1) be just and reasonable and in the public interest and (2) not discriminate against the QF.

The FERC rule implementing PURPA Section 210 requires that, upon the request of a QF, each electric utility shall provide supplemental, back-up and maintenance power at just and reasonable, nondiscriminatory rates.[12] The requirement to provide power may be waived by the

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[12] Section 292.305 of the FERC's Final Rule, Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978, 45 Federal Register 12216, February 25, 1980. This rule also requires electric utilities to offer interruptible power.

appropriate state regulatory authority if it is demonstrated that compliance with the requirement would impair the utility's ability to render adequate service to its customers or place an undue burden on the electric utility.

Additionally, the FERC rule requires that the rates for sales of back-up or maintenance power shall (1) not be based upon an assumption unsupported by factual data that forced outages or other reductions in electric output by all QF's on a system will occur simultaneously, or during the system peak, or both and (2) take into account the extent to which scheduled outages of the QF's can be usefully coordinated with scheduled outages of the utility's facilities.

RATES FOR POWER PURCHASED BY COGENERATORS

1. Maintenance power - Maintenance power is supplied by the utility to the cogenerator when the cogenerator's generating units are taken out of service for scheduled maintenance. A cogenerator's need for maintenance power is known in advance and can be scheduled as with a utility's generating units.

ELCON POSITION

The utility is not required to plan or build capacity to meet maintenance power demands as long as the utility can restrict maintenance power sales to off-peak periods when existing capacity built to serve other customers at system peak is idle. Thus, demand charges, if charged at all, should be at sharply reduced levels from demand charges for firm service power. Additionally, demand ratchets should not be applied to maintenance power. The energy charge for off-peak maintenance power should be the same as the energy charge applicable to other industrial customers for purchases of power during the same time periods.

Clearly, a QF will attempt to schedule maintenance of his unit at other than time of the utility's annual system peak. However, certain production or process characteristics may make it necessary for the QF to schedule maintenance during peak months.

Two options can be offered to a cogenerator that requires maintenance power during peak hours from a utility that does not have adequate installed capacity to meet the maintenance power needs at that time. First, the cogenerator could be offered power on an "as available" basis from spinning (or other) reserves. If these reserves are available, the cogenerator should pay no demand charge as the cogenerator's load was not included in the system expansion plan and the utility was not required to make capital outlays to meet the load. The energy charge should be the same as that applicable to other industrial customers for purchases of power during the same time periods. In order to receive the rates as described in this paragraph, the cogenerator must agree to do without service or be interrupted if the reserves are not available.

Second, the cogenerator could be offered "purchased power" to satisfy peak maintenance power demands. Rates for maintenance power supplied by power purchased by the utility should be based on the price of the purchased power, plus a percentage markup for administrative costs. Capacity charges should not be assessed unless the utility is required to pay similar charges when purchasing the power.

2. Standby (or back-up) power - Standby (or back-up) power is supplied by a utility to meet a cogenerator's electrical needs for those limited number of hours when the cogenerator's generating facilities are unexpectedly out of service. By definition, standby power is not scheduled.

Utilities cannot plan to serve standby power needs with otherwise idle capacity as forced outages may occur at any time. Thus, utilities may be required to make capital outlays to meet standby loads and, if so, standby customers should pay demand charges to cover these capital outlays. An exception to this generalization involves "as available" standby power which is discussed below.

Certain key differences regarding both the duration and the timing of the loads differentiate firm from standby customers. Firm customers require service throughout the year. Furthermore, there is a high probability, particularly for residential customers, that the class peak and the system peak will coincide. Standby cogeneration customers require service only for those hours when their cogeneration facilities experience unexpected outages. The probability that all (or even most) forced outages would occur at the time of system peak is much lower than the probability that the peak firm load, especially the residential load, coincides with the system peak.

Because of these differences, the utility does not have to maintain capacity equal to the total standby load of all cogenerators. The capital outlay required to meet a kw of standby load thus is less than that required to meet a firm load, and standby demand charges should be less than firm demand charges.

Standby power can be either "firm" or "as available." Each are discussed below.

a) Firm standby power - Firm standby power involves a guarantee by a utility that it will provide standby power whenever needed by a cogenerator. Rates for firm standby power can be established in several ways.

First, rates could be established on the principle that the utility is providing the reserve capacity for the cogenerator. A non-generating customer pays rates based on the costs incurred by the utility in meeting the customer's load plus the costs required to maintain a required reserve (for example, 15 or 20 percent of the non-generating firm load). Based on this principle, a cogenerator would pay a standby demand charge per kw equal to the average embedded capacity costs incurred by the utility in meeting its firm load times a specified multiplier since the probability that all cogenerators' units would be out of service at the same point in time is very low. By definition, the multiplier would have a maximum value of one. More than likely, the multiplier would be much less than one. A multiplier often suggested is one equal to the utility's required reserve margin (for example, 15 or 20 percent). Alternatively, the cogenerator could pay a demand charge equal to the firm power demand charge times a smaller multiplier. The multiplier should be lower in the second case since the firm power demand charge includes required reserves. The standby demand charge should reflect the reliabilities of both the utility's and the cogenerator's generating units. The multiplier might be lower than the utility's required reserve margin if the cogenerator's units are more reliable than the utility's units since the utility's required reserve margin might be lower if the reliability of its units were higher. The cogenerator would pay the standby demand charge throughout the year and would be able to call upon the the utility whenever necessary -- for example, to meet shortages caused by forced outages. If the cogenerator demanded standby power at a time when the utility had no excess capacity, the utility would be expected to purchase power to meet the cogenerator's needs. The energy charge for standby power actually consumed should be the same as that applicable to other industrial customers for purchases of energy during the same time periods even if the utility must purchase power to meet the cogenerator's needs because the QF pays a standby demand charge throughout the year to compensate the utility for costs incurred to provide the reserves necessary to meet the standby power needs.

Second, rates for firm standby power could be established on the assumption that the utility would install peaking units to meet the unexpected loads placed on the utility due to forced outages of cogenerators. Since all cogenerators are not expected to experience forced outages simultaneously, the utility would be required to maintain only a fraction of the total standby load in peaking units. The fraction would depend upon the reliability of the units and the diversity of the outages. Each cogenerator would pay a demand charge equal to this fraction times the average carrying costs of all peaking units. The cogenerator would pay energy charges based on the incremental running costs incurred by the utility in meeting the cogenerator's needs.

