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HDC

APALACHICOLA-CHATTAHOOCHEE-FLINT (ACF) REMAND HYDROPOWER STUDY

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APALACHICOLA-CHATTAHOOCHEE-FLINT (ACF) REMAND HYDROPOWER STUDY

1. INTRODUCTION

Under the 11th Circuit Ruling it was decided that "…the district court and Corps erred in concluding that water supply was not an authorized purpose under the RHA (River and Harbor Act of 1946)…the Corps shall have one year to make a final determination of its authority to operate the Buford Project under the RHA and WSA (Water Supply Act)." The Corps has been tasked with determining an "optimal methodology for measuring its authority over water supply", "articulating a policy on whether to account for return flows", and finally deciding if it has the authority to grant the Georgia 2000 request for water supply. This study is a comparative analysis of both Federal and non-Federal hydropower benefits for the ACF River Basin under different water supply demands, return rate assumptions, and operating strategies.

In general, benefits for hydropower are based on the accrued cost of the most likely energy source that would replace hydropower if its generation was reduced or taken away. This benefit is separated into two categories; an energy value and a capacity value. The energy value represents primarily the fuel cost or variable cost of an alternative thermal generation resource that replaces the lost hydropower generation. The capacity value represents the capital cost and fixed operation and maintenance cost of the alternative energy resource. Since the benefits are based on a most likely alternative source of energy, the value of the hydropower in the region is based on the regional landscape of energy sources and available capacity along with how the hydro-plants are used (dispatched) to meet system power demand.

The remaining sections of this study address the following: Section 2 provides a picture of the regional energy landscape for the ACF River Basin describing both the historical available capacity and typical monthly and seasonal energy generation by source; Section 3 describes the current hydropower system within the ACF Basin; Section 4 explains the formulation of this analysis including descriptions of alternatives and RHA comparison sets; Section 5 provides an illustration of the average generation monthly and seasonally patterns for each alternative; Sections 6 and 7 describe the methodology in computing energy and capacity values respectively; and, Section 8 concludes with the benefits calculation for each baseline comparison set.

2. ACF BULK POWER SYSTEM DESCRIPTION

The ACF Watershed lies primarily in the southeastern sub-region of the Southeastern Reliability Corporation (SERC). This corporation is responsible for promoting and improving the reliability related to the critical infrastructure of the bulk power system in the region. Since 1998, the southeastern sub-region has undergone a significant increase in natural gas capacity. Natural gas currently nearly matches coal in percentage of total system capacity at around 35 percent. Nuclear and hydroelectric energy make up the remaining bulk energy with 15 percent and 10 percent of total system capacity respectively. (Figure 1)

