INDEX

TESTIMONY OF

JUERGEN M. BERMEJO, THOMAS R. MURPHY, ALLEN E. INGRAM, and

KATHERINE L. BEALE

Witnesses for Bonneville Power Administration

SUBJECT: GENERATION INPUTS COSTS TESTIMONY

Page

TESTIMONY OF

JUERGEN M. BERMEJO, THOMAS R. MURPHY, ALLEN E. INGRAM, and KATHERINE L. BEALE

Witnesses for Bonneville Power Administration

SUBJECT: GENERATION INPUTS COSTS TESTIMONY

Section 1: Introduction and Purpose of Testimony

Q. Please state your name and qualifications.

A. My name is Juergen M. Bermejo. My qualifications are contained in WI-09-Q-BPA-02.

A. My name is Thomas R. Murphy. My qualifications are contained in WI-09-Q-BPA-11.

A. My name is Allen E. Ingram. My qualifications are contained in WI-09-Q-BPA-06.

A. My name is Katherine L. Beale. My qualifications are contained in WI-09-Q-BPA-01.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to describe the four cost components that BPA Power Services (Power Services) evaluated to calculate the cost of providing an incremental amount of regulating reserves to BPA's Transmission Services (Transmission Services) to provide wind integration within-hour balancing service. These costs will be allocated to transmission rates.

Q. How is your testimony organized?

A. The testimony is organized into seven sections. Section 1 is this introduction. Section 2 describes generally what regulating reserves are and how Power Services recovers the costs of providing regulating reserves to Transmission Services. Section 3 provides a brief overview of the four cost components used to calculate the incremental regulating reserve costs. Section 4 describes the embedded cost component of the regulating reserves. Section 5 describes the energy shift cost component of the regulating reserves.

Section 6 describes the costs associated with system efficiency losses. Section 7 describes the response cost component.

Section 2: Description of Regulating Reserves

Q. What are regulating reserves?

A. As noted in Reserve Capacity Need Forecast, McManus and Enyeart, WI-09-E-BPA-02, regulating reserves are the generation capability of the Federal Columbia River Power System (FCRPS) that Power Services sets aside, at the request of Transmission Services, to balance generation of power and loads (use of power) on the BPA transmission system.

Q. Is Power Services currently providing regulating reserves to BPA Transmission?

A. Yes. Power has ten hydroelectric projects (Grand Coulee, Chief Joseph, McNary, John Day, The Dalles, Bonneville, Ice Harbor, Little Goose, Lower Monumental, and Lower Granite), known as the "Big 10," that are set up to provide regulating reserves for Transmission Services. All ten projects are connected to a computer system called "Automatic Generation Control" or AGC, through which the FCRPS automatically adjusts the amount of generation that is being produced to maintain system stability and respond to changes in load. The AGC computer requests two types of regulating reserves for the transmission system, "regulation" and "following." A signal from the computer tells the Big 10 generators to alter generation output in response to the regulation and following needs of the transmission system.

Q. What is regulation?

A. Regulation is the moment-to-moment adjustments in generation levels that the FCRPS makes to keep load and generation in balance. Regulation provides frequency and voltage control. A more detailed description is provided in Reserve Capacity Need Forecast, McManus and Enyeart, WI-09-E-BPA-02.

Q. What is following?

A. Following consists of the adjustments to generation levels that are made over a time frame of more than one minute but less than 60 minutes. Following is used to respond to larger variations between generation and load, which regulation cannot mitigate. A more detailed description is provided in Reserve Capacity Need Forecast, McManus and Enyeart, WI-09-E-BPA-02.

Q. How does BPA recover the costs of regulating reserves?

A. In general, BPA recovers the cost of regulating reserves by assigning a portion of the costs of the Big 10 to BPA's transmission rates. As more reserves are set aside to meet transmission customers' needs, more costs of the Big 10 are assigned to transmission rates. BPA Power Services projects these costs. Transmission Services sets a rate or rates to recover the costs.

Q. Why does Power Services assign the costs of regulating reserves to Transmission Services?

A. Power Services assigns the costs of regulating reserves to Transmission Services because Power Services supplies the associated generation capacity to Transmission Services so that Transmission Services can provide services to balance generation and load.

Q. Is BPA proposing in this rate case to assign additional regulating reserve costs to transmission rates?

A. Yes. For purposes of this testimony, we assume Transmission Services will need an additional 190 MW of regulating reserves for the first 10 months of fiscal year 2009 and 270 MW for the final two months of fiscal year 2009. Therefore, BPA is proposing to assign to transmission rates the costs of providing 190 MW of reserves for ten months (annual cost of 190 MW X 10/12) plus the costs of providing 270 MW of reserves for two months (annual cost of 270 MW X 2/12). The purpose of this testimony is to establish the cost of these additional regulating reserves.

Q. *Is the amount of regulating reserves you use in this testimony the same as the amount used in the Reserve Capacity Need Forecast, McManus and Enyeart, WI-09-E-BPA-02, testimony?*

A. No. There is a minor difference in the regulating reserve requirement for the last two months of FY 2009. The testimony sponsored by McManus and Enyeart, indicates that 268 MW rather than 270 MW of regulating reserves will be needed for these last two months. We intend to adjust the costs in the final proposal to reflect the reserve amount in the McManus and Enyeart testimony.

Section 3: Overview of Cost Components

Q. *How did Power Services calculate the cost of providing the additional regulating reserves?*

A. There are four cost components to regulating reserves, which together comprise the cost of the generating inputs that Power Services provides to Transmission Services: embedded cost, energy shift costs, system efficiency losses, and response costs. Later sections of this testimony will describe these costs in detail. Briefly, they are as follows:

Embedded cost represents the overall costs of the BPA system, including amortization and depreciation, interest costs, fish and wildlife expenses, and base level plant operation and maintenance costs. These costs are identified in the revenue requirement for the 2007 Power Rate Case. A portion of the embedded costs of the Big 10 projects, which provide regulating reserves, is allocated to transmission rates, and then a corresponding credit is recognized in power rates.

Energy shift costs compensate Power Services for the lost value associated with changes in the timing of energy production. When a portion of the capacity of the Big 10 is dedicated to providing regulating reserves, energy production and sales are shifted from high-use or heavy load hours, when energy prices are higher, to low-use or light load hours, when energy prices are lower. The difference in sale prices between heavy load and light load hours is the energy shift cost.

System efficiency losses are costs associated with setting up the Big 10 generating units in a less-than-optimal way to ensure the units have enough flexibility to provide regulating reserves.

Response costs are the incremental costs the Big 10 experience when they are called on to actually supply regulating reserves for the transmission system.

Q. Is there any general difference between these four cost categories?

A. Yes. The embedded cost, energy shift costs, and system efficiency losses capture the costs to Power Services of making regulating reserves available; that is, having generation capacity standing by ready to supply them. Power Services incurs these costs whether or not the regulating reserves are actually used. For example, as of October 2008 Power Services will stand ready to provide up to 190 MW of additional regulating reserves to Transmission Services. At any given moment, not all these reserves will be needed. However, Power Services must operate the Big 10 projects as if the entire 190 MW may be used at any time. Consequently, Power Services is unable to use this 190 MW of capacity to supply other power obligations or to sell other power products. The embedded cost, energy shift cost, and system efficiency losses cost categories compensate Power Services for reserving the capacity of the Big 10 for this use.

By contrast, the response cost component compensates Power Services for the incremental efficiency losses and wear and tear costs that result when regulating reserves are actually *supplied*. These costs are above and beyond the stand-ready costs described in the preceding paragraph. When regulating reserves are ultimately called upon, they reduce the capability of the federal power system even further and require additional operation and maintenance on the hydroelectric generating units.

Q. *Do any of these cost components use power prices in their calculation?*

A. Yes. The energy shift cost, system efficiency loss, and response cost all use power prices in their calculation.

Q. *What price did you use?*

A. For the initial proposal, we used $62.44 per megawatt-hour (MWh) for HLH prices. This is the forward block price (that is, prices for energy delivered at a given point in the future) as of October 11, 2007, for physical power delivery at the Mid-Columbia (Mid-C) point of delivery, the major trading hub within the Pacific Northwest as published in the Energy Market Report.

Q. *Are you proposing to change the price for the final proposal?*

A. Yes. We plan to update the price to the average of one year's worth of forward prices for delivery in calendar years 2008 and 2009, which BPA will weight to reflect its fiscal year of October 1, 2008, through September 30, 2009 (3/12 * average 2008 forward price + 9/12 * average 2009 forward price).

Q. *Why are you proposing to update the price?*

A. We are proposing to update the price because the best estimates for prices during fiscal year 2009 will be those obtained from prices nearest the actual delivery date. We propose averaging one year's worth of observations to capture any seasonal effects as well as to dampen any aberrant price points.

Q. *What are the total costs Power Services is proposing to assign to Transmission Services for the generation inputs to supply the additional regulating reserves?*

A. Power Services proposes to assign $22,867,842, or $9.39/kilowatt (kW) per month for an annual average of 203 MW of reserve (190 MW X 10/12 + 270 MW X 2/12 = 203 MW). We calculated this figure by summing up the four cost components described above as follows:

Type of Cost	**Costs**	**Price**
Embedded Cost	$14,031,360	$5.76/kW/month
Energy Shift Cost	$4,043,789	$1.66/kW/month
System Efficiency Loss	$ 1,051,269	$0.43/kW/month
Response Cost	$ 3,741,424	$1.54/kW/month
Total	**$22,867,842**	**$9.39/kW/month**

Section 4: Embedded Cost Component

Q. What are embedded costs?

A. Embedded costs refer to amortization, depreciation, base level operation and maintenance costs, fish and wildlife costs, and other costs of the Federal Columbia River Power System (FCRPS).

Q. What are the proposed embedded costs for the incremental regulating reserves?

A. The embedded cost component is $14,031,360, or $5.76/kW/month. This charge is the same as the unit cost of regulating reserves determined in the 2007 Wholesale Power Rate Case for the FY 2007-2009 rate period, and is described in WP-07-FS-BPA-05, p. 99; WP-07-FS-BPA-05B, pp.18-19 and 21, Attachment F. This unit cost is based on the embedded cost of the Big 10 projects.

Q. Is Power Services over-recovering its costs by assigning more embedded cost to Transmission Services for the incremental regulating reserves?

A. No. When Power Services sets its power rates in the upcoming supplemental power rate proceeding, it will include a credit to rates for the revenue that Power Services receives for embedded costs from Transmission Services for providing regulating reserves. This offsetting credit will reduce the amount of embedded costs that BPA will collect from its power customers. Consequently, the total amount of revenue BPA projects to collect to cover the embedded cost of the Big 10 projects will remain the same.

Section 5: Energy Shift Costs

Overview

Q. Please describe the energy shift costs.

A. Broadly speaking, energy shift costs represent the costs BPA incurs when it must de-optimize the timing of power production. BPA generally operates the Big 10 projects to maximize power production when power is most valuable. The value of power is highest when demand is high; this period is known as the heavy load hour period (HLH). BPA maximizes HLH power production by storing energy in the form of water during light load hours (LLH; generally, nighttime and Sundays) so the water can be used to maximize power generation during heavy load hours. Any deviation from BPA's normal operations results in an energy shift; that is, decreased HLH power production and increased LLH power production. BPA must sell power at lower prices.

Q How does providing regulating reserves affect generation levels?

A. During light load hours, Power Services attempts to store as much energy as possible for use for HLH power production the next day. LLH power production is therefore minimized as much as possible, given the power and non-power constraints on generation levels (power constraints exist because Power Services must maintain certain minimum generation levels to support voltage stability on the transmission system; non-power constraints include environmental limitations and the need to use water for other system purposes). However, if BPA sets generation at its absolute minimum and AGC sent a signal to decrease power production even more, Power Services would violate a nighttime operational limit. On the other hand, ignoring the signal could result in a violation of reliability standards.

Q. How does avoiding these problems cause energy shifts?

A. To avoid potential violations of a nighttime operational limit, Power Services generates above the minimum generation level. If regulating reserves are needed, Power Services can reduce Big 10 generation without violating minimum operating constraints. This mode of operation reduces HLH power production because water used to generate power during LLH is not available to generate power during HLH. Consequently, Power Services must make additional sales during LLH, because generation must match load. Rather than storing water for sale during higher value hours, BPA sells energy during lower value hours. The energy shift cost is the price difference between HLH and LLH energy.

Q. Is the need to generate above minimum levels during light load hours the only cause of energy shifts?

A. No. Power Services must be able to increase or decrease generation at any time to match changes in load. Therefore, just as Power Services must be able to decrease generation during light load hours, it must be able to increase generation during heavy load hours. Given available water, there is an upper limit to how much energy the Big 10 projects can generate. If the Big 10 projects are operating at maximum capacity, they are unable to increase generation. Consequently, during HLH Power Services must operate the Big 10 below their maximum generating capability so that they can increase generation when needed. This reduces power sales during HLH and consequently reduces revenues.

Q. How did you calculate the energy shift costs (ESC) component associated with the incremental regulating reserve requirement?

