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BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

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| U.S. GEOTHERMAL, INC., AN IDAHO CORPORATION,<br><br>Complainant,<br><br>vs.<br><br>IDAHO POWER COMPANY, AN IDAHO CORPORATION,<br><br>Respondent. | CASE NO. IPC-E-04-8 |
| BOB LEWANDOWSKI AND BOB SCHROEDER,<br><br>Complainants,<br><br>vs.<br><br>IDAHO POWER COMPANY, AN IDAHO CORPORATION,<br><br>Respondent. | CASE NO. IPC-E-04-10 |

# DIRECT TESTIMONY OF RICK STERLING

IDAHO PUBLIC UTILITIES COMMISSION

AUGUST 5, 2004

Q. Please state your name and business address for the record.

A. My name is Rick Sterling. My business address is 472 West Washington Street, Boise, Idaho.

Q. By whom are you employed and in what capacity?

A. I am employed by the Idaho Public Utilities Commission as a Staff engineer.

Q. What is your educational and professional background?

A. I received a Bachelor of Science degree in Civil Engineering from the University of Idaho in 1981 and a Master of Science degree in Civil Engineering from the University of Idaho in 1983. I worked for the Idaho Department of Water Resources from 1983 to 1994. In 1988, I became licensed in Idaho as a registered professional Civil Engineer. I began working at the Idaho Public Utilities Commission in 1994. My duties at the Commission include analysis of utility applications and customer petitions.

Q. What is your background and experience as it relates to avoided costs and QF contracts?

A. I have worked for the Idaho Public Utilities Commission for over 10 years. Throughout that time, I have been the primary Staff person assigned to all matters related to avoided costs and Qualifying Facility (QF)

contracts. I have been instrumental in developing and employing methods to determine avoided cost rates. I have reviewed and commented on every QF contract that has been submitted to the Commission for approval during the past ten years, and I have been either the witness or sponsor of comments on every PURPA-related proceeding to come before the Commission in that time period.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present Staff's position on the following:

1) Definition of the 10 MW threshold for eligibility for posted avoided cost rates; and
2) Whether the contract provisions offered by Idaho Power to U.S Geothermal, Bob Lewandowski and Mark Schroeder are reasonable, and if not reasonable, to offer recommendations for revised provisions which Staff believes are reasonable; and
3) Whether the "regulatory-out" contract provision sought by Idaho Power is necessary and enforceable.

Q. Please summarize your testimony.

A. I believe that Idaho Power's proposal to define the 10 MW threshold for determining eligibility for posted avoided cost rates is reasonable. Staff has always

interpreted the threshold as a capacity limit, not an average energy limit. I believe that a 10,000 kWh per hour interpretation is easy to administer. I do not support using nameplate capacity to judge eligibility for posted rates.

I support Idaho Power's proposed concept of establishing a performance band as the criteria for distinguishing between firm and non-firm energy. However, I believe that the Company's proposed band is too narrow. I recommend that the band be set between 80 and 120 percent rather than the 90-110 percent band proposed by Idaho Power. In addition, I support Idaho Power's inclusion of a contract provision to excuse performance in the event of forced QF outages, but I recommend that the grace period be extended from 72 hours to 30 days.

I do not support Idaho Power's insistence on inclusion of a "regulatory-out" clause in QF contracts.

Q. Please briefly summarize the various types of avoided cost rates available to QFs in Idaho.

A. Idaho has a 25-year history of QF development in the state. In that 25-year period, an extensive array of power sales and pricing options has evolved to accommodate a very wide variety of project types, financing options, generation characteristics and developer preferences. To more easily illustrate the variety of options, I have

prepared Exhibit No. 101. Although this exhibit is specific to Idaho Power, both Avista and PacifiCorp have similar options.

Beginning at the top of the flowchart, projects either sell to the utility under a contract or under a tariff. Under a tariff, projects have no obligation to deliver power in any specified amount or for any specified length of time. The project is entitled to the rates specified under the tariff as long as the tariff remains in place. On the far right is Idaho Power's Schedule 84 tariff for net metering customers. This tariff is designed for small projects that basically wish to "spin the meter backwards."

The center section of the flowchart shows the options available for "non-firm" energy sales. Projects too large to qualify for the net metering tariff could qualify for the Schedule 86 non-firm tariff. Non-firm energy is that which is delivered on an "if and as-available basis." Non-firm energy projects less than 10 MW in size are paid 85% of Mid-C market prices. Projects 10 MW and larger would be subject to negotiated rates beginning at a price equal to 85% of Mid-C. To date, there have been no non-firm energy projects 10 MW or larger, and there have only been a few non-firm projects smaller than 10 MW.

By far, most projects developed to date have chosen to sign long-term contracts with the utilities. Long-term contracts are depicted on the left hand side of Exhibit No. 101. For projects smaller than 10 MW, the Commission has developed avoided cost rates for fossil-fueled and non-fossil-fueled projects, and rates that are either levelized or non-levelized. Rates for these contracts have been referred to in the past as "published rates" or "posted rates." For projects 10 MW and larger, contractual rates are determined using a methodology that relies on utilities' Integrated Resource Plans (IRPs) and their power supply models. The result of applying the prescribed methodology is a project-specific rate that recognizes the characteristics of individual projects. Since this methodology has been in place, it has been employed only once for a contract between Avista and Potlatch.

Q. Are there any other mechanisms for selling power to utilities?

A. Yes, projects could also become certified as Exempt Wholesale Generators (EWGs) under PURPA, or "merchant plants." In that case, they could sell power to whoever they wanted under whatever terms they are able to negotiate, as long as the sales are not retail.

Finally, projects could choose to respond to

utilities' Request for Proposals (RFPs). Solicitations to acquire power are made from time to time, usually for some specific type of product. For example, PacifiCorp recently issued an RFP for renewables, but has yet to announce which, if any, bids will be accepted. The utility intends to issue more RFPs in the future, as does Idaho Power. Idaho Power's draft 2004 Integrated Resource Plan states that the Company intends to try to acquire 100 MW of geothermal resources and 350 MW of wind resources in the next six years through an RFP process. The Company intends to issue an RFP for 200 MW of wind before the end of this year, and another RFP for 100 MW of geothermal resources next year.