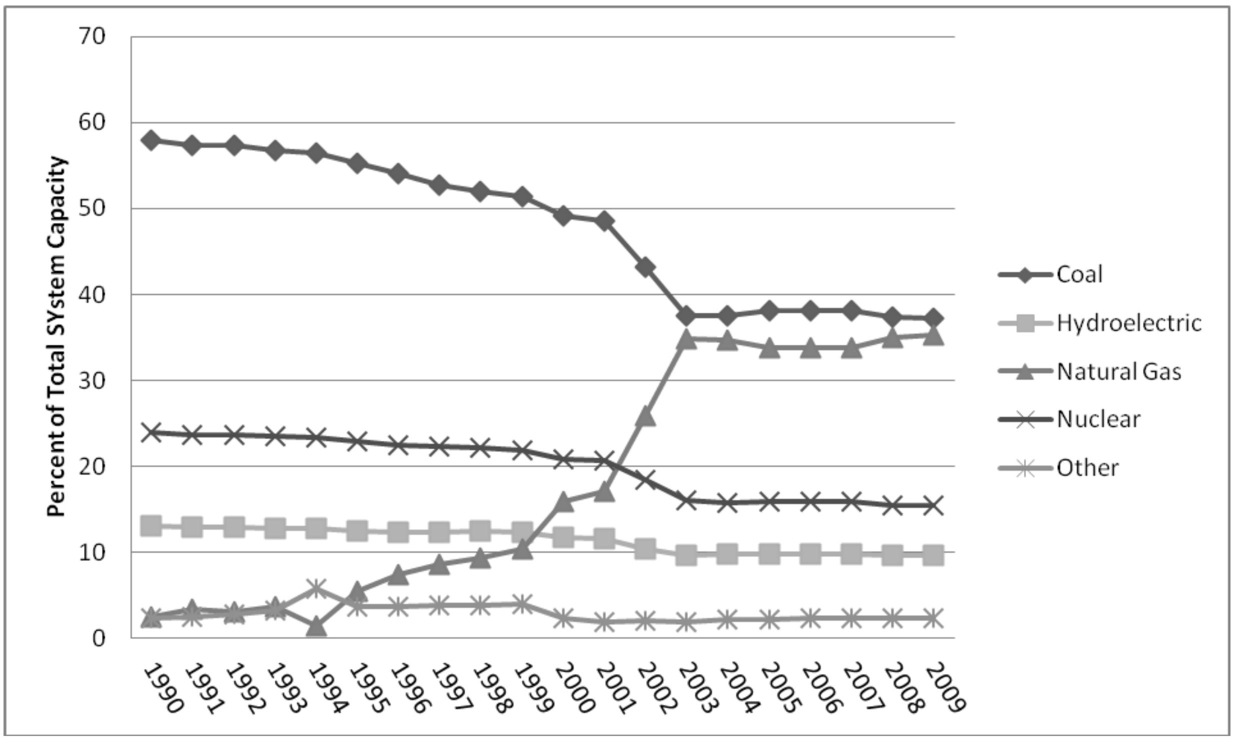


Figure 1. Historical trends for the percent of total system capacity for the southeastern sub-region of SERC.

Coal and nuclear power are predominately run as baseload plants, facilities that produce constant rates of generation to meet the systems continuous regional demands. Natural gas and hydropower plants on the other hand are generally run as peaking plants, meeting the daily and seasonal peak loads throughout the system. This is important in conceptually understanding what alternative thermal plants might be used to replace hydropower if changes in operations dictated such a need. As an illustrative example consider the 2009 monthly generation pattern (Figure 2) reported by the Energy Information Administration (EIA) for the southeastern sub-region. Increases (decreases) in percent of total generation for hydropower are matched by decreases (increases) in percent generation for natural gas. The same coupling of energy sources can be seen in the relationship between coal and nuclear power.

