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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO RATEBASE THE INVESTMENT REQUIRED FOR THE REBUILD OF THE SWAN FALLS HYDROELECTRIC PROJECT.	)	**CASE NO. IPC-E-90-2**

DIRECT TESTIMONY OF THOMAS FAULL

IDAHO PUBLIC UTILITIES COMMISSION

NOVEMBER 9, 1990

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

A. My name is Thomas Faull and 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 Public Utilities Engineer.

Q. Have you included a statement of your qualifications in this testimony?

A. Yes. Exhibit No. 101 is a statement of my qualifications.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the cost effectiveness of Idaho Power Company's (IPCo's) proposed project, to provide an engineering opinion as to the appropriateness of the project, and to recommend Commission action relative to the project.

Q. What is your understanding of the purpose of this case?

A. I believe the purpose of this Case is to determine whether the project concept is sound enough to authorize IPCo to proceed with project development. The purpose is not to determine whether to grant at this time rate base treatment of unknown future costs

of the Swan Falls Power Plant upgrade.

Q. Why is it important to know the cost effectiveness of a project when determining whether or not to authorize continued project development?

A. It is important to know the relative cost effectiveness of a specific project to judge the potential value of the project to ratepayers.

Q. Are there other criteria that should guide the Commission in accepting or rejecting the Swan Falls Plant concept for future rate making analyses?

A. Yes. As discussed by Staff witness Eastlake, there may be features (intrinsic, extrinsic, or both) other than project costs that should be considered. However, I believe the primary guideline ought to be cost effectiveness, with consideration of other factors being supplementary.

Q. What is the starting point for analyzing the cost effectiveness of this project?

A. First, one must attempt to quantify the construction cost of the project, then translate that cost into a unit cost of generating energy.

Q. What do you estimate the cost of this project will be?

A. Rather than estimating the construction cost of the project, I have accepted IPCo's proposed

cap on capital costs of $80,285,000 as a maximum (or worst-case) cost. Then, from that I estimate the 50-year levelized cost to ratepayers for this project will be $73.05/MWh.

Q. Why did you use a 50-year life rather than some longer or shorter period?

A. Fifty years is an arbitrary but common life over which to analyze the value of hydro electric projects. I looked at, but rejected three other project life lengths: 1.) The 17 years that will be left to the FERC license at the time the plant comes on line in 1993 ($84.72/MWh), 2.) a longer arbitrary but also commonly used life of 60 years ($72.57/MWh), and 3.) a shorter arbitrary but also commonly used life of 40 years ($73.88/MWh). As these numbers show, there is little difference among the 40-, 50-, and 60-year estimates.

Although the 17-year life corresponds to IPCo's maximum assured right to operate a plant at the project site, I believe it is reasonable to use longer lives for economic comparisons because if IPCo is unable to obtain a renewal of the license as a result of losing the site to a competitive applicant, it would be entitled to receive any unrecovered value remaining in the plant from the new licensee. Of the three

potential arbitrary life lengths I considered, I chose 50 years because it is, I believe, the most commonly accepted hydro project life used for analyzing and rate basing IPCo projects. Using 60 years, 40 years, or any of a wide range of arbitrary project life lengths would be equally as reasonable as using the 50 year life that I chose, provided the analytic life does not exceed the reasonably expected physical life of the plant. However, if project costs are approved for rate making purposes based on an economic analysis, the depreciation period for rate making purposes should correspond to the economic life used in the economic analysis -- in this case 50 years.

Q. How did you determine the unit costs you cite?

A. I used a "net present value" computer model similar to the one IPCo used to evaluate its Milner Plant. In addition to the Swan Falls capital cost cap, I input the following key data as variables.

- The average annual generation from the plant as included in IPCo's second amended FERC license application, using 60 years of historic water data (166,102 MWh/yr);

- the capital structure and rates required by Order No. 23357 for determining avoided cost rates (11.447%);
- tax variables used by IPCo in its evaluation of the Milner plant, operating and maintenance (O&M) costs of $450,000 ($18.00/kW);
- an escalation rate of 4.5% per year;
- a property tax rate of 0.7381% of capital costs;
- insurance costs of 0.06854% of capital costs;
- FERC licensing costs of $60,743 (the reported cost of IPCo's licensing activities relative to the Milner Plant, which is probably lower than that of the Swan Falls Plant);
- a kilowatt-hour tax rate of 0.5 mills/kWh; and
- values of 25.00/58.27 times the amount recommended by IPCo for its Milner Plant to estimate the expenses associated with headwater benefit payments, environmental mitigation, and water bank payments.

Q. Can you further explain the analysis by which you estimated annual O&M costs?

A. Yes. Using pp. 406-A through 407-B of IPCo's FERC Form 1, I determined the rated capacity, net generation, and variable operating cost for each year from 1985 through 1989, inclusive, for each of

IPCo's 14 major existing hydro electric plants. Using Consumer Price Index (CPI) data and the escalation rates required in Order No. 23357 for future years, I adjusted the cost data to 1992 dollars. I then computed the cost per kW of rated capacity for each year for each plant. After a subjective determination that the variation from year to year of the costs per kW of capacity was acceptable, I averaged the 5 years of data for each plant. I then graphed the cost per kW relative to the rated capacity. The resulting graph is included as Exhibit No. 102, and the data from which Exhibit No. 102 were derived are included as Exhibit No. 103.

As can be seen from Exhibit No. 102, the data yield a relatively smooth curve, except for one significant hydro plant, so it is reasonable to interpolate between data points provided there is a reasonable explanation for the aberrant plant. The aberrant plant is Swan Falls, which is substantially more expensive to operate than would be expected in comparison to IPCo's other plants. Although I didn't confirm it, I assumed that the excessive cost of Swan Falls is due to its remote location and antiquated control system. Thus, it is apparent from the graph (Exhibit No. 102) and the data from which it was

developed (Exhibit No. 103) that one should expect IPCo to experience O&M costs of about $18/kW for a 25 MW hydro plant. This is the rate I used in my analysis of the Swan Falls Plant.

Q. According to Order No. 23357, the maximum avoided cost rate available to Qualifying Facilities (QFs) in Idaho (as defined under the Public Utility Regulatory Policies Act of 1978 (PURPA)) coming on line in 1993 is $61.44/MWh. In light of this, do you consider your estimated cost of $73.05/MWh to represent a cost effective project for IPCo's ratepayers, at least as compared to avoided cost rates?

