IDAHO POWER
IDAHO POWER COMPANY
P.O. BOX 70
BOISE, IDAHO 83707

Craig A. Jones
Hells Canyon Relicensing Project Manager
Hydro Relicensing Department

(208) 388-2934
fax (208) 388-6902
e-mail cjones@idahopower.com

February 17, 2005

Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Room 1A East
Washington, D.C. 20426

Re: Hells Canyon Project No. 1971-079, Responses to Requests for Additional Information

Dear Secretary:

By order dated February 1, 2004 the Federal Energy Regulatory Commission (FERC) granted an extension of time to file responses to additional information requests (AIRs) OP-1(a) and DR-3 parts (a) and (b) on February 18, 2004. Accordingly, enclosed for filing with the FERC are one (1) original hard copy and eight (8) CD copies of responses to the aforementioned AIRs.

In AIR OP-1(a), the FERC requested that IPC also file an Excel spreadsheet showing how power economics for each alternative operational scenario was calculated. That spreadsheet, along with other supporting spreadsheets, is included on a separate CD. The spreadsheets are also included in the CD copies of AIRs OP-1(a) and DR-3.

Finally, by copy of this letter, the Service List is hereby notified that all of the AIRs filed with the FERC will be available for viewing at ipchydro.org. In addition, CD copies of these AIRs may by requested by contacting Dee Aulbach by phone at (208) 388-6109 or e-mail at daulbach@idahopower.com.

Please contact me if there are any questions regarding this filing.

Sincerely,

Craig A. Jones

CAJ/da
Cc: Service List
Jim Tucker, IPC
Dave Meyers, IPC
Jim Vasile, DWT

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Idaho Power Company) Hells Canyon Hydroelectric Project
) Project No. 1971-079
___________________________________)

CERTIFICATE OF SERVICE

I hereby certify that in accordance with the Commission's Rules of Practice and Procedure, I have served the foregoing document upon each person designated on the official service list compiled by the Federal Energy Regulatory Commission in the above-captioned proceeding.

Dated this 17th day of February, 2004.

Craig A. Jones
Idaho Power Company
1221 W. Idaho
Boise, Idaho 83702
(208) 388-2934

Responses to FERC Additional Information Request DR-3

Parts (a) and (b)

Power Economics

Final Report

Jon Bowling
Engineering Leader

Kirk Whittaker
Manager, Market Risk

Hells Canyon Project
FERC No. P-1971-079

February 2005

TABLE OF CONTENTS

LIST OF TABLES

SCHEDULE A: ADDITIONAL INFORMATION REQUEST DR-3 POWER ECONOMICS

Time Required: 6 months

In your license application (exhibits D and H) you provide the estimated average annual cost of the project and you estimate the value of the project based on replacement costs, but there is no information regarding the cost of implementing potential operational changes that we may need to assess in our NEPA analysis.[1]

Accordingly, please provide the following information:

(a) A power generation and economic baseline consistent with your simulation of current and proposed operations[2] that details the project's power generation attributes and their economic value within Idaho Power's overall power supply system. This baseline, at a minimum, should include the following:

(i) Monthly on-peak generation for each of your 5 representative years (1992, 1994, 1995, 1999, and 1997);

(ii) Monthly off-peak generation for each of your 5 representative years;

(iii) Dependable capacity reflecting the seasonal effects of low inflow and your seasonal load requirements; and

(iv) The economic value of the foregoing attributes.

(b) A fully detailed method for estimating the power system and economic impacts (in relation to the baseline) associated with potential operational changes, such as alternative minimum flow levels and ramp rate restrictions downstream of Hells Canyon dam, alternative daily reservoir-level fluctuation limits at Hells Canyon reservoir, and potential late summer drawdowns of Brownlee reservoir (reference AIR OP-1, *Operational Scenarios*). Your method should be designed to capture as much of the economic impact of the Hells Canyon Project operational changes on your overall power supply system as feasible. If you use a project-based analysis, the analysis should specify the effect of the operational changes on all of the project's significant power supply attributes (e.g., dependable capacity, on-peak energy, off-peak energy, system reserve) and provide estimates of the value of these attributes within your integrated power supply system. If you use a system-wide cost of power analysis, the analysis should show the effect of any operational changes at the Hells Canyon Project on overall system power production costs, assuming no change in overall system reliability.

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[1] In your Response to Comment FERC 1-141 (New License Application, Volume 11, Second Stage Consultation), you state that you performed an analysis to estimate the economic cost to implement the fall chinook plan, one aspect of the current and proposed operation. You state that the costs of the fall chinook plan are attributable to "…differences in heavy-load/light-load energy production, reserves, and spring flow requirement…." You estimate the costs of the fall chinook plan at $75 million over 30 years ($2.5 million annually), but you provide insufficient detail on methods, assumptions and calculations to allow us to independently confirm your estimate or to apply your method to other potential operational scenarios that may require evaluation in our environmental analysis for this relicensing.