Third, firm standby power can be viewed as the "flip-side" of interruptible power. An interruptible customer is served most of the time. This customer is interrupted only when the utility must curtail. A standby customer is <u>not</u> served most of the time. This customer is served only for a limited number of hours when the cogenerator experiences a forced outage.

The probability of a standby customer requiring service at the time of system peak is far lower than that of a firm customer. Based on this principle, the demand charge paid by a cogenerator for standby service could be established as a value equal to the interruptible credit offered to an interruptible customer (provided the interruptible credit was realistic).

The energy charge should be the same as that applicable to other industrial customers for purchases of power during the same time periods.

As discussed above, a firm standby customer is responsible for some capacity costs, but the demand charge should be less than that applicable to firm customers. In some cases utilities charge standby customers a standby demand charge each month, but they bill cogenerators for standby power actually consumed at the firm power rate. Such a procedure overcharges the cogenerator. If a cogenerator is required to pay a standby demand charge each month of the year, no additional demand charge should be required when the cogenerator requires standby power. Alternatively, if the utility charges a standby customer the firm power demand charge when power is consumed, no standby demand charge should apply since the firm demand charge includes an allowance for reserve capacity investment. To minimize inequities caused when utilities charge firm power rates for standby power, billings should be calculated only for the actual time period that the cogenerator receives service. The cogenerator should not be charged a full month's firm power demand charge if power is taken for only a fraction of the month. Additionally, demand ratchets otherwise applicable to the firm power customer should not be applied to standby customers paying monthly standby demand charges since these customers already are required to pay for capacity costs incurred for their use.

b) As available standby power - A cogenerator may negotiate an arrangement with its supplying utility for standby power on an "as available" basis. With this arrangement, the utility agrees to provide standby power from its existing capacity as long as reserves are available. If reserves are not available, the utility agrees to try to purchase energy on the spot market to meet the cogenerator's unexpected needs, although the utility does not guarantee the cogenerator that its power needs will be met.

Under this agreement, the cogenerator should not pay capacity charges. When the cogenerator requires service, he pays the out-of-pocket costs incurred by the utility in providing the energy. These costs are either the incremental production costs associated with the extra generation or the costs of purchased energy.

ELCON POSITION

Several principles should be adhered to when negotiating standby rates:

- o Standby power rates must be negotiated on a utility-by-utility basis as each situation is utility specific.
- o Standby rates should always be priced below rates for firm service.
- o Standby rates should only be available to cogenerators that meet specific performance criteria. If a cogenerator demands standby power in excess of the specified criteria (e.g., x hours/year, y percent of peak hours, etc.), the cogenerator should be required either to accept different standby rates or be treated as a firm customer.

3. Supplemental firm power - Supplemental firm power is supplied to a cogenerator to satisfy a load in excess of the amount of power generated by the cogenerator.

ELCON POSITION

The costs incurred by a utility in serving a supplemental load do not differ from the costs incurred in serving any other firm load of the same size. Thus, supplemental power customers would be included in the appropriate industrial rate classification and charged rates based on the approved tariff for that class. If time-of-use rates have been determined to be appropriate for similar rate classifications, such rates may be applied to supplemental customers to account for the differences in costs associated with the pattern and the timing of the load.

ATTACHMENT A

A DISCUSSION OF THE THEORIES UNDERLYING AVOIDED, INCREMENTAL AND MARGINAL COSTS

The Public Utility Regulatory Policies Act of 1978 (PURPA) requires that rates paid by utilities to qualified facilities (QF's) for the purchase of cogenerated power be based on the utility's "incremental costs." Under the Federal Energy Regulatory Commission (FERC) rules implementing PURPA, utilities must purchase power from QF's at rates that equal each utility's full "avoided cost" unless a state regulatory authority waives this requirement. The FERC rule defines avoided cost as the incremental cost to an electric utility of electric energy or capacity or both which, but for the purchase from the QF, such utilities would generate itself or purchase from another source.

PURPA changed the way that regulators view utility purchases of power from cogenerators. Traditional utility regulation would set prices for the purchases of power at the producer's (i.e., cogenerator's) costs plus a reasonable rate of return. PURPA requires regulators to look at changes in the <u>utility's</u> costs caused by the utility's purchase of cogenerated power. PURPA does not require utilities to purchase cogenerated power at rates that exceed the costs that the utility avoids by purchasing this power, although rates may be less than this amount.

Basing rates for purchases of cogenerated power on <u>changes</u> in the purchasing utility's costs, rather than on the producing cogenerator's <u>total</u> costs, leads some analysts to assert that "avoided cost pricing" is similar to the "marginal cost pricing" concept embodied in economic theory.

As an example, the North Carolina Utilities Commission (NCUC) recently issued an order regarding the rates for purchase and sale of electricity between electric utilities and QF's.[1] In this order, the NCUC states:

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[1]"In the Matter of Determination of Rates for Purchase and Sale of Electricity Between Electric Utility and Qualifying Cogenerators or Small Power Producers," North Carolina Utilities Commission, Raleigh, N.C., Docket No. E-100, Sub 41, April 1, 1983, page 9.

> In order to calculate avoided costs it is proper to look at what the company can reasonably be expected to do to provide service at the lowest possible cost; i.e., construct fuel efficient base loaded plants. The marginal costs associated with that expansion path are the utility's avoided costs. (Emphasis added.)

The California Public Utilities Commission recently investigated the issue of payments to QF's.[2] After extensive study and debate, the CPUC concluded that:

> ...Energy payments should be derived from a utility's short-run operating costs, reflecting the variable cost of providing an additional unit of electricity. In calculating energy prices, the intent of the decision was 'to capture as accurately and timely as possible the current marginal energy costs incurred by the utility.'

In yet another example, a respected consultant in the cogeneration area prepared a report for the Colorado Energy Research Institute setting forth guidelines for developing rates and designing tariffs for QF's.[3] This consultant defines "avoided costs" by quoting verbatim the language of the FERC rule implementing PURPA:

> "Avoided costs" means the incremental costs to an electric utility of the 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.