Q. Do you have any concerns about the RFP process being used by utilities to acquire renewables?

A. I do not have concerns about using the RFP process to acquire renewables, but I do have concerns about inconsistencies between rates that might be paid for renewables acquired under the RFP process and those acquired as QFs under PURPA.

Q. Do you believe that the tariffs and mechanisms in place for enabling non-utilities to sell power to the utilities are adequate?

A. Yes, I believe that this Commission's tariffs and mechanisms are very extensive and can accommodate projects

of nearly any type and size. In fact, my experience has been that few people are aware and even fewer understand just how many options there are for selling power to utilities in Idaho. Many people have had the mistaken impression for many years that projects 10 MW and larger could not even be developed in Idaho.

Q. What is the advantage, if any, for a project to be smaller than 10 MW in size?

A. The advantage is that there is a pre-determined schedule of rates developed that utilities must pay under contract. With a pre-determined schedule of rates, developers are relieved of being required to negotiate a rate. Another possible advantage is that the "posted rates" may exceed the rates determined using the project-specific IRP-based methodology.

Q. Why do you say *possible* advantage?

A. I say there may be a possible advantage because it is not possible to know which rates will be higher unless the IRP-based methodology is actually applied and a rate computed. The assumption most people seem to make is that the "posted rates" will always be higher, but I contend this assumption is almost always made without any information comparing the two rates.

Q. Without actually making a comparison of the under- and over-10 MW rates, which do you think are more

likely to be higher?

A. I believe it depends on the generation characteristics of the project. For a project that generates as a mostly base-load type of project, the under-10 MW rates will probably be higher. However, for a project that is able to generate more during on-peak hours and during peak seasons, the over-10 MW rates are likely to be higher because the project-specific modeling is able to recognize the added value of peak generation.

Q. Has a project-specific rate been determined for any of the parties in this case for project sizes larger than 10 MW?

A. No, not that I am aware. Quite frankly, I am amazed that neither Idaho Power nor the complainants have made any effort to determine what the rate would be if the project were larger than 10 MW.

Q. Would it be difficult for Idaho Power to compute a rate for U.S. Geothermal for a project size of say, 20 MW?

A. I wouldn't say it is a trivial exercise, but I would say that Idaho Power should be quite capable of doing it in a relatively short period of time. According to the methodology description adopted in the settlement stipulation in Case No. IPC-E-95-9, Order No. 26576, utilities are required to make such a computation within 30

days of the request.

Q. If U.S. Geothermal simply cannot size its Raft River project to produce no more than 10,000 kWh per hour and remain cost-effective, does that mean that the project must be abandoned?

A. No, clearly not. If the project must be sized larger than 10 MW, it just means that the IRP-based methodology would be used to establish its rate as a QF project, or that it must become a merchant generator or participate in an RFP process.

Q. Idaho Power seeks to define the 10 MW threshold for eligibility for posted avoided cost rates as being "not to exceed 10,000 kWh per hour" while U.S. Geothermal seeks to define the threshold as 10 average megawatts (aMW) measured on an annual basis. How do you believe the threshold should be defined?

A. I believe that Idaho Power's proposal to define the threshold as "not to exceed 10,000 kWh per hour" is reasonable. Idaho Power has used this definition in the past when 10 MW was formerly the threshold. While not stated in any prior Commission Order or formally endorsed by either the Commission or its Staff, Staff has historically viewed this definition as reasonable and has interpreted the threshold as an actual capacity generation limit. Although capacity, by definition, is normally not

associated with generation over any specified time period, defining capacity by measuring generation over a one-hour period has proven to be a relatively easy method for Idaho Power to use. In many respects, it is analogous to how demand is measured for purposes of billing commercial, industrial and irrigation customers, except that a one-hour period is used instead of a 15-minute period that is used for demand billing purposes. In the past, several QF contracts have included this definition.

Q. There has been a 10 MW threshold for posted rates for most of the years PURPA has been implemented in Idaho. Why has this issue not come up sooner?

A. I believe it has never been an issue before because there have only been a few projects close to 10 MW in size. Of these, all have been either hydropower projects or wood waste fired projects with generally higher capacity factors. Existing projects close to 10 MW in size can and do generate at their rated capacity a large share of the time. The vast majority of existing QFs are much smaller than 10 MW. Now, however, with the recent introduction of lower capacity factor projects, particularly wind, it is likely that some will rarely generate at their rated capacity. For example, a wind project might be sized to be capable of generating 10 MWs of capacity, but it will likely do so only for a very small

portion of the year. Thus, for some generation technologies, how the 10 MW threshold is defined is crucial.

Q. In the past, has Staff viewed the 10 MW threshold as a capacity limit or an energy limit?

A. Staff has always viewed it as a capacity limit. Furthermore, I believe the utilities and developers have also viewed it as a capacity limit. Although there has been some question in recent years about how the limit should be measured, I am not aware of anyone, until now, who has ever suggested that it be viewed as an energy limit. If 10 MW had been viewed as an energy limit, Staff would have been careful to always specify it as "10 average megawatts" or 10 aMW. Contrary to Mr. Kitz's testimony, in the regulatory arena, plants are always generally described by their rated capacities, not by their average annual capacities. For example, Idaho Power's Danskin project is normally referred to as a 90 MW plant because it has the capability to generate 90 MW under normal conditions. If it were to be described instead based on its average annual generation, it would be described as a 5 or 10 MW plant due to its limited hours of operation. Moreover, its capacity based on average annual generation would vary considerably from one year to the next because it would never consistently operate the same amount of time from year to

year. Quite frankly, I have never heard of a plant generally described by its average annual energy unless it is specifically stated as average megawatts. If the Commission had intended for the threshold to be 10 aMW, I believe it would have stated it that way in its prior Orders.