[2] In making this request, we assume that your proposed operations are the same as current operations. In the event that you determine in your response to AIR OP-2 that there is a difference between your proposed operations and current operations, please provide the requested information separately for current operations and for proposed operations.

> Your method should be transparent and your assumptions explicit. All power system-related project attributes that you believe could be affected by potential operational changes, including ancillary services, should be addressed, at least qualitatively. The method should be based on current power values and should exclude the effects of inflation, but should otherwise be consistent with your integrated resource planning process that you describe in your Integrated Resource Plan (Technical Report H.2-1.)[3] Provide any data and supporting calculations, including formulas, in Microsoft Excel.
>
> Within 60 days of the date of this additional information request, provide a description of your proposed method for Commission staff review. Any comments received from the Commission staff should be addressed in your filing with an explanation of how these comments were addressed.

1. INTRODUCTION

Agency review of the Idaho Power Company (IPC) license application for the three-dam Hells Canyon Complex (HCC), which includes the Brownlee, Oxbow, and Hells Canyon projects resulted in requests to the Federal Energy Regulatory Commission (FERC) for additional studies. FERC evaluated these study requests and formulated a list of additional information requests (AIRs) to help in determining potential project-related impacts resulting from these IPC hydroelectric projects. This document addresses AIR DR-3 quoted above. In this AIR, FERC requested a power generation and economic baseline consistent with our simulation of current and proposed operations that details the project's power generation attributes and their economic value within Idaho Power's overall power supply system, and a full description of the method that will be used for estimating the power system and economic impacts (in relation to the baseline) associated with potential operational changes.

Part (b), which was originally submitted to FERC in December 2004, has been included in this final version of DR-3 along with updates, corrections and additional information. Also included is a section in response to FERC comments on the draft submittal of DR-3(b).

2. RESPONSE TO PART (a)—PROPOSED OPERATIONS, POWER GENERATION AND ECONOMIC BASELINE

For proposed operations, the monthly on-peak generation for each of the five representative years (1992, 1994, 1995, 1999, and 1997) and the monthly off-peak generation for each of the representative years is given in Table 1. The dependable capacity reflecting the seasonal effects of low inflow and seasonal load requirements is given in Table 2 for each project.

[3] If you update this information in your response to AIR DR-1, *Thermal Alternative Cost of Capital,* please use the more current Integrated Resource Plan information.

It is difficult to place a value on the generation and operational attributes for the Hells Canyon Complex under current proposed operations. This value can be best described and quantified in relation to the estimated costs necessary to replace the attributes or the portion of these attributes that are lost as a result of more restrictive alternative operations. The costs associated with the evaluation of the alternative operational scenarios, in comparison to the current proposed operations, are provided in Table 10 of the IPC's response to OP-1(a).

3. Response to Part (b)—Valuation of Alternative Scenarios

The methodology that will be employed for estimating the power system and economic impacts (in relation to the baseline) associated with potential operational changes is a project-based approach. Although the HCC is a significant generation source for IPC and any additional constraints imposed will have system wide influences, the analysis will address localized, project-specific impacts, including changes to heavy-load energy, light-load energy, dependable capacity, reserves, flexibility, and any other potential modifications to the HCC's ability to generate as proposed in the final license application.

3.1. Heavy-Load and Light-Load Energy Impacts

The CHEOPS model will be used to summarize and compare the heavy-load and light-load energy differences between IPC's proposed operations and the various alternative scenarios identified by FERC (see FERC 2004). For each alternative scenario, five runs will be performed to evaluate the five representative hydrologic conditions (Table 3).

Energy will be presented in megawatt hours (MWh) and summarized monthly for each scenario. For each alternative scenario, the shift in heavy-load or light-load generation due to the imposed constraints will be captured in the operations model as a result of reservoir elevation differences or minimum flow requirements in the calculations.

The energy generated will be priced at year 2005 Mid C forward pricing curves, dated October 22, 2004 (Table 4).

3.2. Dependable Capacity

July is the most critical month for IPC's projects in meeting peak energy load demands. In concert with the planning process for the *2004 Integrated Resource Plan* (IRP) (IPC 2004), the medium-low hydrologic year, 1994, will be used for assessing capacity impacts, in megawatts (MW), for each alternative scenario. Proposed constraints for the HCC can result in changes to the HCC's ability to achieve current peaking capabilities. Constrained operations posed in the alternative operational scenarios can also limit IPC's ability to react quickly to protect against or minimize reliability problems on the electrical grid. This capability is critical throughout the year, but even more so during the summer months when IPC experiences peak load conditions. These constraints include reduced elevation in Brownlee Reservoir as well as increased ramp rate restrictions below Hells Canyon Dam during the critical summer months. Capacity impacts will be calculated for July only, which is typically the month that the peak day occurs, and compared with IPC's modeled proposed operations scenario for determining the size of a constructed supply-side resource to replace lost peaking generation capacity. Current transmission constraints preclude IPC from reliably obtaining this resource during the peak hours from generation sources outside of IPC's system as a long-term solution.