This consultant then states:

> Although the term "marginal cost" is not used, the concept expressed in this quote regarding the pricing of power purchased from QF's is synonymous with that of "marginal costs." For the purposes of this paper, avoided costs will be assumed to be the marginal savings experienced by an electric utility as a consequence of the power generated by a QF.

ELCON agrees that it is appropriate to use the terms short-run marginal, incremental and avoided costs interchangeably. However, for

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[2]Decision of the Public Utilities Commission of the State of California, Decision 82-12-120, December 30, 1982, page 100.

[3]Davitian, Harry and Brainard, Joel, "Purchases From Qualifying Facilities Under PURPA 210: Guidelines for Developing Rates and Designing Tariffs," ENTEK Research, Inc., East Setauket, New York, 11733, May 1982, page 4.

the reasons set forth in the paragraphs below, we submit that differences between the intermediate-run avoided and incremental cost concepts and the theoretical long-run marginal cost concept contained in economic theory make the long-run marginal cost concept inappropriate for use in establishing rates for purchases of cogenerated power.

Our discussion first outlines the relevant theoretical economic cost concepts. These concepts are then related to avoided and incremental costs as used by utility analysts in discussions of rates for purchases of cogenerated power.

1. Economic costs - The common meaning of "cost" differs from the concept of cost as embodied in economic theory. In common usage, costs imply money expenditures incurred in producing a good or service. In economic theory, costs represent foregone alternatives or opportunities. Hence, economic costs are "alternative costs" or "opportunity costs."

The economic cost concept is based on trade-offs. Under conditions of full employment, and when resources are used and allocated efficiently, an increase in the production of one good or service requires a reduction in the production of some other good(s) or service(s). Economic costs are the value of the alternative products that could have been produced but were sacrificed when the inputs to one productive process are reallocated to produce another product. These costs are reflected in the price of inputs as, simply, their market prices. These are what any buyer must pay and thus are the same as those costs on the books of the buying firm where there is a market transaction.

Economic costs may be either "explicit" or "implicit." Explicit costs are outlays actually made by a firm in producing a good or service. They are costs that accountants list as expenses. Implicit costs represent foregone opportunities by inputs to a productive process that are not directly paid by the firm. The owner of a business who draws no salary nevertheless incurs a cost since he foregoes the opportunity to work and earn income in another endeavor.

2. The short-run and the long-run - Economic theory distinguishes between the short-run and the long-run. The short-run is a period so

short that the firm is unable to vary the quantities of some inputs to the productive process. The long-run is a period long enough for the firm to be able to vary the quantities of all inputs.

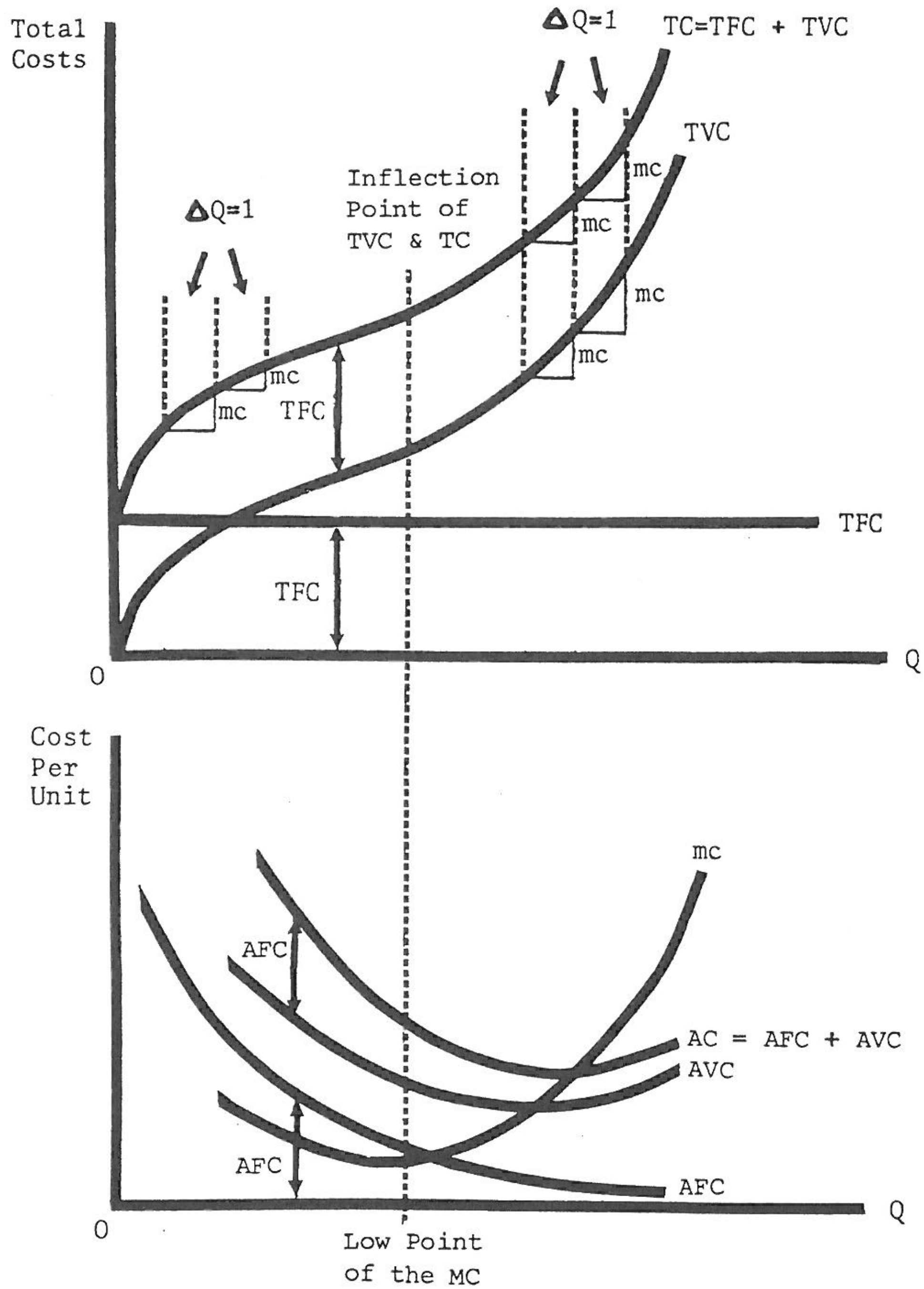
The term "plant" is used in economic theory in a broad manner to cover the whole scope of the firm's operations. The combined total of all assets of a firm comprises the firm's plant. The size of the firm's plant is fixed in the short-run; therefore, some costs are fixed. The firm can build any size plant in the long-run; thus, all costs are variable in the long-run.

