Hydropower Appendix

Economic Analysis Concepts

This document describes the results of an economic analysis from the national accounting stance. The purpose of this economic analysis is to describe the benefits and costs of the actions contemplated to whom-so-ever and wherever they may accrue within the United States. The approach used here is based on methods prescribed by the U.S. Water Resources Council (1983) and is consistent with professionally accepted practice.

Economists classify impacts which arise from a management action as economic impacts and financial impacts. Economic impacts are the dollar value of resources committed in the nation as a result of a proposed action. For energy analyses, this would include the use of fossil and nuclear fuels, the cost of any incremental capital expense necessitated by the action within the period of analysis, and, the value of environmental and other nonmarket impacts such as recreation. Explicitly omitted from all economic analyses is consideration of investments made prior to the period of analysis. These investments are called sunk costs.

Transfer payments also should be omitted from economic analyses. The reason for this is that no net change in the national economy results when a payment is made from one entity to another which is not accompanied by the exchange of a good. Taxes and insurance are examples of transfer payments frequently cited in basic undergraduate textbooks.

In contrast to an economic analysis, the focus of a financial analysis is to provide an estimate of the monetary impact to an identifiable sub-group or organization rather than the entire economy. Financial analyses typically include sunk costs and transfer payments but omit nonmarket costs which are included in an economic analysis. In general, financial impacts may be less than, greater than, or equal to economic impacts.

The value of a comprehensive and technically adequate economic analysis is that it allows the decision maker to consider the costs and benefits to society in the same units of measure. This facilitates a reasoned assessment of the public interest effects associated with a management action. In contrast, a financial analysis provides narrowly defined information about the incidence of these costs and benefits with regard to specific sectors or population groups.

Background

Electricity cannot be efficiently stored on a large scale using currently available technology. It must be produced as needed. Consequently, when a change in demand occurs, such as when an irrigation pump is turned on, somewhere in the interconnected power system the production of electricity must be increased to satisfy this demand. In the language of the utility industry, the demand for electricity is known as "load." Load varies on a monthly, weekly, daily, and hourly basis. Across the year the aggregate demand for electricity is highest when winter heating and summer cooling needs, respectively, are greatest (Figure 1). During a given week, the demand for electricity is typically higher on weekdays, with less demand on weekends, particularly holiday weekends. As shown in Figure 2, during a weekday the aggregate demand for electricity is relatively low from midnight through the early morning hours, rises sharply during working hours, and falls off during the late evening.

The large variation in hourly, daily and seasonal loads has important implications for the electrical generation system. In particular, it greatly influences the amount of generation capacity required and therefore the capital cost of the system. This can be readily illustrated by two extreme cases. For the first example, assume the demand for electricity is constant and is 1.0 MW at all times. This would imply (ignoring security and reliability concerns) that a utility could supply this demand by building a 1.0 MW power plant and operating it continuously. For a month (30 days), this would imply generation of 1.0 MW for 720 hrs which would generate 720 Mwhrs of electricity. In example number two we will assume the demand for electricity is quite variable. We will assume it is 1 MW for (1) hour of the month and 0.1 MW for the rest of the hours in the month. In the latter example, the costs of constructing a 1 MW power plant must also be incurred but the plant generates only 72.9 Mwhrs of energy (1MW*1 hr + 0.1MW*719 hrs) or approximately 10% of its potential. This example is somewhat extreme but is nonetheless illustrative[1]. The highly variable nature of the demand for electricity results in the following observable characteristics of the electrical power system; (1) many power plants are idle for some or all of the day or season, and, (2) the capital costs of electricity production are a significant portion of the total.

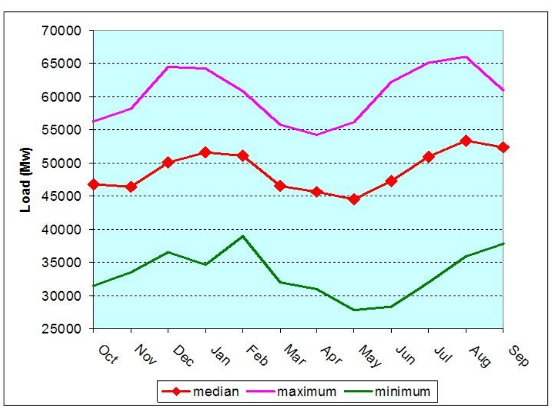

Figure 1. Seasonal Demand for Electricity

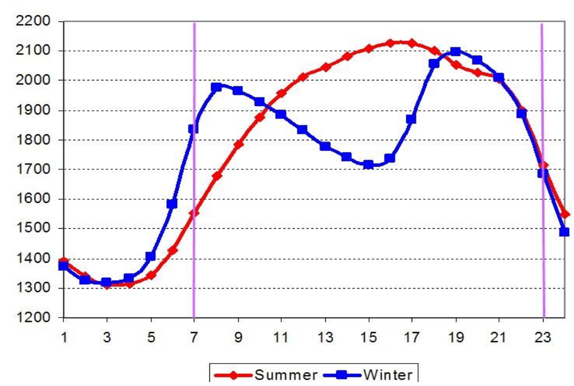

Figure 2. Demand for Electricity During a Typical Weekday.

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[1]Nationwide, the total annual energy generated is approximately 50% of the total generation capability. This reflects an average load factor of about 60%, a variety of reserves and margins, as well as scheduled and forced outages.

Electric energy is most valuable when it's most in demand— during the day when people are awake and when industry and businesses are operating. This period, when the demand is highest, is called the "on-peak period." In the West, the on-peak period is defined as the hours from 7:00 a.m. to 11:00 p.m., Monday through Saturday. All other hours are considered to be off-peak.