Capital construction costs for a simple-cycle combustion turbine from IPC's Final IRP will be annualized for comparing each scenario. For these analyses, a simple-cycle combustion turbine, modeled after the 162 MW type located at the Bennett Mountain site, will be assumed to replace the lost peaking capability of the hydroelectric facilities. We will also assume that the fixed operations and maintenance (O&M) cost is included in the annualized capital cost of the plant. This cost is presented in Table 5 along with assumptions. An additional cost estimate will be provided using the estimated construction cost for new capacity of $114/kW-year that was used by FERC staff in the IPC Mid Snake economic analysis.

As mentioned earlier, IPC's system needs are most critical during the summer months. Consistent with the IRP, we will assume that the newly constructed replacement facility will be operating during the peak hours in the summer months. We will also assume, for this analysis, that all surpluses and deficiencies between the proposed operations and the alternative scenarios will be sold and exported, or purchased and imported on the market and that the cost of such will be included in the energy effects analysis with transmission wheeling costs and losses added. For this analysis we will also assume that the fuel and variable O&M costs of the combustion turbine capacity are already reflected in the energy effects calculation, and consistent with the IRP, the gas turbines will be available to run during those peak hours on the peak days in the summer months.

Parameters used in calculating the economic impact will be based on today's conditions and information presented in IPC's final IRP, dated July 2004. Future impacts will depend on water conditions, market conditions, construction costs and other resource issues.

3.3. Ancillary Services

As described in Exhibit B of the license application (IPC 2003), ancillary services provided by the HCC include load shaping, load following, voltage control, and generating reserves. In this analysis, the deficit capacity to be constructed will be increased by 7% to include thermal generating reserves for this new generating resource as required by the Western Electric Coordinating Council (WECC).

Capital construction costs for a simple-cycle combustion turbine from IPC's Final 2004 IRP will be annualized for comparing each scenario. For these analyses, a simple-cycle combustion turbine, modeled after the 162 MW type located at the Bennett Mountain site, will be assumed to replace the lost peaking capability of the hydroelectric facilities. We will also assume that the fixed O&M cost is included in the annualized capital cost of the plant. This cost is presented in Table 5 with assumptions. This 7% of newly constructed reserve capacity would be available as spinning reserve when the gas peakers are running during those peak hours in those months that peak energy cannot be imported into the IPC system.

Constrained operations posed in the alternative operational scenarios can also limit IPC's ability to provide additional ancillary services for itself or others during those months when the Company does not need them. For instance, IPC currently provides +/– 30 MW of load following services to NorthWestern Energy. A restricted ramp rate at Hells Canyon will negatively impact IPC's ability to provide voltage support, operating reserves and load following services. In this analysis IPC has not quantified the economic impact due to loss of voltage support.

3.4. Physical Modifications

In an attempt to comply with the restrictive ramp rate scenarios below Hells Canyon Dam, various modifications to the control system protocol, powerhouse equipment, and dam structure may be necessary. Physical modifications to the HCC have been identified and included in the economic evaluation. OP-1(a) Table 10 includes capital and O&M costs for physical modifications to the Hells Canyon Project. Please reference Appendix A of OP-1(a) for a detailed description of the physical modifications recommendations report by Devine Tarbell & Associates, Inc. (DTA).

3.5. Flexibility of Operation

Additional operating restrictions placed upon any of the three dams of the Hells Canyon Complex can degrade Idaho Power's ability to adjust planned reservoir releases in order to react most efficiently to system or market conditions that may call for modified operations. This analysis is aimed at quantifying the ability to alter planned releases from Brownlee reservoir. Components of the analysis will include the amount, timing, and value of generator output at the three projects. Idaho Power will use the methodology described below to quantify operational flexibility.

3.5.1. Value Proposition

Water and energy storage in reservoirs is productive if the value of commodity has the potential to vary over time. Electricity prices vary by time, day, and season, and the owner of electricity storage (a reservoir upstream from hydroelectric turbines) has the option to produce during the highest value periods. When a new forecast is assembled, the storage owner may adjust the planned allocation of product throughout the delivery time frame to maximize value. The factors involved in the reallocation decision are identical to the factors, which determine the value of a financial call option. Using standard techniques for estimating the value of an option, we can estimate the value of operational flexibility.