For an electric utility, the term plant means the combined total of all generating, transmission, distribution and other assets used in the utility's operations. At any point in time, a utility owns a certain mix of generating and other assets. Although this mix of assets is fixed in the short-run, the utility can vary its output by varying the inputs (to a large extent, fuel). The short-run for an electric utility is a very long calendar time period since it takes a very long time to change a utility's total plant, i.e., vary all of its fixed costs.

3. Short-run economic costs - In the short-run, the total costs of a firm depend on the firm's fixed assets and the level of output. Fixed costs by definition do not vary with changes in output since the fixed resources (the plant) do not vary. Thus, total fixed costs (TFC) are constant. In Diagram A, the TFC curve appears as a line parallel to the quantity axis.

The output of the firm is determined by the quantity of variable resources used with the fixed resources. Larger outputs require more inputs of variable resources. The relationship between the inputs required to increase the output depends upon the "law of diminishing returns." This law states that as the input of one resource is increased by equal increments (while the inputs of all other resources are held constant), total output will increase; but at some point, the increases in output associated with the equal increases in inputs will become smaller and smaller. Alternatively stated, beyond some output size, larger and larger increases in inputs are required to bring about any given increase in output.

DIAGRAM A: SHORT-RUN ECONOMIC COST CURVES



Total variable costs (TVC) depend upon the amount of variable resources used. Since larger outputs require increased quantities of variable inputs, TVC increase with increases in output. Because of the law of diminishing returns, the TVC first increase at a decreasing rate; but, beyond some output level, the TVC increase at an increasing rate. Diagram A illustrates the TVC curve.

The total cost of production at each output level is the summation of the TFC and the TVC. The total costs (TC) must have the same shape as the TVC, since each increase in output per unit of time increases total costs and total variable costs by the same amount. Diagram A illustrates the relationship between the TVC and the TC curves.

Marginal cost (MC) is the change in total cost associated with a one-unit change in output. Since some costs are fixed, MC represents the change in variable cost associated with a one-unit change in output. Marginal cost can be derived from either the TVC or the TC functions since these curves have the same slope at each output.

The marginal cost falls whenever the TVC and the TC increase at a decreasing rate. Throughout this output range, smaller and smaller increases in inputs are required to increase output by equal increments. However, because of the law of diminishing returns, the TVC and the TC eventually begin to increase at an increasing rate. Throughout this output range, larger and larger increases in inputs are required to increase output by equal increments. The additional cost -- or marginal cost -- of equal increases in output thus rises.

Total cost can be stated as an average or per-unit cost. Average fixed cost (AFC), average variable cost (AVC) and average total cost (AC) are derived by dividing the corresponding total cost by output.

Any average falls when the quantity at the margin is less than the average and vice versa. For example, the average weight of a football team falls if a player is added to the team that weighs less than the original average. Diagram A illustrates this characteristic as each average cost curve (AVC and AC) falls when the MC is less than the average and rises when the MC is greater than the average. The MC crosses both the AVC and the AC at their respective low points.

4. Long-run economic costs - Theoretically, the long-run is a series of alternative short-run situations. The long-run may be viewed as a motion picture -- the short-run is any one, single frame (and there are many).

Any size plant can be built in the long-run. The firm can change the quantities and the types of any resource -- land, buildings, machinery or management. No resource is fixed in the long-run, and there are no fixed costs.

Long-run average cost (LRAC) is "U" shaped due to "economies and diseconomies of scale."[4] A firm can build more efficient plants only up to some size. The firm then finds that building an even larger plant results in certain diseconomies. Economies and diseconomies of scale are illustrated in Diagram B. Four plants are illustrated in the diagram. Theoretically, many others could be shown. Each plant has a specific short-run average cost (SRAC) associated with that plant. Throughout the range of net economies of scale, the low points of each SRAC curve fall as output rises. However, throughout the range of net diseconomies of scale, the low points of each SRAC curve rise as output is increased.[5]

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[4] We point out the sharp distinction between the law of diminishing returns and economies and diseconomies of scale (scale economies). The law of diminishing returns is a short-run concept describing the relationship between the various quantities of variable resources required to produce alternative outputs given a fixed plant. Scale economy is a long-run concept explaining why, once a plant is large enough to take advantage of all economies of scale, still larger sizes are likely to result in a less efficient plant. Put differently, diseconomies then outweigh economies of scale. If there were neither, LRAC would be a constant at all output levels.

[5] Changes in the levels of the cost curves represent increases or decreases in efficiencies associated with various sizes of plants, ceteris paribus (everything else held constant). Specifically, it is assumed that the prices of all inputs, the level of technological development, inflation and other related factors all are constant and thus do not affect the level of the curves. Changes in any of these factors (for example, increases in inflation), would shift (increase) the entire set of cost curves, but have nothing at all to do with economies or diseconomies of scale. Analysts confuse terms if they allege that the electric power industry experiences

(Footnote Continued)

A single output can be produced with several plants (e.g., output Q_1 can be produced with $SRAC_1$, $SRAC_2$ or $SRAC_3$ in Diagram B). However, the SRAC for that output is the lowest (AC_2) for only one plant ($SRAC_2$). This cost (AC_2) becomes the point associated with Q_1 on the LRAC. Thus, the LRAC illustrates efficiency -- a schedule of the lowest possible average costs associated with each output.

The long-run marginal cost (LRMC) is the change in total cost when output is increased by one unit and the firm is able to build precisely the plant that is desired. The LRMC is the change in total cost if output were increased one unit with each output produced by the most efficient plant for each of those outputs.

The LRMC is a theoretical concept. All existing firms (including electric utilities) have plant in place -- plant that more than likely is not optimal or the most efficient (i.e., the lowest possible LRAC).