A. We calculated these costs by comparing historical power operations with and without the incremental regulating reserves. The base case is a historical Big 10 operation without the additional regulating reserves. We then added the incremental regulating reserves to the base case operation to estimate the annual energy shift from HLH to LLH. Finally, we estimated the revenue loss to BPA because of the energy shift. Thus, energy shift costs are a function of three items: (1) the percentage of ten-minute intervals during which BPA has to shift energy when providing the incremental regulating reserve (x); (2) the average annual amount of energy shift needed to provide sufficient regulating reserves (y); and (3) an expected spread price between HLH and LLH (z).

Thus, the formula we used to calculate the energy shift cost component is as follows:

ESC = 8760 hours/year * x * y *z.

Each of these components is discussed in greater detail below.

<u>Percentage of 10-Minute Intervals Requiring Energy Shift (x)</u>

Q. What do you mean by the percentage of 10-minute intervals needing to shift energy?

A. The percentage of 10-minute intervals needing to shift energy is the likelihood that Power Services will have to alter operations to ensure that sufficient regulating reserves are available. At times there are excess regulating reserves and Power Services will be able to respond to the increased regulating reserve requirement without shifting energy from HLH to LLH. However, increasing the regulating reserve requirement will increase the number of times when excess regulating capability does not exist and energy must be shifted to provide the additional regulating reserves. By reviewing data that show the number of times during a year when regulating reserves are insufficient, we can determine the number of times during the rate year that we can expect to need to shift energy.

Q. What data did you use to estimate this percentage?

A We reviewed actual data covering all 10-minute increments from April 2006 to April 2007, showing the supply of available reserve and the reserve obligation for each interval. We used the data to calculate how often the Big 10 would have to increase generation during LLH or decrease generation during HLH to ensure sufficient regulating reserve availability. ESC costs are assumed to be zero during hours when there is enough excess regulating capability to meet the added regulating reserve requirement.

The data used in the calculation is in an Excel spreadsheet under the name ShiftCostEst.vFinal.xls, tab "Data & Calculations" with results summarized in Attachment A: Energy Shift Cost Tables, Tables 2A through 4A.

Q. How did Power Services calculate the percentage of 10- minute intervals needing to shift energy?

A. We calculated the percentage of 10- minute intervals needing to shift energy by calculating the number of 10-minute intervals during the year which the available supply of regulating reserve was less than the existing regulating reserve obligation plus the incremental regulating reserve requirement. We used 10-minute intervals because that is how much time the system has to adjust without violating reliability requirements. Each interval during which reserves were insufficient had what we called a control deficit. The probability of needing to shift energy is the number of 10-minute intervals with control deficits divided by the total number of 10-minute intervals during the year. The data used in the calculation is in an Excel spreadsheet under the name ShiftCostEst.vFinal.xls, tab "Data & Calculations" with results summarized in Attachment A: Energy Shift Cost Tables, Tables 2A through 4A.

Q. What is the percentage of 10- minute intervals needing to shift energy for the incremental regulating reserves?

A. Our calculations showed that, with a need for an additional 190 MW of regulating reserves (the amount required for the first ten months of the rate period), the amount of available reserves was insufficient 20.75% of the time. Therefore, the percentage of 10-minute intervals needing to shift energy production is 20.75%. At 270 MW of regulating reserves (the estimated amount required for the last two months of the rate period), Reserve Capacity Need Forecast, McManus and Enyeart, WI-09-E-BPA-02, the percentage is 27.84%.

Please refer to Attachment A: Energy Shift Cost Tables, Table 4A, to view the percentage of 10-minute intervals needing to shift energy and how it impacts the calculation of energy shift costs.

<u>Average Amount of Energy Shift (y)</u>

Q. How did you calculate the average amount of energy shift?

A. Power Services calculated the average amount of energy shift as the average of all observed control deficit values. As discussed earlier, a control deficit occurs whenever the total regulating reserve requirement exceeds the available regulating reserve capability of the Big 10 for a 10-minute interval. The average control deficit is the average amount of energy that must be shifted between HLH and LLH to ensure that the FCRPS can instantaneously balance loads and resources.

The data used in the calculation is in an Excel spreadsheet under the name ShiftCostEst.vFinal.xls, tab "Data & Calculations" with results summarized in Attachment A: Energy Shift Cost Tables, Tables 5A through 6A.

Q. Why is this component relevant to the calculation of energy shift costs?

A. The percentage of 10-minute intervals needing to shift energy multiplied by the average quantity of energy shift yields the expected annual amount of energy shift. Multiplying this amount by expected price for shifting energy yields the expected annual cost of energy shifts.

Q. What is the average amount of energy shift?

A. The average annual control deficit for providing 190 MW of additional regulating reserves is 167 MW. The average annual control deficit for providing 270 MW of additional regulating reserves is 199 MW.

Please refer to Attachment A: Energy Shift Cost Tables, Tables 5A through 6A, to view the expected control deficit and how it impacts the calculation of energy shift costs.

Expected Spread Price Between HLH and LLH (z)

Q. What do you mean by "the expected spread price" of shifting energy between HLH and LLH?

A. The expected spread price is the average price differential between forward traded HLH power contracts and forward traded LLH power contracts. We used forward contract prices from the Energy Market Report.

Q. How did you calculate the spread price between HLH and LLH?

A. To calculate this spread, we reviewed the difference in HLH and LLH prices for annual (12 month blocks of power), forward power contracts trading as of October 11,2007, at the Mid-Columbia (Mid-C) point of delivery for physical delivery during fiscal year 2009. Based on prices published in the Energy Market Report, the spread price is \$12.13/MWh. Since 12-month blocks of power trade by calendar year and a fiscal year value is needed for the energy shift calculation, a weighted average is used. A weight of 3/12 is assigned to the calendar year 2008 contract and a weight of 9/12 is assigned to the 2009 calendar year contract. This weighting is intended to approximate the price of a contract spanning BPA's October through September fiscal year. We will update this price for the final proposal.

Energy Shift Cost Summary Calculation

Q. What are the total forecasted costs of energy shifts?

A. The total forecasted costs of energy shifts is the percentage of 10-minute intervals needing to shift energy, multiplied by the average energy shift, multiplied by the HLH/LLH spread price. As shown above, for an additional 190 MW of reserves (the amount needed for the first 10 months of FY 2009), the probability of shifting energy is

20.75%; the average energy shift is 167 MW; and the spread price is $12.13/MWh. Therefore, the costs of providing regulating reserves is 20.75% X 167 MW X 12.13 X 8760 (hours in a year) = $3,678,104.

For an additional 270 MW of reserves (the amount needed for last two months of FY 09), the probability of shifting energy is 27.84%; the average energy shift is 199 MW, and the spread price is $12.13. Therefore, the costs of providing regulating reserves is 27.84% X 199 MW X 12.13 X 8760 (hours in a year) = $5,872,216.

The overall cost is the weighted average of these two costs: (10/12 X $3,678,104) + (2/12 X $5,872,216) = $4,043,789.

Q. How did you calculate the unit cost per kW per month for energy shift costs?

A. The unit cost per kW per month is the weighted average of the cost to provide 190 MW of regulating reserve for 10 months and 270 MW for two months. The calculation is as follows:

[10/12 X $3,678,104/(190 MW X 12 mo/yr X 1000kW/MW)] + [2/12 X $ 5,872,216/(270 X 12 mo/yr X 1000kW/MW)] = $1.66/kW-mo.

Please refer to Attachment A, Energy Shift Cost Tables, Table 7A, to view the calculation of energy shift costs.

Section 6: System Efficiency Losses

Overview

Q. What are system efficiency losses?

A. System efficiency losses refer to lost Big 10 power production capability associated with using available water less effectively because capacity is being set aside to provide regulating reserves. Each generator at a plant has a "point of peak efficiency" at which the generation per unit of water is maximized. Any departure from this point increases the amount of water consumed per unit of power production, resulting in system efficiency losses.

One way to think of this is to analogize it to the speed at which a car gets its best fuel mileage. Moving a generator off its point of peak efficiency is analogous to traveling at a speed either above the point at which fuel mileage is maximized, in order to be able to slow down, or below that point, in order to be able to speed up. A hydroelectric project that is providing regulating reserve capability is producing power at a level above or below peak efficiency in order to be "standing ready" to either increase or decrease generation as needed by the transmission system. The resulting costs caused by increased use of water per unit of power production are called system efficiency losses.

Q. *How is the efficiency of a generating unit portrayed?*

A. Generating unit efficiency is portrayed using an "efficiency curve." An efficiency curve describes the relationship between power generation and efficiency of a unit to turn mechanical power (in this case, moving water) into electric power. The curves are generally parabolic; that is, the further away you get from the top of the efficiency curve (i.e., the point of peak efficiency) the steeper the decline in efficiency. Figure 1 below shows a typical example of an efficiency curve.

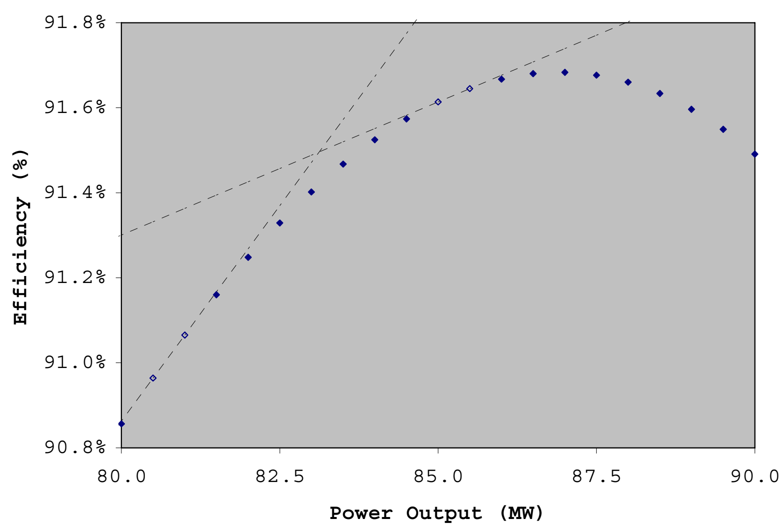


Figure 1.

Q. *Please provide an example of how carrying regulating reserves causes a generator to experience system efficiency losses.*

A. For example, a unit may have a maximum output of 125 MW and generate most efficiently at 100 MW. When operating at peak efficiency, the unit can increase power production by 25 MW. This ability to increase power production beyond current levels of power production is a regulating reserve. If, for reliability purposes, the unit must carry 30 MW of regulating reserves, it will be set to generate at 95 MW, below its peak-efficient generation of 100 MW. The consequence is efficiency losses because more water is consumed per unit of power generated. Conversely, if the unit is needed to reduce generation on short notice, it may be set to operate at 110 MW instead of its peak efficiency of 100 MW, again incurring efficiency losses.

Q. *Does carrying additional regulating reserves cause the Big 10 to experience system efficiency losses?*

A. Yes. Power Services must set the Big 10 generators to operate off of their point of peak efficiency.

Q. *How can Power Services minimize these losses?*

A. For purposes of this rate case, Power Services has analyzed system efficiency costs only for LLH. At times Power Services can minimize efficiency costs during LLH by bringing additional units online. Having more units online allows many units to change generation slightly from their peak efficient operation rather than having a few units change generation by large amounts. When calculating the impact of system efficiency losses, Power Services minimizes the impact of efficiency losses by assuming that additional units would have been brought online to reduce the efficiency loss.

Q. *How did Power Services calculate the costs associated with system efficiency losses?*

A. For each project we calculated the expected loss of efficiency as a percentage of generation lost because of the need to carry the incremental regulating reserves. Next, we multiplied this percentage by the actual generation output of the project. This result is the generation lost because additional water was consumed. Finally, we valued the lost generation at the HLH price to arrive at a cost.

Q. Why did you use the HLH price?

A. We used the HLH price because Power Services would have stored the additional water during LLH to generate energy during HLH. By having to use more water to generate a given amount of energy during LLH, Power Services loses revenues from sales that would have been made during HLH.

Q. Are system efficiency losses realized only on LLH?

A. No. Losses are potentially realized any time unit power production is altered. We calculated losses only for LLH because our current methodology is not capable of performing the calculation for the number of units involved with HLH operation. The current methodology also does not consider the potential for increased spill (running water through a spillway instead of through the turbines), which can affect operations during HLH. Efficiency losses during HLH are a cost of providing regulating reserves, however, and it would be appropriate to include them in the rate once BPA has a methodology to quantify them.

Expected Change in Efficiency

Q. How did you calculate the expected change in efficiency?

A. We developed a base case that assumed the generating units at four projects (Grand Coulee, Chief Joe, John Day, and The Dalles) are producing power at their peak efficiency during LLH. We looked at this subset of the Big 10 because these are the projects that typically provide regulating reserves. The level of peak efficient generation is a generation level as close as possible to the expected minimum generation level during LLH. We assumed that the minimum generation level at each project was the average minimum generation level of all 10-minute intervals from April 2006 to April

2007. From this data, we determined the number of units at each project that would be generating to attain this minimum generation level. The amount of regulating reserves available is the minimum generation level minus the load.