Within the physical/environmental constraints of the river system the storage owner holds a matrix of options to alter forecast releases in the most optimal way based on new information. The term “discretionary hydro” refers to the quantity of water (or equivalent generation) that is available for reallocation. The matrix of potential uses of the discretionary hydro is immense (from any month to any other month, within the scope of feasibility), as is the value of retaining flexibility to respond to uncertain economic or non-economic events.

We can quantify a portion of this value by applying option pricing theory, and monetize storage value by applying strategies used in trading and managing options. We do not intend this analysis to represent the full value of flexibility. Analyses of this type routinely under-value options because of the difficulty in sufficiently representing the nature and breadth of multiple uncertain influences on the potential decisions. In many cases, exercising options can eliminate existing options or create new ones, further complicating a “complete” analysis. Also, certain assumptions may not match real world conditions; e.g., observed variances exceed those predicted by normal distributions.

Nevertheless, this study will establish the representative value of the flexibility inherent in a storage facility. In practice, the strategy requires excellent market liquidity, a balanced risk/reward profile, enabling regulatory structure, and a healthy credit environment. The market environment since the California energy crisis is not always robust in these areas, but conditions are improving.

3.5.2. Option Pricing Theory

Using standard option pricing techniques, we can determine an estimated value for any one option or decision related to discretionary hydro. The matrix of decisions, then, can be represented by a collection of individual options where many competing decisions will be made moot by higher value alternatives.

Storage can be represented by a collection of "spread" options, where the owner will shift production when the price at time step two (t2) exceeds the price at time step one (t1) by an amount greater than the variable cost of the shift (in IPC's case, head losses). A spread option model requires the same information many other option models require: the current price of electricity for delivery periods in question, the exercise price of the option, the time remaining before the option expires, and assumptions about interest rates and volatility of electricity prices over the life of the option.

3.5.3. Trading Strategy

One of the byproducts of the option valuation process is a measure called "delta". Delta represents (given the current state of all variables) the sensitivity of the option's value to a small change in the price of the underlying product. To hedge the value of an option, the owner uses delta to determine the volume of the hedge position that must be established.

From the analysis, delta will indicate the highest value decisions to make regarding discretionary hydro, after incorporating head-losses. A companion analysis will be performed to establish, by period, how much discretionary hydro is available, and the limits of the flexibility over time. The two analyses combined indicate when and how much discretionary hydro should be reallocated.

Used as a decision-making tool, the model describes transactions of a given volume which must be executed in order to monetize the value of the option: an electricity purchase in the period losing discretionary hydro, and an electricity sale in the period gaining discretionary hydro. Each pair of transactions creates a financial gain for the storage owner, because delta will only direct us to move discretionary hydro when sufficient profit margin will be created by the pair of hedging transactions.

3.5.4. The Study

By applying the modeling techniques described, and accumulating the inherent benefits of executing the strategy, we will attempt to quantify the dollar impact of loss of flexibility (discretionary hydro) due to the variety of proposed operating restrictions assembled in the AIR.

The components of the study include:

- *Discretionary Generation*—the volume of hydroelectric energy potentially subject to OP-1 Scenario 2 1995 restricted operation

- *Study Period*—the window of opportunity to reallocate the energy if not restricted

- *Head Losses*—account for reduced efficiency of a generator as the elevation of the reservoir behind it drops
- *Power Prices*—historical daily record of forward power market prices
- *The Model*—a mathematical model (plus required inputs) built to value a type of financial contract known as a spread option.

The primary impact of restrictions on discretionary generation would occur each year between the months of July and October (the Study Period). Unconstrained, IPC would plan to enter July with Brownlee reservoir essentially full and retain the ability to draft to the end of October target any time within the Study Period. In the restricted case this draft must occur during July regardless of the potential value of the generation in other months. Hydro generation produced by the draft is calculated to be 180,838 megawatt-hours.

Drafting early in the period, as dictated by the restricted case, maximizes the negative effect of Head Losses. By dropping reservoir elevation for the remainder of the period, the early draft reduces efficiency for non-discretionary generation.

If Power Prices were equal and static across the Study Period, the optimal draft would be as late as possible in the period to minimize Head Losses. However, the value of power varies from month to month, and the amount of variation changes as well. When the generation is allocated the first time, the draft should be scheduled during the periods with the highest market price for power, after considering the effect of Head Losses.

Over time prices fluctuate, leading to considerable uncertainty as to whether the initial forecast remains the highest value plan. Opportunities arise to create value by reallocating scheduled hydro generation to different months as dictated by changing Power Prices. As we consider the reallocation decision, we ask how much should be reallocated and when. Arbitrary thresholds could be designed for monthly price differentials and the amounts to be reallocated. Instead, delta-hedging using an option model provides a systematic approach to the reallocation decisions.