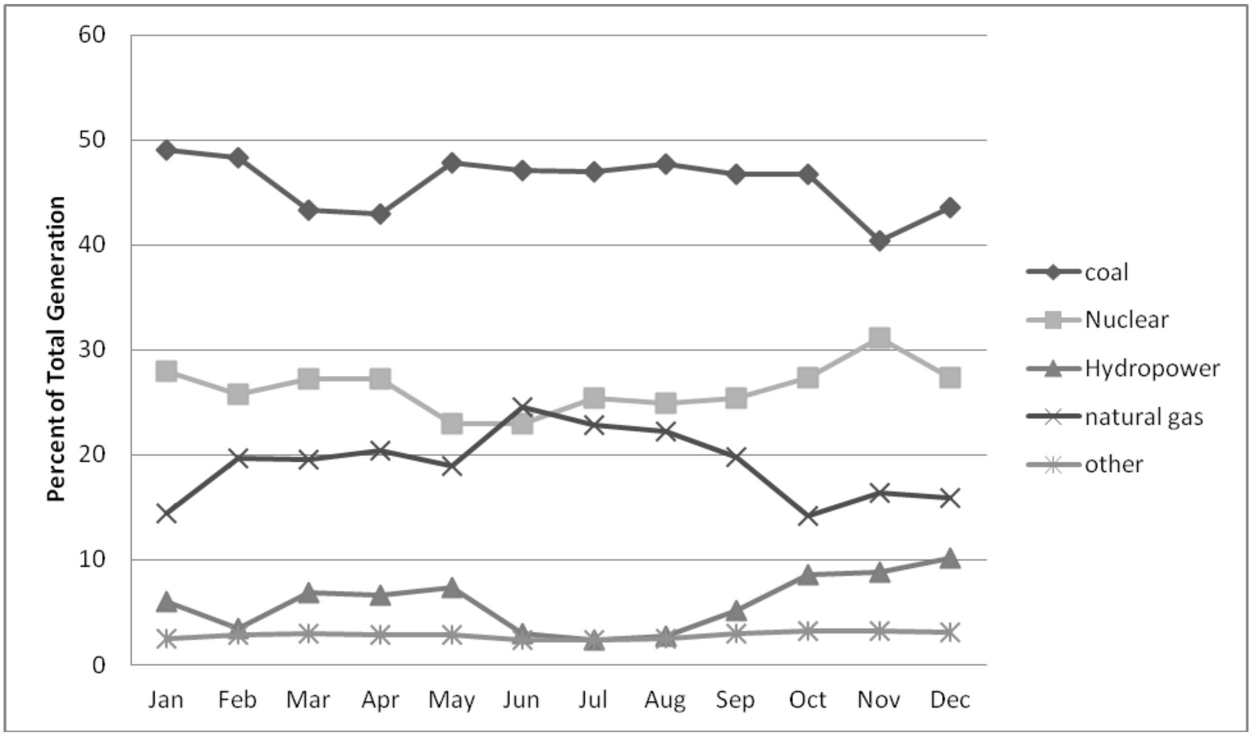


Figure 2. Percent of total generation by fuel type for southeastern sub-region of SERC.

3. ACF HYDROPOWER SYSTEM DESCRIPTION

The U.S. Army Corps of Engineers (Corps) operates four dams with hydropower capabilities in the ACF River Basin: Buford Dam, West Point Dam, Walter F. George Lock and Dam, and Jim Woodruff Lock and Dam. Buford Dam, West Point Dam and Walter F. George Lock and Dam are operated as peaking plants with an installed capacity of 381 megawatts (MW) while Jim Woodruff Lock and Dam, located near the confluence of the Chattahoochee and Flint Rivers, is operated as a run-of-river plant with an installed capacity of 43.3 MW. Buford and West Point Dams both have small units, generally used for system station service, that are excluded from the plant's combined nameplate capacity and Reservoir Simulation model (ResSim) simulation.

Five non-Corps plants owned by Georgia Power Company (GPC) are also considered in this analysis. Morgan Falls, Barlett's Ferry, Goat Rock, Oliver, and North Highlands (listed in downstream order) all act as modified run-of-river plants. The GPC plants utilize small amounts of storage to help re-regulate the variable releases of the upstream Corps reservoirs. These plants have a combined installed capacity of 342.9 MW.

Table 1 provides specific plant level details. In this table an individual plant is described by three different capacity terms, each playing a different role in the analysis. The nameplate capacity describes the actual amount of capacity installed for the plant according to the turbine manufacturers and does not account for limits imposed by other power train equipment. The maximum or operating capacity describes the maximum capacity at which a plant can operate based on the turbines running at full gate, the adjustment of the turbine to utilize maximum capacity instead of maximum efficiency. This value varies slightly depending on factors such as head and cooling capabilities. This is the capacity assumed in the ResSim model. Finally, the marketable capacity is meant to describe the amount of capacity available during the heavy load periods of summer months during extreme hydrological conditions such as a drought. For the Federal plants, the marketable capacity was confirmed by Southeastern Power Administration (SEPA), while for the GPC plants nameplate capacity (reference http://www.georgiapower.com) was assumed for both operating and marketable capacity.

Table 1. Plant Characteristics for Corps and Non-Corps Hydropower Plants

Plant	Owner	No. of Units	(Installed) Capacity (MW)	Operating Capacity (MW)	Marketable Capacity (MW)
Buford Dam	USACE	3	125	116.5	105
Morgan Falls	GPC	7	16.8	16.8	16.8
West Point Dam	USACE	3	88	85.5	75
Bartletts Ferry	GPC	6	197.9	198.6	197.9
Goat Rock Dam	GPC	6	26	40.04	26
Oliver Dam	GPC	4	60	60	60
North Highlands	GPC	4	29.6	35.2	29.6
Walter F. George	USACE	4	168	167.6	150
Jim Woodruff L&D	USACE	3	43.3	43.2	36