Q. *What did you do next?*

A. Next, we developed two "adjusted cases" in which Power Services is providing the incremental regulating reserves requested by Transmission Services also from these four projects. In the first case, we looked at the change in efficiency for carrying 190 MW of regulating reserves, and in the second case, we looked at the efficiency change for carrying 270 MW. The purpose of these "adjusted cases" is to determine how the efficiency of the plants changes when they must be set to provide additional regulating reserves. We then weighted the change in efficiency for the two cases by 10/12 for the first case (190 MW) and 2/12 for the second case (270 MW).

The difference in plant efficiency between the base case and the adjusted case yields the expected change in efficiency.

The data we relied on are contained in an Excel spreadsheet under the name, Eff.Worsheet.LossCalc.vFinal. Additionally, an example of how we calculated the change in efficiency for John Day in the 190 MW case is provided in Attachment C: System Efficiency Loss Tables.

Q. *What is the expected change in efficiency?*

A. For the 190 MW case, the expected changes in efficiency are 0.00% for Grand Coulee, -1.04% for Chief Joseph, -0.10% for John Day, and -0.06% for The Dalles. This totals to a loss of -1.20%. For the 270 MW case, the expected changes in efficiency are 0.00% for Grand Coulee, -0.27% for Chief Joseph, -0.34% for John Day, and -0.12% for The Dalles. This totals to a loss of -0.72%.

Please refer to Attachment C, System Efficiency Loss Tables, to view changes in efficiency by plant. The specific efficiency curves may be viewed in Attachment B: Efficiency Curves.

Lost Generation Due to Change in System Efficiency

Q. How did you calculate lost generation?

A. Forecasted lost generation for a given plant is its LLH generation multiplied by the percentage change in efficiency due to the incremental regulating reserve requirement. For each of the four projects mentioned above, we multiplied the project's expected LLH generation by the change in plant efficiency. This calculation yields the amount of generation that is lost due to inefficient operation.

Please refer to Attachment C, System Efficiency Loss Tables, to view a summary of how the lost generation is calculated.

Q. What is your estimate of total lost generation due to system efficiency losses?

A. We estimated lost generation for LLH of 4.77 aMW for 190 MW of regulating reserves and 3.06 aMW for 270 MW of regulating reserves.

Q. How did BPA value this lost generation?

A. The value of lost generation is the average price of forward traded HLH power contracts for delivery during FY 2009. As explained above, we used the HLH contract for valuation purposes because lost generation would have been used for HLH power production.

Q. What is the total amount of forecasted costs associated with system efficiency losses?

A. The total forecasted cost for LLH system efficiency losses is $1,051,269. This cost is a weighted average of the two reserve cases described above. Since the regulating reserve is expected to be 190 MW for the first 10 months of the fiscal year and 270 MW for the last two months of the fiscal year, the forecasted cost is 10/12 * $ 1,118,292 (the 190 MW case) + 2/12 * $ 716,154 (the 270 MW case), which equals the $ 1,051,269.

Please refer to Attachment C, System Efficiency Loss Tables, to view a summary of how the lost generation is calculated.

Section 7: Response Costs

Overview

Q. Please describe the response costs.

A. Response costs refer to the machine operation costs and efficiency losses that a generating unit experiences when it instantaneously alters power production in response to the AGC signal. Response costs differ from embedded cost, energy shift cost, and system efficiency costs because, rather than relating to how the hydro system is set up to provide regulating reserves, these costs occur when regulating reserves are actually supplied. There are four components to response costs: regulation efficiency loss, incremental operation and maintenance (O&M) due to regulation, cycling efficiency loss, and incremental O&M due to cycling.

Q. What happens when generating units are used to provide regulating reserves?

A. As noted in Reserve Capacity Need Forecast, McManus and Enyeart, WI-09-E-BPA-02, regulating reserves can be divided into two categories based on time frames. In the moment-to-moment time frame, regulating reserves provide small adjustments in generation to balance the variability between load and generation. Regulating reserves used for these small adjustments are referred to as "regulation." In order to supply regulation, generators must be online and running. As explained further below, the small up and down movements cause a net loss of efficiency and increase O&M costs.

Second, regulating reserves also respond to the larger variability in loads and generation within an hour. Regulating reserves used for this purpose are called "following." Providing "following" can sometimes be done with generating units that are online and running. Often, however, generating units must be turned on or off to provide following reserves. When a generating unit is turned on or off to provide following reserves, it is called "cycling." Cycling units on or off causes additional efficiency losses and increased O&M.

Q. Of the incremental regulating reserves Power Services is providing for the rate period, how much are regulation reserves and how much are following reserves?

A. As noted above, Power Services is providing 190 MW of reserves for the first 10 months of FY 2009 and 270 MW for the last two months. The weighted average of these amounts is 203 MW, of which 32 MW are regulation and 171 MW are following. In the following sections, we calculate efficiency losses due to regulation and cycling and O&M costs due to following.

Section 7.1: Regulation Costs

<u>Regulation Efficiency Losses</u>

Q. What are regulation efficiency losses?

A. Regulation efficiency losses occur when generating units respond to actual regulation needs by frequently changing power production over short time intervals. Operating at fluctuating generation levels is less efficient than operating at a steady state.

Q. How are regulation efficiency losses different from system efficiency losses?

A. System efficiency losses are losses incurred when a unit is set to generate at a level above or below peak efficiency so that it can provide reserves if needed. Regulation efficiency losses are additional losses realized as the generation level increases and decreases from this set point to actually provide the reserves. Efficiency increases as a generating unit moves toward peak efficiency and decreases as it moves away from peak efficiency. The efficiency curve flattens out as generation approaches the point of peak efficiency and gets steeper as it moves away from the point of peak efficiency. Therefore, the efficiency gained by a generation movement toward peak efficiency is less than the efficiency lost by a generation movement away from peak efficiency. This additional lost efficiency is analogous to lost fuel efficiency when driving a car in stop-and-go traffic rather than at a steady speed.

Figure 1 above, as well as Attachment D, Regulation Efficiency Loss, Figure 1D, describes this asymmetrical nature of movement along the efficiency curve.

Q. *How did you calculate the costs of regulation efficiency losses?*

A. We calculated the cost of regulation efficiency losses by multiplying the efficiency loss (in megawatts) by an energy price in $/MWh.

Q. *How did you estimate the regulation efficiency loss?*

A. First, we estimated typical percentage efficiency losses for two types of generating units used at the Big 10 projects: Francis generating units and Kaplan generating units. (Francis units are fixed blade turbines and are used on higher head, or deeper, projects; Kaplan generating units have movable turbine blades and are used on lower head, or shallower, projects). Units on regulation increase or decrease up to 5 MW to provide regulation reserves before another unit responds. In any given time period, we can expect that the average change in generation to be approximately 2.5 MW in either direction.

We then calculated the efficiency gain associated with a 2.5 MW movement towards peak efficiency and the efficiency loss associated with a 2.5 MW movement away from peak efficiency. The difference between the gain and loss in efficiency is the estimated regulation efficiency loss. The charts contained in Attachment D, Regulation Efficiency Loss, Figure 2D, demonstrate how we calculated the efficiency loss percentages. For Francis units the efficiency loss is 0.28% of total generation; that is 0.22 MW is lost with every MW of regulation provided by a typical unit loading of 79 MW. For Kaplan units estimated regulation efficiency losses are 0.05% of total generation; that is 0.04 MW is lost with every MW of regulation provided by a typical unit loading of 85 MW.

Please refer to Attachment D, Regulation Efficiency Loss, Tables 1D and 2D, to view a summary of how the lost generation is calculated.

Q. How did you get to an overall average efficiency loss per MW of regulation?

A. Based on historical operational data, 83% of regulating reserves are carried by Francis units and 17% are carried by Kaplan units. Thus, for each MW of regulation provided, the efficiency loss is:

(0.22 MW/MW regulation on F units) X (83% F units) +
(0.04 MW/MW regulation on K units) X (17% K units) =
0.0382 MW efficiency lost for each MW of regulation.

Q. How did you calculate the costs of the regulation efficiency losses?

A. We multiplied the MW of lost efficiency by an energy price to get the cost of regulation efficiency losses. We used the same $62.44/MWh energy price previously discussed in system efficiency losses above. Therefore, for each MW of regulation provided the cost is (0.0382 MW efficiency lost) X ($62.44) = $2.38/MWh

Since Power Services will be providing a weighted average of 32 MW of regulation during the rate period, the costs of efficiency losses are ($2.38/MWh)(32MW)(8760 hours/year) = $668,621.

We converted this cost into a price as follows:

($668,621/203 MW) X (1000kW/MW) = $0.27/kW per month

<u>Incremental O&M Costs for Regulation</u>

Q. What is the incremental O&M cost associated with regulation?

A. The incremental O&M cost accounts for incremental impacts to the generating equipment when it responds to constant changes in generation output caused by the moment-to-moment fluctuations of regulation.

Q, How did BPA calculate the incremental O&M costs?

A. We used the incremental O&M costs for regulation as calculated in the 2007 Power Rate Case final rate proposal. See WP-07-FS-BPA-05B, Section 4.4.2, Table 3, Attachment F. That calculation is based on three steps. First, BPA calculated the total O&M costs for Kaplan units and for Francis units per kilowatt-year. For Kaplan units the cost is $13.78/kW-year and for Francis units it is $8.78/kW-year. BPA then calculated the incremental increase in O&M costs caused by regulation based on consultations with the Corp of Engineers (COE). For Kaplan units the increased O&M cost is 15%, which is $0.50/kW-month for each MW of regulation. For Francis units, carrying additional regulation reserves increases O&M cost by 10%, which is $.96/kW-month for each MW of regulation.

To convert this value to a rate that applies to total MW of regulating reserves, we multiply by the proportional share of regulation: (32MW/203 MW)($1.46/kWm)= $0.23 per kW-month of regulating reserves.

Section 7.2: Cycling Costs

Cycling Efficiency Losses

Q. What are cycling efficiency losses?

A. Cycling losses are incurred for following; that is, for relatively large changes in regulating reserves over a period of time longer than the instantaneous regulation time frame, but still less than one hour. A change is considered large any time units must be turned on or off in order to provide following reserves. The average Big 10 generating unit providing following reserves is set to operate at 84 MW. We assumed that any change larger than 84 MW required another generating unit to be turned on or off. For this analysis, we calculated how many times per hour a unit must be cycled on or off to provide following reserves.

Q. How are cycling efficiency losses different from system efficiency losses?

A. Cycling efficiency losses are different from system efficiency losses because they relate to the costs of turning generating units on and off, rather than the generation level the unit is set to operate to.

Q. How are cycling efficiency losses different than regulation efficiency losses?

A. Regulation efficiency losses relate to the small range of movement around the point the unit is set to. Cycling efficiency losses, in contrast, relate to the lost efficiency that occurs when BPA turns a unit on, synchronizes it (getting the rotation of the generator compatible with system frequency), and ramps it up to full operating level.

Q. How did you calculate the costs of cycling efficiency losses?

A. We calculated cycling costs in two steps.

Q. What is the first step?

A. First, we calculated the expected number of additional times a generating unit cycles on or off per hour when providing the following portion of the incremental regulating reserves (i.e., 160 WM for the first 10 months of FY 2009 and 228 MW for the last two months). To do this, we calculated the following requirement difference between the load only scenario and load with wind scenario as noted in, Reserve Capacity Need Forecast, McManus and Enyeart, WI-09-E-BPA-02, for each 60-minute time interval. Then we divided each difference by 84 MW, the average size of the units typically responding to the following requirement, and rounded down to the nearest integer to determine whether a unit cycle is required. Averaging all of the unit cycle events yields the expected number of additional unit cycles per hour. Table 1E of Attachment E, Unit Cycling, summarizes the results.

For the first 10 months of the year, this average is equal to .9038 cycles per hour, and for the last two months of the year, this average is 1.2591 cycles per hour.

Q. What is the second step?

A In the second step, we estimated the efficiency losses associated with turning a unit on and bringing it up to full power. It takes a hydroelectric generating unit about 10 minutes to come up to full power. For the first three or so minutes the generating unit is synchronizing. During the remaining seven minutes the unit is ramping up to full power. During these two stages, water is lost. This lost water is an efficiency loss because the water is not producing as much power as it would have had it been run through a unit operating at full power.

Q. How did you calculate the losses associated with synchronization?

A. BPA estimated that 10% of the water is lost during synchronization. The cost of this operation in dollars is a function of the following four items:

1) the production at peak efficiency in MW/cubic feet per second (cfs) (a),

2) the amount of water lost during synchronization in cfs (b),

3) the price of power in $/MWh (c),

4) the number hours it takes to synchronize (3 min/ 60 min) (d).

The total synchronization cost = a * b *c *d

BPA estimates the total cost of synchronization at $33 per cycle event. Table 2E of Attachment E, Unit Cycling, summarizes this calculation.

Q. How did you calculate ramping losses?

A. Ramping losses are the losses that occur while the unit ramps up to peak efficiency. We calculated the ramping cost by multiplying the following 3 items:

1) the ramp time in hours (7 minutes/60 minutes) (a),
2) the lost efficiency during the ramp in MW (b) (the difference between the peak efficiency and the average efficiency during the ramp),
3) the price of power in $/MWh (c).