A spread option derives its value from the difference in price of two products. Another way to think of it is converting product A into product B: if the price of B is higher, then the conversion is profitable; but if the price of A is higher, the conversion would lose money and would not be chosen. Examples of this in the power industry include burning any fuel (coal, natural gas) to generate electricity, using power transmission (transporting power from one location to another location), and storage (shifting generation from one time period to another time period).

The factors dictating the value of a spread option include:

- **Underlying Price:** target product price (product B) minus source product price (product A)
- **Strike Price:** any variable cost of execution; in our examples the strike price is the efficiency of conversion (Head Losses in this study)
- **Time Until Expiration:** most options have a finite lifetime
- **Volatility & Correlation:** statistical representation of how the prices change, and how those changes relate to each other
- **Interest Rate:** for discounting a future payout; a minor influence compared to other factors

If the products in question are priced the same, and prices never change (or always change together in the same direction and magnitude), a spread option based on the products has no current value and no chance of becoming valuable. The value of the option increases with the frequency and magnitude of expansion/contraction of the price spread.

A spread option model is a mathematical analysis estimating the value of the option based on the variables described above. IPC has licensed a family of software products called "FinTools" from Montgomery Investment Technology, Inc. Montgomery's Binomial Spread Option model was used for this analysis. Conservative values were used to set the interest rate, volatilities, and correlation, which are 3%, 40%, and 92%, respectively. Volatility and correlation likely change throughout the lifetime of the options, but a process to modify these values throughout the analysis would contain numerous assumptions that are difficult to verify, and therefore is not included.

In addition to calculating the value of an option, the model computes a value known as "delta". Delta in this case is a measure of the sensitivity of the value of the option to a change in price of the underlying. The delta of an option is also referred to as its "hedge ratio" because it is the amount of the underlying that must be held to hedge the current value of the option. If the spread is very wide (deep in-the-money) relative to volatility, correlation, and time until expiration, then delta will approach 1. If the spread is reversed (deep out-of-the-money) with all other factors unchanged, delta will approach zero. If the spread is small, then delta will be near 0.5 (about equal probability the option will expire in- or out-of-the-money).

The following identifies the process that was used in the calculation:

1. Choose the options to manage
2. Allocate hydro energy based on delta from the option model
3. Re-run the model daily to produce new allocations
4. Buy/Sell energy as it is reallocated
5. Accumulate proceeds of buys/sells
6. Subtract value of head losses and liquidity penalty

The options managed in this analysis were Summer 2004 starting one year in advance, and Summer 2005 starting one year in advance. The decision to manage these particular options was partially dictated by the amount of reliable market price data available. Prices fed into the model were extracted from IPC's database of forward market prices developed from daily broker quotes dating back to July 2003.

The matrix of options evaluated for each of the above summer periods includes every pair of potential comparisons. Moving volume from any month to any other month within the Study Period gives 4 months times 4 months (16) minus the months matched with themselves (4) equals 12. As forward market prices change each day, the model recalculates delta for each option. The daily changes in delta indicate fractions of the 180,838 MWh Discretionary Generation, which should be reallocated to optimize the value of the plan. From the matrix of options, a weighted average delta is calculated for each month and used to create the allocation percentages.

Just before delivery of each month begins, the full monthly product ceases to trade. A balance-of-month product, which excludes days already scheduled, will begin trading. This product would be used to continue reallocating from/to that partial month, adding to the value of flexibility. However, we do not have ready access to historical balance-of-month prices. IPC's analysis assumes volume allocated to July is fixed upon entering July, and at this time the matrix of options falls to six (3 x 3 – 3 = 6). The matrix falls to two as August begins delivery, and the allocation process stops as September begins delivery.

Throughout the process of reallocation, production removed from any month is replaced by power purchases from the market. An increased allocation in any month is considered to be sold at the market price. The cost/revenue from all transactions is accumulated to generate the gross benefit versus the AIR case.

Two adjustments are made at this time. The first is to subtract the value of Head Losses from the gross benefit. Head Losses were used in deciding whether and how much to reallocate energy, but the benefit calculated from all transactions does not yet reflect the loss of generation from any early drafting.

The second adjustment is for market liquidity. The forward market prices used are comparable to a mid-market price with an estimated average bid/offer spread of $1.00. Assuming all transactions were executed at mid-market could be optimistic, but assuming they were always done at the bid or offer could be overly pessimistic. A $0.25 liquidity “penalty” (halfway between mid-market and the bid/offer) is subtracted from the gross benefit to reflect this assumption.

At the time of this writing the Summer-2005 option is still active. The total value includes the same allocation process applied to-date, plus the current value of the remaining options through the summer.