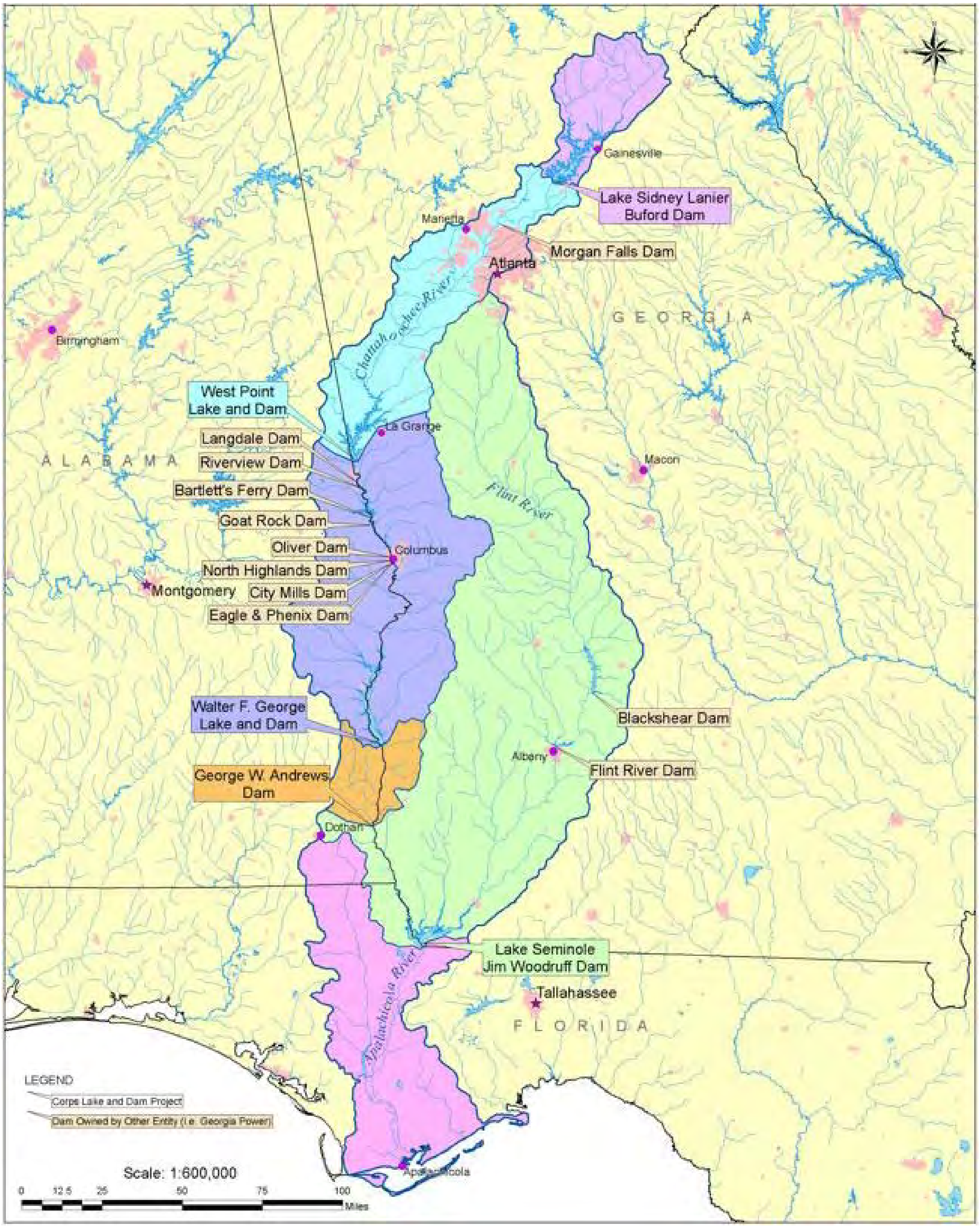


Figure 3. Map of Hydropower Facilities in the ACF Basin.

4. ALTERNATIVES DESCRIPTION

The Corps modeled and evaluated eighteen (18) alternatives in this analysis. These alternatives were chosen to represent different assumptions in Lake Lanier withdrawals, Lake Lanier return rates, Chattahoochee River withdrawals, and operating procedures. Appendix A, Alternatives Description provides a detailed description of the alternatives. Figure 4 provides a brief description of each alternative and the operation set it is based on. Table 2 provides the baselines for each data set. Table 3 provides the Georgia 2000 request (lake and river amounts) as well as the current return rate to the river. Table 4 provides the projected lake return rates that were used in the modeling.

The objective of a baseline, in the context of this analysis, is to distinguish effects to hydropower that are attributable to river withdrawals and the effects to hydropower that are attributable to lake withdrawals. As used in this report, the term “baseline” may reflect different withdrawal amounts from the Chattahoochee River, because the Corps modeled different amounts of river withdrawals pursuant to Georgia’s 2000 request. Therefore, each data set has a “baseline.” The term baseline in each data set always denotes the RHA withdrawal amounts, i.e. the amount of water withdrawn from the river and 20 million gallons per day (mgd) from the Lanier reservoir. For example, the baseline for a Georgia’s 2010 request is 347 mgd from the river and 20 mgd from the reservoir. Below is a list of baselines used.