The maximum amount of electricity which can be produced by a powerplant is called its capacity. Capacity is often measured in megawatts (MW). The capacity of thermal powerplants is determined by their design and is essentially fixed. In the case of hydroelectric powerplants, capacity varies over time because it is a function of reservoir elevation, the amount of water available for release, and the design of the facility. Because the capacity at hydropower plants is highly variable, the amount of dependable or marketable capacity is of particular significance. The amount of dependable or marketable capacity is determined using various probabilistic methods (e.g. Ouarda, Labadie and Fontane 1997).

Hydropower and the Interconnected Power System

Ignoring pumped storage facilities, there are two principle types of hydropower plants. These are run-of-river plants and peaking plants. Run-of-river plants typically have little water storage capability. Consequently, generation at run-of-river plants is proportional to water inflow and there is little variation in electrical output during the day. Peaking hydropower plants, such as Hell's Canyon, often have significant water storage capability and are designed to rapidly change output levels in order to satisfy changes in the demand for electricity. Peaking hydropower plants are particularly valuable because they can be used to generate power during on-peak periods avoiding the cost of operating more expensive thermal plants such as gas turbine units. Hydropower plants are also more reliable than thermal plants and do not generate emissions.

In addition to furnishing capacity and energy, hydropower plants play an important role in the interconnected electric power system by supplying so-called ancillary services. They contribute to system reliability by furnishing Automatic Generation Control (AGU) and Automatic Frequency Control (AFC) services which adjust generation and frequency respectively, second by second, to stabilize the power system. These facilities also fulfill part of the regional reserve requirements and provide backup generation in the event of unexpected outages. In addition, they provide extra energy during extreme hot or cold weather periods and help maintain transmission stability during system disturbances.

The Economic Value of Hydropower

The economic value of operating an existing hydropower plant is measured by the avoided cost of doing so. In this context, avoided cost is the difference between the cost of satisfying the demand for electricity with and without operating the hydropower plant. Alternatively, avoided cost is the difference in system costs which arises through the operation of a hydropower plant at differing levels of output. Conceptually, avoided cost is the savings realized by supplying electricity from a low cost hydropower source rather than a higher cost thermal source. These savings arise because the variable cost of operating a hydropower plant is relatively low in comparison to thermal units. For example, the average operating expense for a typical hydropower plant in 2003 was $7.51 per MWh. In contrast, the average cost of operating a typical fossil-fuel steam plant was $22.59 per MWh, and the average cost of operating a typical gas turbine unit was approximately $48.93 per MWh (Energy Information Administration 2004, Table 8.2 page 49).

The economic value of operating an existing hydropower plant varies considerably with time of day. The variable cost of meeting demand varies on an hourly basis depending on the demand for electricity, the mix of plants being operated to meet demand, and their output levels. During off-peak periods, demand is typically satisfied with lower cost coal, run-of-river hydropower, and nuclear units. During on-peak periods, the additional load is met with more expensive sources such as gas turbine units. Consequently, the economic value of hydropower is greatest during the hours when the demand for electricity, and the variable cost of meeting demand, is the highest.

If the variable cost of purchasing an additional megawatt of electricity from a least cost source were observable in the market, the economic value of producing hydroelectricity could be readily determined. For example, assume that the cost of purchasing a megawatt of electricity, from the least cost source was $30.00 in a particular hour, and the cost of producing a megawatt of hydroelectricity was $6.00. Then, the avoided cost or economic value of producing an additional megawatt of hydropower at that time would be (30.00-6.00) or $24.00.

Geographic Descriptors

In this analysis three descriptors of geographic location are used. These are North Platte, South Platte and Central Platte. These descriptors are not geographically accurate and are primarily an artifact of preceding analyses such as the Federal Energy Regulatory Commission's relicensing case. Because of their long history of use, they are retained here. For purposes of this analysis, "North Platte" refers to the Platte River Basin from the Wyoming state line upstream. The term "South Platte" is used to describe the Platte River Basin from the Colorado state line upstream. Finally, "Central Platte" refers to the remainder of the Platte River Basin. These three regions are illustrated in Figure 3.

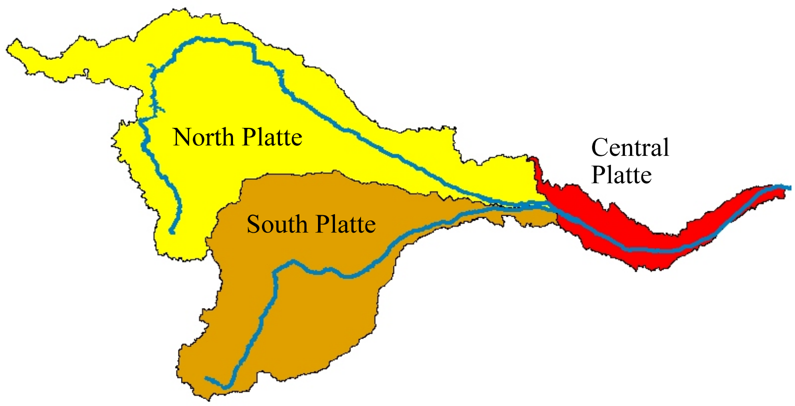

Figure 3. Illustration of the North, South and Central Platte River regions used in the hydropower analysis.

Hydropower Resources in the Platte Basin

Hydroelectric and other generation facilities in the Platte River Basin are linked to each other and to final users through a system of interconnected electric power transmission lines. Operation of any of these generation units affect, and are affected by, operations of the other interconnected units in the system.