A. Yes, I do. For at least three reasons, the published avoided cost rates are not appropriate for direct comparison to a cost estimate of a specific project. First, the computer model that computes the published avoided cost rate assumes a "first deficit year" (i.e. year of new resource need) of 1993 for IPCo. I currently believe that, as clearly explained in IPCo's petition for reconsideration in Case No. IPC-E-89-11, the correct first deficit year should have been 1994. Based on the assumption that the Commission will authorize this change, I have

determined that the comparable avoided cost rate (without "tilting") would be $59.17/MWh.

Second, the published rates include an adjustable portion of $8.78/MWh that will be adjusted in the future based on actual operating costs of the Colstrip coal fired generating plant. For direct comparison to an actual project the adjustable portion should be assumed to escalate at the same rate as comparable costs associated with the actual project. When this adjustment is made the comparable 20 year avoided cost rate (without "tilting") is $64.77/MWh.

Third, even as adjusted above, the published avoided cost rates apply only to projects with a 20 year availability to IPCo. Although there have been numerous arguments made about the unfairness of limiting QF contracts and their rates to 20 years, nonetheless, from a ratepayer viewpoint, IPCo's 50-year project should be compared to 50 years of avoidable costs. That is, when IPCo builds a resource with a 50 year life ratepayers can reasonably expect that they will have access to the energy from that resource for the full 50 years, so other resource costs can be avoided for the full 50 years.

Using the Surrogate Avoidable Resource (SAR) methodology specified by the Commission,

assuming a new SAR will be built at the end of the 35-year life of the first SAR, assuming a first deficit year of 1994, assuming that the adjustable portion will escalate, and assuming an on-line year of 1993 yields a 50-year avoided cost of $70.54/MWh. Taking into account the seasonality weighting of avoided costs relative to the availability of the Swan Falls Plant reduces the value of the avoided costs applicable at Swan Falls to $69.48/MWh. I believe this is the appropriate avoided cost rate to use for determining the cost effectiveness of the Swan Falls Plant.

Thus, the Swan Falls Plant, with an estimated cost of $73.05/MWh, is approximately as cost effective as the comparable avoided cost rate, within the reasonable limits of accuracy for the methodologies used to determine the costs and rates. (73.05/69.47 = 105.2%)

Q. You indicate that there has been a Petition for Reconsideration of Order No. 23357 filed that could affect the "first deficit year" of the avoided cost computation. Are there any other issues pertinent to that petition that might affect the avoided cost rate comparable to the Swan Falls Plant?

A. There is a potential that a mathematical error made in Case No. WWP-E-89-6 will cause a change in the estimated cost of transmission construction in that case and that the WWP transmission cost change will flow through to Case No. IPC-E-89-11, thus sightly reducing the avoided cost rates comparable to the Swan Falls Plant. I would expect that change to be less than 3% of avoided costs. Otherwise, I believe that none of the issues pertinent to the Petition for Reconsideration of Order No. 23357 will affect the avoided cost rate that is comparable to the Swan Falls Plant.

Q. You discuss the Swan Falls Plant as though IPCo could avoid all the costs of the project by simply walking away from it. Isn't it true that IPCo must incur costs at the Swan Falls site no matter what course of action it chooses?

A. Yes. Even if IPCo were to decide to abandon the Swan Falls site, it would be required to return the site and reservoir area to a condition approximating natural conditions. This would be an expensive undertaking, making the abandonment option totally impractical. However, if this was the only option to the proposed Swan Falls upgrade, these costs would have to be subtracted from the upgrade

construction costs for avoided cost analysis because they would be non-avoidable costs. Nonetheless, these costs could be avoided by selecting some different, more practical alternative to IPCo's proposed Swan Falls upgrade.

The most practical alternatives to the proposed project are either an up-(down-)sizing of the proposed plant or an alternative stabilization method for the powerhouse that permits using the existing turbine bays for new or modified turbines. The up-(down-)sizing option is just a matter of project optimization and will be discussed later. But the option of using the existing turbine bays presents a more complex situation. In that case, powerhouse stabilization can be expected to be more expensive and net annual generation can be expected to be less. It is difficult to guess whether this option would have presented a more cost effective solution to the Swan Falls problem, but the comparison could only be made by comparing the projected unit costs of the most optimal arrangement of the options.

In any event, with that in mind it could easily be argued that, regardless of which option is being considered, historic preservation costs and dam/powerhouse stabilization costs are unavoidable.

Had I used this approach, I would have reduced Swan Falls capital costs by about $4,000,000 (5%), thus improving the cost effectiveness of the project.

Q. Suppose for a moment that, as a result of this (or some future) proceeding, the estimated cost of the Swan Falls Project is found to be substantially greater than your estimate or the comparable avoidable costs are found to be substantially less than your estimate. For example, assume that the Commission determines that the Swan Falls costs should be compared to the interim 20-year avoided cost rates in effect prior to Order No. 23357. Under those conditions, would you still consider the Swan Falls Project to be cost effective?

A. No. Under those circumstances I believe IPCo should be limited in its recovery to the Commission determined comparable avoided cost rate.

Q. Other than using pre-Order No. 23357 avoided cost assumptions, are there any obvious conditions that might be found appropriate for reducing the comparable avoided cost rate for evaluating the Swan Falls Plant?

A. Yes. The computation of avoided cost rates for purpose of evaluating capacity and energy to be purchased under PURPA specifically excludes the use

of projected future purchases of QF power and demand side resources (conservation) for estimating the first year of power need for each utility. Although this is appropriate for PURPA applications (as explained elsewhere, including in Order No. 22636), it could easily be argued that it is not appropriate for evaluating the utilities' proposed resources.

This is especially true in the case of conservation resources. The Commission has been encouraging Idaho utilities to acquire cost effective conservation resources for years, but with little avail. Now, when it appears that new resources are needed, the utilities have little conservation "on-line", and are essentially unprepared to aggressively bring such resources on line. Therefore, it appears inequitable to ascribe a benefit to IPCo in evaluating its supply side resources by ignoring the utility's apparent negligence in acquiring demand side resources. I believe the Commission should consider imputing prior and future demand side resource acquisition to IPCo's avoided cost computation for the purpose of evaluating proposed utility owned supply side resources, including the Swan Falls Plant.