Table 2. Baseline Data Sets

Name	Lake Lanier Withdrawals (mgd)	Chattahoochee River Withdrawals (mgd)
Improved Operations Baseline	**20**	**277**
2010 Baseline	**20**	**347**
2020 Baseline	**20**	**392**
2030 Baseline	**20**	**408**

The RHA comparison set contrasts different baselines, including two alternatives not requested by Georgia, one that would maximize the benefits for hydropower and the other that would maximize the benefits for downstream river withdrawals for water supply. The RHA comparison isolates the project and system effects attributable to water released downstream (either indirectly, as the result of hydropower generation or directly, for the purpose of water supply) and the 20 mgd from the lake.

Alternative	Description	Operation Set
IMP_Power	Improved operations without downstream water supply, 20 mgd from Lake Lanier, 600 cfs (388 mgd) off-peak release from Buford Dam, 13.5 hrs/weekday of peak generation at Buford Dam	IMProved
Current	Current operations including 2008 Revised Interim Operating Plan with 2007 water use as reported by the State of Georgia	Current
IMPBase	Improved operations with Lake Lanier withdrawals limited to 20 mgd and current Chatthoochee River withdrawals at Atlanta, Georgia	IMProved
IMProved	Improved operations with water supply, current Lake Lanier and Chattahoochee River river withdrawals at Atlanta, Georgia	IMProved
IMPGA2010B	Baseline for evaluating Georgia's 2010 request; Lake Lanier withdrawals limited to 20 mgd, Improved operations with 2010 projected Chattahoochee River withdrawals at Atlanta, Georgia	IMProved
IMPGA2010R	Georgia's 2010 request, with Georgia's 2010 projected lake and river withdrawals and projected lake return rate, improved operations	IMProved
IMPGA2020B	Baseline for evaluating Georgia's 2020 request; Lake Lanier withdrawals limited to 20 mgd, improved operations with 2020 projected Chattahoochee River withdrawals at Atlanta, Georgia	IMProved
IMPGA2020R	Georgia's 2020 request, with Georgia's 2020 projected Lake Lanier and Chattahoochee River withdrawals at Atlanta, Georgia, using Georgia's projected lake return rate, improved operations	IMProved
IMPGA2020P	Georgia's 2020 request, with Georgia's 2020 projected Lake Lanier and Chattahoochee River withdrawals at Atlanta, Georgia, using lake return rate based on current permits, improved operations	IMProved
IMPGA2020C	Georgia's 2020 request, with Georgia's 2020 projected Lake Lanier and Chattahoochee River withdrawals at Atlanta, Georgia, using Lake Lanier return rate based on historic water use, improved operations	IMProved
IR392L125	Georgia's 2020 requested Chattahoochee River withdrawals at Atlanta, Georgia and 2007 Lake Lanier withdrawals as reported by Georgia	IMProved
IMPGA2030B	Baseline for evaluating Georgia's 2030 request; Lake Lanier withdrawals limited to 20 mgd, Improved operations with 2030 projected Chattahoochee River withdrawals at Atlanta, Georgia	IMProved
IMPGA2030R	Georgia's 2030 request, with Georgia's 2030 projected Lake Lanier and Chattahoochee River withdrawals at Atlanta, Georgia, using Georgia's projected Lake Lanier return rate, improved operations	IMProved
IMPGA2030P	Georgia's 2030 request, with Georgia's 2030 projected Lake Lanier and Chattahoochee River withdrawals at Atlanta, Georgia, using lake return rate based on current permits, improved operations	IMProved
IMPGA2030C	Georgia's 2030 request, with Georgia's 2030 projected Lake Lanier and Chattahoochee River withdrawals at Atlanta, Georgia, using Lake Lanier return rate based on historic water use	IMProved
IR408L125	Georgia's 2030 requested Chattahoochee River withdrawals at Atlanta, Georgia, plus Lake withdrawals in 2007 as reported by Georgia, Lake Lanier return rate based on historic water use, improved operations	IMProved
IR408LMAX	Georgia's requested 2030 Chattahoochee River withdrawal at Atlanta, Georgia combined with the maximum amount of Lake Lanier withdrawals that could be made to drain lake storage to, but not below, the bottom of the conservation pool at elevation 1035', improved operations	IMProved
IMPMAXRHA	20mgd withdrawal from Lake Lanier, combined with the maximum amount of Chattahoochee River withdrawal at Atlanta, Georgia that could be made to drain lake storage to, but not below, the bottom of conversation pool at elevation 1035', improved operations	IMProved