There are 29 hydropower plants of at least 0.1 MW in capacity located in the Platte River Basin. These are listed in Tables 1, 2 and 3. Of the total, Only the 11 hydropower plants in the North Platte and Central Platte would be directly affected by the alternatives examined in this document. These are comprised of 5 Bureau of Reclamation power plants with a combined capacity of 235.2 MW, 3 Central Nebraska Public Power and Irrigation District (CNPPID) power plants with a combined capacity of 104 MW and 2 Nebraska Public Power District (NPPD) hydropower plants with a combined capacity of 25.5 MW.

Table 1. Hydropower Facilities in Central Platte Region

Feature	Use	Installed Capacity (MW)	Ownership
Kingsley Dam	peaking	50.0	CNPPID
Jeffrey Canyon	run of river	18.0	CNPPID
Johnson 1, 2	run of river	36.0	CNPPID
North Platte	run of river	24.0	NPPD
Kearney	run of river	1.5	NPPD
Total		129.5	

Table 2. Hydropower Facilities in North Platte Region

Feature	Use	Installed Capacity (MW)	Ownership
Seminoe	intermediate	51.0	USBR
Kortes	intermediate	37.0	USBR
Fremont Canyon	intermediate	66.8	USBR
Alcova	peaking	36.0	USBR
Glendo	intermediate	38.0	USBR
Guernsey	intermediate	6.4	USBR
Total		235.2	

Table 3. Hydropower Facilities in South Platte Region

Feature	Use	Installed Capacity (MW)	Ownership
Betasso	na	3.00	Boulder
Big Thompson	intermediate	4.50	USBR
Boulder Canyon	na	20.00	PSCCO
Cabin Creek	pump-store	300.00	PSCCO
Estes	intermediate	45.00	USBR
Flatiron	pump-store	94.50	USBR
Georgetown	na	1.44	PSCCO
Jerry B. Buckley	na	0.30	JB Buckley
Kohler	na	0.10	Boulder
Idlywilde	na	0.90	Loveland
Foothills Water Treatment	na	3.10	Denver
Longmont	na	0.30	Longmont
Mary’s Lake	run-of-river	8.10	USBR
Maxwell	na	0.10	Boulder
North Fork	na	5.50	Denver
Orodell	na	0.20	Boulder
Pole Hill	run-of-river	38.20	USBR
Strantia Springs	na	1.00	Denver
Total		526.24	

Power Marketing

Central Platte. As shown in Table 1, 3 of the 5 hydropower plants in the Central Platte Region are owned by CNPPID. The capacity and energy produced by these 3 CNPPID powerplants are sold directly to NPPD. NPPD, in turn, provides electricity to a variety of customer classes within Nebraska as well as making bulk power sales to customers in the Midwestern Reliability Organization (MRO)[2] region.

North Platte. The capacity and energy are produced at all of the hydropower facilities in the North Platte and marketed by Western Area Power Administration (WAPA). WAPA is a federal power marketing entity charged with consolidating and marketing the electricity produced at federal generation facilities. The capacity and energy produced at federal facilities is primarily marketed to "preferred customers" such as rural electric cooperatives, irrigation districts, federal reservations and public power districts. WAPA's rate setting procedure differs from that of a profit-making utility. Customer rates are designed to ensure that revenues are sufficient to repay all costs assigned to the power function within a prescribed period. These costs include annual power operation and maintenance costs, certain environment-related costs, power facilities construction costs, and irrigation project costs allocated to the power function.

Institutional Considerations

The hydropower analysis described here and in the EIS spans two different North American Electric Reliability Council (NERC) regions. Operation of the electricity production and transmission systems within these NERC regions are largely independent of each other. NERC is a voluntary industry organization formed subsequent to the 1965 Northeast blackout. Its purpose is to promote the reliability and adequacy of bulk power supply in the United States parts of Canada and Mexico. There are 10 NERC regions. The geographic boundaries of these regions were are based primarily on their marketing inter-relationships and the degree to which transmission lines allowed for the interchange of energy. The Platte River Basin spans two of these regions: the Midwest Reliability Organization (MRO) and the Western Electricity Coordinating Council (WECC). In particular, the North and South Platte Regions as described previously are within the WECC region while the Central Platte Region is located within the MRO region. There are a few direct current (DC) inter-ties between the MRO and WECC regions. However, for all practical purposes these two regions operate independently of each other.

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[2]Prior to 1 January 2005, this entity was known as the Mid-continent Area Power Pool (MAPP)

Hydrologic Period

The hydrologic data on which hydropower analysis is based span the 48 year period from 1947 to 1994. These data reflect the drought periods of the 1950's and 1989-1991 and also capture periods of bountiful precipitation in the 1970's and 1983-1984. These data have been adjusted to reflect current condition gains and losses and are reflective of anticipated hydrologic conditions in the study area.

Absence of a South Platte Analysis

Currently, no management actions are anticipated which might directly affect hydropower operations in the South Platte. Since no hydropower effect are expected in the South Platte, this document does not contain such an analysis.

Reconnaissance Level Analysis

The focus of this reconnaissance level analysis is on the hydropower facilities in the Platte River Basin whose operations are directly affected by changes in inflows and operations associated with the Platte River Recovery Implementation Plan. To the extent that there are affects on these hydropower plants, there will be resultant indirect changes in the operations of other interconnected powerplants in the system. However, estimation of these indirect effects are beyond the scope of this reconnaissance level analysis.

Analysis Assumptions

The hydropower analysis described here is based on a single representative year—2002. The results described encapsulate the assumption all project components are on-line and fully operational in 2002.