Graphically, the LRMC must be below the LRAC when the LRAC is falling (when the firm is experiencing net economies of scale). The LRMC exceeds the LRAC when the LRAC is rising (when the firm is experiencing net diseconomies of scale). The LRMC must equal the LRAC at the low point of the LRAC.[6]

The term "optimum plant" means the most efficient plant that can be built. The optimum plant is one with the lowest SRAC of all of the possible plants. That optimum plant's low point will establish the low point on

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(Footnote Continued)
diseconomies of scale when the cost of building new power plants today exceeds the cost of building plants in the past. Inflation increases the costs of building both "small" and "large" plants. Diseconomies of scale are evident when (or if) it is demonstrated that the building of a larger plant of one type (say coal-fired) results in higher electricity costs than would occur if a smaller plant of the same type were built, ceteris paribus.

[6] It is often suggested that a firm planning larger plants would experience "constant returns to scale" before being subjected to diseconomies of scale. Under conditions of constant returns to scale, the low point on alternative SRAC curves would neither rise nor fall as larger plants are planned. The LRAC would be comprised of the (constant) low points of the alternative SRAC curves under such conditions. Throughout this range, the LRMC would equal the LRAC.

the LRAC. The optimum plant's SRAC is tangent to the LRAC at the low point of both curves. $SRAC_3$ represents the optimum plant in Diagram B.

5. Incremental and avoided costs - Although not clearly defined in either law or economics, analysts generally use incremental and avoided costs to mean the following:

Incremental cost is the cost of generating and transmitting an increased quantity of electricity. Incremental cost is the change in total cost when the output of a utility is increased by a specified increment or block. The change in output usually is assumed to be "small" relative to the total output, although no criteria are specified regarding the size of the change in output. Incremental cost is usually expressed as the average (or per unit) change over the incremental change in output. Incremental cost is either short-run (SRIC) or long-run (LRIC). SRIC assumes a time period so short that the firm can make no changes in its fixed resources. LRIC assumes a time period long enough to allow modifications or additions to certain fixed resources, although a large portion of the assets remain unaltered.

Avoided cost represents the cost that would not be incurred if an electric utility elected to purchase a cogenerator's power, but that would be incurred if the utility elected not to purchase the cogenerator's power. Avoided cost is either short-run or long-run. Short-run avoided cost assumes a time period so short that the utility can make no changes in its generating, transmission, distribution or other assets -- the system capacity cannot be altered. Long-run avoided cost assumes a time period long enough to allow certain modifications in system capacity, although a "large" portion of the assets remain unchanged.

6. Observations on the cost concepts - Incremental, avoided and marginal costs are often confused. We offer the following observations relative to the various cost concepts to establish clearly our view of these terms throughout the paper.

Short-run marginal, incremental and avoided costs each represent changes in total cost that occur because of a specified change in output holding fixed resources constant. To be precise, the reader is referred to

Diagram C. SRMC represents the change (either increase or decrease) in total cost when output is changed only one unit. Incremental cost is the change in total cost when output is increased by a "block" or an increment. Diagram C indicates that measurements of incremental and marginal costs are identical as long as the change in output associated with each measurement equals +1 ($\Delta Q = +1$). Alternatively, avoided cost is the change in total cost when output is decreased by a "block" or an increment. Diagram C indicates that measurements of avoided and marginal costs are identical as long as the change in output associated with each measurement equals -1 ($\Delta Q = -1$). Thus, the differences in measurements of these terms are insignificant if the change in output is small relative to total output. Hence, we believe that it is appropriate to use short-run marginal, incremental and avoided costs interchangeably.

However, we draw a sharp distinction between long-run avoided, long-run incremental (LRIC) and long-run marginal (LRMC) costs. Long-run incremental and avoided costs represent an "intermediate" period between the short-run and the theoretical long-run.[7] Both terms suggest time periods where it is possible to make changes in or additions to some fixed resources, although a very large portion of assets remain fixed. These costs represent real-life situations where utilities with existing assets are contemplating changes in or additions to some, but not all, of these assets. Because neither LRIC and long-run avoided costs are consistent with the long-run as embodied in economic theory, the optimum connotations of economic theory are not applicable to either term. Often, LRIC and long-run avoided costs are implicitly viewed as the "cost of the next plant" that is not incurred due to the purchase of QF power. As such, these costs can be estimated; specific dollar values can be placed on them.

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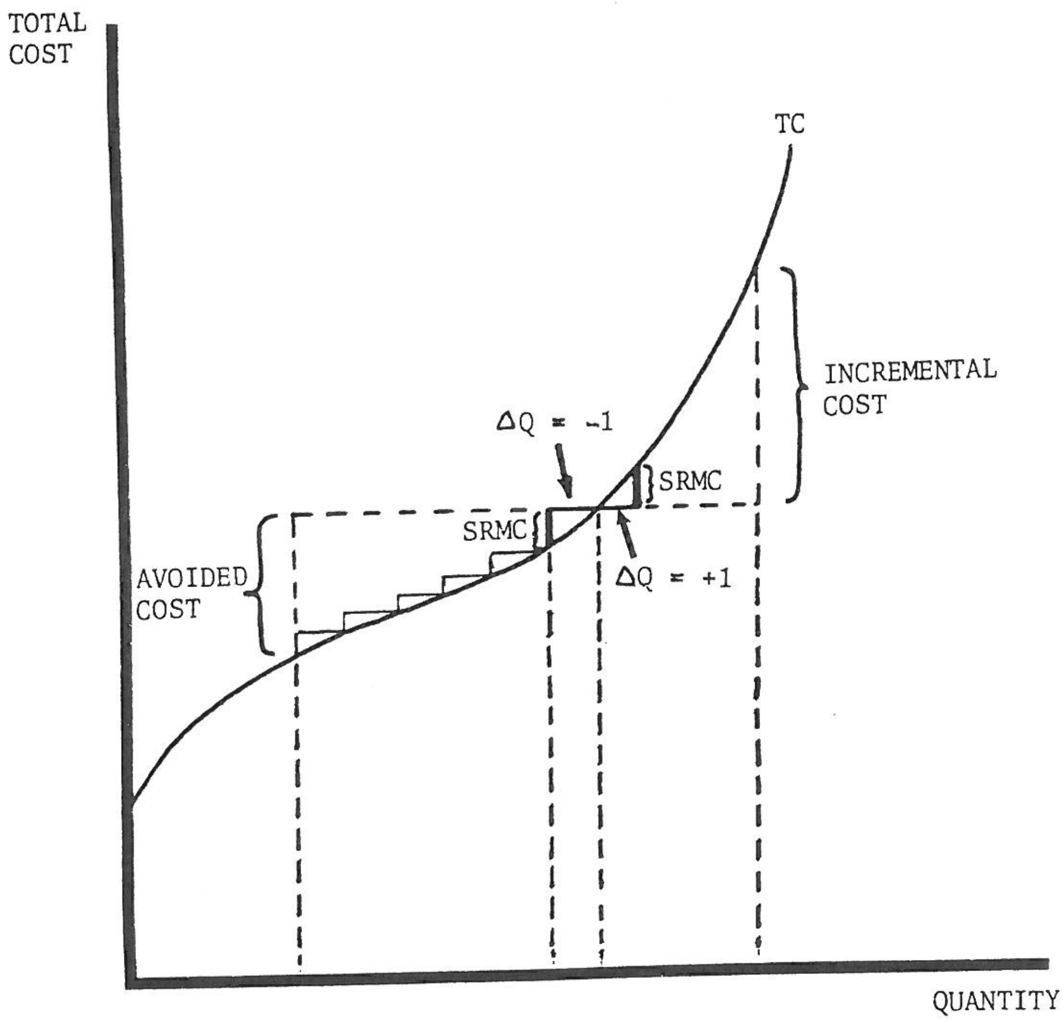
[7] Note that there can be as many intermediate periods as the analysts can conjure up. Thus, there is no limit on the number of different LRIC's in dollar terms.