Figure 4. Alternatives Descriptions

Table 3. Georgia 2000 Request and Current River Return Rate

	Lake Lanier Withdrawals (mgd)	Chattahoochee River Withdrawals (mgd)	River Return Rate
2010 Request	202	347	76%
2020 Request	256	392	76%
2030 Request	297	408	76%

Table 4. Assumed Lake Lanier Withdrawal Return Rates for Studied Alternatives

Source	Lake Lanier Return Rates
2010 Georgia projection	15%
2020 Georgia projection	27%
2030 Georgia projection	36%
2007 Georgia reported	7%
Current Georgia permits	23%/20%

4.1 277 River Comparison Set

The 277 River withdrawal comparison set was developed to contrast the current operating strategy with the IMProved operation strategy. Current operations are the highest river and lake withdrawals which have occurred (in 2007) and the Revised Interim Operations Plan (RIOP). Current operations were then compared to two alternatives: IMPBase and IMProved. IMPBase assumes an improved operations set (revised action zones, hydropower generation, modified RIOP and Jan through May navigation operations) with lake withdrawals limited to 20 mgd. The IMProved alternative assumes the improved operations with 2007 lake and river withdrawals. All three of the alternatives considered in this set assume a river withdrawal of 277 mgd. In addition to the 277 mgd downstream, the IMProved and IMPBase alternatives also assume some amount of lake withdrawals and a seven percent lake return rate. All eighteen (18) alternatives other than the Current operations utilize the IMProved operating scheme.

4.2 2010:347 MGD River Withdrawal Comparisons

The 2010: 347 mgd river withdrawal comparison contrasts IMPGA2010B, the 2010 baseline (347 mgd river and 20 mgd reservoir), with IMPGA2010R, Georgia 2010 request of 202 mgd of Lake Lanier withdrawals. The IMPGA2010R assumes the GA2000 projected lake return rate of 15 percent.

4.3 2020:392 MGD Withdrawal Comparisons

The 2020: 392 mgd river withdrawal comparison contrasts the 2020 baseline (IMPGA2020B, representing withdrawals of 392 mgd from the river and 20 mgd from the reservoir) with other alternatives having the same gross river withdrawals but differing return rates and lake withdrawal rates.

IMPG2020B acts as the baseline on two different sets. IMPGA2020R assumes the Georgia projected return rate of 27 percent. IMPGA2020C assumes the 2007 reported return rate of seven percent; IMPGA2020P assumes the current permitted water use return rate which represents 23 percent of withdrawals. The additional comparison includes the previous set and alternative IR392L125. IR392L125 assumes 392 mgd for river withdrawals, and also assumes the 125 mgd net withdrawal from Lake Lanier and seven percent return rate (both as reported by Georgia for the year 2007).

4.4 2030:408 MGD Withdrawal Comparisons

The 2030: 408 mgd river withdrawal comparison contrasts the 2030 baseline IMPAGA2030B (408 mgd river and 20 mgd reservoir) with other alternatives reflecting gross river withdrawals of 408 mgd. IMPGA2030B acts as a baseline on two different sets.

IMPGA2030R assumes the Georgia projected return rate of 36 percent. IMPGA2030C assumes Georgia's reported return rate for 2007 (seven percent). IMPGA2030P assumes the current permitted water use return rate of 20 percent. The alternative IR408L125 assumes the 2030 request for downstream river withdrawals and the current lake withdrawals of net 125 mgd. The other alternative, IR408LMAX assumes the 408 mgd gross river withdrawals and a maximum drawdown that could be made without draining storage below the bottom of the conservation pool.

5. HYDROPOWER GENERATION

The value of energy has a seasonal trend following the demand and generating resource availability through the year. This can be captured on a monthly level and is usually highly correlated with extreme temperatures. A first step in comparing alternatives is to notice if any changes in an alternative's operation strategy results in fundamental changes to the normal seasonal generating pattern.

Figure 5 provides a comparison of six alternatives, all of which include only 20 mgd in withdrawals from the reservoir. As shown in Figure 5, all of the alternatives in the comparison set demonstrate the same monthly shapes. Peak generation falls in the March and April time periods following spring runoff and tapers off to a minimum during the hot August and September time period. Since Figure 5 is only looking at the baseline comparison set, all of these alternatives only differ by the amount of downstream river withdrawals.