For purposes of the Platte River EIS, a 13 year period of analysis is used. It is assumed that program implementation will occur January 1, 2002 and the "first increment" of the program will conclude on December 31, 2014. This analysis is based on calender year data (January through December) although, as noted in the section on input files, some of the hydrologic input data was furnished in water years defined as October 1 through September 30. The currently available hydrology data spans the 48 year period from 1947 through 1994. Finally, the variable cost of operating a hydropower plant is assumed to be $0.00/MWhr. This assumption has an important implication for this analysis. When the variable cost of hydropower operation are assumed to be zero, the marginal cost of operating the thermal system is the same as the costs avoided through the production of hydropower.

Analysis Approach

Three indicators are employed to capture the effects of the alternatives on the hydropower system. These are (1) the amount of electrical energy generated [generation], (2) the dependable generation capacity [dependable capacity], and, (3) the economic value of the hydropower produced [economic value].

Figure 4 illustrates the conceptual approach used in this reconnaissance level analysis.

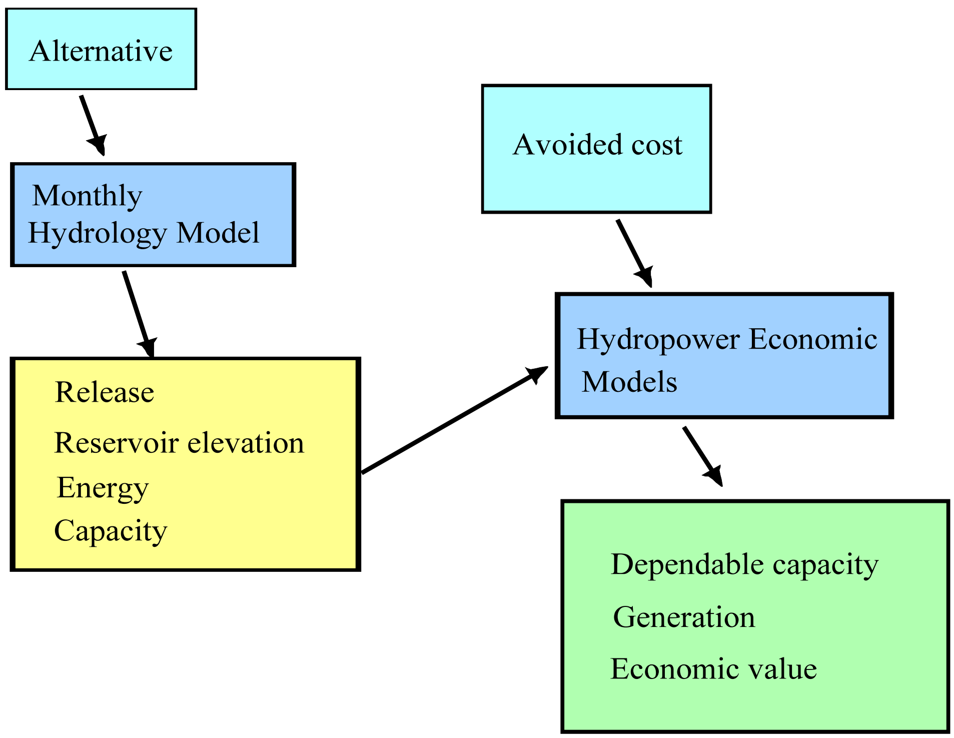

Figure 4. Conceptual Overview of this Analysis

Methodology

Energy. For each alternative, the amount of hydroelectric energy generated in the North Platte River Basin for each month for the period 1947 - 1994 (48 years) was estimated using the North Platte River Water Utilization Model (Bureau of Reclamation 1997). For each alternative, the amount of hydroelectric energy generated in the Central Platte River Basin for each month for the period 1947 - 1994 (48 years) was estimated using the Central Platte OPSTUDY Hydrology Model (Fish and Wildlife Service 1999).

Dependable Capacity. The dependable capacity in both basins is calculated for a summer marketing season (April through September) and a winter marketing season (October through March) using two different methods. These are called the “Minimum Median”and the “90%

Exceedence” methods.

Dependable capacity is calculated using the minimum median method in the following manner. First, the monthly capacity for each of the 48 years ×12 months in the analysis period is computed by the appropriate hydrology model. The median capacity for each month is then calculated. The minimum of these median capacities for the summer marketing season (April to September) and the winter marketing season (October to March) are identified. These values are reported as the minimum median dependable capacity for each marketing season.

Dependable capacity is also calculated using the 90% exceedence method described in Western Area Power Administration (1986, 1993). To apply this method, the monthly capacity for each of the 48 years ×12 months in the analysis period is calculated by the relevant hydrology model. These capacity data are categorized into the winter marketing season (October to March) and the summer marketing season (April to September). For each month in the marketing season, the capacity value which corresponds to the 90 percent empirical exceedence level is then calculated. The maximum of these exceedence values is reported as the 90 percent exceedence dependable capacity for each marketing season.

The capacity values which underlie the dependable capacity calculations are computed somewhat differently in the two basins. In the North Platte, the capacity for each plant in the system is calculated by the NPWUM Model using the methods described in Bureau of Reclamation (1997). For the Central Platte, the capacity at the Kingsley Dam hydropower plant (50 MW nameplate capacity) is calculated using the method supplied by Killgore (1996). The monthly capacity at the other 4 hydropower plants in the Central Platte is approximated by their average monthly generation which is estimated using the OPStudy Model (Fish and Wildlife Service 2000).