The total ramping loss = a * b * c.

BPA estimates the total costs of ramping as $90 per cycle event. Table 3E of Attachment E, Unit Cycling, summarizes this calculation.

Q. What are the total costs of cycling efficiency losses?

A. The total cost of cycling efficiency loss per cycle event is the sum of the following: $33 per cycle event for synchronization plus $90 per cycle event for ramping = $123 per cycle event. In the following section, we add this cost to the O&M costs per cycle to calculate a total cost for cycling.

Incremental O&M Cost for Cycling

Q. What are O&M costs for cycling?

A. This cost component estimates wear and tear on machines associated with cycling units on and off to respond to the following component of regulating reserves. These costs reflect the added wear and tear due to stresses on equipment during start up and ramping. These stresses are unique to cycling.

Q. Please describe your general approach to calculating cycling O&M costs?

A. We calculated cycling O&M costs using an industry study that discusses the wear and tear on generating units due to cycling. This study, which BPA co-sponsored, was done in Norway through the Canadian Electric Association Technologies Incorporated (CEATI). The study, Cost of Start-Stop Operations, CEATI Report # T022700-0315, was prepared by Norconsult/Statkraft SF, Oslo, Norway, for the Swedish utility Vattenfall AB. We started with the total cost of cycling used in the CEATI study for a Francis generating unit. We then reduced the total cost by eliminating or modifying components that needed adjustment or were duplicative to other costs already accounted for above. The modified CEATI equation more accurately reflects the operations of the FCRPS. The original CEATI equation and BPA's modification are available in Table 5E of Attachment E, Unit Cycling.

Q. What modifications did you make to the CEATI equation?

A. We made four modifications to the cycling equation from the CEATI study. First, we removed the operator labor portion because these costs are already accounted for in the embedded cost component described above. Second, we removed the efficiency losses during cycling component because these costs are calculated in the cycling efficiency losses. Third, a unit occasionally fails to start when turned on, called a "failed start." We reduced the cost in the CEATI study associated with failed starts by 90%. The study assumed it would take a much longer time to restart a unit than has been the case in BPA's experience. Finally, we reduced the wear and tear on the turbine water-passage gates by 40%. We made this adjustment because the FCRPS uses a type of water-passage gate that requires less maintenance.

Q. What are the incremental O&M costs of cycling?

A. The CEATI study estimated a cost per cycling event of approximately $444. BPA's modified estimate was $175. Table 5E of Attachment E shows the adjustments BPA made.

Q. Please summarize the total costs of cycling.

A. The total cycling cost per cycling event is calculated by adding the cycling efficiency losses ($123) and the incremental O&M due to cycling ($175). The result is $298 per cycling event. As shown in Attachment E, Unit Cycling, Table 6E, this translates to a rate of $1.03/kWm per kilowatt month of following.

Section 7.3 Summary of Response Costs

Q. Please summarize how you calculate the charge for the response cost component.

A. The charge for the response cost component is comprised of the following:

$.27/kW per month for regulation efficiency loss +

$0.23/kW per month for regulation O&M +

$1.03/kW per month for cycling (cycling efficiency losses and O&M cycling costs)

= $1.54/kW per month.

Q. *Does this conclude your testimony?*

A. Yes.

This page intentionally left blank.

Attachment A: Energy Shift Cost Tables

Calculating the percentage of ten minute intervals needing to shift energy

Table 1A: Results from observing 10-minute data:

Number of Monthly Observations Containing a Control Deficit for Each Given Quantity of Regulating Reserve per 10 min. SCADA data.		
Historic Month	Regulating Reserve: 190 MW	Regulating Reserve: 270 MW
Jan	633	872
Feb	317	482
Mar	977	1286
Apr	2177	2927
May	2031	2363
Jun	1479	1779
Jul	444	702
Aug	796	1186
Sep	565	904
Oct	1190	1563
Nov	729	1015
Dec	494	783

Table 2A: Total number of monthly, 10 minute data observations:

Historic Month	Total Number of 10 min Data
Jan	4342
Feb	3995
Mar	4447
Apr	8587
May	4379
Jun	4251
Jul	4424
Aug	4336
Sep	3919
Oct	4428
Nov	4294
Dec	4382

Table 3A: Probability of control deficit by month:

Probability of Control Deficit by Month for Each Given Level of Regulating Reserve.		
Historic Month	Prob. of Control Deficit @ 190 MW	Prob. of Control Deficit @ 270 MW
Jan	0.1458	0.2008
Feb	0.0793	0.1207
Mar	0.2197	0.2892
Apr	0.2535	0.3409
May	0.4638	0.5396
Jun	0.3479	0.4185
Jul	0.1004	0.1587
Aug	0.1836	0.2735
Sep	0.1442	0.2307
Oct	0.2687	0.3530
Nov	0.1698	0.2364
Dec	0.1127	0.1787

Table 4A: Average Probability of a control deficit:

	Regulating Reserve: 190 MW	Regulating Reserve: 270 MW
Average Prob. of Control Deficit	0.2075	0.2784

Calculating the expected control deficit

Table 5A: Expected control deficit by month:

Average Control Deficit by Month for Each Given Level of Regulating Reserve.		
Historic Month	Average Control Deficit @ 190 MW	Average Control Deficit @ 270 MW
Jan	-180	-206
Feb	-152	-171
Mar	-203	-232
Apr	-187	-214
May	-218	-273
Jun	-218	-284
Jul	-136	-156
Aug	-154	-175
Sep	-112	-140
Oct	-136	-180
Nov	-167	-194
Dec	-139	-157

Table 6A: Average control deficit:

	Regulating Reserve: 190 MW	Regulating Reserve: 270 MW
Average Control Deficit	-167	-199

Table 7A: Total energy shift cost:

A) Incremental Regulating Reserve (MW)	B) Prob. of Control Deficit (%)	C) Expected Value Control Defict (MW)	D) Expected Energy Shift Price ($/MWh)	E) Prob. Weighted Cost of Control Deficit ($)	F) Unit Cost $/kWm of Reserve
190	20.75%	167	11.58	3,510,067	1.54
270	27.84%	199	11.58	5,603,940	1.73

E = 8760 * B * C * D

Attachment B: Efficiency Curves

Chart 1B: Grand Coulee small unit:

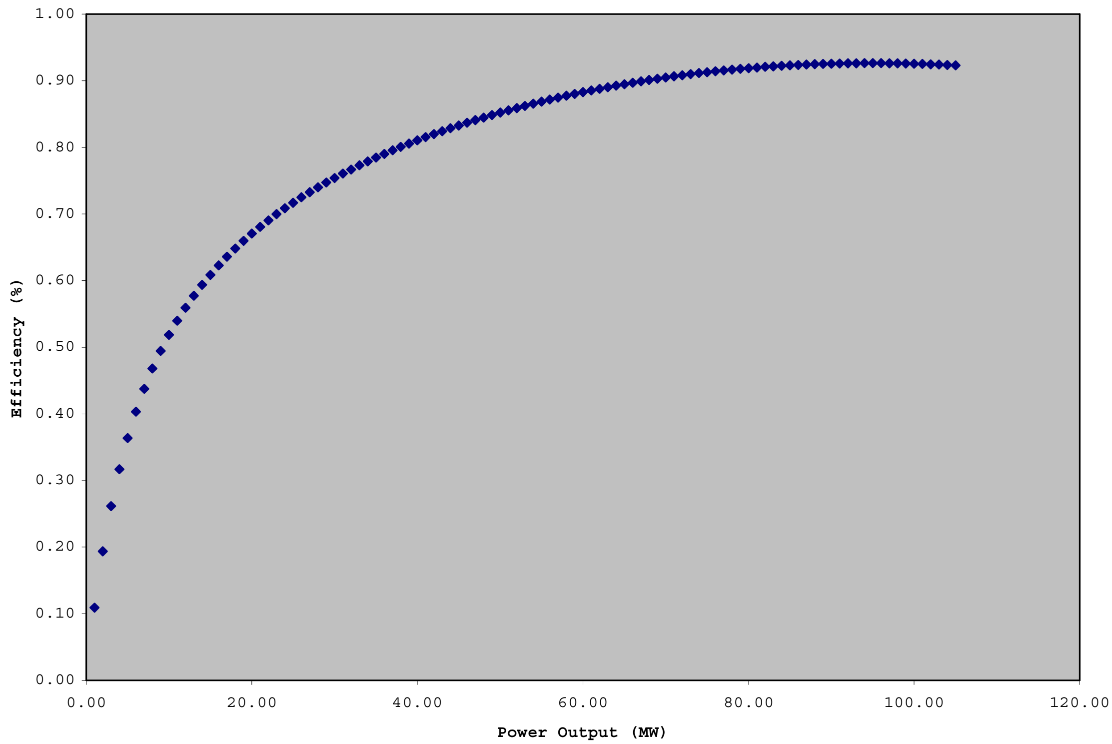


Chart 2B: Chief Joseph:

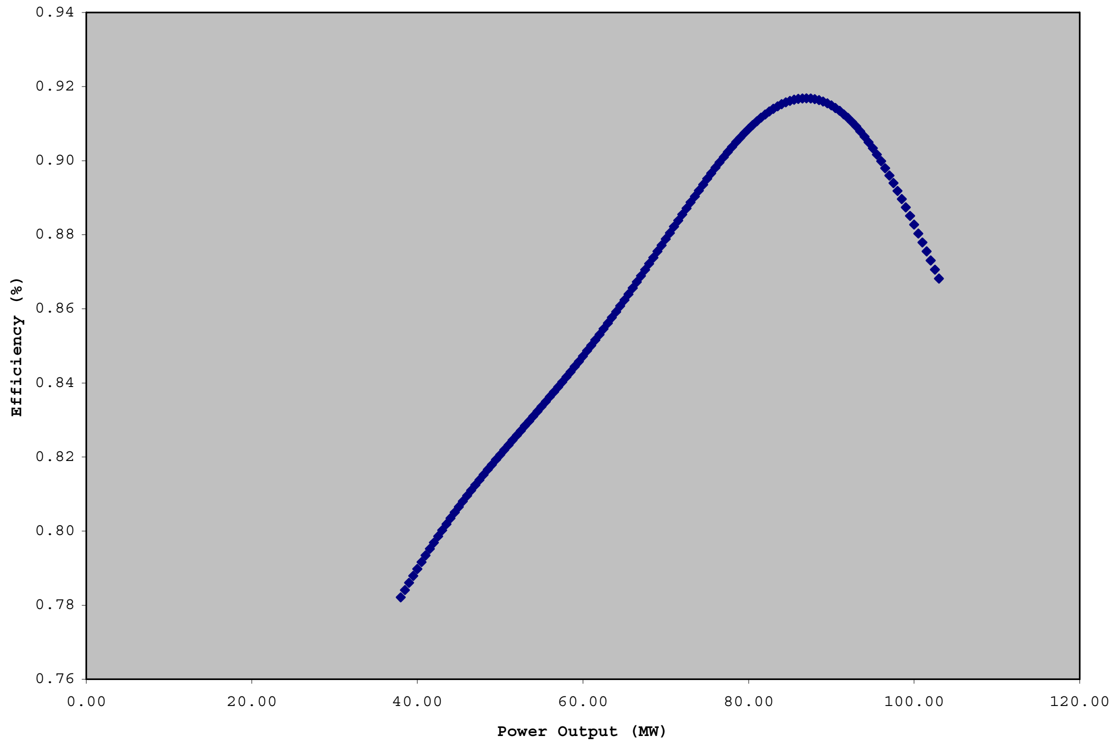


Chart 3B: John Day:

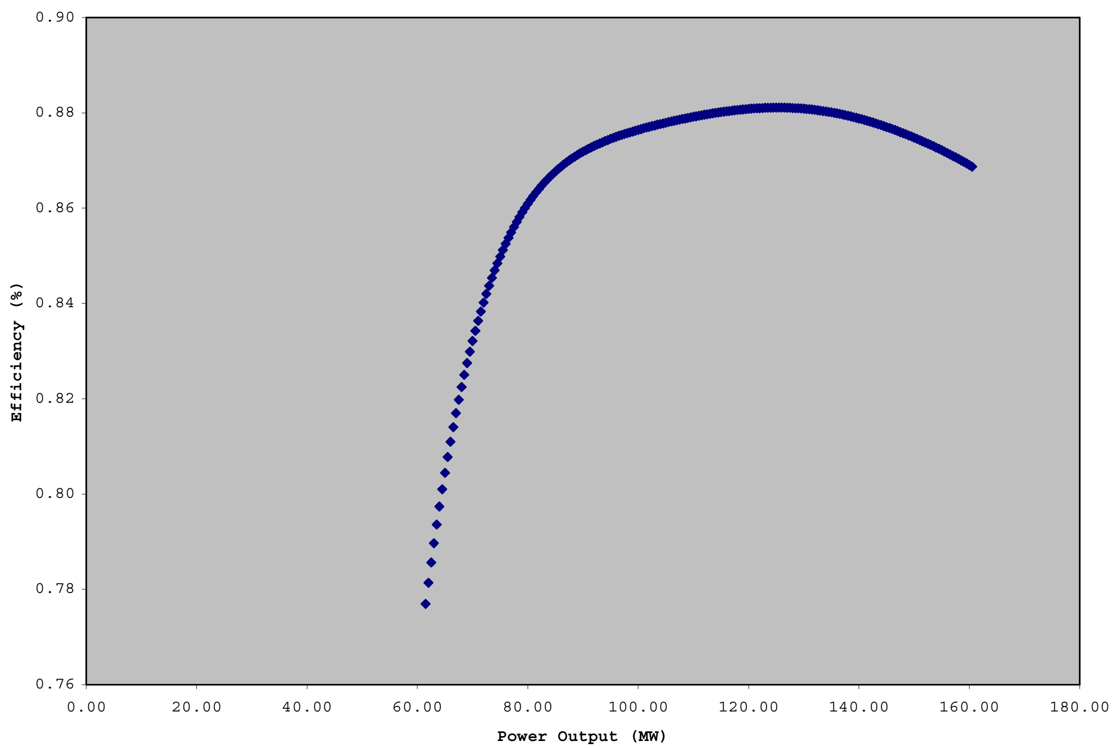
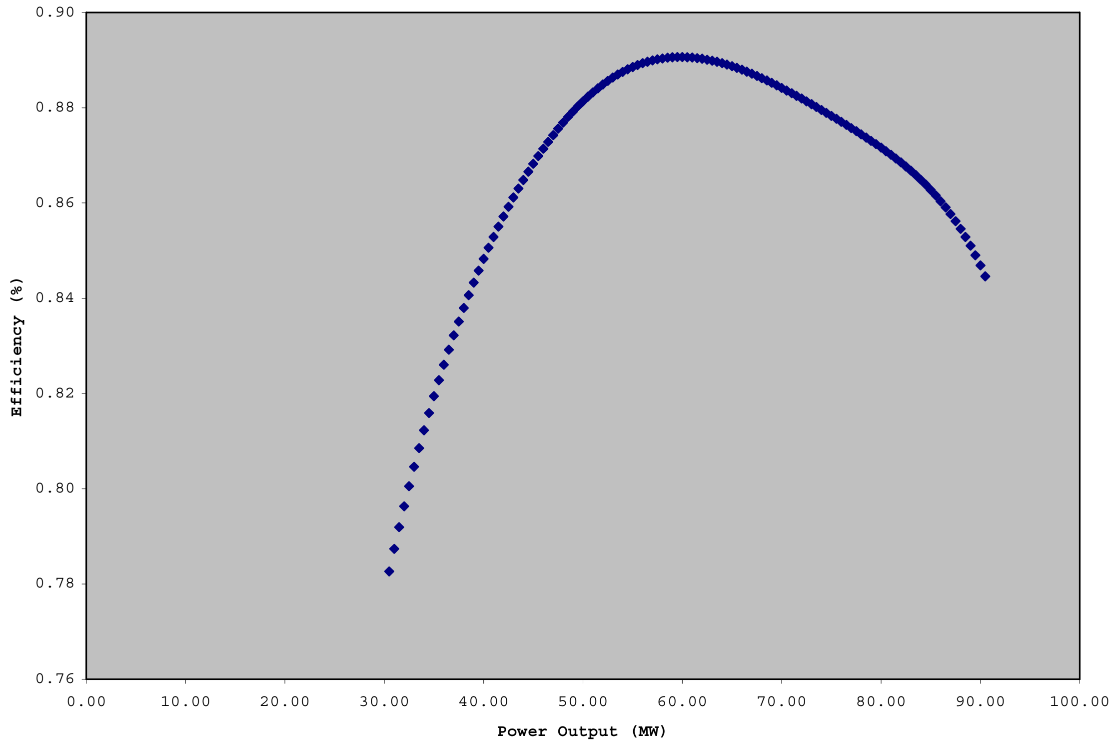


Chart 4B: The Dalles:



This page intentionally left blank.

Attachment C: System Efficiency Loss Tables

Table 1C:

190MW Regulating Reserve	TDA	JDA	CHJ	GCL	Total
Typical Response/MW Reserve (%)	10.00%	15.00%	25.00%	50.00%	100.00%
Average LLH Min. Gen. (aMW)	439.0	405.0	395.5	1045.0	2284.5
Efficiency Change w/Reg. Res. (%)	-0.06%	-0.10%	-1.04%	0.00%	-1.20%
Lost Generation (aMW)	-0.28	-0.40	-4.10	0.00	-4.77

Hours of Efficiency Loss (h)	3,754
Price of Power ($/MWh)	62.44
Total Cost of Lost Generation ($)	1,118,292
$/kWm of Reserve	0.49

270MW Regulating Reserve	TDA	JDA	CHJ	GCL	Total
Typical Response/MW Reserve (%)	10.00%	15.00%	25.00%	50.00%	100.00%
Average LLH Min. Gen. (aMW)	447.0	417.0	415.5	1085.0	2364.5
Efficiency Change w/Reg. Res. (%)	-0.12%	-0.34%	-0.27%	0.00%	-0.72%
Lost Generation (aMW)	-0.53	-1.41	-1.11	0.00	-3.06

Hours of Efficiency Loss (h)	3,754
Price of Power ($/MWh)	62.44
Total Cost of Lost Generation ($)	716,154
$/kWm of Reserve	0.22

Example:
The Change in Efficiency
The following example calculates the change in efficiency for JDA under the 190 MW regulating reserve scenario:

For JDA:

Min Gen (MW)	376.5
Pk. eff. Gen. (MW)	125.5
Pk. eff. (%)	0.8811

Three units generating at a peak efficient power output of 125.5 MW produces a minimum generation of 376.5 MW. Refer to Attachment B, Efficiency Curves, Chart 3B: John Day.

For 190 MW of regulating reserve, 15% is expected to be met by JDA: 190 MW * 0.15 = 28.5 MW.

To provide for the down regulation without violating the minimum generation of 376.5 MW, JDA must generate 405 MW: 28.5 MW + 376.5 MW.

Each of the 3 online units must increase power output by 9.5 MW: 28.5 / 3.

Each of the 3 JDA units are now generating at 135 MW: 9.5 MW + 125.5 MW.

From Attachment B, Efficiency Curves, Chart 3B: John Day, it is observed that increasing generation from 125.5 MW to 135 MW causes efficiency to drop. Efficiency at 125.5 MW of generation is 0.8811, while efficiency at 135 MW of generation is 0.8801. The change is efficiency is 0.0010 (0.8811 – 0.8801).

Lost Generation

With 3 JDA units generating at 135 MW in order to provide 28.5 MW of capability to back down, JDA's total generation is 405 MW.

JDA's lost generation is 405 MW * 0.0010: 0.3989 MW.