While this analysis specifically looks at alternative operational scenario OP1-2, this same type of impact to flexibility would occur with any alternative operational scenario in which IPC’s ability to utilize the storage in Brownlee reservoir at its discretion is restricted. This impact applies to AIR’s scenarios OP1-2, OP1-5, and OP1-6, where IPC essentially gives up year round control of Brownlee Reservoir. There would also be a proportionate loss in flexibility in relation to current proposed operations if more restrictive ramp rates were imposed.

The resulting economic impacts from the foregoing described analyses can be found in OP-1(a) Table 10. The Excel spreadsheet with data and formulas used to derive these costs is provided on CD with the AIR OP-1(a), submittal.

4. Response to FERC Staff's Comments on DR-3(b)—Power Economic Methodology

Time Required: 3weeks

As you know, Additional Information Request DR-3(b) requires you to describe your proposed method for estimating the effect of potential operational changes on your power system for Commission staff review. After reviewing your submittal, we have the following comments:

2.1 Energy. You say that to look at how heavy-load and light-load energy differ for each alternative scenario, you will evaluate the five representative inflow years (extreme low, medium low, medium, medium high, and extreme high). What is unclear to us is whether you also plan to calculate the effect of each alternative scenario on the average annual energy over the hydrologic period of record.

2.2 A) Dependable Capacity. In the first paragraph, you say that to determine how dependable capacity differs between any given alternative you would use the dependable capacity for the month of July. What is unclear to us is how you are going to calculate the July dependable capacity for each alternative. Are you proposing to average the project's capacity over the 424 heavy load hours for each alternative or average the project's capacity over a different period?

2.2 B) Dependable Capacity. In paragraph 3, you say that, for each alternative, you plan to include a cost for operating any combustion turbine capacity needed to make up for a loss in dependable capacity. You say this combustion turbine capacity would be operated during the summer time heavy load hours and that you will include fuel and variable operation and maintenance (O&M) will be included in your dependable capacity calculation. What we do not understand is why the fuel and variable O&M costs of the combustion turbine capacity are not already reflected in your energy effects calculation. This approach would seem to double count fuel and variable O&M.

2.3 Ancillary Services. In the third paragraph of this section you mention that the number of peaking hours during which the new facility will be operating is presented in Table 4. Table 4 includes a column labeled "Capacity and Reserves (% Heavy Load Hours)." It is unclear to us what the purpose of this information is and how you plan to use it. It is also not clear from your proposed method whether any effects on ancillary services would be computed for each representative hydrologic year or only during adverse hydrologic conditions.

2.4 Physical Modifications. In your final response to our AIR, please be sure to include both capital and operations and maintenance costs separately.

2.5 Flexibility of Operation. In your opening paragraph, you say that your flexibility analysis will include the amount, timing, and value of generator output at the three projects. Since your energy and dependable capacity analysis will also look at generator output, we request you explain very clearly how the flexibility analysis will avoid any double counting of the effects calculated in the energy and dependable capacity analyses (such as the shifting of energy from peak to off-peak periods described in section 2.1). Please also clarify whether you would compute this flexibility on an annual basis or for the selected representative hydrologic years.

The above comments must be addressed in your response to DR-3(b), which is due by February 5, 2005.

In a letter dated January 12, 2005 the FERC staff provided comments after reviewing IPC's draft submittal of AIR DR-3(b). The following is in response to the above referenced comments. Some of the table numbers from the initial filing of DR-3(b) have changed through the development of the final response to DR-3, parts (a) and (b). The content of some of the tables has also changed based in part to FERC staff provided comments and further review of the methodology by IPC staff. An explanation of any changes is provided in the following response to FERC staff's comments. The text presented above has been altered to address comments received on the draft submittal.

Comment

2.1 Energy. You say that to look at how heavy-load and light-load energy differ for each alternative scenario, you will evaluate the five representative inflow years (extreme low, medium low, medium, medium high, and extreme high). What is unclear to us is whether you also plan to calculate the effect of each alternative scenario on the average annual energy over the hydrologic period of record.

Response

The effect of each alternative scenario will be calculated and compared to the proposed operations scenario only and averaged over the five representative inflow years.

Comment

2.2 A) Dependable Capacity. In the first paragraph, you say that to determine how dependable capacity differs between any given alternative you would use the dependable capacity for the month of July. What is unclear to us is how you are going to calculate the July dependable capacity for each alternative. Are you proposing to average the project's capacity over the 424 heavy load hours for each alternative or average the project's capacity over a different period?