Data and Sources

Avoided cost data. For purposes of this reconnaissance level analysis, the difference in the hydroelectric energy generated in any alternative relative to the present condition baseline is evaluated using a set of monthly avoided costs. These avoided cost data were estimated using the AURORA model (Electric Power Information Solutions 1999) a proprietary production-cost and market simulation model. The model was used to estimate the hourly avoided costs and calculate the total cost of operating the WECC and MRO systems at a variety of market nodes within these systems. For the Central Platte, the avoided costs for the Eastern (MRO) Regional node were used for this analysis. For the North Platte, the avoided costs for the 4-Corners node were used for this analysis. Although the AURORA model produces hourly estimates of avoided cost, mean monthly avoided cost data for calender year 2002 were employed here. Figures 5 and 6 show the projected pattern of monthly avoided cost in the Central Platte and North Platte systems respectively across calender year 2002.

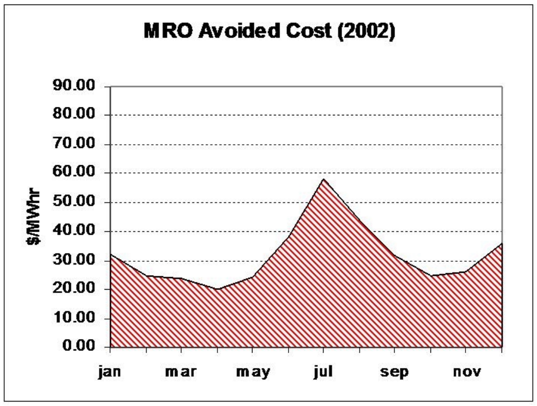

Figure 5. Projected Avoided Cost in Central Platte River Basin

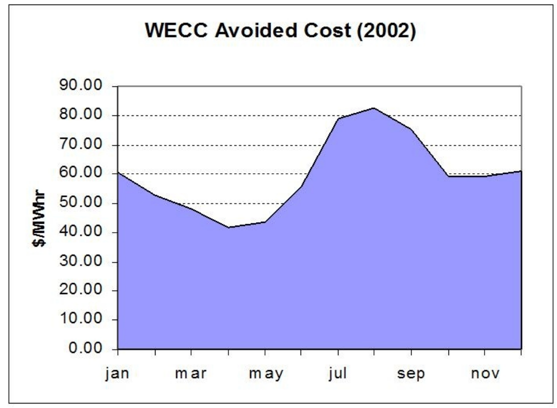

Figure 6. Projected Avoided Cost in the North Platte River Basin

As shown in these two figures, the 2002 avoided costs in the WECC region are generally higher and have a higher on-peak value than do those in the MRO region. This reflects an installed generation base which more closely matches regional demand than is the case in the MRO region. Because the opportunity for energy interchange (or arbitrage) across these two NERC reliability regions is extremely limited, these avoided cost differentials can exist and are expected to persist over time.

Known Analysis Limitations

The reconnaissance level approach used in this analysis is relatively simple and readily applied but has several limitations. First, the model employs a monthly time step. As a result, intra-month phenomena, such as pulse flows, cannot be characterized. In contrast, more rigorous modeling frameworks (e.g. Harpman 1999, Edwards, Flaim and Howitt 1999) are designed to characterize hourly capacity effects although their implementation is both more complex and resource intensive. In this analysis, it is assumed the marginal cost of operating each hydropower plant is $0.00/MWhr. Although the marginal cost of operating a hydropower plant is typically low compared to a thermal unit, these costs are positive and can be significant over a range of generation. For example, the average cost of operating a large hydropower plant and a typical gas turbine unit in 2003 was $7.51 and $48.93 per MWhr respectively (Energy Information Administration 2004, p. 49 Table 8.2). While some published sources of specific marginal cost data for hydropower plants exist (e.g. National Performance Review Power Management Laboratory 1997), neither this nor many other modeling frameworks (commercial or otherwise) employ these data.

Present Condition Baseline

The modeled hydrology for the present condition baseline and the methodologies described here and in Harpman (2003) were employed to estimate generation, dependable capacity and economic value for the present condition baseline or "base case." Expected monthly generation under the present condition baseline is shown in Figures 7 and 8. As illustrated in Figure 7, generation in the Central Platte peaks in the summer months and is considerably less than North Platte generation.

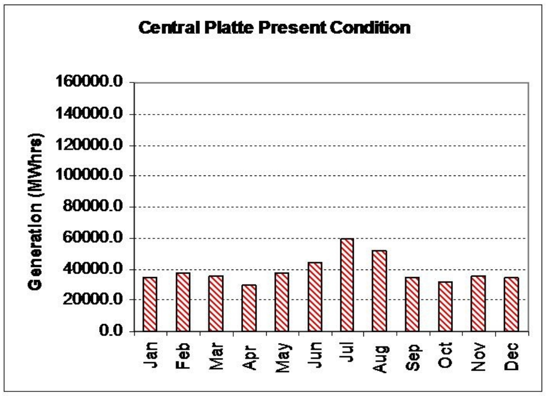

Figure 7. Expected monthly generation in the base case.

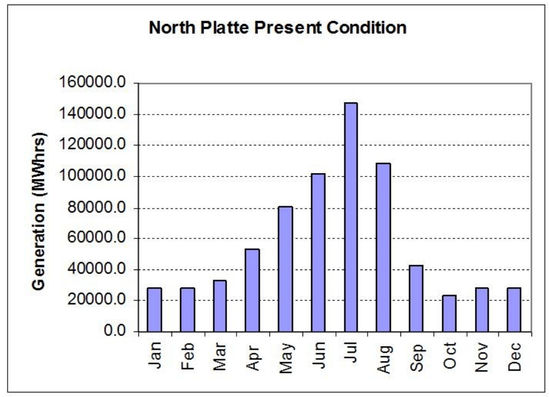

Figure 8. Expected monthly generation in the base case.