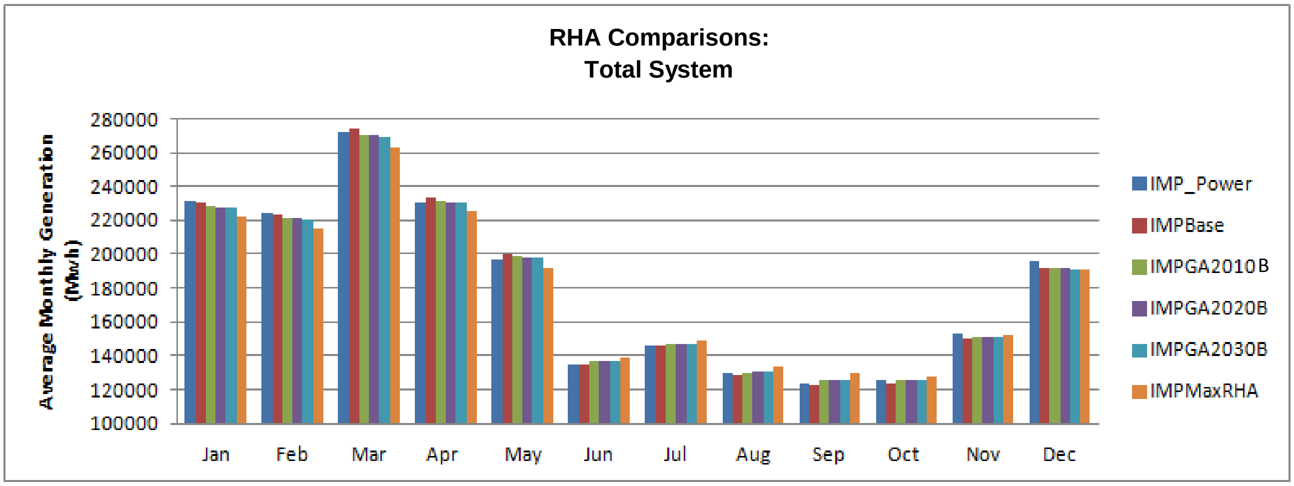


Figure 5. Average Total System (Peak and Off-Peak) Monthly Generation for Alternatives in the RHA Comparison Set

In Figure 6, we see the same generating pattern for Buford Dam as for the total system, with peak generation occurring in March and minimum generation occurring in September. Since all of these alternatives assume the same Lake Lanier withdrawals the expectation would be to notice very little change among the alternatives. This expectation is consistent with results for all of the alternatives except IMPMAXRHA which is showing a decrease in hydropower generation during the winter months and an increase in generation during the summer months.

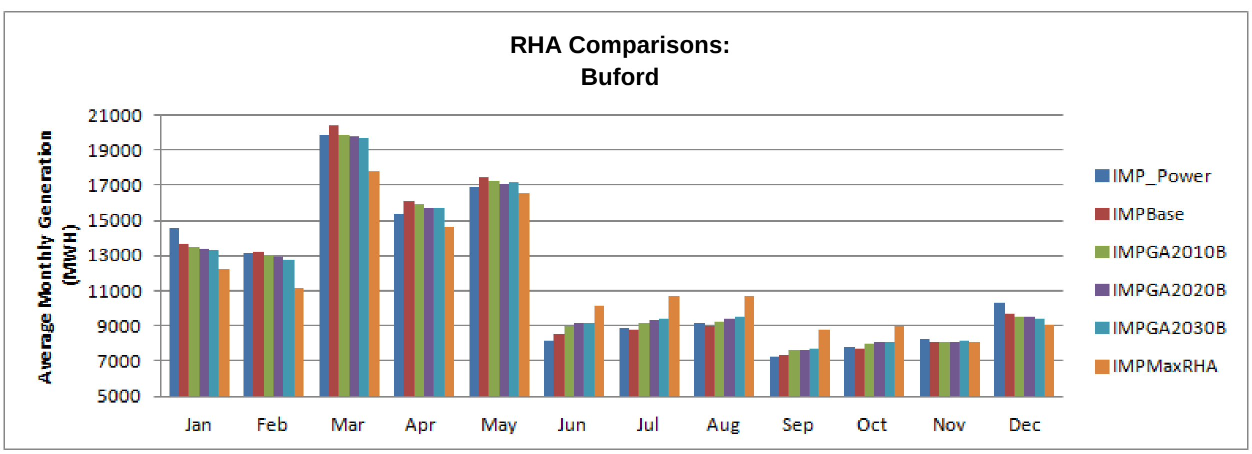


Figure 6. Average Buford Total (Peak and Off-Peak) Monthly Generation for Alternatives in the RHA Comparison Set

Aside from the seasonal trends, analyzing the total energy generation also allows an estimate of a plant's contribution to the total system. Since the alternatives discussed in this study consider different withdrawal rates from Lake Lanier, hydropower generation at Buford Dam would be expected to be affected. The RHA comparison set, assuming the same Lake Lanier withdrawal rates, provides a suitable platform to estimate this contribution. Figure 7 shows that Buford Dam contributes anywhere from about five percent to nine percent throughout the year. Buford's highest contribution occurs in May while its lowest occurs in December.