Q. Could the Commission choose to define the threshold as 10 aMW?

A. Certainly; however, I think it could become even more problematic to administer if it were to do so. First, if a threshold of 10 average megawatts measured over the course of a year were used, it could not be verified except on an annual basis. A test based on hourly metering would instead be able to provide almost immediate verification. Second, if 10 aMW were used as the criterion, it would take a complete year before it could be verified that a project was or was not less than 10 aMW. Moreover, that same difficulty would persist every year thereafter. If the QF were found to have exceeded a 10 aMW threshold at the end of a year, I think it would present administrative and accounting difficulties to adjust for payments already made to the QF in prior months based on an assumption that the project was less than 10 aMW.

Q. Do you believe it would be unfair to certain technologies to define the 10 MW threshold as being 10,000

kWh per hour?

A. No, I do not. One of the key reasons for having any threshold at all is because there are better, more accurate ways to establish a value for projects whose generation characteristics and timing differ markedly from the SAR plant used as the basis for computing posted rates. A case could be made that the more sophisticated IRP-based methodology should be used for all projects, especially those that are radically different than a gas-fired CCCT. I believe it is very reasonable to use the IRP-based methodology for wind or geothermal projects with a capacity of 10 MW or more because their generation is so different from the SAR's. If a different capacity threshold were chosen for each generation technology, or if a 10 aMW energy threshold were adopted, then I do believe certain technologies would be given a preference over others.

Q. Do you believe "nameplate capacity" is a reasonable way to define the 10 MW threshold?

A. No, I do not. Other parties in this case have pointed out the problems associated with this sort of a definition so I will not reiterate them here. I don't believe anyone in this case is advocating such a definition.

Q. Idaho Power has proposed that a "90/110 percent band" as described in Mr. Gale's testimony be used to

determine eligibility for posted rates. Using some examples, can you illustrate how such a concept would work?

A. To illustrate the concept, I have prepared Exhibit Nos. 102 and 103. Exhibit No. 102 illustrates three scenarios in which base energy prices (or the posted energy rates) are less than the market energy cost (or 85% of Mid-C prices). Scenario 1 shows the payment if the project produces exactly as expected. Scenario 2 shows the net payment in the event the project fails to produce at least 90 percent of its estimated monthly generation. Note that it is possible in this instance, if generation falls short enough, for the project to owe money to the utility if it fails to produce. Scenario 3 shows the net payment in the event generation exceeds 100 percent of the estimate. Exhibit No. 103 illustrates comparable scenarios, except in the instance where base energy prices (posted rates) exceed market energy costs (85% of Mid-C).

Q. Do you agree conceptually with the "90/110 percent band" concept as proposed by Idaho Power?

A. Yes, I do for the most part; however, I will propose modifications to the proposed contract terms that I believe are fairer to both parties. Wind generation is generally considered non-firm in the traditional sense because it is not possible to know in advance how much, if any, generation will be available. However, wind projects

are not all alike. Some larger, more sophisticated projects may have some ability to predict generation with varying degrees of accuracy. For example, a multi-turbine wind farm in a location with steady winds and good historical data may be capable of forecasting its generation to some extent, while a single, small "mom and pop" turbine is unlikely to have any ability to forecast generation. Idaho Power's proposal gives the opportunity to receive posted rates to those who can predict their generation with some certainty. Those who cannot would be relegated to selling power under Idaho Power's Schedule 86 for non-firm energy sales.

Q. Are there other ways besides establishing a "band" that could be used to properly discount the value of non-firm energy?

A. Yes, I believe there are. Many studies have been done in the past few years to attempt to determine the cost of firming non-firm wind energy. Exhibit No. 104 lists several recent studies. One of the purposes of these studies is to quantify the capacity value of wind generation and to evaluate the costs of integrating wind into utility systems. The studies usually assume that a gas-fired simple cycle plant must be built to provide backup capacity for those times when the wind plant cannot produce its rated capacity. The results of these studies

vary, but all conclude that there is some cost associated with integrating wind. The results often depend on assumptions about how much wind generation would be added in relation to the size of the utility's existing generation fleet, along with how much peaking capability the utility already has. The range of wind integration costs from various studies is from approximately $1.50 to $5.50 per MWh. Hirst's April 2004 study showed a very broad range of integration costs, from almost none for very small amounts of wind to as much as $14 per MWh for large amounts of wind. PacifiCorp's studies have estimated integration costs at $5.50 per MWh. Another way of looking at these integration costs is that they represent the decreased value of wind energy as compared to some other type of generation that does provide capacity whenever needed. As I will discuss later in my testimony, BPA began offering a wind shaping and storage service in which the costs of the service are based on BPA studies of wind integration costs. BPA charges $6.00 per MWH for its storage and shaping service for wind energy.

Q. Idaho Power proposes that projects be required to produce at least 90 percent of their estimated monthly generation in order to receive posted avoided cost rates. Do you believe this percentage is appropriate as a lower limit?

A. In the calculation of rates using the SAR, we assume a capacity factor of 92 percent. In other words, we assume that the gas-fired CCCT would operate 92 percent of the time. The remaining eight percent of the time, the plant would not be operational due to forced or unforced outages (e.g., scheduled maintenance is an example of an unforced outage; equipment breakdown is an example of a forced outage). Thus, there is a greater than 92 percent likelihood that the SAR would be able to generate at any specific time since unforced outages would reasonably be scheduled during times when the plant would not be expected to be needed. Requiring non-utility generators to meet the same standard in order to receive firm energy rates makes some theoretical sense, however, I do not believe that many potential projects could forecast their generation with such high accuracy.

Q. If you do not believe 90 percent would be attainable by most QFs, what do you suggest as an alternative?

A. First, I would recommend that a lower percentage be set. I believe 80 percent is reasonable. Idaho Power has been providing reports to the Commission since December 2002 showing statistics concerning its PURPA contracts. One statistic provided in the reports is a monthly comparison of contracted generation to actual generation.