As illustrated in Figure 8, expected generation in the North Platte is much greater in the summer months (when run-off is the highest) and considerably reduced in the winter months.

The annual results are shown in Table 4 for the North Platte (NP) and the Central Platte (CP). As shown in this table, expected generation in the North Platte is greater than that in the Central Platte and the economic value of the hydropower produced is much larger.

Table 4. Present Condition Baseline for the Hydropower Resource

Scope	Generation (MWhrs)	Economic Value (2002$)	Dependable Capacity (MW)			
			Minimum Median Method		90% Exceedence Method	
			Summer	Winter	Summer	Winter
NP	702,740	44,732,993	87.12	71.88	215.78	80.37
CP	465,780	15,835,153	76.36	80.26	89.08	69.48

North Platte. As shown in Table 4, under the present condition baseline the expected annual generation in the NP is approximately 703,000 Mwhrs. The dependable summer capacity, calculated using the 90% exceedence method is approximately 216 MW and the dependable winter capacity is approximately 80 MW. For comparison purposes, the installed nameplate capacity of all the plants in the North Platte System is 235.2 MW. The dependable or reliably available capacities for the present condition baseline represent 92% (Summer) and 34% (Winter) respectively of the installed capacity in the basin. The expected annual economic value of electricity production is approximately $45,000,000 (2002 $).

Central Platte. In the Central Platte the expected annual generation is approximately 466,000 Mwhrs. Central Platte dependable capacity calculated using the 90% exceedence method is approximately 89 MW in the summer and 69 MW in the winter. For comparison purposes, the installed nameplate capacity of all the plants in the Central Platte System is 129.5 MW. The dependable or reliably available capacities for the present condition baseline represent 69% (Summer) and 54% (Winter) respectively of the installed capacity in the basin. The expected annual economic value of electricity production is approximately $16,000,000 (2002 $).

Full Water Leasing Alternative (FWL)

Relative to the present condition baseline, the monthly change in generation under the Full Water Leasing Alternative is illustrated in Figures 9 and 10.

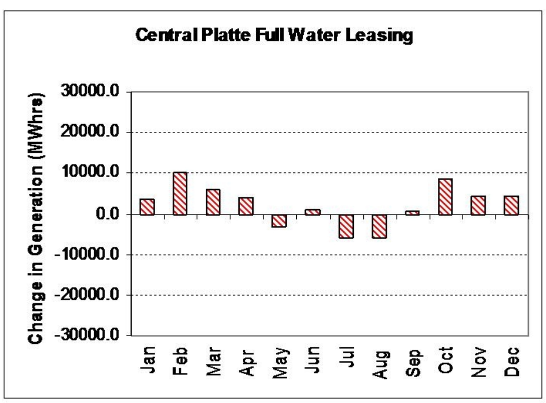

Figure 9. Changes in monthly generation under the Full Water Leasing Alternative relative to the baseline.

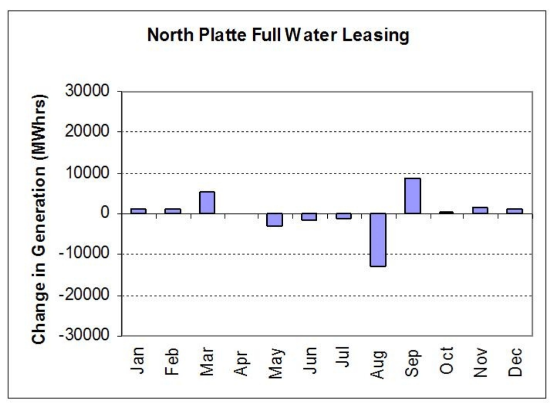

Figure 10. Changes in monthly generation under the Full Water Leasing Alternative relative to the baseline.

As shown in Figure 9, in the Central Platte there are pronounced monthly changes in generation throughout the year. On balance, these are somewhat more positive than negative. However, some declines in winter capacity result. In the North Platte (Figure 10), relatively minor monthly changes in generation occur during the year. For both systems, there is ann increase in the winter marketable capacity.

North Platte. Relative to the present condition baseline, the annual generation under the Full Water Leasing Alternative is increased by 1,160 Mwhrs (+0.17%). Calculated using the 90% exceedence method, the dependable summer capacity is decreased by 16.21 MW and the dependable winter capacity is increased by 3.12 MW. The expected change in the annual economic value of electricity production is -$133,614 (2002 $).

Central Platte. Relative to the present condition baseline, the annual generation under the Full Water Leasing Alternative is increased by 27,403 Mwhrs (+5.88%). Calculated using the 90% exceedence method, the dependable summer capacity is decreased by 4.85 MW and the dependable winter capacity is increased by 9.23 MW. The expected change in annual economic value of electricity production is 441,700 (2002 $).

Governance Committee Alternative

Relative to the present condition baseline, the monthly change in generation under the Governance Committee Alternative is illustrated in Figures 11 and 12.