ELCON

DIAGRAM C: A COMPARISON OF SHORT-RUN MARGINAL, INCREMENTAL AND AVOIDED COSTS



Long-run marginal cost (LRMC) is a theoretical concept. LRMC represents the change in total cost associated with a one unit change in output assuming no fixed plant -- i.e., no fixed cost. Thus, theoretically, the firm selects from an infinite number of options. It is not limited to changes or modifications to certain assets of the utility's existing plant.

The key point is that in the short-run, marginal, incremental and avoided costs are concepts so closely related that they can be used interchangeably -- particularly when the change in quantity associated with each is small relative to total output. This is not the case in other than the short-run. When either intermediate or long-run time periods are considered, the concepts associated with marginal cost are so different from those of either incremental or avoided costs that the terms must be clearly differentiated both in theory and in practice.

Rates for Power Purchased From QFs by State-Regulated Utilities

Utility	Energy payments (¢/kWh)	Capacity payments ($/kW-yr)	Comments
Alabama			Nuclear 24%, coal 58%, oil 1%, gas 3%, hydro 14%.
Alabama Power Co.	2.59 on-peak, June-October 2.17 off-peak, June-October 2.14 on-peak, November-May 2.05 off-peak, November-May		Off-peak purchase rates are offered for utilities without time-of-day metering. Rates are for facilities less than 100 kW.
Arkansas			Nuclear 17%, coal 9%, oil 44%, gas 10%, hydro 20%.
Arkansas Power & Light Co.	Reverse metering currently used		Comments on proposed rates were due by June 1, 1981.
California			Nuclear 4%, oil 67%, gas 1%, hydro 25%, other 3%.
Pacific Gas & Electric Co.	6.58 on-peak 6.219 mid-peak 5.553 off-peak 6.030 non-TOD	$0.75-$1.50/kW-month	Rates are for February-April 1981.
Southern California Edison	6.6 on-peak 6.0 mid-peak 5.8 off-peak 6.0 non-TOD	25% of full value	Rates are for February-April 1981.
San Diego Gas & Electric Co.	8.333 on-peak 7.069 mid-peak 6.225 off-peak 6.650 non-TOD	$0.70-$2.00/kW-month	Rates are for February-April 1981.
Connecticut			Nuclear 38%, oil 60%, hydro 2%.
Connecticut Light & Power Co. and Hartford Electric Light Co.	*Firm power:* 6.7 on-peak (114.5% of fossil fuels cost) 5.4 off-peak (90.5% of fossil fuels cost) *Nonfirm power:* 6.6 on-peak (110% of fossil fuels cost) 5.2 off-peak (86.5% of fossil fuels cost)		Purchase rates are temporarily in effect pending approval of utility proposals. Percentage is tied to monthly fuel adjustment. Firm power rates are for facilities greater than 100 kW. Off-peak purchase rates are offered for facilities without time-of-day metering. No size restrictions apply to nonfirm facilities.
Idaho			Oil 1%, gas 3%, hydro 96%.
Utah Power & Light Co.	*Firm power:* 1.2 *Non-firm power:* 2.6	88-266 increasing with contract length 4-35 years.	The Idaho PUC has ordered UP&L to add some capacity credit to the nonfirm energy payment.
Washington Water Power Co.	*Firm power:* 1.6 *Nonfirm power:* 2.4	96-280 increasing with contract length 4-35 years. 0.3¢/kWh	Rates are for facilities less than 100 kW.
Idaho Power Co.	*Firm power:* 1.639 *Nonfirm power:* 1.41-3.86 (varies each month, 2.4 average)	116-318 increasing with contract length 4-35 years.	The Idaho PUC has ordered IPC to add some capacity credit to the nonfirm energy payment.
Illinois			Nuclear 19%, coal 57%, oil 23%, <1% gas, <1% hydro, 1% other.
Illinois Power	2.42 on-peak summer 1.55 off-peak summer 2.65 on-peak winter 1.88 off-peak winter *Non-TOD:* 1.89 summer 2.18 winter		
Commonwealth Edison	5.31 on-peak summer 2.90 off-peak summer 5.17 on-peak winter 3.37 off-peak winter		1,000 kW or less.
Central Illinois Light Co.	*34 kV or greater:* 2.3 on-peak 2.1 off-peak *12 kV to 34 kV:* 2.4 on-peak 2.2 off-peak *Less than 12 kV:* 2.5 on-peak 2.3 off-peak		