Q. Wouldn't limitations such as described in your two prior answers unfairly deny IPCo from recovering prudently incurred investment costs?

A. No. IPCo made its decisions, commitments, and contracts relative to this project while fully aware of the interim avoided cost rates, while arguing for future avoided cost rates substantially less than those included in Order No. 23357, while fully aware of the Commission's position on cost effective conservation resources, and while fully aware of the SAR methodology ordered by the Commission. Therefore, based on the knowledge and assumptions that IPCo was publicly espousing at the time it made those decisions, commitments, and contracts relative to this Project, they appear, on their faces, to have been imprudent. It is only as a result of chance that it now appears that those decisions may have turned out to be marginally prudent (at least as determined by my analyses). Therefore, if it is determined that my analyses are in error and that the Swan Falls Project costs are ***not*** competitive with avoided costs, IPCo should be imputed to have known that the project was not cost effective, at least to the extent that Swan Falls costs exceed avoided costs using the assumptions included in IPCo's

recommended avoided costs in Case No. IPC-E-89-11 and, perhaps, imputed conservation resource acquisitions.

Q. In your statement of purpose you said that you would "...provide an engineering opinion as to the appropriateness of the project...". What did you mean by that?

A. I meant that in addition to providing an analysis of the cost effectiveness of the project as proposed by IPCo, I would provide an engineering opinion relative to the IPCo proposal being the most cost effective development from the family of reasonably potential developments at the site -- that is, an opinion as to whether I believe IPCo has provided the most cost effective development practicable for this resource.

Q. What is your opinion in this regard?

A. Before answering that question, I should make two important qualifying points. First, it is much easier to second-guess the quality of a project after someone else has spent the money and labor to develop it than it is to actually do the development. Second, it appears that IPCo has made a substantially greater effort to control costs on this project than on many of its prior power supply developments.

Nonetheless, bearing those two caveats in mind, it does not appear to me that IPCo has made the same level of project optimization effort that one would find in a QF development. The most glaring weakness that I find in the project is that the Swan Falls Plant appears to have been under-sized for the flows at the site. The overall average capacity factor of the project is more than 72%. The standard in the industry is typically for overall capacity factors of between 45% and 65%.

Although I cannot say with certainty that a higher capacity plant (yielding a lower capacity factor) would be more cost effective, I believe it would. Most of the civil costs of this project are fixed, regardless of the mechanical and electrical capacities of the turbine-generators. Therefore, it is very likely that the increased costs of up-sizing the plant to yield about a 50% plant factor would be more than recovered over the life of the project.

Note that the average generation estimated by IPCo in its license application (and accepted by me for economic analyses) results from analysis of historic river flows, ignoring the possibility that future flows may be reduced due to

consumptive uses upstream of Swan Falls. Although this may be the reason IPCo sized the proposed plant at 25 MW rather than something larger, it ignores the possibility that Swan Falls flows may increase (rather than decrease) in the future due to increased irrigation efficiencies on upstream farms. Furthermore, IPCo's sizing of the Swan Falls Plant is contradicted by its sizing of the proposed Milner Plant, which has a capacity factor under 35%. If IPCo expects future flow reductions in the Snake River due to consumptive use developments, surely it must expect at least a few of those developments to be upstream of the Milner site.

Another criticism I have of the Swan Falls project costs as now estimated is the type of mechanical technology selected. IPCo has specified a system known as a modified bulb turbine for this project. Bulb turbines and modified bulb turbines have been around for years and are advertised as very cost effective for low head sites such as Swan Falls. Although there are good physical reasons why bulb-type systems should be the most cost effective technology available for low head sites, my experience has been that vertical shaft kaplan turbines and S-type turbines are always more economical than bulb

turbines, even though they require more draft tube excavation. Although I have no evidence that modified bulb turbines are not the most cost effective technology for the Swan Falls Plant, it is my understanding that IPCo did not make a rigorous comparison to assure that they are.

A third criticism I have of the Swan Falls project costs as now estimated is that IPCo appears to be using the standard firm bid process to procure equipment and construction services, rather than the more cost effective request for proposals (RFP) and negotiation process. Although the bidding method is immune to administrative challenge because it appears to result in supplier competition, my experience has been that it actually stifles competition and results in higher costs; especially on large, complex projects such as the Swan Falls Plant.

There are several reasons for this. Foremost among them is that in preparing requests for bids the design engineer is constrained to "guessing" about the best combinations of size, arrangement, and timing, with minimal input from suppliers; whereas in competitively negotiated contracts based on RFPs the suppliers are challenged to provide their most innovative combinations with fruitful give-and-take

discussions between supplier(s), the owner, and the engineer. In my experience, this method almost always results in better projects at lower cost. Furthermore, it reduces the probability of suppliers receiving cost over-run payments for extra work, unexpected conditions, and ambiguous contract language being construed against the owner (the risk of over-run payments is reduced in this case because the contract is drafted jointly by all parties, not just the owner).

An example of the limitations inherent in the firm bid system can be seen in IPCo's acquisition of the Swan Falls Plant's speed increaser. I understand that, based on subjective considerations, IPCo specified a concentric shaft speed increaser with helical gear teeth, using a specific manufacturer's design (perhaps the only supplier of that technology) as the standard to meet for determining bid responsiveness. The specification presumes, by definition, that this technology is the most cost effective for the application. Although that presumption ***may*** be true, there is no way to be assured that it is. Under an RFP procurement method, suppliers would have proposed competing technologies as well as competing prices. Then IPCo could have

negotiated the trade-offs between their preconceived preferred technology and the simpler, less expensive technologies to assure that the purchased equipment was, in fact, the most cost effective.

Another example shows up in the limited number of suppliers asked by IPCo to bid on the turbine-generator package for the Swan Falls Plant. It is probably reasonable under the firm bid methodology that IPCo limited the list of potential bidders to the four known suppliers of the type of equipment specified. However, under the RFP method there would have been a much larger number of potential suppliers. Competition between other suppliers and other technologies would have encouraged manufacturers of modified bulb turbines to propose their very best combination of technologies and prices. Under the firm bid method actually used by IPCo, all four bidders knew their competition's approximate costs, present work loads, and the approximate extent of interest in the project. (The results of this particular bid process currently appear to be three "courtesy" bids and one serious, but not "hungry", bid.)