In the past 19 months, Idaho Power's PURPA QFs have delivered an average of 71 percent of their contracted energy. None of the projects included in the summary have ever been held to their contract amounts, nor have any ever revised their original contract amounts based on amounts the project has proven able to deliver. With incentives to deliver at least 80 percent of their monthly generation estimates and periodic opportunities to revise the estimates, I believe that 80 percent is achievable by most projects.

Second, I would recommend that project owners be given more frequent opportunities to revise their monthly generation estimates than has been proposed by Idaho Power. Rather than an initial six-month revision opportunity followed by two-year intervals thereafter, I would recommend six-month intervals for the duration of the contract. That way, Idaho Power will at least have some certainty, but project owners will be able to adjust for the effects of expected water conditions.

Q. U.S. Geothermal witness Kitz states in his direct testimony that Idaho Power's draft contract makes no allowance for forced QF plant outages, yet he points out that in the event of a forced outage at one of Idaho Power's own plants, it could recover 90 percent of any resulting higher power supply costs through its PCA. What

is you opinion on this issue?

A. First, as stated by Idaho Power witness Gale and as included in section 14.4.1 of the draft contract, Idaho Power does, in fact, make an allowance for forced outages by allowing a 72-hour grace period during which the QF's inability to perform is excused. I believe it is completely reasonable to include provisions in the contract that excuse the QF during forced outages such as equipment breakdowns because this is consistent with the treatment Idaho Power's own plants receive through the PCA. However, a critical difference is that QF's are only allowed a 72-hour grace period, while the utility's is unlimited except to the extent it would be subject to Commission scrutiny in the PCA proceedings. To resolve this disparity in treatment, I recommend that the grace period for QF contracts be extended to 30 days. This would enable QF project owners time to diagnose problems, order replacement equipment and make repairs.

I do not believe that QFs should be held to as strict of delivery requirements as short-term firm energy purchases utilities routinely make with each other. However, I do believe it is reasonable to compare the firmness requirements of QFs to those of the utility's own generating resources.

Q. Complainants in this case have objected to Idaho

Power's proposed contract provisions that require developers to pay Idaho Power liquidated damages based on the additional market purchase expenses Idaho Power may incur if developers do not deliver 90 percent of the energy they have agreed to provide in any month. In response to the complainants' concerns about unlimited exposure to market prices, Idaho Power has offered to limit developers' exposure to a dollar per MWh amount equal to 150 percent of the net energy price for the month in which the shortfall occurs multiplied by the shortfall amount. Do you believe this is necessary, and if so, do you believe it is reasonable?

A. Yes, I do believe it is necessary to place a cap on the potential exposure developers would face in the event their project is unable to meet the lower band, whether the band is set at 90 percent or 80 percent. Furthermore, I believe that the 150 percent cap proposed by Idaho Power as described in Idaho Power witness Gale's Exhibit No. 202 is reasonable.

Q. What about the 110 percent upper bound? Do you think this is appropriate?

A. Again, I believe there is good rationale for imposing an upper bound, but I think it creates an unrealistically tight band. I would recommend that the band be symmetric with the lower bound; thus, I recommend

an upper bound of 120 percent.

Q. Are there ways for the non-firm output from a project to be firmed?

A. Yes, there are. One way is to purchase firming service. BPA has developed a service for regional public utilities that buy fixed amounts of power from BPA as well as for investor-owned utilities. The service integrates the wind energy and stores it in the hydropower system, delivering the power to the utility a week later in a steady, predictable supply. For this service, for utilities and other entities outside of the BPA control area, BPA charges $6 per MWh. BPA provides a similar service for publicly owned utilities within its control area at a cost of $4.50 per MWh. I have attached a brief description of BPA's wind integration service as Exhibit No. 105. Under BPA's program, participants are required to pay any wheeling charges to deliver power to and to receive power back from BPA's system. In addition, participants are responsible for the cost of any losses along the way. These charges would be in addition to the $6.00 per MWh storage and shaping charge, so the total charge to participate in this program could be much higher than $6.00 per MWh. For large wind projects or those easily able to deliver to and receive from BPA's control area, BPA's wind integration service may be a viable option, but I

acknowledge that this service is not realistic for small wind projects.

Another possibility is to use a battery storage system to store energy for short periods of time and deliver it later at a specific time and amount. I am not very familiar with this technology for large scale applications, but I have been told by Idaho Power personnel that a wind developer in Montana (the same developer who is responsible for the recently signed United Materials contract, IPC-E-04-01) has proposed to use such a system and sell the output to Idaho Power if a pricing mechanism can be devised to accommodate on-peak and off-peak pricing.

A project unable to perform within the band such as Idaho Power has proposed in this case might be able to use either of these two methods to firm its output in order to qualify for the posted avoided cost rates. The project owner would have to weigh whether it would be better to pay for a firming service or install batteries and receive posted energy rates, or whether the non-firm market-based rate (Schedule 86) would provide a higher rate.

Q. U.S. Geothermal witness Runyan discusses his client's negotiations with Idaho Power in which he alleges that Idaho Power had initially offered to purchase the first 10 MW of U.S. Geothermal's output at the posted avoided cost rate and any additional amounts at a

negotiated rate. He then goes on to explain that Idaho Power has since withdrawn its earlier offer and he suggests that U.S. Geothermal be "grandfathered" to allow it such a contractual arrangement if the Commission rules that the project is in fact larger than 10 MW. What is your response to his suggestion?