Attachment D: Regulation Efficiency Loss

Figure 1D: Regulation Efficiency Loss Example

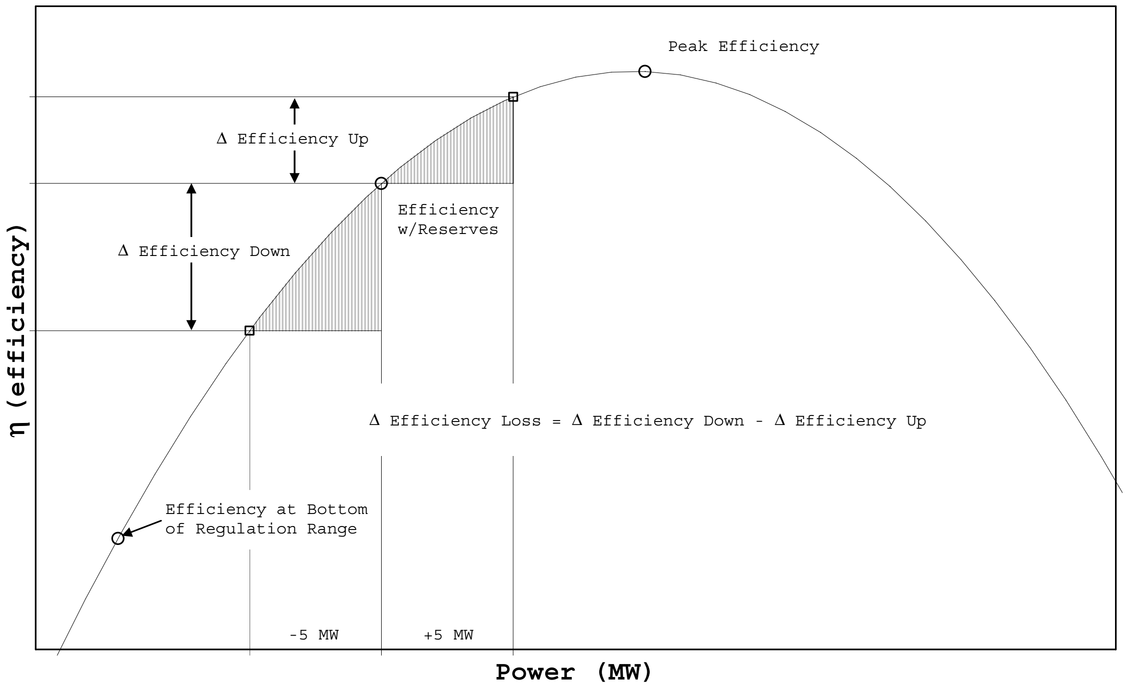
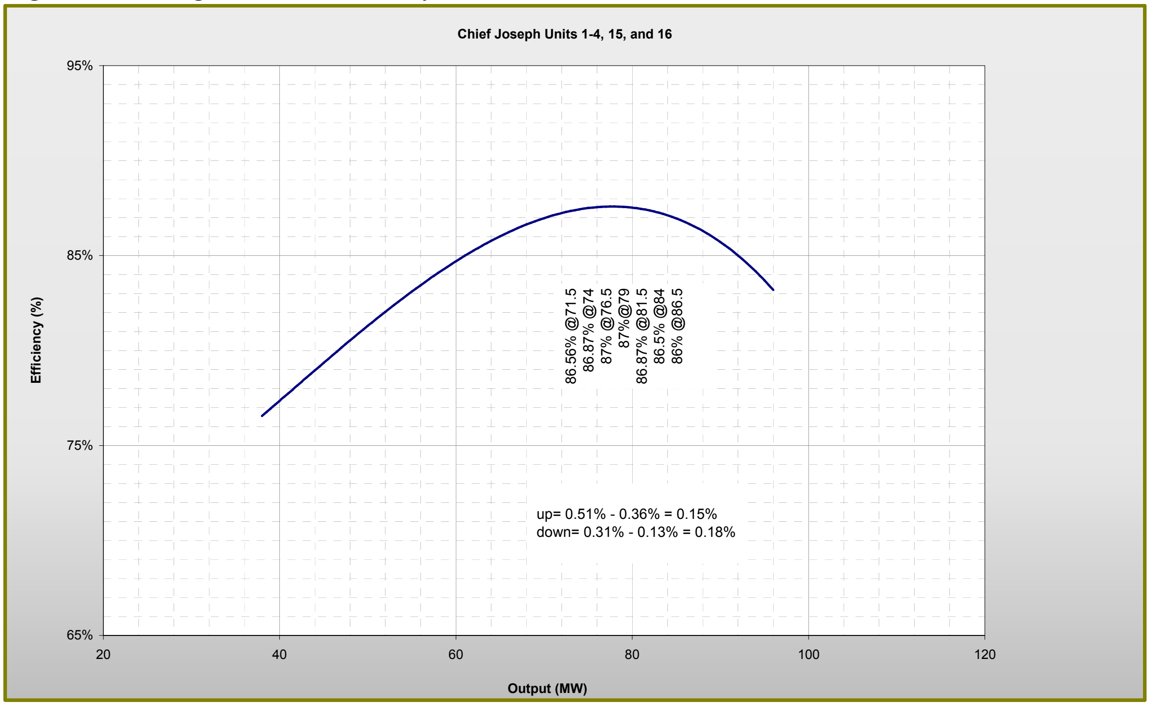
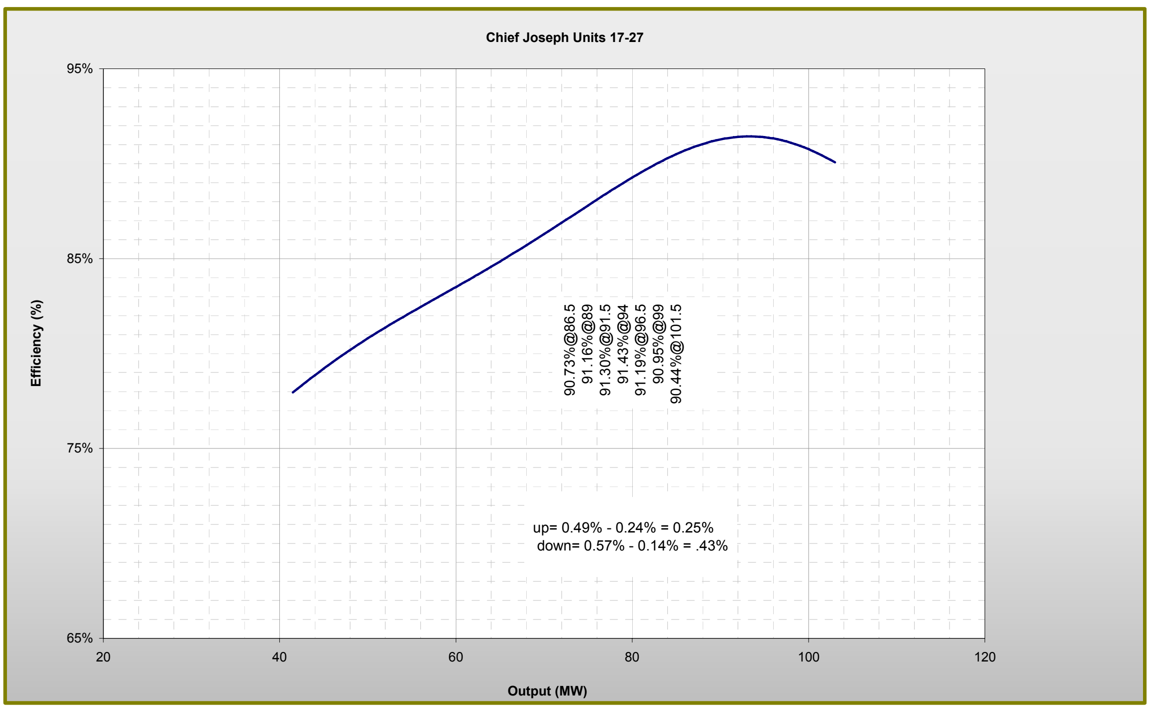
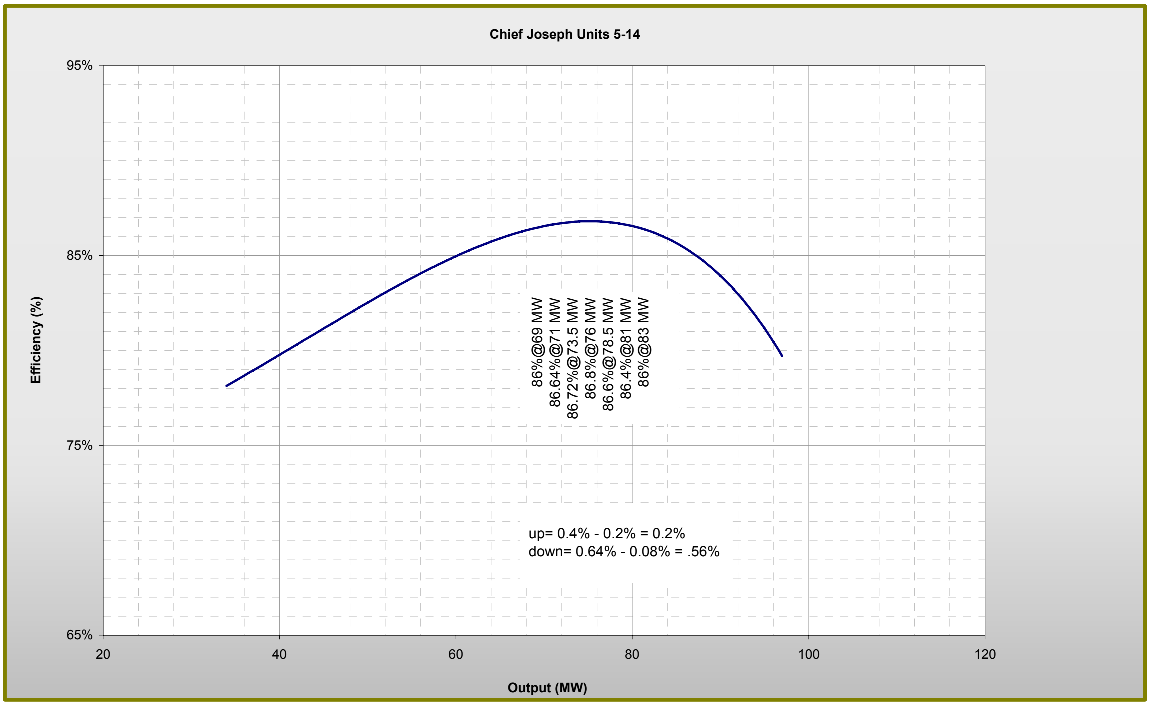
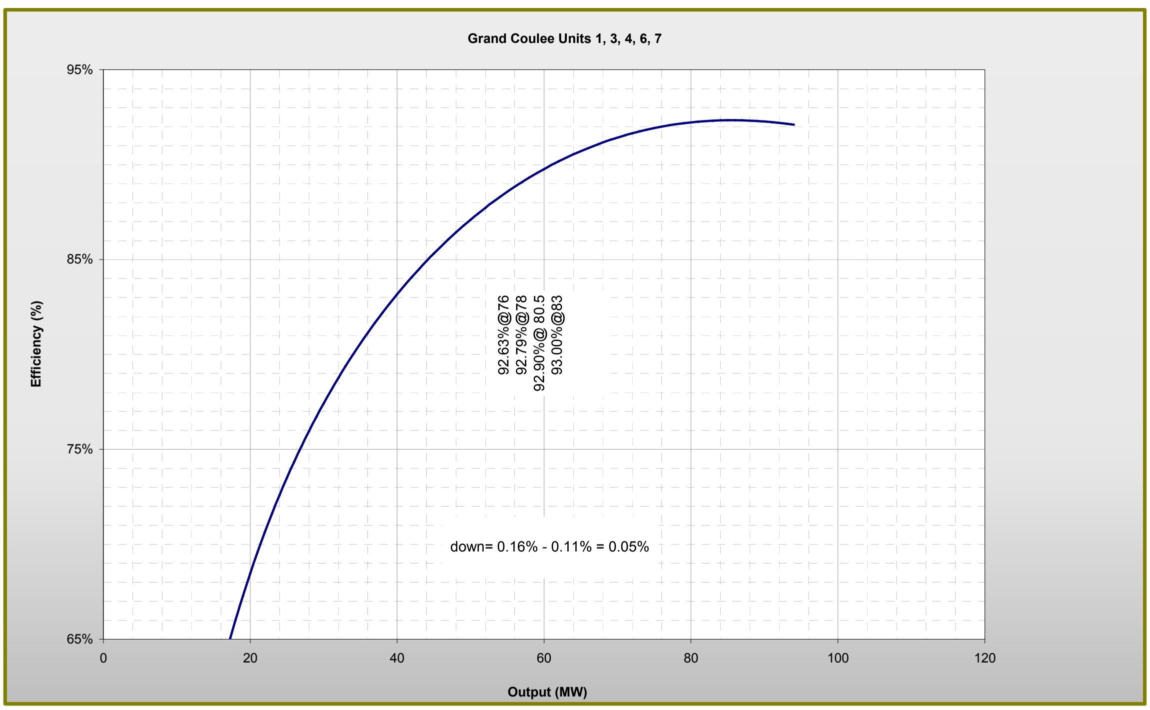


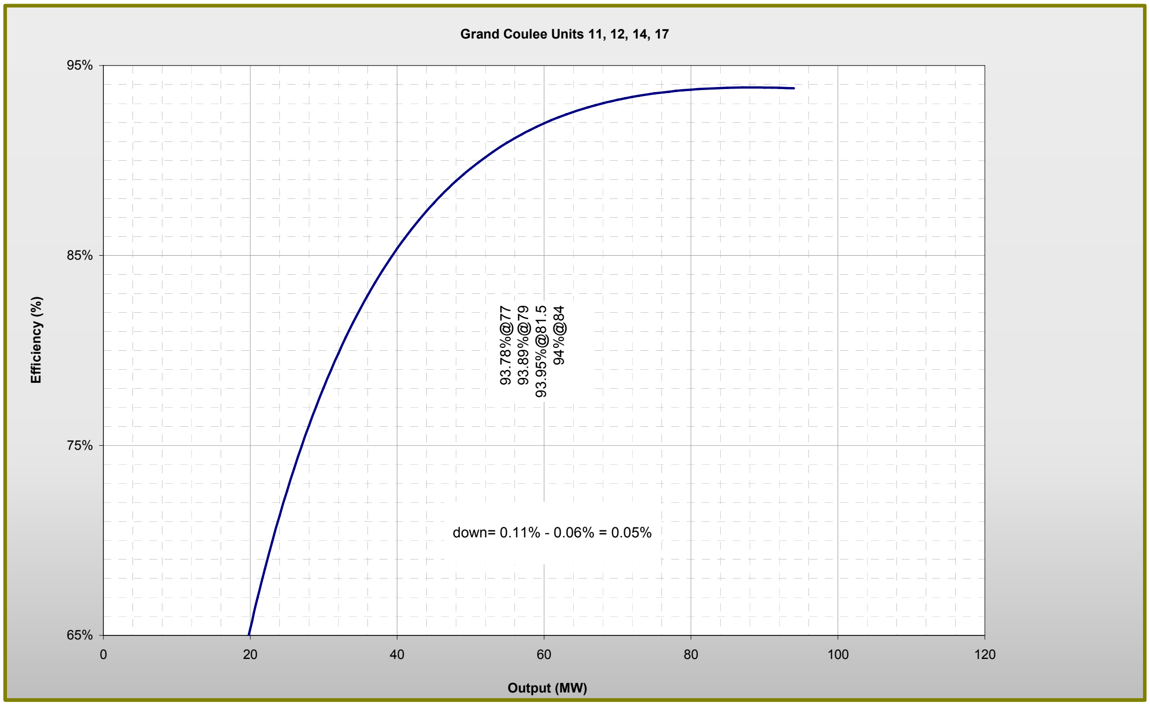
Figure 2D: Regulation Efficiency Loss Calculation