Q. Do you propose that project costs should be disallowed for ratemaking purposes because you believe IPCo has not optimized its Swan Falls resource?

A. No, at least not at this time. My speculative criticisms do not provide ***evidence*** of imprudent management. I merely include this part of my testimony to provide support for the position that IPCo should be held to a standard of avoided cost to cap the ratemaking allowability of new resource costs, and should have a heavy burden of proof to fully justify its design and construction decisions prior to such costs being allowed for rate making purposes. Clearly the Swan Falls Plant could not be developed as proposed by IPCo if its costs had to be recovered under a QF contract, even under the rates included in Order No. 23357 (which IPCo claims are too high). Furthermore, it is my professional opinion that the Swan Falls site may have been developable under the 23357 rates by a QF developer, albeit only after hard-nosed negotiations and extensive design modifications.

However, because it would be nearly impossible to provide evidence to prove that IPCo had not provided the optimum development for the resource, the Commission is limited to using avoided cost as the

imputed surrogate for identifying prudent decision making. The utility is perfectly able to determine how its proposed projects stack up against comparable avoided costs and it is perfectly capable of estimating the risks that its cost estimates may be low, so it should be held accountable for keeping its costs below those comparable avoided costs. Ratepayers should not be held at risk for utility executives' poor decision making beyond what has clearly been established as achievable costs -- in fact costs the utility claims are excessive (i.e., avoided cost). It's bad enough that it is impossible to identify and reject sub-optimal features that cause excess costs that are below avoided costs.

Q. What are your recommendations in this case?

A. I recommend that, based on the estimate that the Swan Falls Project (as proposed by IPCo) could possibly provide energy at less than avoided costs, the Commission find that the Swan Falls Hydro Electric Plant concept is competitive enough for costs incurred in developing the project to be potentially reasonable for future rate making consideration, with the specific caveat that costs in excess of the appropriate comparable avoided cost rate (to be

determined in future proceedings) are, by definition, imprudently incurred. I further recommend that the Commission advise IPCo that this Certificate in no way implies that all costs incurred in developing the project are necessarily prudent, but that the Commission will review all costs so incurred at a later date and will determine at that time whether IPCo's execution of the project was prudent in light of the generally accepted standards of the hydro electric construction industry. In determining the comparable avoided cost rate the Commission should consider and estimate all non-quantifiable risks.

Q. What kinds of non-quantifiable relative risks should be considered, and how?

A. A few of the "relative risks" that come to mind immediately are, for the Swan Falls Project, the risk that future Snake River flows at the site may be more (less) than the historic flows, that the Swan Falls water rights play a pivotal role in IPCo's system-wide hydro electric operations and their loss could severely reduce generation at other Snake River power plants, and that the environmental impacts of the project may be more (less) than expected. For potential thermal projects that could compete economically with the Swan Falls Project, a couple of

the "relative risks" that come to mind immediately are the risk that future fuel will be unavailable, undeliverable, or more (less) expensive than expected, and that the environmental impacts of such a project may be more (less) than expected.

Because such risks are unquantifiable, decision makers must make their own best estimate of the level and impact of each of the potential occurrences actually happening and then decide how to factor that risk into granting or denying Certification and/or rate making application of project costs. With adequate evidence, the Commission could convert its estimates into approximate costs for comparison purposes.

For example, it is currently taken as an historic axiom that hydro plants have "always" been more cost effective than thermal plants, so we should expect them to be more cost effective in the future. However, on careful reflection, it becomes apparent that the reason hydro has been more cost effective than thermal is that fuel costs have escalated much more rapidly than expected. Thus, the critical question when comparing a specific hydro plant to potential thermal plants is "How does the probability that we have over (under) estimated water flows

compare to the probability that we have over (under) estimated fuel costs?". The answer to this question could be assigned an estimated cost value for comparing potential projects.

Q. Doesn't the consideration of relatively unquantifiable risks invalidate the concept of using avoided cost as the only implied surrogate for estimating prudent project selection and management?

A. Yes, slightly. Rather than using avoided cost as the only measure of prudence, the Commission should use avoided cost as the ***presumed*** measure of prudence. Thus, as part of its application for rate making treatment of any project, a utility should be expected to justify projected generation costs that exceed avoided cost. That justification would be in addition to justification for other factors and conditions such as project size, contract over-runs, type(s) of technology selected, method of project management, etc. Whether the Commission should attempt to quantify its judgments on these issues should be determined after accumulation of the appropriate evidence impacting those judgments.

Q. Does this conclude your testimony?

A. Yes, it does.

QUALIFICATIONS
OF
Thomas G. Faull, P.E.
of the
Idaho Public Utilities Commission

Mr. Faull received a Bachelor of Science degree from the University of Idaho in 1970. His major was Mechanical Engineering with emphasis on Nuclear Engineering and Stress Analysis. His minor was Business Administration with emphasis on Economics and Management.

PROFESSIONAL REGISTRATIONS AND HONORS:

Mr. Faull is a member of Sigma Tau, the collegiate engineering honorary society. He has received registration to practice Professional Engineering in the following states:

1974: Idaho; Mechanical
1975: Colorado; General
1977: New Mexico; General
1979: Oregon; Civil

He is also registered to practice before the U.S. Office of Patents and Trademarks as a Patent Agent.

PROFESSIONAL EXPERIENCE:

A. From 1970 through 1978, Mr. Faull worked for the U.S. Bureau of Reclamation in the capacities of Mechanical Engineer, Contract Administrator, and

Resident Engineer. As a Mechanical Engineer he provided quality control for mechanical, electrical, and civil works at major hydroelectric construction projects. As a Contract Administrator he analyzed and made recommendations pertaining to claims for additional compensation under contracts to build and supply equipment for major hydroelectric and irrigation projects, negotiated settlements thereto, and wrote contract addenda to reflect negotiated settlements. As a Resident Engineer he supervised up to 50 engineers, surveyors, and technicians providing quality control of electrical, mechanical, and civil works of a 100,000 acre irrigation project; including roads, highways, canals, pumping plants, pipelines substations, and a 115kV transmission line.