A. My position is that U.S. Geothermal should not be grandfathered. It is true that the Commission recently approved a contract for Renewable Energy of Idaho with a pricing scheme like the one described by Mr. Runyan. (See Case No. IPC-E-04-05, Order No. 29487). The Commission very reluctantly approved that contract, in part because of Idaho Power's stated inability to compute a rate using the prescribed methodology, in part because it did not wish to delay Renewable Energy's progress on completing the project and in part because it did not wish to penalize Renewable Energy for mistakes not of its creation. This case differs in that U.S. Geothermal has not presented a signed contract for Commission approval. In addition, I specifically remember telling U.S. Geothermal on one or more occasions that if it wanted to pursue a project 10 MW or larger, it must request that Idaho Power compute a rate using the IRP-based methodology. Finally, just because the Commission approved one contract with posted rates for the first 10 MW, I do not believe it should approve another. If it did,

all projects regardless of size could get posted rates for the first 10 MW and Schedule 86 rates for all excess generation. The size threshold would not matter except for determination of how much generation would be paid at posted rates. This approach would undermine the primary rationale for the IRP-based methodology for over 10 MW projects - that the IRP-based methodology produces more accurate results for large projects by being able to account for project specific generation characteristics.

Q. Idaho Power has included a "regulatory-out" clause (Section 23.2) in its draft contracts to U.S. Geothermal, Lewandowski and Schroeder that in effect permits Idaho Power to terminate its contractual responsibilities in the event deregulation is implemented in Idaho in the future and Idaho Power is denied full recovery of its QF contract costs. Do you believe such a clause is reasonable?

A. I do not support Idaho Power's insistence on inclusion of a "regulatory-out" clause in QF contracts. While I would not characterize the utility's attempt to include same as obstructionist or as anything other than good faith, I believe such a clause is unnecessary to protect the Company's economic interest and is further prohibited by PURPA and FERC regulations.

A utility has no discretion under PURPA as to

whether or not to purchase QF power. It is a federal obligation to purchase. Similarly, a QF is entitled to a fixed rate contract for sale of power over a fixed period of time. Once a QF contract and price are approved by the Commission, QF costs pursuant to that price are no longer at issue as to prudency.

The Company-proposed regulatory-out provision conditions termination on a change in state law resulting in Idaho Power being unable to fully recover in its retail revenue requirement all costs attributed to the QF purchase. The very next section of the Company-proposed firm energy sales agreement is a provision that conditions contract approval on a Commission declaration that all payments made to Idaho Power be allowed as prudently incurred expenses for ratemaking purposes. This provision alone gives the utility all the assurance it should require regarding the recovery of costs. The QF is also entitled to certainty, a certainty that it will receive a fixed price and stream of revenue through the life of the contract, without a re-opener clause, without rate revision, and assuming compliance with contract terms and conditions, without termination. The QF should not be denied the certainty of an arrangement and the benefits of its commitment as a result of changed circumstances.

Staff attorney informs me that the proposed

regulatory-out clause gives the Commission continuing jurisdiction over the avoided cost rate and subjects the QF to the same "utility type regulations" precluded by PURPA Section 210(e); implementing FERC regulations, 18 C.F.R. § 292.602(c)(1); by federal Courts; by State Supreme Courts and by the Idaho Supreme Court.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes, it does.