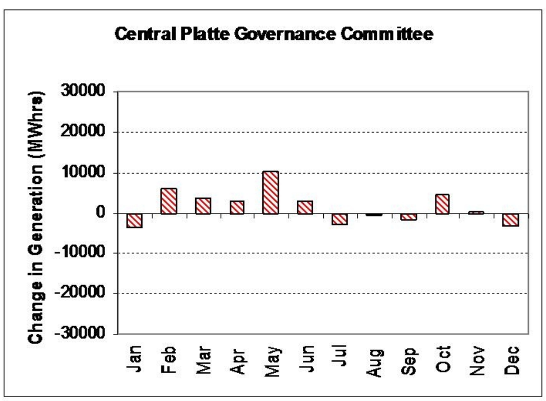

Figure 11. Monthly changes in generation under the Governance Committee Alternative relative to the base case.

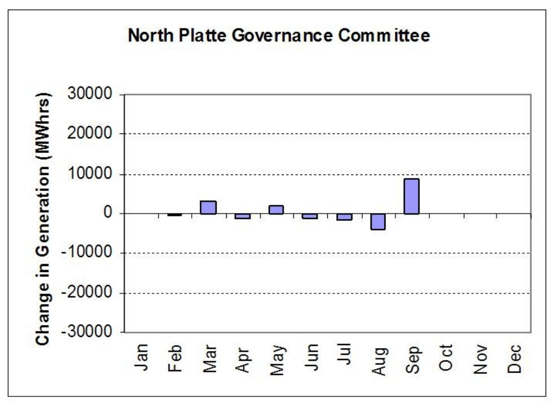

Figure 12. Monthly changes in generation under the Governance Committee Alternative relative to the base case.

As shown in Figure 11, in the Central Platte there are pronounced monthly changes in generation through much of the year. On balance, these are somewhat more positive than negative. However, some declines in capacity result. In the North Platte (Figure 12), relatively small monthly changes in generation also occur in many months during the year. Reductions in winter generation in both systems slightly reduce the maximum generation capacity in the winter marketing season.

North Platte. Relative to the present condition baseline, the annual generation under the Governance Committee Alternative is increased by 5376 Mwhrs (+0.77%). Calculated using the 90% exceedence method, the dependable summer capacity is decreased by 13.93 MW and the dependable winter capacity is reduced by 0.02 MW. The expected change in annual economic value of electricity production is $304,881 (2002 $).

Central Platte. Relative to the present condition baseline, the annual generation under the Governance Committee Alternative is increased by 17,693 Mwhrs (+3.80%). Calculated using the 90% exceedence method, the dependable summer capacity is decreased by 3.45 MW and the dependable winter capacity is reduced by 2.24 MW. The expected change in annual economic value of electricity production is $272,788 (2002 $).

Water Emphasis Alternative (WE)

Relative to the present condition baseline, the monthly change in generation under the Water Emphasis alternative is illustrated in Figures 13 and 14.

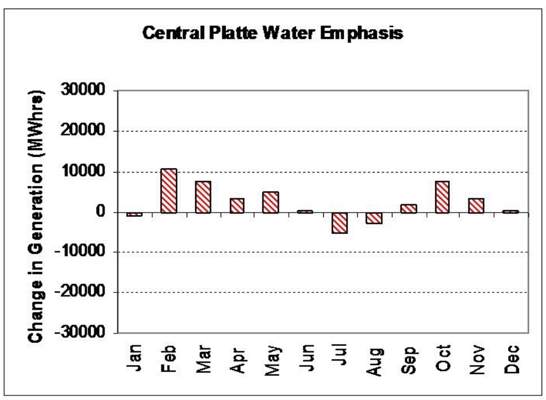

Figure 13. Monthly changes in generation in the Water Emphasis Alternative relative to the baseline

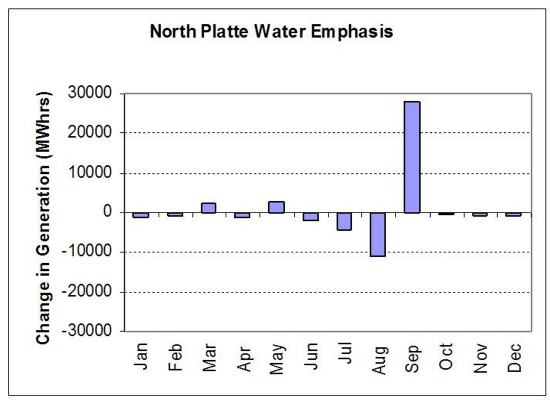

Figure 14. Monthly changes in generation in the Water Emphasis Alternative relative to the baseline.

As shown in Figure 13, in the Central Platte there are pronounced monthly changes in generation through much of the year. These are somewhat more positive than negative. In the North Platte (Figure 14), there is an especially large monthly change in generation during the month of September. This increase in generation results from environmental account releases which are a component of the alternative.

North Platte. Relative to the present condition baseline, the annual generation under the Water Emphasis Alternative is increased by 11,643 Mwhrs (7.66%). The 90% exceedence dependable summer capacity is decreased by 15.08 MW and the dependable winter capacity is decreased by 0.54 MW. The expected change in annual economic value of electricity production is $760,275

(2002 $).

Central Platte. Relative to the present condition baseline, the annual generation under the Water Emphasis Alternative is increased by 30,139 Mwhrs (+6.47%). The 90% exceedence dependable summer capacity is decreased by 3.50 MW and the dependable winter capacity is increased by 11.70 MW. The expected change in annual economic value of electricity production is about $507,042 (2002 $).

Wet Meadow Alternative (WM)

Relative to the present condition baseline, the monthly change in generation under the Wet Meadow Alternative is illustrated in Figures 15 and 16.