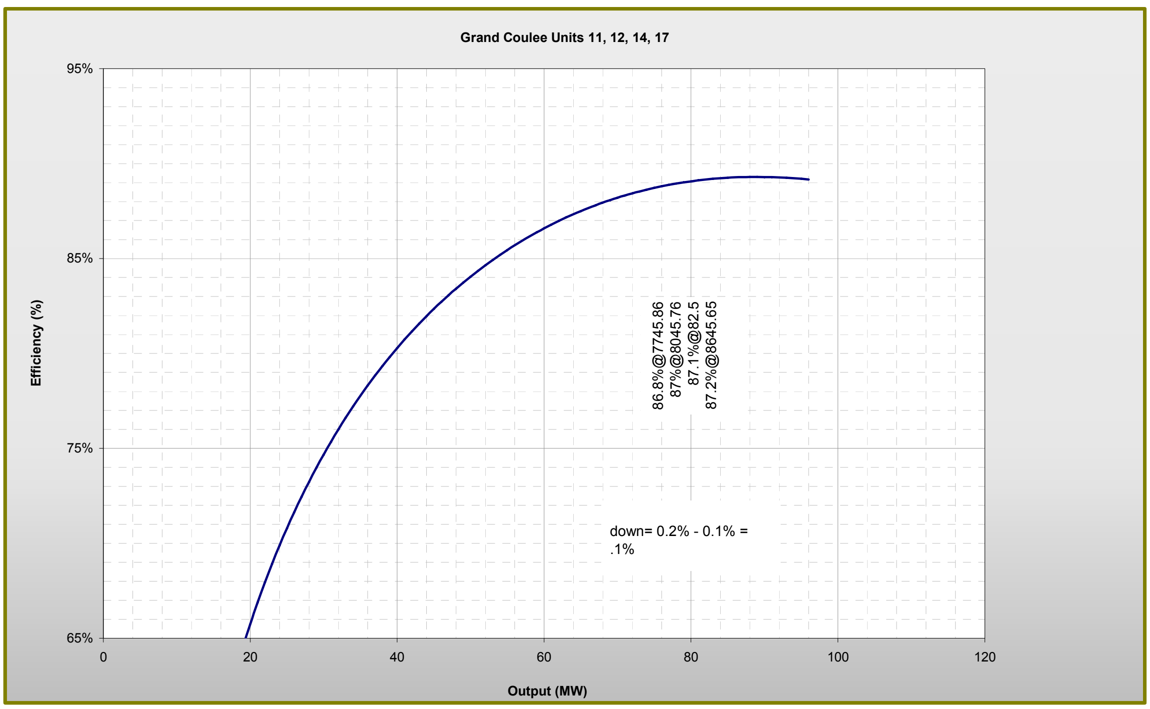


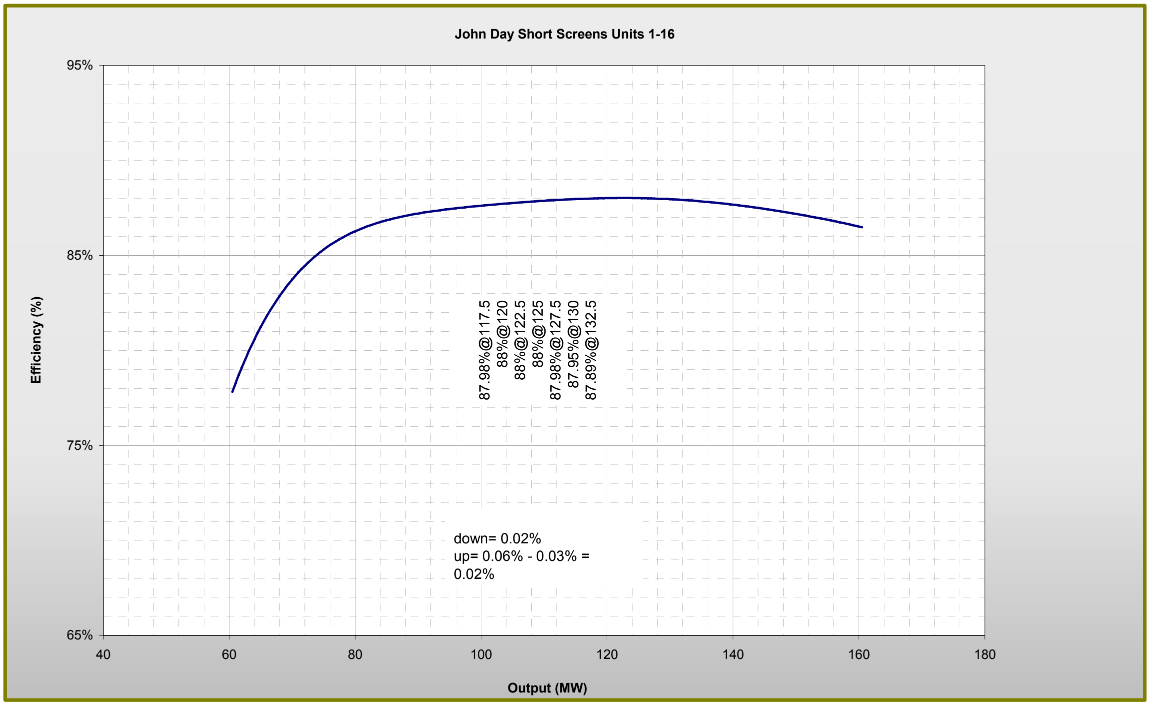


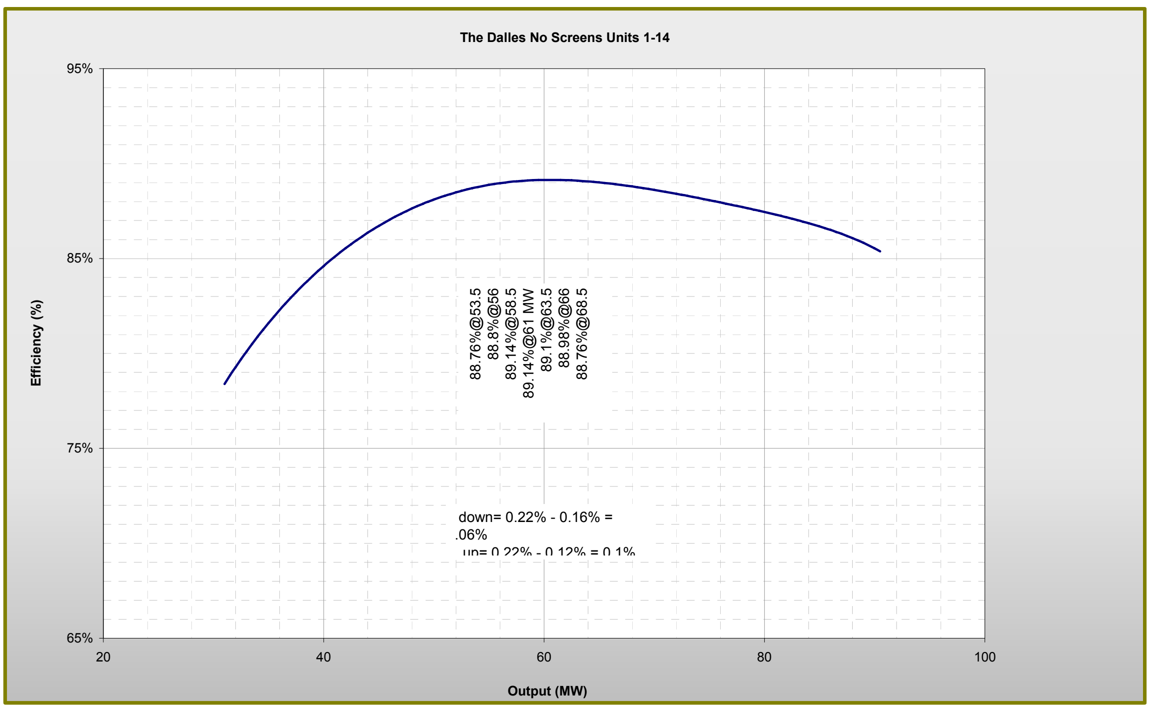

Chief Joseph Units 5-14
95%
85%
75%
65%
Efficiency (%)
20
40
60
80
100
120
Output (MW)
86%@69 MW
86.64%@71 MW
86.72%@73.5 MW
86.8%@76 MW
86.6%@78.5 MW
86.4%@81 MW
86%@83 MW
up= 0.4% - 0.2% = 0.2%
down= 0.64% - 0.08% = .56%

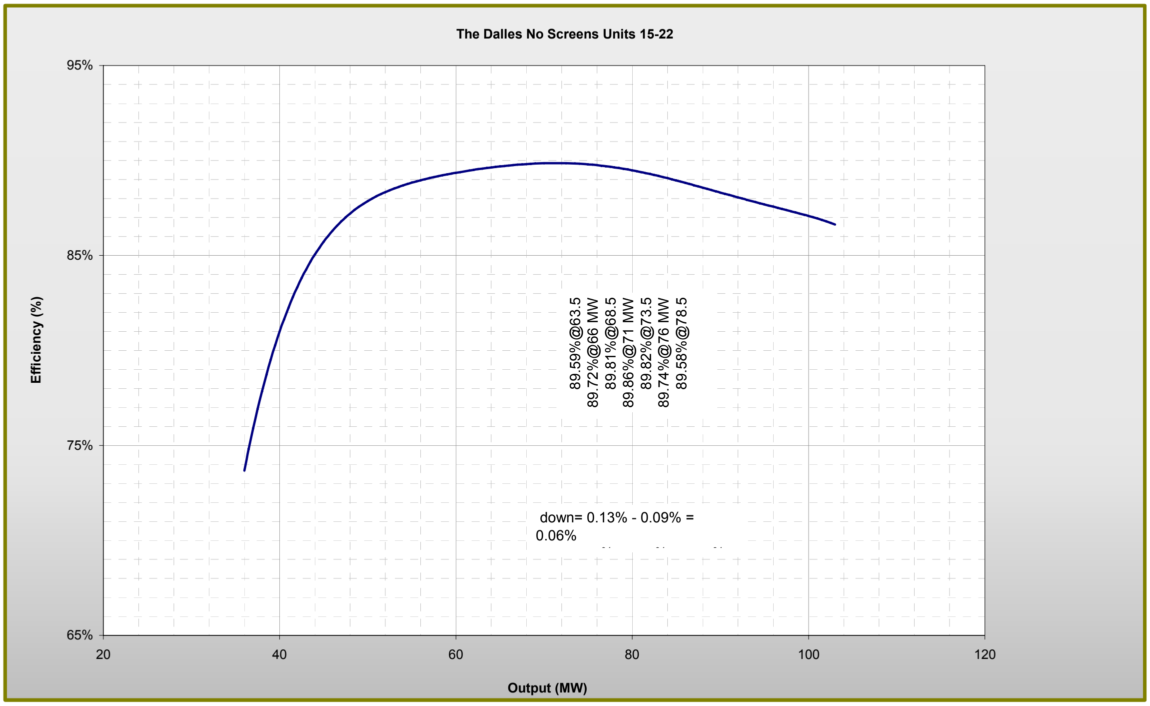

Grand Coulee Units 1, 3, 4, 6, 7
95%
85%
75%
65%
Efficiency (%)
0
20
40
60
80
100
120
Output (MW)
92.63%@76
92.79%@78
92.90%@ 80.5
93.00%@83
down= 0.16% - 0.11% = 0.05%


Grand Coulee Units 11, 12, 14, 17
95%
85%
75%
65%
Efficiency (%)
93.78%@77
93.89%@79
93.95%@81.5
94%@84
down= 0.11% - 0.06% = 0.05%
0
20
40
60
80
100
120
Output (MW)


Grand Coulee Units 11, 12, 14, 17
95%
85%
75%
65%
Efficiency (%)
86.8%@7745.86
87%@8045.76
87.1%@82.5
87.2%@8645.65
down= 0.2% - 0.1% =
.1%
0
20
40
60
80
100
120
Output (MW)


John Day Short Screens Units 1-16
95%
85%
75%
65%
Efficiency (%)
87.98%@117.5
88%@120
88%@122.5
88%@125
87.98%@127.5
87.95%@130
87.89%@132.5
down= 0.02%
up= 0.06% - 0.03% =
0.02%
40
60
80
100
120
140
160
180
Output (MW)


The Dalles No Screens Units 1-14
95%
85%
75%
65%
Efficiency (%)
88.76%@53.5
88.8%@56
89.14%@58.5
89.14%@61 MW
89.1%@63.5
88.98%@66
88.76%@68.5
down= 0.22% - 0.16% =
.06%
20
40
60
80
100
Output (MW)



The Dalles No Screens Units 15-22
95%
85%
75%
65%
Efficiency (%)
20
40
60
80
100
120
Output (MW)
89.59%@63.5
89.72%@66 MW
89.81%@68.5
89.86%@71 MW
89.82%@73.5
89.74%@76 MW
89.58%@78.5
down= 0.13% - 0.09% = 0.06%

Table 1D: Regulation Efficiency Loss Calculations (Francis Units)

Francis Units: Calculate Efficiency Loss for AGC Operation			
Location	**Down %**	**Up %**	**# of Units**
CJ-10	0.56	0.20	10
CJ-11	0.43	0.25	11
CJ-6	0.18	0.15	6
GC-5	0.05		5
GC-4	0.05		4
GC-5	0.10		5

Francis Units: Set 90% Time Down (Lower than Peak Efficiency Generation)	
Weighted Average Efficiency Loss (%)	0.276

Weighted Average Francis Generating Unit			
Location	**# of Units**	**Generation**	**Regulation**
CJ-10	10	71	5
CJ-11	11	89	5
CJ-6	6	74	5
GC-5	5	78	5
GC-4	4	79	5
GC-5	5	80	5
Weighted Average		79.0	5

Francis Regulation Efficiency Loss	
Weighted Average Efficiency Loss (%)	0.28
Weighted Average Francis Gen (MW)	79.0
MW Loss/MW Francis Generation (MW)	0.22

Table 2D: Regulation Efficiency Loss Calculations (Kaplan Units)

Kaplan Units: Calculate Efficiency Loss for AGC Operation			
Location	**Down %**	**Up %**	**# of Units**
JD-16	0.02	0.03	16
TD-14	0.06	0.10	14
TD-8	0.06	0.08	8

Kaplan Units: Set 90% Time Down (Lower than Peak Efficiency Generation)	
Weighted Average Efficiency Loss (%)	0.045

Weighted Average Kaplan Generating Unit			
Location	**# of Units**	**Generation**	**Regulation**
JD-16	16	120	5
TD-14	14	56	5
TD-8	8	66	5
Weighted Average		85.1	5

Kaplan Regulation Efficiency Loss	
Weighted Average Efficiency Loss (%)	0.05
Weighted Average Kaplan Gen (MW)	85.1
MW Loss/MW Francis Generation (MW)	0.04

This page intentionally left blank.