# NON-UTILITY GENERATION OPTIONS FOR POWER SALES TO IDAHO POWER

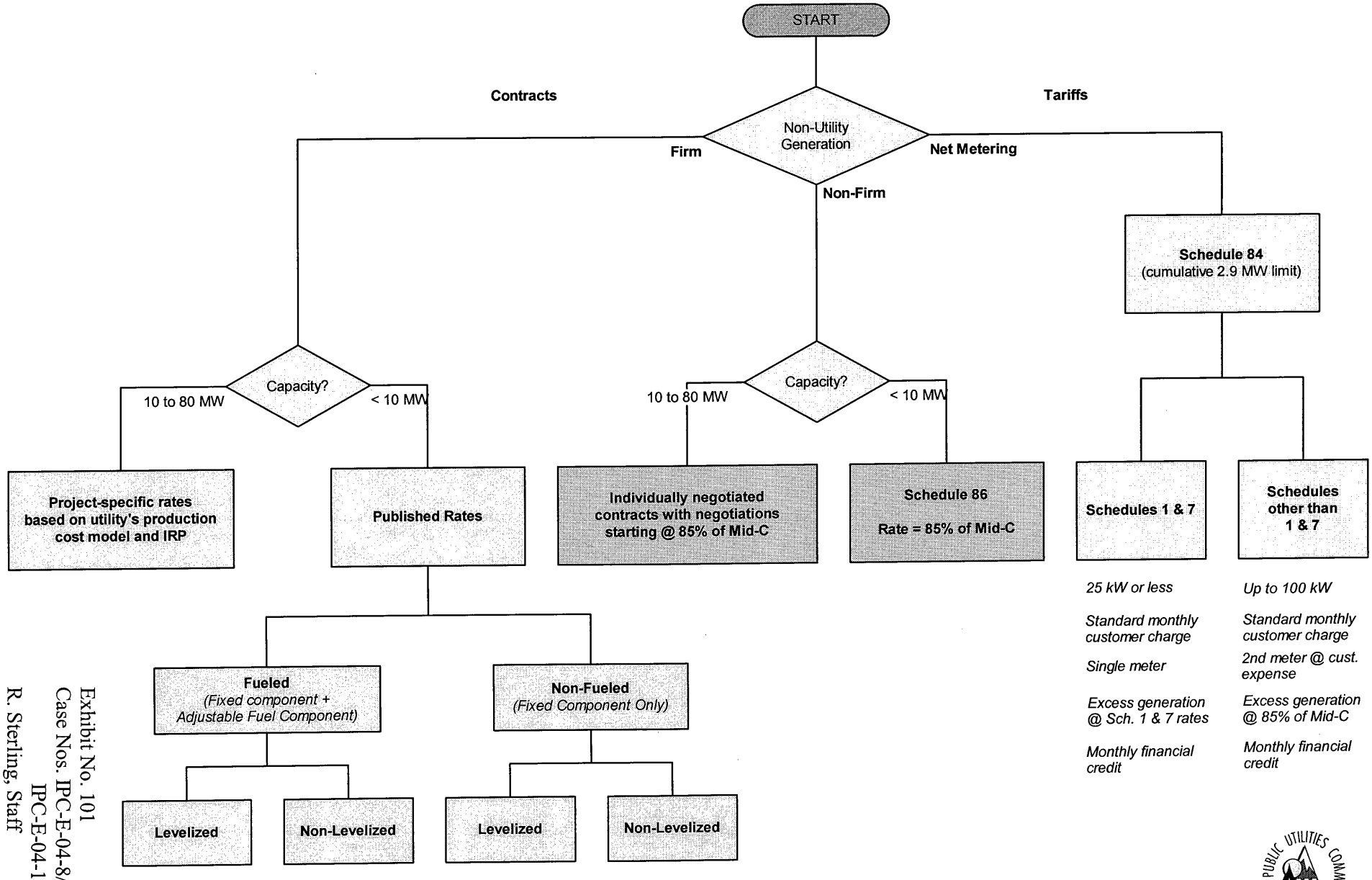


Exhibit No. 101
Case Nos. IPC-E-04-8/
IPC-E-04-10
R. Sterling, Staff
8/05/04

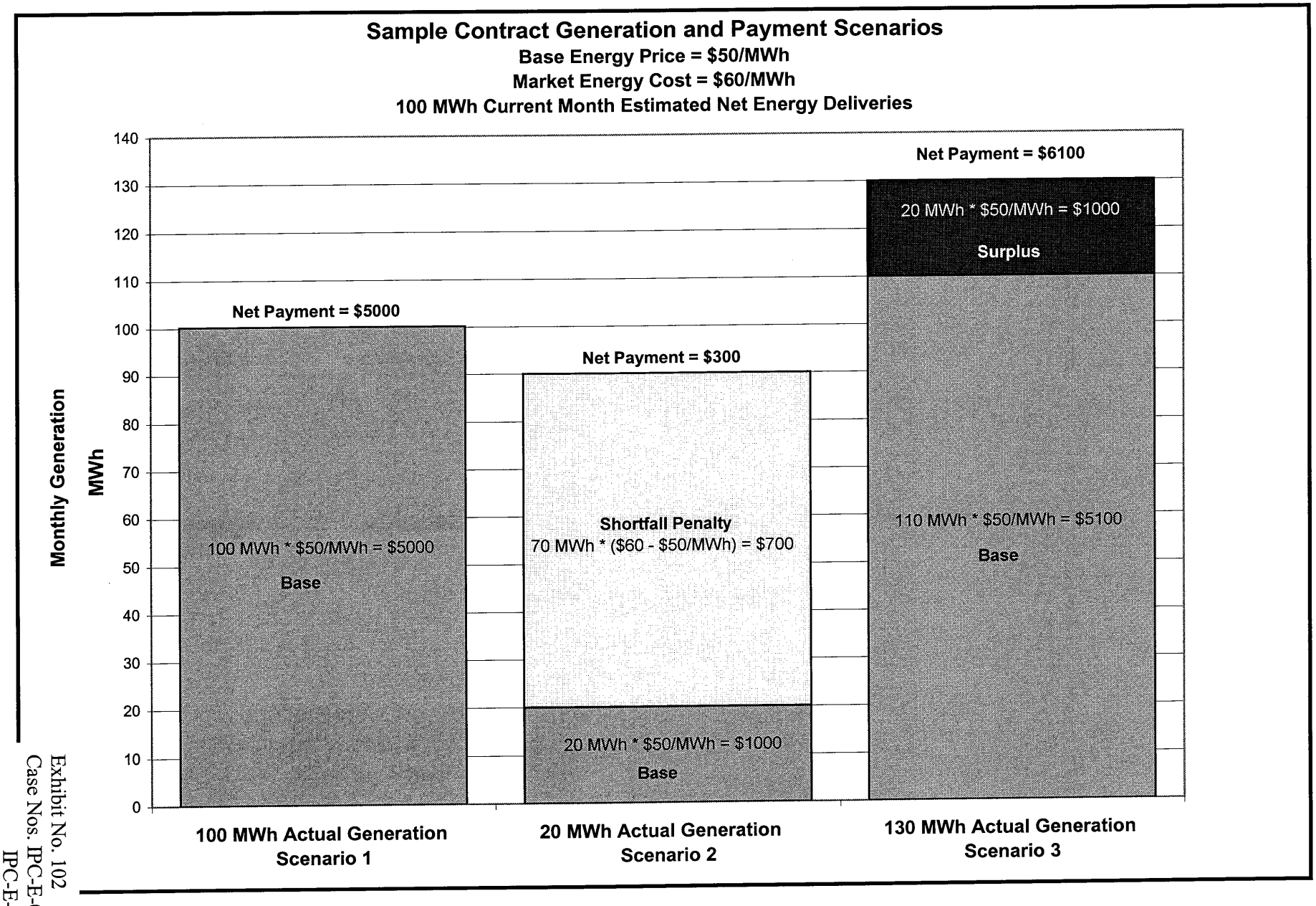


Exhibit No. 102
Case Nos. IPC-E-04-8/
IPC-E-04-10
R. Sterling, Staff
8/05/04

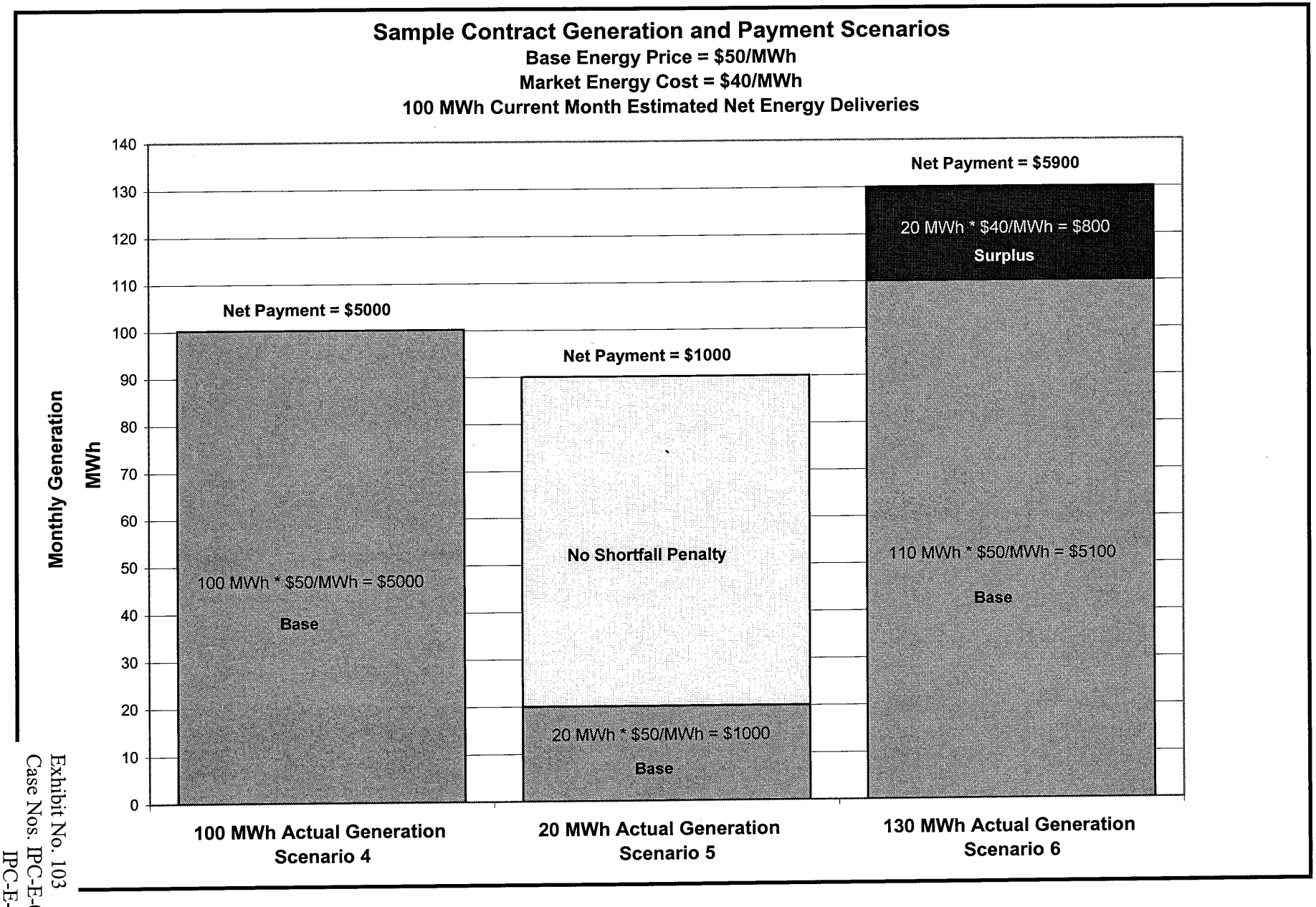


Exhibit No. 103
Case Nos. IPC-E-04-8/
IPC-E-04-10
R. Sterling, Staff
8/05/04

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Exhibit No. 104
Case Nos. IPC-E-04-8/
IPC-E-04-10
R. Sterling, Staff
8/05/04

# BPA Wind Integration Services

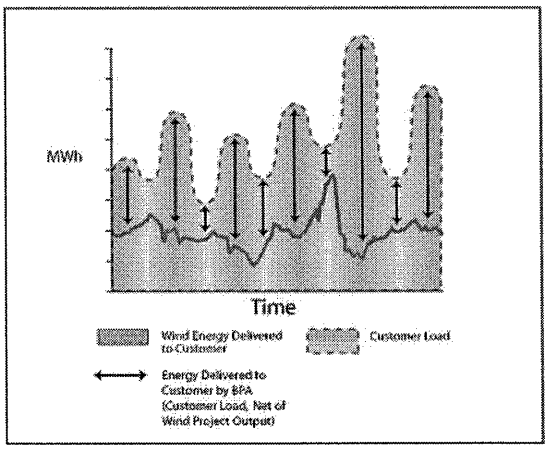
Over the past two years, BPA has undertaken an extensive research and development effort to evaluate the costs and opportunities associated with integrating wind energy into the Federal Columbia River Hydroelectric System (FCRPS). This evaluation phase is now complete and we are pleased to announce two new services that will utilize the flexibility of the hydro system to integrate wind energy into our control area on behalf of electrical utilities in the Pacific Northwest. BPA has established a goal of providing up to 450 MW (nameplate) of wind integration services over the 2004-2011 time period. At least 200 MW of these services will be earmarked for public power customers.