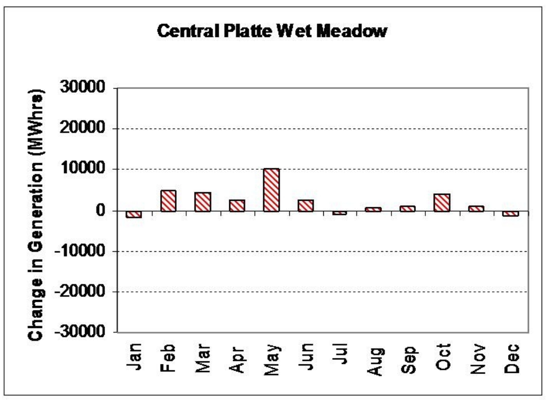

Figure 15. Changes in monthly generation under the Wet Meadow Alternative relative to the baseline.

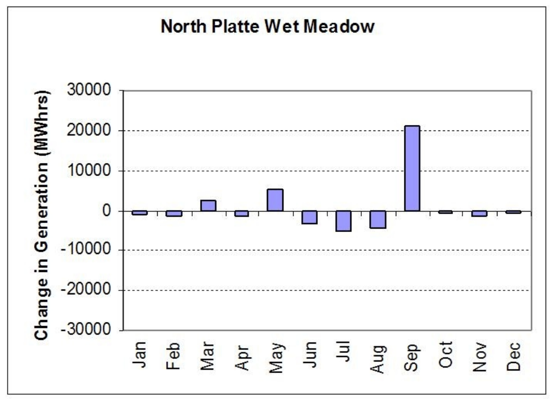

Figure 16. Changes in monthly generation under the Wet Meadow Alternative relative to the baseline.

As shown in Figure 15, in the Central Platte there are monthly changes in generation throughout the year. On balance, these are somewhat more positive than negative. However, there are some reductions in capacity. In the North Platte (Figure 16), there is an especially large monthly change in generation during the month of September. This increase in generation results from environmental account releases which are a component of the alternative.

North Platte. Relative to the present condition baseline, the expected annual generation under the Wet Meadow Alternative is increased by 10,456 Mwhrs (+1.49%). Calculated using the 90% exceedence method, the dependable summer capacity is decreased by 8.62 MW and the dependable winter capacity is reduced by 0.54 MW. The expected change in annual economic value of electricity production is $689,874 (2002 $).

Central Platte. Relative to the present condition baseline, the annual generation under the Wet Meadow Alternative is increased by 26,498 Mwhrs (+5.69%). Calculated using the 90%

exceedence method, the dependable summer capacity is reduced by 1.08 MW and the dependable winter capacity is decreased by 6.20 MW. The expected change in annual economic value of electricity production is $631,097 (2002 $).

Summary of Hydropower Impacts

Table 5 summarizes the expected annual impacts of all of the action alternatives. In this Table, all economic effects are evaluated at projected 2002 avoided cost levels and are measured in 2002 dollars.

In both basins, there are instances in which the generation and/or capacity is decreased (increased) but the economic value is increased (decreased). Although this may seem counterintuitive, these results arise from shifting generation from months in which electricity is less (more) valuable to months in which it is more (less) valuable.

In the North Platte Basin, relative to the present condition baseline, the Full Water Leasing Alternative has the greatest negative effect on economic value and the Water Emphasis Alternative has the greatest positive effect. All of the alternatives cause a reduction of generating capacity during the summer marketing season. As shown in Table 5, the Full Water Leasing and Water Emphasis alternatives have a positive effect on winter capacity while the other two alternatives result in capacity losses.

In the Central Platte Basin, relative to the Present Condition Baseline, all of the alternatives increase the economic value of the hydropower produced. The Wet Meadow Alternative would result in the greatest increase in economic value. As shown in Table 5, the Full Water Leasing and Water Emphasis alternatives have a positive effect on winter capacity. All of the alternatives cause a reduction of generating capacity during the summer marketing season.

Table 6 compares the dependable capacities calculated using the minimum median and the 90% exceedance methods. As shown in the Table there are differences in both the sign and magnitudes of the results obtained using these two different approaches.

Table 5. Summary of the Generation and Economic Impacts Relative to the Present Condition Baseline

Alternative	Scope	Change in Generation (MWhrs)	Change in Economic Value (2002$)	Change in Dependable Capacity[3] (MW)	
				Summer	Winter
Full Water Leasing	NP	1,160.1	-133,614	-16.21	3.12
	CP	27,402.7	441,700	-4.85	9.23
Governance Committee	NP	5,376.0	304,881	-13.93	-0.02
	CP	17,693.4	272,788	-3.45	-2.24
Water Emphasis	NP	11,642.8	760,275	-15.08	-0.54
	CP	30,139.5	507,042	-3.50	11.70
Wet Meadow	NP	10,455.7	689,874	-8.62	-0.54
	CP	26,497.7	631,097	-1.08	-6.20

[3]Calculated using the 90% exceedence method as described in the Appendix.

Table 6. Summary of Capacity Impacts Relative to the Present Condition Baseline

Alternative	Scope	Change in Dependable Capacity (MW)			
		Minimum Median Method		90% Exceedence Method	
		Summer	Winter	Summer	Winter
Full Water Leasing	NP	6.95	-2.36	-16.21	3.12
	CP	-0.55	9.30	-4.85	9.23
Governance Committee	NP	1.52	-3.97	-13.93	-0.02
	CP	-1.53	-2.40	-3.45	-2.24
Water Emphasis	NP	50.17	-5.18	-15.08	-0.54
	CP	2.22	4.92	-3.50	11.70
Wet Meadow	NP	50.89	-6.75	-8.62	-0.54
	CP	-0.41	1.15	-1.08	-6.20

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