From 1978 through 1986 Mr. Faull worked in various capacities of consulting engineering. As such, he did (or supervised) financial feasibility analyses, design, construction management, construction, and start-up of chemical, water, and energy projects, including PURPA hydro, coal, and MSW projects. He also did business development, billing, personnel management, and hiring/firing.

From 1987 through the present Mr. Faull has served as a Utilities Engineer at the Idaho Public Utilities Commission. In that capacity he has analyzed Cogeneration and Small Power Producers' (CSPPs') projects; developed computer models to represent utilities' Avoided Costs, power supplies, cash flows, and other features; testified in electric avoided cost cases; authored Proposed Orders pertaining to avoided costs, CSPPs' security arrangements, utility surcharges, and utilities' conservation/least-costplanning programs; and authored proposed Idaho comments to Federal Notices of Proposed Rulemaking. He has also attended several related training programs and conferences, including the NARUC 1987 Western Utility Rate Seminar, the NARUC 1987 19th Annual Williamsburg Regulatory Conference, The 1988 First Annual Utility Least-Cost-Planning Conference, the 6th NARUC Biennial Regulatory Information Conference, a NARUC Conference on Transmission Issues in Washington D.C., two privately sponsored conferences on CSPP regulation, and one privately sponsored conference on bidding for CSPP power.

PUBLICATIONS:

Mr. Faull has authored and presented three papers that were published in the "Proceedings of the Sixth NARUC Biennial Information Conference". The papers were entitled:

1. "Irreconcilable Conflicts of Interest Inherent in Vertically Integrated Electric Utilities",

2. "Solving the Overpayment Dilemma for Levelized Rate PURPA Contracts", and

3. "Bid Price and Reserve Margin: Chicken and Egg? An Approach to Pricing Power in the Post-Spiral World".

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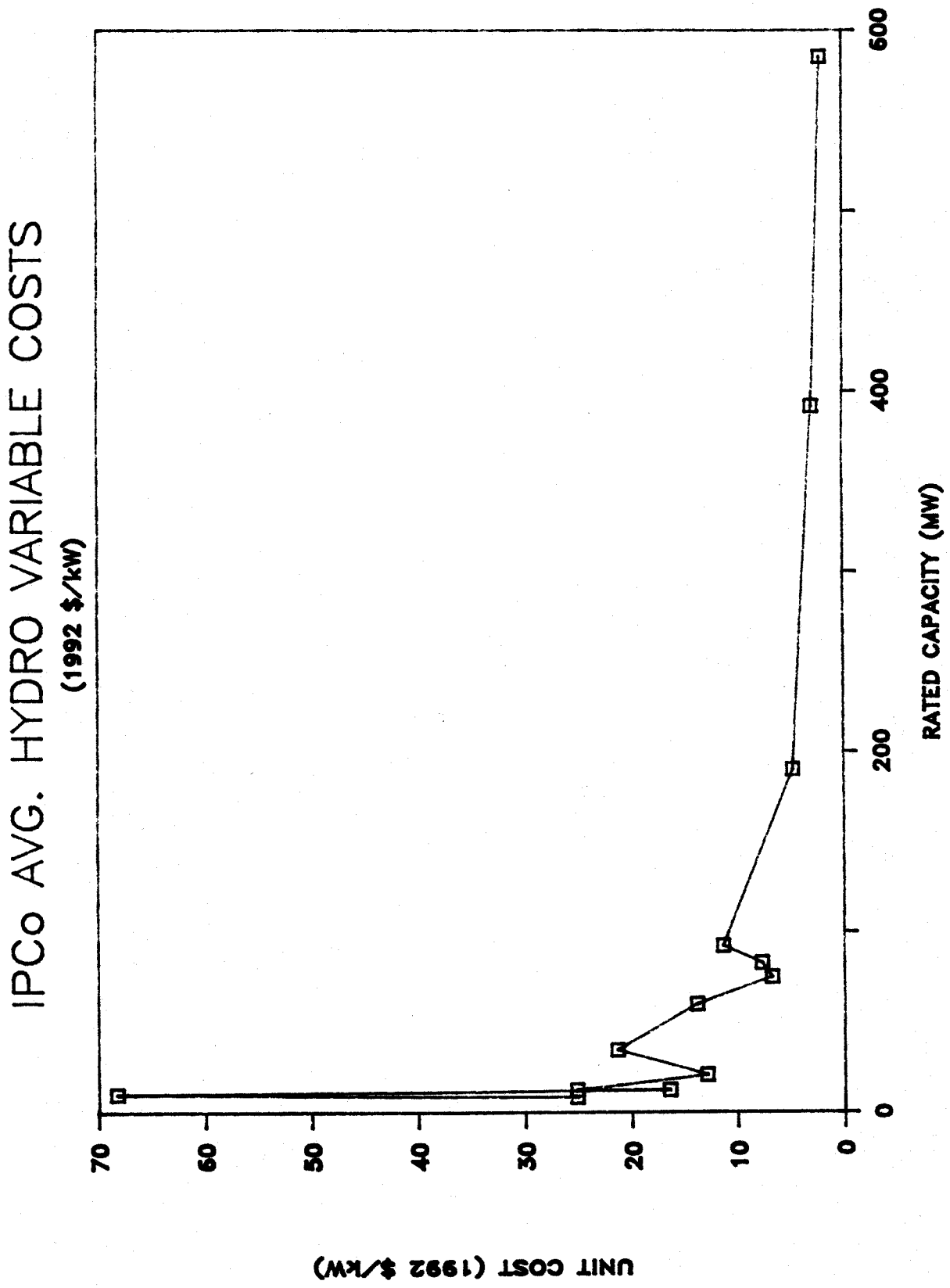