## Network Wind Integration Service

Network Wind Integration Service has been designed to serve the needs of public power customers with loads embedded in the BPA control area who elect to purchase all or a portion of their power from a new wind resource. Once the customer has (a) signed a bilateral power purchase agreement with a new wind resource, (b) procured firm transmission and (c) determined a scheduling agent for the power, the BPA Power Business Line will use its hydro system to integrate the scheduled output of the resource with the customer's load. The scheduled energy from the wind resource will offset an equal amount of HLH and LLH PF energy that BPA otherwise would have provided. BPA will continue to meet and follow the customer's load at all times, including during those periods when there is no output from the wind resource. The customer's PF demand billing determinant will not be reduced for the amount of wind generation scheduled to its load on the hour of the generation system peak. BPA PBL cannot count on the generation being there and thus must hold sufficient generating capacity available to fully back up the resource. The PF Load Variance charge will continue to be based on the customer's Total Retail Load, so will not be reduced by the amount of wind generation.

The customer will be charged a fee of $4.50/MWh for all scheduled energy that BPA integrates into its system. This fee may be subject to annual escalation depending on the length of the requested contract. For contracts that extend beyond the current rate period, the fee will be escalated at the rate associated with the Gross Domestic Product Implicit Price Deflator, which is the same index used to escalate the Federal Production Tax Credit for wind.