Rates for Power Purchased From QFs by State-Regulated Utilities—Continued

Utility	Energy payments (¢/kWh)	Capacity payments ($/kW-yr)	Comments
Interstate Power Co.	2.45 on-peak, June-September 2.05 off-peak, June-September 2.19 on-peak, October-May 2.05 off-peak, October-May		
Central Illinois Public Service	1.978 on-peak summer (3 months) 1.620 off-peak summer 1.884 on-peak winter (3 months) 1.661 off-peak winter 1.805 on-peak (rest of year) 1.565 off-peak		
South Beloit Water, Gas & Electric Co.	2.30 on-peak 1.70 off-peak		
Union Electric	*Non-TOD:* 1.77 summer 1.53 winter *TOD:* 2.41 on-peak summer 1.36 off-peak summer 1.50 summer, weekends and holidays 1.86 on-peak winter 1.35 off-peak winter 1.35 winter, weekends and holidays		
Indiana			Nuclear 0%, coal 89%, oil 8%, gas < 1%, hydro 1%, other 2%.
Indiana & Michigan Electric Co.	*TOD:* 1.36 on-peak 0.81 off-peak *Non-TOD:* 0.81		
Indianapolis Power & Light	1.14 general rate *Seasonal:* 1.19 on-peak summer 1.07 off-peak summer 1.28 on-peak winter 1.08 off-peak winter		
Northern Indiana Public Service Co.	2.62 on-peak summer 2.29 off-peak summer 2.61 on-peak winter 2.29 off-peak winter *Non-TOD seasonal:* 1.86 summer 1.83 winter		
Public Service Co. of Indiana	1.33		
Southern Indiana Gas & Electric	1.49 on-peak summer 1.02 off-peak summer 1.15 on-peak winter 1.00 off-peak winter		
Richmond Power & Light	0.914		
Kansas			Coal 35%, oil 11%, gas 55%.
Kansas Power & Light	1.60		Rate is for a cogenerator on-line since the 1920's.
Massachusetts			Nuclear 9%, coal 0%, oil 72%, gas < 1%, hydro 18%, other 1%.
Boston Edison	6.971 on-peak 4.047 off-peak 5.543 flat		
Commonwealth Electric	7.16 on-peak 6.15 off-peak 6.51 flat		Interim rates. Energy rates will be reset every 3 months when fuel adjustment is figured. QFs of 30 kW or less can use reverse metering.
Eastern Edison	6.792 on-peak 5.161 off-peak 5.995 flat		
Massachusetts Electric	5.51 on-peak 4.79 off-peak 5.08 flat		
Cambridge Electric	7.22 on-peak 5.91 off-peak 6.34 flat		
Nantucket Electric	7.44		
Manchester Electric	4.748		
Fitchburg Gas & Electric	6.081 on-peak 3.313 off-peak 4.940 flat		
Western Massachusetts Electric	5.813 on-peak 4.238 off-peak 4.979 flat		
Michigan			Nuclear 14%, coal 47%, oil 23%, gas 4%, hydro 11%, other 1%.
Statewide purchase rate includes: Consumers Power Co. and Detroit Edison	2.5		This rate was established prior to PURPA compliance. New purchase rates implemented in March or April of 1982.
Minnesota			Nuclear 21%, coal 55%, oil 19%, gas 1%, hydro 2%, other 2%.

Rates for Power Purchased From QFs by State-Regulated Utilities—Continued

Utility	Energy payments (¢/kWh)	Capacity payments ($/kW-yr)	Comments
Northern States Power Co.	*Firm power:* 2.06-3.07 increasing with contract length 5-25 years. *TOD metering service:* 2.15 on-peak 1.39 off-peak *Nonfirm power:* 1.35 *Occasional power:* 1.66		Temporary rate schedule in effect until further studies are completed. These rates are intended to comply with PURPA requirements and are restricted to facilities less than 100 kW. Capacity credits are included in firm power purchase rates. Nonfirm power rates take effect in the event that a firm producer does not provide dependable generation. Occasional power is limited to 500 kWh/month.
Montana			Nuclear 0%, coal 32%, oil 5%, gas 1%, hydro 61%, other 1%.
Montana Power	2.7642	77.24 (25-year contract only)	
Montana-Dakota	*Nonfirm power:* 2.21 on-peak 1.57 off-peak *Nonfirm, non-TOD:* 1.91 *Firm power:* 1.97-3.08 (depending on contract length)		Nonfirm rates for QFs of 100 kW or less.
Pacific Power & Light	1.34-1.66	3.75-7.37 per kW-month	
Nebraska			Nuclear 26%, coal 46%, oil 13%, gas 9%, hydro 3%, other 3%.
Omaha Public Power District	*TOD metering:* 1.60 on-peak summer 1.00 off-peak all year 1.20 on-peak winter *Standard rate:* 1.10		Rates apply to facilities of 100 kW or less.
Nevada			Nuclear 0%, coal 54%, oil 5%, gas 23%, hydro 18%.
Idaho Power	1.71 (February)-4.16 (August)	116.00-263.00 (1981)	Energy payments vary monthly. Capacity payments vary by length of contract.
Sierra Pacific	4.09	6.1¢/kWh	
Nevada Power Co.	3.602 on-peak, October 1981	6.55 on-peak October 1981	Energy payments and capacity payments vary monthly.
	1.943 off-peak, October 1981	0.07 off-peak October 1981	
	3.528 on-peak, November 1981	0.14 on-peak November 1981	
	2.331 off-peak, November 1981	0.00 off-peak November 1981	
	4.311 on-peak, December 1981	0.14 on-peak December 1981	
	2.630 off-peak, December 1981	0.00 off-peak December 1981	
New Hampshire			
Statewide rate	*Firm power:* 8.2 *Nonfirm power:* 7.7		Coal 30%, oil 47%, hydro 23%. Granite State Electric Utility is not required to pay the firm power rate due to excess capacity.
New Jersey			Nuclear 14%, coal 13%, oil 69%, gas 1%, hydro 3%.
Jersey Central Power and Light Co.	*Approximate only:* 6.0-7.5 on-peak 2.0-5.0 off-peak		Actual rates are determined by averaging marginal energy rates for previous 3-month on-peak and off-peak hours. The rate applies to facilities between 10 and 1,000 kW.
Atlantic City Electric Co.	*Temporary rate:* 2.5		This October 1980 rate was greater than average energy costs. The utility has proposed that buyback rates may be set at time of interconnection.
New York			Nuclear 13%, coal 8%, oil 63%, hydro 15%, gas and other 1%.
Statewide minimum rate includes: Long Island Lighting Co., Niagara Mohawk Power Co., New York State Electric & Gas Co., Consolidated Edison, Orange & Rockland Utilities, Inc., Central Hudson Gas & Electric Corp. and others	6.00 minimum		
North Carolina (Note: North Carolina capacity payments are given as ¢/kWh not $/kW-yr as shown above.)			Nuclear 11%, coal 71%, oil 6%, hydro 12%.
Carolina Light & Power Co.	2.80-5.55 on-peak	1.49-2.39 summer month	Rates increase with contract length.
	2.07-4.04 off-peak	1.29-2.08 nonsummer months	
Duke Power Co.	2.38-5.20 on-peak	1.11-1.66 on-peak months	Rates increase with contract length.
	1.78-3.91 off-peak	0.66-1.00 off-peak months	
Virginia Electric & Power Co.	4.23-9.30 on-peak summer 3.59-4.30 peak nonsummer 2.62-5.77 all others	1.61-2.50 summer 1.42-2.25 nonsummer	Rates increase with contract length.
Nanthahala Power & Light Co.	2.05	2.50	NP&L purchases power from TVA.
North Dakota (Note: proposed rates—not yet finished.)			Coal 82%, oil 4%, hydro 14%.
Northern States Power Co.	2.15 on-peak 1.39 off-peak	2.06-3.07 (¢/kWh)	Rates apply to facilities less than 100 kW. Capacity payments increase with length of contract 5-25 years. Facilities larger than 100 kW treated case-by-case.