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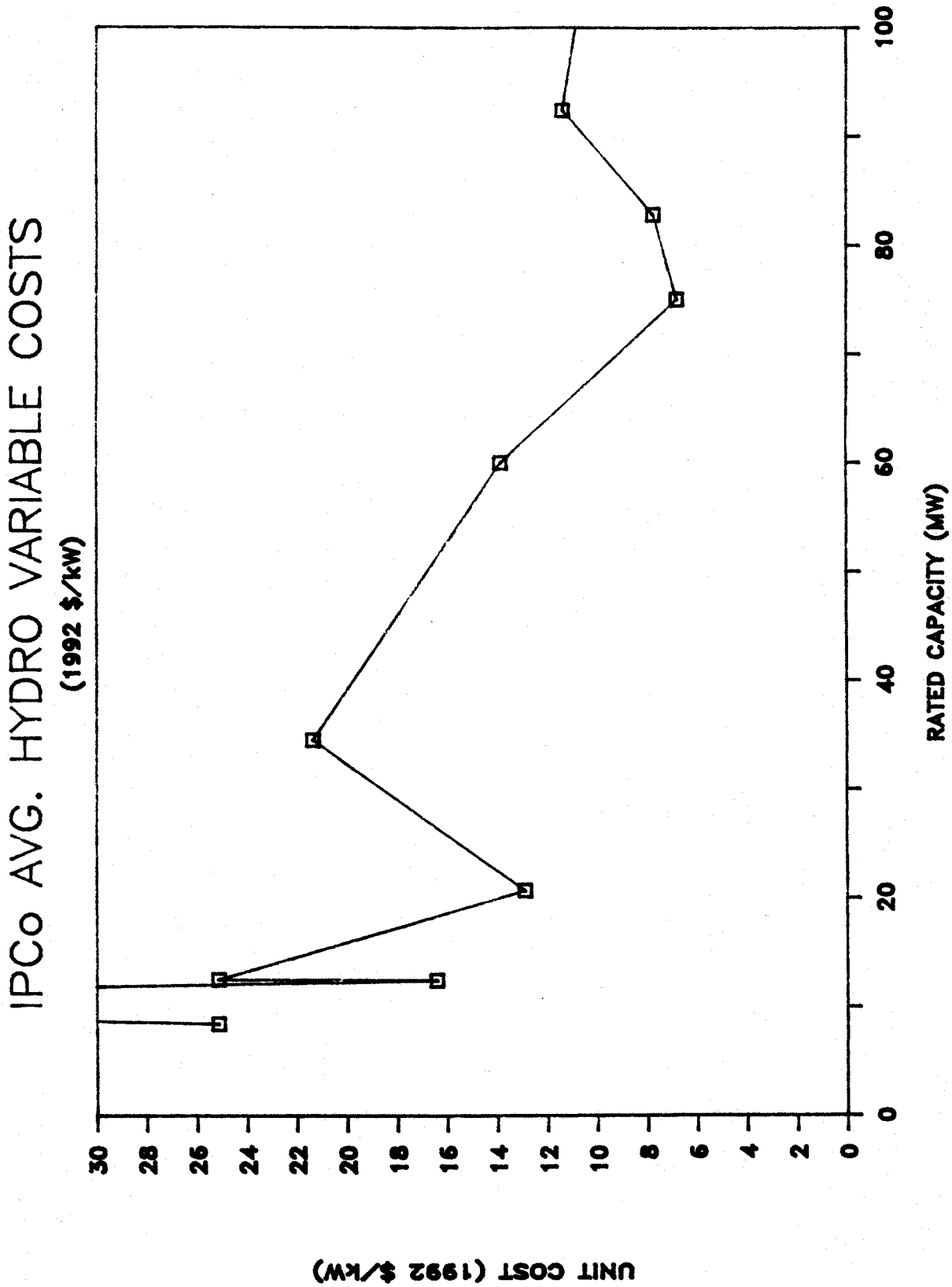

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HYDRO PLANT	YEAR	UNIT COST (1992 $/MWh)	UNIT COST (1992 $/kW)	
TWIN FALLS '89	1989	AVG.	AVG.	**********
TWIN FALLS '88	1988	AVG.	AVG.	
TWIN FALLS '87	1987	$3.34	$25.15	TWIN FALLS
TWIN FALLS '86	1986	AVG.	AVG.	8.4 MW
TWIN FALLS '85	1985	AVG.	AVG.	55.0 YEARS OLD
SWAN FALLS '89	1989	AVG.	AVG.	
SWAN FALLS '88	1988	AVG.	AVG.	
SWAN FALLS '87	1987	$8.05	$68.28	SWAN FALLS
SWAN FALLS '86	1986	AVG.	AVG.	10.3 MW
SWAN FALLS '85	1985	AVG.	AVG.	45.0 YEARS OLD
CASCADE '89	1989	AVG.	AVG.	
CASCADE '88	1988	AVG.	AVG.	
CASCADE '87	1987	$5.93	$16.42	CASCADE
CASCADE '86	1986	AVG.	AVG.	12.4 MW
CASCADE '85	1985	AVG.	AVG.	6.0 YEARS OLD
SHOSHONE FALLS '89	1989	AVG.	AVG.	
SHOSHONE FALLS '88	1988	AVG.	AVG.	
SHOSHONE FALLS '87	1987	$5.58	$25.14	SHOSHONE FALLS
SHOSHONE FALLS '86	1986	AVG.	AVG.	12.5 MW
SHOSHONE FALLS '85	1985	AVG.	AVG.	69.0 YEARS OLD
MALAD '89	1989	AVG.	AVG.	
MALAD '88	1988	AVG.	AVG.	
MALAD '87	1987	$1.99	$12.89	MALAD
MALAD '86	1986	AVG.	AVG.	20.7 MW
MALAD '85	1985	AVG.	AVG.	42.0 YEARS OLD
UPPER SALMON '89	1989	AVG.	AVG.	
UPPER SALMON '88	1988	AVG.	AVG.	
UPPER SALMON '87	1987	$2.81	$21.35	UPPER SALMON
UPPER SALMON '86	1986	AVG.	AVG.	34.5 MW
UPPER SALMON '85	1985	AVG.	AVG.	43.0 YEARS OLD
LOWER SALMON '89	1989	AVG.	AVG.	
LOWER SALMON '88	1988	AVG.	AVG.	
LOWER SALMON '87	1987	$2.99	$13.83	LOWER SALMON
LOWER SALMON '86	1986	AVG.	AVG.	60.0 MW
LOWER SALMON '85	1985	AVG.	AVG.	41.0 YEARS OLD
BLISS '89	1989	AVG.	AVG.	
BLISS '88	1988	AVG.	AVG.	
BLISS '87	1987	$1.29	$6.79	BLISS
BLISS '86	1986	AVG.	AVG.	75.0 MW
BLISS '85	1985	AVG.	AVG.	40.0 YEARS OLD
STRIKE '89	1989	AVG.	AVG.	
STRIKE '88	1988	AVG.	AVG.	
STRIKE '87	1987	$1.32	$7.73	STRIKE
STRIKE '86	1986	AVG.	AVG.	82.8 MW
STRIKE '85	1985	AVG.	AVG.	38.0 YEARS OLD
AMERICAN FALLS '89	1989	AVG.	AVG.	
AMERICAN FALLS '88	1988	AVG.	AVG.	
AMERICAN FALLS '87	1987	$3.02	$11.35	AMERICAN FALLS
AMERICAN FALLS '86	1986	AVG.	AVG.	92.3 MW
AMERICAN FALLS '85	1985	AVG.	AVG.	12.0 YEARS OLD
OXBOW '89	1989	AVG.	AVG.	
OXBOW '88	1988	AVG.	AVG.	
OXBOW '87	1987	$0.96	$4.81	OXBOW
OXBOW '86	1986	AVG.	AVG.	190.0 MW
OXBOW '85	1985	AVG.	AVG.	29.0 YEARS OLD
HELLS CANYON '89	1989	AVG.	AVG.	
HELLS CANYON '88	1988	AVG.	AVG.	
HELLS CANYON '87	1987	$0.56	$2.90	HELLS CANYON
HELLS CANYON '86	1986	AVG.	AVG.	391.5 MW
HELLS CANYON '85	1985	AVG.	AVG.	23.0 YEARS OLD
BROWNLEE '89	1989	AVG.	AVG.	
BROWNLEE '88	1988	AVG.	AVG.	
BROWNLEE '87	1987	$0.53	$2.08	BROWNLEE
BROWNLEE '86	1986	AVG.	AVG.	585.4 MW
BROWNLEE '85	1985	AVG.	AVG.	23.0 YEARS OLD