Response

The methodology used to calculate July dependable capacity is the same methodology used for the IPC's (IRP). The method assumes that gas peakers will be constructed and will be available to provide peaking energy for the peak hour in the peak day. The method essentially averages the dependable capacity of the Hells Canyon Complex over the entire month of July using 1994 hydrology, which is the 70th percentile exceedence water condition. Because it is not known which day the peak demand will occur, the method assumes that the daily average outflow, on any given day in July from the Hells Canyon Dam, must equal the July monthly average Hells Canyon Dam outflow. The daily outflow is shaped hourly based on headwater and tailwater constraints imposed in each alternative scenario while maintaining the required monthly average outflow as the minimum baseflow.

Comment

> 2.2 B) Dependable Capacity. In paragraph 3, you say that, for each alternative, you plan to include a cost for operating any combustion turbine capacity needed to make up for a loss in dependable capacity. You say this combustion turbine capacity would be operated during the summer time heavy load hours and that you will include fuel and variable operation and maintenance (O&M) will be included in your dependable capacity calculation. What we do not understand is why the fuel and variable O&M costs of the combustion turbine capacity are not already reflected in your energy effects calculation. This approach would seem to double count fuel and variable O&M.

Response

For this analysis IPC assumes that the fuel and variable O&M costs of the combustion turbine capacity are already reflected in the energy effects calculation, and consistent with the IRP, the gas turbines will be available to run during those peak hours on the peak summer days in the summer months.

Comment

> 2.3 Ancillary Services. In the third paragraph of this section you mention that the number of peaking hours during which the new facility will be operating is presented in Table 4. Table 4 includes a column labeled "Capacity and Reserves (% Heavy Load Hours)." It is unclear to us what the purpose of this information is and how you plan to use it. It is also not clear from your proposed method whether any effects on ancillary services would be computed for each representative hydrologic year or only during adverse hydrologic conditions.

Response

It is assumed that 7 % operating reserves would be added on top of the constructed supply-side resource to replace the lost HCC capacity. This 7% reserve capacity would be available when the gas peakers are running during those peak hours in those months that peak energy cannot be imported into the IPC system. Table 4 has been removed because those assumptions are no longer valid in the cost analysis.

Comment

> It is also not clear from your proposed method whether any effects on ancillary services would be computed for each representative hydrologic year or only during adverse hydrologic conditions.

Response

The effects on capacity and ancillary services (load shaping, load following, voltage control and reserves) are computed for the 70th percentile water condition, which is consistent with the IPC's IRP methodology.

In the IRP, peaking resources are constructed based on peak hour capacity deficits. Those newly constructed projects are operated to fill identified capacity needs during peak hours in the summer months.

In the other nine months of the year, the ability to generate ancillary services will be reduced, assuming that the gas peakers are not running. The impact to IPC from that loss is included in the ancillary services cost impact estimate in OP-1(a) Table 10.

Comment

2.4 Physical Modifications. In your final response to our AIR, please be sure to include both capital and operations and maintenance costs separately.

Response

OP-1(a) Table 10 includes capital and O&M costs for physical modifications to the Hell Canyon Project. Also, please reference report by DTA in Appendix A of OP-1(a).

Comment

2.5 Flexibility of Operation. In your opening paragraph, you say that your flexibility analysis will include the amount, timing, and value of generator output at the three projects. Since your energy and dependable capacity analysis will also look at generator output, we request you explain very clearly how the flexibility analysis will avoid any double counting of the effects calculated in the energy and dependable capacity analyses (such as the shifting of energy from peak to off-peak periods described in section 2.1). Please also clarify whether you would compute this flexibility on an annual basis or for the selected representative hydrologic years.

Response

The analysis involves reallocating forecast hydro throughout the forecast period based on daily changes in power market prices, and executing power transactions each day. The flexibility analysis does not capture any benefits or impacts of shifting between peak and off-peak periods, nor does it deal with capacity value. The analysis compared the value of: shifting and re-shifting (on a forward basis) hydro generation between July, August, September, and October (based on the 1995 flows) to the value of: forcing that generation into July (with no ability to use storage to shift generation to the other months).

It is important to note that storage does not merely allow allocation to the highest value periods **once**. Until the water is consumed and power produced, the option to adjust the plan still exists as often as the value of price spreads between the months change.

For this analysis, only the median hydrologic condition, 1995, was examined. However, because IPC is specifically focusing on the ability to shift Brownlee storage between months, the benefit or impact to flexibility would occur under all hydrologic conditions as long as Brownlee storage is available for discretionary use.

Please refer to the additional write-up and explanation provided in *Section 3.5.4, The Study,* for additional details.

5. LITERATURE CITED

Federal Energy Regulatory Commission (FERC). 2004. Schedule A: Additional information request (AIR)—Hells Canyon Project (FERC No. 1971-079). Appended to May 4, 2004, letter to Robert W. Stahman, Idaho Power Company, from Timothy J. Welch, FERC. FERC, Office of Energy Projects, Washington, DC. 25 p.