Rates for Power Purchased From QFs by State-Regulated Utilities—Continued

Utility	Energy payments (¢/kWh)	Capacity payments ($/kW-yr)	Comments
Oklahoma			Nuclear 0%, coal 20%, oil 3%, gas 65%, hydro 8%, other 4%.
Statewide rate schedule includes: Oklahoma Gas & Electric Co. Public Service Co.	0.86-3.05 depending on firmness of capacity		Formulae have been established to treat purchase rates for various types of small power producers. Both energy and capacity components are considered.
Oregon	Reverse metering currently used		Nuclear 12%, coal 0%, oil 7%, gas 1%, hydro 78%, other 2%.
Rhode Island			Nuclear 0%, coal 0%, oil 99%, gas 0%, hydro 1%.
New England Power Co.	5.5247 on-peak 4.5339 off-peak 4.9843 average		
Blackstone Valley Electric Co.	*Primary:* 6.412 on-peak 4.842 off-peak 5.511 average *Secondary:* 6.726 on-peak 4.985 off-peak 5.723 average		
Newport Electric Co.	4.473 on-peak 4.093 off-peak 4.317 average		
South Carolina			Nuclear 29%, coal 30%, oil 21%, hydro 19%, gas and other 1%.
Carolina Power & Light Co.	2.80 on-peak 2.07 off-peak	46.68 summer 40.20 nonsummer	Rates are for facilities less than 5 MW.
Duke Power Co.	1.98 on-peak 1.49 off-peak	60.00 (Based on integrated capacity during peak months June-September, December-March).	
Utah			Coal 86%, oil 2%, gas 2%, hydro 10%.
Utah Power & Light Co.	2.2 (temporary rate)	2.6¢/kWh	Purchase rates are for facilities less than 1,000 kW (100 kW for hydro). Larger facilities are considered case-by-case (up to 3.5¢/kWh).
C.P. National	2.2 (temporary rate)	2.6¢/kWh	
Vermont			Nuclear 57%, coal 3%, oil 16%, hydro 24%.
Statewide rate schedule	7.8 standard rate *TOD rates:* 9.0 on-peak 6.6 off-peak		Avoided costs are higher than would be expected from Vermont's capacity mix due to dispatch and accounting practices of NEPOOL.
Wisconsin			Nuclear 17%, coal 59%, oil 17%, gas 2%, hydro 5%.
Wisconsin Power & Light Co.	1.80 on-peak 1.75 off-peak (includes capacity)		Purchase rates are for facilities less than 200 kW. Larger facilities are treated case-by-case.
Madison Gas & Electric Co.	2.75 on-peak summer 1.50 off-peak summer 2.22 on-peak winter 1.50 off-peak winter		Purchase rates are for facilities less than 200 kW. Larger facilities are treated case-by-case.
Wisconsin Electric Co.	*Firm power:* 3.65 on-peak summer 1.45 off-peak summer 3.45 on-peak winter 1.45 off-peak winter *Nonfirm power:* 2.90 on-peak 1.45 off-peak		
Northern States Power Co.	*For 20 kW or less:* 1.81 on-peak 1.14 off-peak *For 21-500 kW after 1986:* 1.60 on-peak 1.14 off-peak	$4/kW/month $4/kW-month	Prior to 1986 the rates for 20 kW and less apply to 21-500 kW. No capacity credits will be paid until after 1986. Facilities greater than 500 kW are treated case-by-case.
Lake Superior District Power Co.	1.90	$6.02/kW-month	Purchase rates are for facilities between 6 and 200 kW. Smaller facilities receive no payments. Larger facilities are considered case-by-case.
Wisconsin Public Service Corp.	1.85 on-peak 1.32 off-peak	To be determined according to characteristics of each facility.	
Wyoming			Coal 93%, hydro 6%, oil and gas 1%.
(Note: All of the Wyoming purchase rates are "experimental.")			
Utah Power & Light Co.	*Nonfirm power:* 2.2 *Firm power:* 2.6		Purchase rates are for facilities less than 100 kW.
Cheyenne Light, Fuel and Power Co.	0.53	Available on demonstration of demand reduction.	
Tri-County Electric Association	1.07		This is a nongenerating utility which has based its avoided costs on wholesale supply rates.
Montana-Dakota Utilities Co.	0.405	Available on demonstration of capacity displacement or demand reduction potential.	

SOURCE: Reiner H. J. H. Lock and Jack C. Van Kuiken, "Cogeneration and Small Power Production: State Implementation of Section 210 of PURPA," 3 *Solar L. Rep.* 659 (November-December 1981).

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