Network Wind Integration Service




### *Transmission*

With respect to transmission, customers will be able to import power from new resources using their NT transmission rights. BPA will work with public power customers and wind project developers to identify regions of the BPA grid best suited for wind development with respect to the availability



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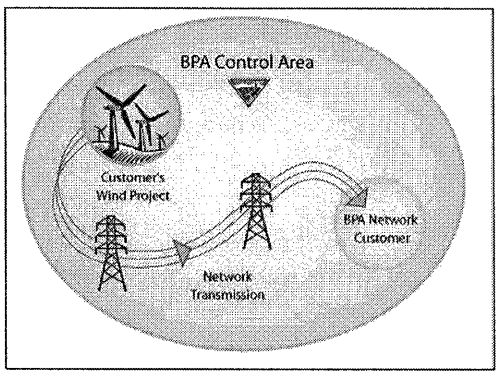
of firm transmission. BPA plans to take an active role in developing a diversified portfolio of regional wind resources. This diversification will be a key factor in increasing the amount of wind energy selling into the BPA grid.

Network Wind Integration Service
Transmission




One Transmission Wheel Using Customer's Network Transmission Rights

### Scheduling and Generation Imbalance

The customer (or its scheduling agent) will be responsible for transmission arrangements and for scheduling the wind output from the point where the generation is integrated into the BPA transmission system to a point of delivery where the customer's system interconnects with the BPA transmission system. Generally, the customer will need to request a new Point of Receipt under its NT transmission contract and there is no guarantee that firm transmission capacity will be available.

The wind project operator or its scheduling agent will provide the Transmission Business Line with a Day-Ahead Generation Estimate followed by revisions up to 30 minutes before the start of the hour if changes are required. The project operator will be responsible for paying the BPA TBL Generation Imbalance charges for deviations between wind project actual generation and the Generation Estimate. Whether the project operator directly assigns these generation imbalance costs to project participants or not will depend on the specific contractual agreements between those entities. Accurate wind forecasting will minimize these charges. If changes are made to the Generation Imbalance tariff in the future, these changes will be amended to the Network Wind Integration Service Contract.

## Storage and Shaping Service

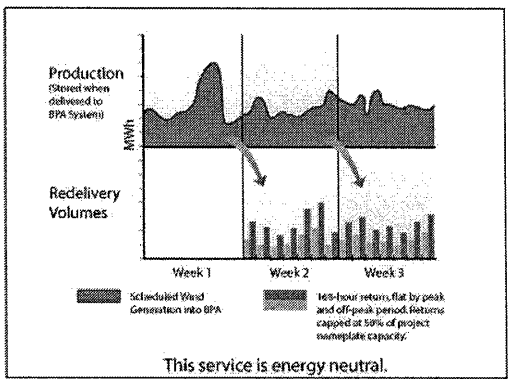
Storage and Shaping Service has been designed to serve the needs of utilities and other entities outside of the BPA Control Area who have chosen to purchase the output of a new wind resource but do not want to manage the hour-to-hour variability associated with the wind output. To facilitate such an arrangement, BPA's Power Business Line will take the hourly output of new wind projects physically located and/or scheduling directly into the BPA Control Area, integrate and store the energy in the Federal hydro system, and redeliver it a week later in flat peak and off-peak blocks to the power purchasing customer. In order to help reduce transmission costs, returns will be capped at 50 percent of the participant's share of project capacity. The base charge for storage and shaping service is $6.00/MWh, escalated annually at the GDP Implicit Price Deflator.

### *Transmission*

Storage and Shaping Service is for energy delivered *to* and *from* the BPA system. Thus, two transmission wheels are required to receive the service. Generators will be responsible for Generation Imbalance charges for generation scheduled into the BPA system. BPA expects that the transmission arrangements will vary from project to project, depending on (a) the

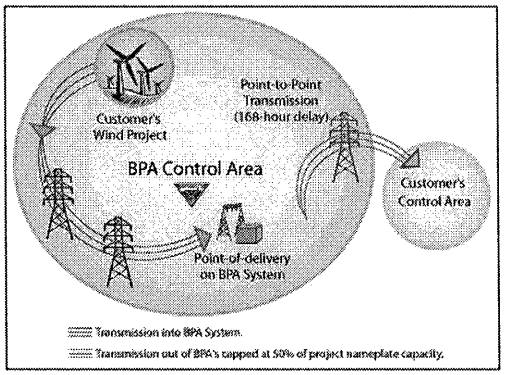
locations of the project and the end-use buyer, and (b) the availability of firm transmission along both transmission paths.

Storage & Shaping Service
Power Redelivery




BPA is committed to working with potential customers to minimize the transmission costs associated with Storage and Shaping Service. So far, we have been able to limit the cost of the wheel out of our system by agreeing to cap returns at 50% of the nameplate rating of the participating project. During periods when generation exceeds the 50% threshold (i.e. greater than 50 MW on a 100 MW project), BPA will bank this excess energy in a storage account. When generation falls below the 50% threshold, BPA will draw from the Excess Energy account and redeliver additional quantities above and beyond the current redelivery obligation. This will reduce the amount of transmission required to move the stored energy out of the BPA system. We are also examining a number of potential cost-saving approaches to the transmission wheel into our system.

Storage & Shaping Service
Transmission




Customer purchases point-to-point transmission out of BPA's Control Area into their own area.

BPA plans to work closely with project developers, Investor Owned Utilizes and other entities with well-developed and active purchasing plans to help determine which projects can be most efficiently integrated into the BPA system. Siting projects in areas of the grid with minimal congestion and in a way that takes advantage of regional diversity in wind patterns is essential to the growth of cost-effective wind energy in the Pacific Northwest.

***For More Information***

To learn more about Network Wind Integration Service or Storage and Shaping Service, please contact your PBL or TBL Customer Account Executive or the BPA PBL Renewable Power Group at (503) 230-3530. We look forward to working with you on these exciting new services.



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# CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 5TH DAY OF AUGUST 2004, SERVED THE FOREGOING **DIRECT TESTIMONY OF RICK STERLING,** IN CASE NOS. IPC-E-04-08 / IPC-E-04-10, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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