Idaho Power Company (IPC). 2003. New license application: Hells Canyon hydroelectric project (FERC Project No. 1971). 6 CD-ROM set. IPC, Boise, ID.

Idaho Power Company (IPC). 2004. 2004 Integrated Resource Plan. FINAL. IPC, Boise, ID. 88 p. plus appendices. Available at: www.idahopower.com/energycenter/2004irpfinal.htm.

Table 1. Proposed Operations, On-peak and Off-peak energy (MWh)

		January	February	March	April	May	June	July	August	September	October	November	December	TOTALS
1992	Heavy Load	339,496	351,041	336,145	274,883	268,819	171,059	199,069	179,040	235,044	281,237	256,628	300,580	3,193,041
	Light Load	43,594	48,846	45,274	34,860	36,146	23,689	28,130	26,137	27,952	38,017	41,135	42,034	435,815
	Total	383,090	399,888	381,419	309,743	304,965	194,748	227,199	205,177	262,996	319,254	297,763	342,614	3,628,856
1994	Heavy Load	392,939	330,978	419,378	400,990	449,646	286,969	297,176	263,470	301,527	341,623	256,377	306,266	4,047,338
	Light Load	52,764	43,930	58,439	38,958	42,882	29,429	30,203	28,829	29,467	46,466	40,352	43,376	485,095
	Total	445,703	374,908	477,817	439,949	492,528	316,398	327,379	292,299	330,994	388,088	296,729	349,642	4,532,433
1995	Heavy Load	490,394	483,109	512,430	547,280	625,556	635,208	511,938	379,195	439,501	409,064	310,292	480,232	5,824,199
	Light Load	131,684	138,807	180,415	129,624	256,221	316,314	93,141	36,366	45,023	63,656	51,001	121,356	1,563,607
	Total	622,078	621,916	692,846	676,903	881,777	951,523	605,079	415,561	484,525	472,720	361,292	601,587	7,387,806
1999	Heavy Load	580,151	518,479	574,183	554,449	582,248	636,793	467,326	453,879	426,673	415,293	354,359	424,591	5,988,425
	Light Load	301,687	279,090	362,688	291,608	254,130	334,601	53,952	45,052	43,206	67,975	59,928	65,557	2,159,472
	Total	881,838	797,569	936,871	846,056	836,378	971,394	521,278	498,931	469,879	483,268	414,286	490,148	8,147,896
1997	Heavy Load	611,912	528,847	544,558	524,497	589,564	633,005	565,474	534,339	577,217	471,120	344,629	476,513	6,401,675
	Light Load	386,590	342,642	364,137	275,793	308,459	334,672	122,501	66,257	173,512	179,726	64,400	93,864	2,712,553
	Total	998,503	871,490	908,695	800,289	898,023	967,676	687,975	600,595	750,730	650,846	409,028	570,378	9,114,228

Table 2. Dependable Capacity by Project for the Hells Canyon Complex

Project	Capacity
Brownlee	728 MW
Oxbow	220 MW
Hells Canyon	330 MW

Table 3. Inflow years chosen to represent categories of flow.

Year	Category
1992	Extreme low
1994	Medium low
1995	Medium
1999	Medium high
1997	Extreme high

Table 4. Year 2005 forward pricing values, dated October 2004, used for annual energy benefit.

Mid C

	HL	LL
Jan-05	70.09	60.00
Feb-05	64.25	55.00
Mar-05	58.41	50.00
Apr-05	44.03	35.12
May-05	39.81	31.76
Jun-05	45.90	36.62
Jul-05	53.59	43.70
Aug-05	62.04	50.59
Sep-05	59.12	48.21
Oct-05	58.18	48.81
Nov-05	56.54	47.44
Dec-05	62.28	52.25

Palo Verde HL :

					Mona cost
Jun-05	$63.53	+	$5.00	=	$68.53
Jul-05	$74.16	+	$5.00	=	$79.16
Aug-05	$72.00	+	$5.00	=	$77.00

Table 5. Levelized Fixed Cost for Proposed Gas Peaker.

Bennett Mountain (162 MW)
Nominally Levelized Fixed Cost per Kw/Year
prepared on February 11th, 2005

Capacity Costs	$ 52.44
Fixed O&M	$ 8.49
Prop. Taxes & Insurance	$ 4.23
Fixed Fuel Transportation	$ 8.55
Levelized Fixed Cost/Kw/Year	$ 73.70

** carrying cost, O&M, taxes, and insurance figures based strictly on the inputs from the 2004 IRP.

Operating Life: 30 Years
Discount Rate: 7.20% (2004 IRP)
Total Investment (incl AFUDC): $78,570,000 (2004 IRP)
Annual Escalation (Op Expenses): O&M = 2.52%, Insurance = 5%, Prop. Taxes = 0%

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