HYDRO PLANT	YEAR	CAPACITY (MW)	GENERATION (MWh)	AVERAGE (aMW)	CAP. FACT. (%)
TWIN FALLS '89	1989	8.4	63,593	7.3	86.0%
TWIN FALLS '88	1988	8.4	54,367	6.2	73.6%
TWIN FALLS '87	1987	8.4	66,036	7.5	89.3%
TWIN FALLS '86	1986	8.4	73,261	8.4	99.1%
TWIN FALLS '85	1985	8.4	74,005	8.4	100.1%
SWAN FALLS '89	1989	10.3	88,451	10.1	98.4%
SWAN FALLS '88	1988	10.3	92,710	10.6	103.1%
SWAN FALLS '87	1987	10.3	88,302	10.1	98.2%
SWAN FALLS '86	1986	10.3	80,345	9.2	89.4%
SWAN FALLS '85	1985	10.3	34,495	9.6	94.0%
CASCADE '89	1989	12.4	37,264	4.3	34.3%
CASCADE '88	1988	12.4	22,328	2.5	20.5%
CASCADE '87	1987	12.4	30,021	3.4	27.6%
CASCADE '86	1986	12.4	52,624	6.0	48.4%
CASCADE '85	1985	12.4	39,051	4.5	35.9%
SHOSHONE FALLS '89	1989	12.5	99,258	11.3	90.6%
SHOSHONE FALLS '88	1988	12.5	94,546	10.8	86.3%
SHOSHONE FALLS '87	1987	12.5	69,558	7.9	63.5%
SHOSHONE FALLS '86	1986	12.5	37,334	4.3	34.1%
SHOSHONE FALLS '85	1985	12.5	48,528	5.5	44.3%
MALAD '89	1989	20.7	78,047	8.9	43.0%
MALAD '88	1988	20.7	180,474	20.6	99.5%
MALAD '87	1987	20.7	185,584	21.2	102.3%
MALAD '86	1986	20.7	155,989	17.8	86.0%
MALAD '85	1985	20.7	180,612	20.6	99.6%
UPPER SALMON '89	1989	34.5	249,042	28.4	82.4%
UPPER SALMON '88	1988	34.5	235,512	26.9	77.9%
UPPER SALMON '87	1987	34.5	274,806	31.4	90.9%
UPPER SALMON '86	1986	34.5	282,465	32.2	93.5%
UPPER SALMON '85	1985	34.5	290,873.0	33.2	96.2%
LOWER SALMON '89	1989	60.0	235,299	26.9	44.8%
LOWER SALMON '88	1988	60.0	221,461	25.3	42.1%
LOWER SALMON '87	1987	60.0	263,047	30.0	50.0%
LOWER SALMON '86	1986	60.0	457,749	52.3	87.1%
LOWER SALMON '85	1985	60.0	379,213	43.3	72.1%
BLISS '89	1989	75.0	349,575	39.9	53.2%
BLISS '88	1988	75.0	333,319	38.1	50.7%
BLISS '87	1987	75.0	391,367	44.7	59.6%
BLISS '86	1986	75.0	484,596	55.3	73.8%
BLISS '85	1985	75.0	508,491	58.0	77.4%
STRIKE '89	1989	82.8	439,626	50.2	60.6%
STRIKE '88	1988	82.8	403,106	46.0	55.6%
STRIKE '87	1987	82.8	465,243	53.1	64.1%
STRIKE '86	1986	82.8	681,166	77.8	93.9%
STRIKE '85	1985	82.8	592,109	67.6	81.6%
AMERICAN FALLS '89	1989	92.3	269,790	30.8	33.4%
AMERICAN FALLS '88	1988	92.3	234,808	26.8	29.0%
AMERICAN FALLS '87	1987	92.3	327,622	37.4	40.5%
AMERICAN FALLS '86	1986	92.3	667,174	76.2	82.5%
AMERICAN FALLS '85	1985	92.3	536,430	61.2	66.3%
OXBOW '89	1989	190.0	980,413	111.9	58.9%
OXBOW '88	1988	190.0	677,644	77.4	40.7%
OXBOW '87	1987	190.0	878,563	100.3	52.8%
OXBOW '86	1986	190.0	1,397,061	159.5	83.9%
OXBOW '85	1985	190.0	1,194,306	136.3	71.8%
HELLS CANYON '89	1989	391.5	2,032,046	232.0	59.3%
HELLS CANYON '88	1988	391.5	1,370,368	156.4	40.0%
HELLS CANYON '87	1987	391.5	1,727,751	197.2	50.4%
HELLS CANYON '86	1986	391.5	2,509,024	286.4	73.2%
HELLS CANYON '85	1985	391.5	2,405,854	274.6	70.2%
BROWNLEE '89	1989	585.4	2,351,817	268.5	45.9%
BROWNLEE '88	1988	585.4	1,587,272	181.2	31.0%
BROWNLEE '87	1987	585.4	2,103,407	240.1	41.0%
BROWNLEE '86	1986	585.4	3,887,256	443.8	75.8%
BROWNLEE '85	1985	585.4	2,983,072	340.5	58.2%