Attachment E: Unit Cycling

Table 1E: Calculating the Expected Increase in Unit Cycling

Expected Additional Unit Cycles for 190 MW of Regulating Reserve

Observation #	Following No RegRes	Following w/RegRes	Number of Cycles
1	201.7	179.6	0
2	201.0	178.5	0
3	199.9	177.0	0
4	198.0	174.7	0
5	198.1	174.5	0
6	198.3	174.6	0
7	196.2	172.4	0
8	193.9	169.9	0
9	192.6	168.5	0
10	191.3	167.2	1
11	190.6	166.4	1
12	189.9	165.7	1
13	188.9	164.7	1
14	188.1	163.7	1
15	187.2	162.8	1
16	187.1	162.9	1
17	187.2	163.2	1
18	186.2	162.2	1
19	185.4	161.3	1
20	184.7	160.6	1
.	.	.	.
.	.	.	.
.	.	.	.
.	.	.	.
175280	130.2	75.6	1
175281	127.7	75.2	1
175282	125.1	74.7	1
175283	122.4	74.0	1
175284	119.1	72.6	1
175285	116.2	71.3	1
175286	113.2	69.9	1
175287	110.3	68.8	1
175288	107.0	67.1	1
175289	103.4	65.0	1
175290	99.8	62.9	1
175291	96.1	60.8	1
175292	92.3	58.5	1
175293	88.2	56.0	1
175294	84.1	53.2	1
175295	80.0	50.2	0
175296	76.5	47.8	0
175297	74.2	46.3	0
175298	72.1	45.2	0
175299	69.9	43.8	0

Expected Additional Cycles/Hour	0.9038

Expected Additional Unit Cycles for 270 MW of Regulating Reserve

Observation #	Following No RegRes	Following w/RegRes	Number of Cycles
1	157.6	65.2	1
2	157.2	61.8	1
3	157.7	59.2	1
4	158.6	57.2	1
5	159.6	55.5	1
6	160.5	53.8	1
7	161.2	52.2	1
8	160.3	49.1	1
9	158.4	44.8	1
10	157.5	41.5	1
11	156.7	38.5	1
12	156.1	35.7	1
13	155.6	33.3	1
14	155.2	31.4	1
15	155.1	29.9	1
16	155.0	28.3	2
17	154.7	26.6	2
18	152.8	23.3	2
19	150.9	20.1	2
20	149.4	17.4	2
.	.	.	.
.	.	.	.
.	.	.	.
.	.	.	.
175280	270.6	370.1	1
175281	276.8	374.9	1
175282	283.1	380.1	1
175283	288.9	384.8	1
175284	295.3	390.3	1
175285	300.4	394.8	1
175286	305.3	399.3	1
175287	309.6	403.7	1
175288	313.9	408.2	1
175289	318.0	412.8	1
175290	320.9	416.1	1
175291	323.1	418.9	1
175292	325.0	421.5	1
175293	328.3	425.7	1
175294	332.0	430.3	1
175295	335.1	434.5	1
175296	338.1	438.4	1
175297	339.4	440.8	1
175298	339.6	442.2	1
175299	339.1	442.7	1

Expected Additional Cycles/Hour	1.2591

For any given observation, n, increase in the number of unit cycles is given by:

$$\text{Number of Cycles}_n = |\text{Following No RegRes}_n - \text{Following w/RegRes}_n| / 84 = \mathbf{N}.$$

The Expected Additional Cycles/Hour is the average of column vector **N**.

Table 2E: Synchronization Cost Calculation

	Typical Unit Characteristics		
a.	Unit Nameplate (MW)	103	Input
b.	Peak Eff. Generation (MW)	93	Input
c.	Full Gate Flow (cfs)	7,500	Input
d.	Flow @ Pk. Eff. Gen. (cfs)	6,680	Input
	Calculated Values Given Unit Characteristics		
e.	Peak Eff. Production Coeff. (MW/cfs)	0.0139	b / d
f.	Synchonizatoin Loss: 10% Full Gate Flow (cfs)	750	0.10 * c
g.	Price of Power ($/MWh)	62.44	Input
h.	Hours Synchonizing (3min/60min/h)	0.0500	3 / 60
i.	Synchonization Cost per Cycle Event ($/cycle)	32.6	e *f *g * h

Table 3E: Ramping Cost Calculation

	Typical Unit Characteristics		
a.	Unit Nameplate (MW)	103	Input
b.	Peak Eff. Generation (MW)	93	Input
c.	Full Gate Flow (cfs)	7,500	Input
d.	Flow @ Pk. Eff. Gen. (cfs)	6,680	Input
e.	Average Gen. Over 7 min. Ramp (MW)	45	Input
f.	Flow Over Ramp (cfs)	3,730	Input
	Calculated Values Given Unit Characteristics		
g.	Peak Eff. Production Coeff. (MW/cfs)	0.0139	b / d
h.	Ramp Production Coeff. (MW/cfs)	0.0121	e / f
i.	Lost Efficiency (MW/cfs)	-0.0019	h - g
j.	Lost Efficiency per minute over Ramp (MW)	-12.4	i * d
k.	Price of Power ($/MWh)	62.44	Input
l.	Hours Ramping (7min/60min/h)	0.1167	7 / 60
m.	Ramping Cost per Cycle Event ($/cycle)	90.4	j * k * l

Table 4E: Calculating the Average Nameplate of GCL, CHJ, JDA, TDA

	Nameplate of Unit	Number of Units
CHJ	88.3	16
CHJ	95.0	11
GCL	125.0	18
JDA	135.0	16
TDA	78.0	14
TDA	86.0	7
Total	8561.8	82
Average Nameplate		104.4

Table 5E: Start/Stop Equation

Norwegian Study Equation:

Start/Stop Cost = Turbine Power (MW) * 10 NOK/MW + 1400 NOK

Turbine Power (MW)	104.0
Constant (NOK/MW)	10.0
USD/NOK	0.18
Constant (NOK)	1,400.0
USD/NOK	0.18
Total Start/Stop Cost	444.08

Costs Reflected in the Norwegian Study Equation:

Percent of Study Equation Output Reflecting the Following Costs	Total Study Cost	FCRPS Applied Cost
Cost at normal start:	19.40%	0.00%
Error:	35.71%	3.60%
Water loss:	1.83%	0.00%
Turbine aggregate:	4.52%	4.52%
Valve aggregate:	17.30%	10.00%
Generator:	21.24%	21.24%
Breakers:	0.00%	0.00%
Other costs:	0.00%	0.00%
Sum:	100.00%	39.36%

Start/Stop Cost per Norwegian Study Equation:

Total ($/event)	444.08
% Applicable to FCRPS (%)	39.36%
FCRPS Total Start/Stop ($/event)	174.79

Table 6E: Calculating the Total Cycling Cost per Event

	190 MW Reg Res	270 MW Reg Res
Expected Additional Cycles/Hour	0.9038	1.2591
$/Cycle	298	298
Hours/Year	8,760	8,760
Total Cost/Year	2,359,352	3,286,855
Reserve (MW)	190	270
$/kWm of Reserve	1.03	1.01

Weighting $1.03for ten months of the year and $1.01 for 2 months of the year yields a rate of $1.03.

This page intentionally left blank.

Section 4.4.2 - Table 1
Summary of Costs Assigned to TBL for the Generation Input for Regulating Reserves
(x1000)

	Regulating Reserves Generation Input	Average Over Rate Period Subtotals (X000)	Average Over Rate Period Totals (X000)
1	**Big 10 Dams**		
2	O&M	$ 166,675	
3	Depreciation	$ 66,928	
4	Net Interest	$ 88,949	
5	Planned Net Revenues	$ 26,225	
6	Total Revenue Requirement		$ 348,777
7	**Fish & Wildlife**		
8	O&M **1/**	$ 208,872	
9	Amortization/Depreciation	$ 36,042	
10	Net Interest	$ 35,053	
11	Planned Net Revenues	$ 10,397	
12	Subtotal Fish & Wildlife		$ 290,364
13	**A&G Expense 1/**		$ 92,349
14	**Total Revenue Requirement**		
15	Revenue Credits		
16	4h10C (non-operations)	$ 39,917	
17	Colville payment Treas. Credit	$ 4,600	
18	Generation Supplied Reactive Generation Input Cost **2/**	$16,394	
19	Subtotal Revenue Credits		$ 60,911
20	**Net Revenue Requirement**		**$ 670,579**

1/ Power Marketing, Power Scheduling, Generation Oversight, Corporate Expense and 1/2 Planning Council

2/ Average forecasted revenue for Generation Supplied Reactive over three-year rate period

WP-07-FS-BPA-05B
Page 18

Section 4.4.2 - Table 1B
Summary of Assumptions and Application of Methods to Develop Per Unit Generation Input and Annual Revenue Forecast for Regulating Reserves
(Average over Rate Period)

		FY07-09
	Regulating Reserve Assumptions	**Average MWs**
1	**Regulated + Independent Hydro**	**9,217**
2	Total BPA Control Area Reserve Obligation (Line 3 + 4)	690
3	Total Self-Supply and Third Party-Supply Reserve Obligation	310
4	**Total PBL Reserve Obligation**	**380**
5	**Control Area Regulation Requirement.**	**350**
5b	**TBL Regulating Reserves Requirement**	**150**
	Forecast of Average Hydro Generation System Uses	**Average MWs**
6	Average Hydro Generation (Line 1)	9,217
7	Total PBL Reserve Obligation (Line 4)	380
8	Control Area Regulation Requirement (Line 5)	350
9	**89% Average Hydro Generation System Uses**	**8,933**
	Factor to Apply to Revenue Requirement	**Average MWs**
10	Control Area Regulating Requirement (Line 5)	350
11	Total Average Control Area Generation (Line 9)	8,933
12	**Multiplication Factor for Revenue Requirement (Line 10 / Line 11)**	**0.03918**
	Adjusted Revenue Requirement	**Average $'s**
13	Power Revenue Requirement for Big 10 Hydro Projects	**$670,579,044**
14	Multiplication Factor (Line 12)	3.9180%
15	**Adjusted Revenue Requirement for Regulating Reserves**	**$ 26,273,284**
	Per Unit Rate	**Average $'s**
16	Adjusted Revenue Requirement for Regulating Reserves (Line 15)	$ 26,273,284
17	Total Regulating Reserve Obligation (Line 4) * 12 *1000	4,560,000
18	**Per Unit Rate in Kw-Mo (Line 16 / Line 17)**	$ 5.76
	Annual Revenue Forecast for Operating Reserves	**Average $'s**
19	Total TBL Regulating Reserve Obligation (Line 5b)	150
20	Per Unit Rate in Kw-Mo (Line 16 / Line 17)	$ 5.76
20a	AGC Adder	$ 1.55
20b	Total Per Unit Rate (Linw 20 + 20a)	**$ 7.31**
21	**Annual Revenue Forecast (Line 19 * Line 20b *12*1000)**	**$ 13,161,033**

WP-07-FS-BPA-05B
Page 19

Section 4.4.2 - Table 3
AGC Adder Calculation
BPA Incremental Cost of Regulation (AGC)

	Efficiency-Lost Costs of Regulation 1/	**Kaplan**	**Francis**	**Notes**
1	Efficiency Loss	25%	29%	On all kWh on AGC
2	kWh with Efficiency Loss	8,760	8,760	kWh per kW-yr on AGC
3	kWh Lost	22	25	per kW-yr on AGC
4	Average Price	30	30	$/MWh
5	Revenue Loss	0.66	0.77	per kW-yr on AGC
	Incremental Increased O&M Costs of Regualtion 1/	**Kaplan**	**Francis**	
6	Base O&M Cost per kW of Francis & Kaplan Capacity	13.78	8.78	$/kW-yr
7	Percent O&M Increase due to AGC (inc. small capital)	15%	10%	
8	Incremental O&M Costs for Regulation	2.07	0.88	per kW-yr on AGC
	AGC Multiplier 2/	**Kaplan**	**Francis**	
9	AGC Multiplier	3.70	12.30	kW on AGC per kW of AGC Resp
	Total Cost of Regulation	**Kaplan**	**Francis**	
10	Efficiency Loss Cost	0.66	0.77	kW on AGC per kW of AGC Resp
11	Increased O&M Cost	2.07	0.88	
12	Subtotal	2.73	1.65	
13	Multiply Costs by AGC Multiplier	3.70	12.30	
14	Costs per kW-yr of AGC Effciency Lost Cost	$2.44	$9.47	
15	Increased O&M Cost	$7.66	$10.82	
16	Total AGC Incremental Cost	$10.10	$20.30	
17	MW * Hours of AGC	3,485,639	16,708,059	per kW-yr of AGC Capability
18	Weight	17%	83%	
19	Weighted Average	18.56		per kW-yr of AGC Capability
20	**Weighted Average**	**1.55**		**per kW-mo** of AGC Capability

1/ Applied to all MW on AGC, not just MW of AGC Capability
2/ Calculate MW on AGC required to yield 1 MW of AGC Response Capability

4.1.4.7 Calculation of Unit Cost of Regulating Reserve Generation Input

BPA calculated the average annual cost of the Big 10 FCRPS hydro projects less generation supplied reactive revenue to be $670 million. (*See* Section 4.4.2, Table 1 of the WPRDS Documentation, WP-07-FS-BPA-05B.) The forecasted average system use for the Big 10 (generation, Spinning and Supplemental Operating Reserve obligation, and the Regulating Reserve obligation) is 8,927 MW. (*See* Section 4.4.2, Table 1B of the WPRDS Documentation, WP-07-FS-BPA-05B.) System uses that are provided by all FCRPS hydro projects (generation, Spinning and Supplemental Operating Reserve obligations) are multiplied by 89 percent to determine the Big 10 share of the obligation. The BPA Control Area Regulating reserve obligation that is provided by the Big 10 hydro projects is forecasted to be a minimum of 350 MW. Of this amount, the TBL share is estimated to be 150 MW, and the remaining 200 MW is capacity available to meet load following needs for BPA requirements customers. The per unit base charge of $5.76/kW per month is calculated using the average system use (generation, Spinning and Supplemental Operating Reserve obligations, as well as the Regulating Reserve obligation) divided into the revenue requirement. The revenue requirement for Regulating Reserve is found by multiplying the revenue requirement by the ratio of the Regulating Reserve obligation to the total average system uses. The up to Generation Input charge of $7.31/kW per month equals the Big 10 base cost of $5.76/kW per month plus the AGC Adder of $1.55/kW per month. (*See,* Section 4.4.2, Table 2 of the WPRDS Documentation, WP-07-E-BPA-05B.)