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HYDRO PLANT	COSTS ($)	COSTS (1992 $)	UNIT COST (1992 $/MWh)	UNIT COST (1992 $/kW)
TWIN FALLS '89	$219,050	$246,401	$3.875	$29.20
TWIN FALLS '88	$263,923	$308,753	$5.679	$36.60
TWIN FALLS '87	$139,252	$169,421	$2.566	$20.08
TWIN FALLS '86	$132,680	$167,883	$2.292	$19.90
TWIN FALLS '85	$127,923	$168,338	$2.275	$19.95
SWAN FALLS '89	$952,425	$1,071,349	$12.112	$104.37
SWAN FALLS '88	$575,638	$673,415	$7.264	$65.60
SWAN FALLS '87	$484,351	$589,287	$6.674	$57.41
SWAN FALLS '86	$466,493	$590,262	$7.347	$57.50
SWAN FALLS '85	$441,014	$580,344	$6.868	$56.54
CASCADE '89	$131,255	$147,644	$3.962	$11.89
CASCADE '88	$152,297	$178,166	$7.979	$14.35
CASCADE '87	$155,118	$188,725	$6.286	$15.20
CASCADE '86	$183,334	$231,976	$4.408	$18.68
CASCADE '85	$207,783	$273,428	$7.002	$22.02
SHOSHONE FALLS '89	$278,917	$313,744	$3.161	$25.10
SHOSHONE FALLS '88	$175,099	$204,841	$2.167	$16.39
SHOSHONE FALLS '87	$196,672	$239,282	$3.440	$19.14
SHOSHONE FALLS '86	$306,024	$387,218	$10.372	$30.98
SHOSHONE FALLS '85	$323,892	$426,220	$8.783	$34.10
MALAD '89	$244,868	$275,443	$3.529	$13.31
MALAD '88	$203,374	$237,919	$1.318	$11.49
MALAD '87	($66,145)	($80,476)	($0.434)	($3.89)
MALAD '86	$511,085	$646,686	$4.146	$31.24
MALAD '85	$193,131	$254,147	$1.407	$12.28
UPPER SALMON '89	$762,935	$858,198	$3.446	$24.88
UPPER SALMON '88	$711,545	$832,407	$3.534	$24.13
UPPER SALMON '87	$534,441	$650,229	$2.366	$18.85
UPPER SALMON '86	$566,535	$716,848	$2.538	$20.78
UPPER SALMON '85	$474,928	$624,973	$2.149	$18.12
LOWER SALMON '89	$914,930	$1,029,172	$4.374	$17.15
LOWER SALMON '88	$696,710	$815,052	$3.680	$13.58
LOWER SALMON '87	$780,201	$949,234	$3.609	$15.82
LOWER SALMON '86	$498,667	$630,973	$1.378	$10.52
LOWER SALMON '85	$550,449	$724,353	$1.910	$12.07
BLISS '89	$483,908	$544,331	$1.557	$7.26
BLISS '88	$474,894	$555,559	$1.667	$7.41
BLISS '87	$469,001	$570,611	$1.458	$7.61
BLISS '86	$427,579	$541,024	$1.116	$7.21
BLISS '85	$254,431	$334,814	$0.658	$4.46
STRIKE '89	$746,261	$839,442	$1.909	$10.14
STRIKE '88	$596,342	$697,636	$1.731	$3.43
STRIKE '87	$429,668	$522,757	$1.124	$6.31
STRIKE '86	$353,651	$447,481	$0.657	$5.40
STRIKE '85	$527,101	$693,629	$1.171	$8.38
AMERICAN FALLS '89	$877,496	$987,064	$3.659	$10.69
AMERICAN FALLS '88	$919,701	$1,075,920	$4.582	$11.65
AMERICAN FALLS '87	$865,762	$1,053,332	$3.215	$11.41
AMERICAN FALLS '86	$739,771	$936,046	$1.403	$10.14
AMERICAN FALLS '85	$903,766	$1,189,294	$2.217	$12.88
OXBOW '89	$932,351	$1,048,768	$1.070	$5.52
OXBOW '88	$812,699	$950,743	$1.403	$5.00
OXBOW '87	$732,162	$890,787	$1.014	$4.69
OXBOW '86	$603,416	$763,514	$0.547	$4.02
OXBOW '85	$695,998	$915,886	$0.767	$4.82
HELLS CANYON '89	$673,591	$757,698	$0.373	$1.94
HELLS CANYON '88	$631,940	$739,280	$0.539	$1.89
HELLS CANYON '87	$813,807	$990,121	$0.573	$2.53
HELLS CANYON '86	$1,133,393	$1,434,104	$0.572	$3.66
HELLS CANYON '85	$1,333,740	$1,755,111	$0.730	$4.48
BROWNLEE '89	$1,223,548	$1,376,325	$0.585	$2.35
BROWNLEE '88	$1,148,602	$1,343,702	$0.847	$2.30
BROWNLEE '87	$1,032,048	$1,255,644	$0.597	$2.14
BROWNLEE '86	$905,745	$1,146,056	$0.295	$1.96
BROWNLEE '85	$741,394	$975,624	$0.327	$1.67

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 9TH DAY OF NOVEMBER, 1990, SERVED THE FOREGOING **DIRECT TESTIMONY OF THOMAS FAULL**, CASE NO. IPC-E-90-2, ON ALL PARTIES OF RECORD BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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1CERT/120