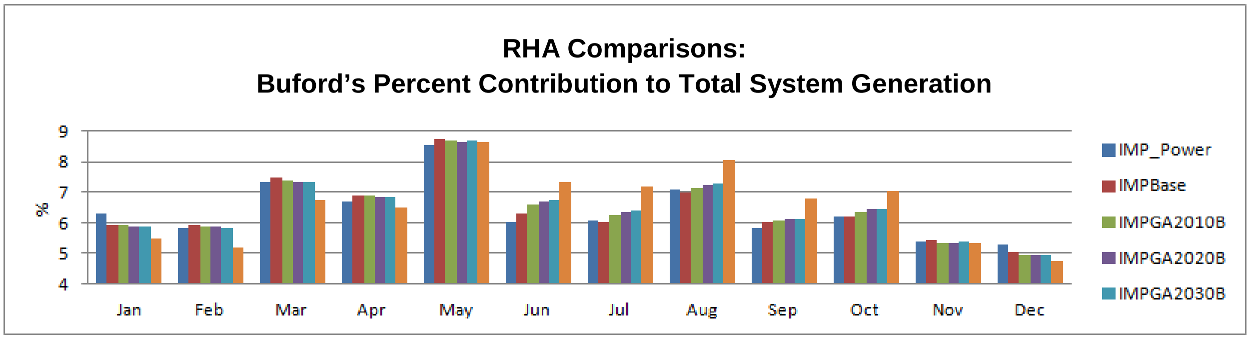


Figure 7. Buford Dam's Percent Contribution of Generation to Total System Generation

5.1 Total Hydropower Generation Across Comparison Sets

The remainder of this section provides analysis of total hydropower generation across the comparison sets described in Section 4. Average seasonal generation patterns are demonstrated for both the total system and Buford Dam. The objective is to validate the assumptions of the model.

5.1.1 277 River Withdrawal Comparisons

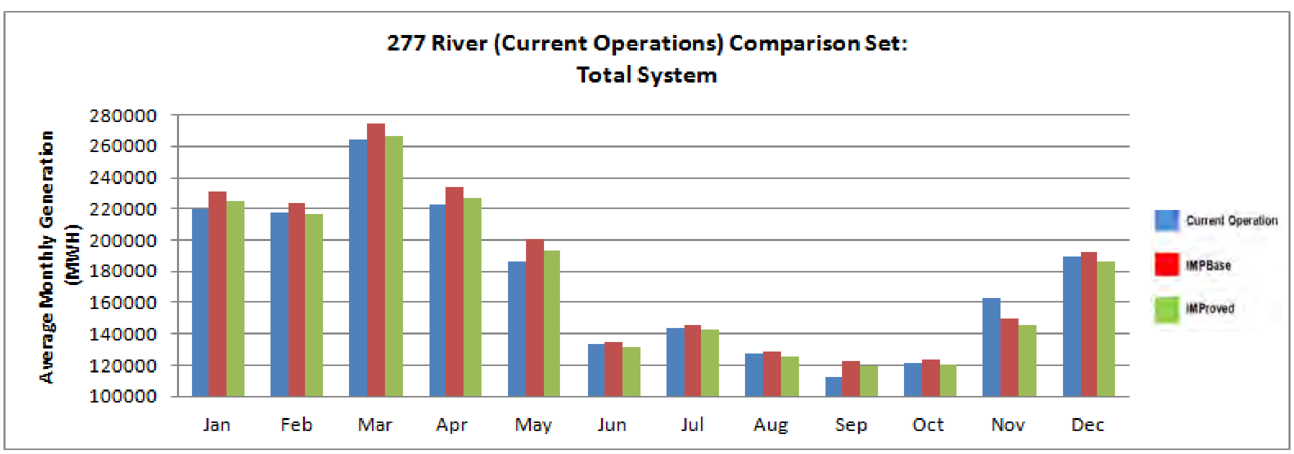


Figure 8. Average Total System (Peak and Off-Peak) Monthly Generation for Alternatives in the 277 Comparison Set

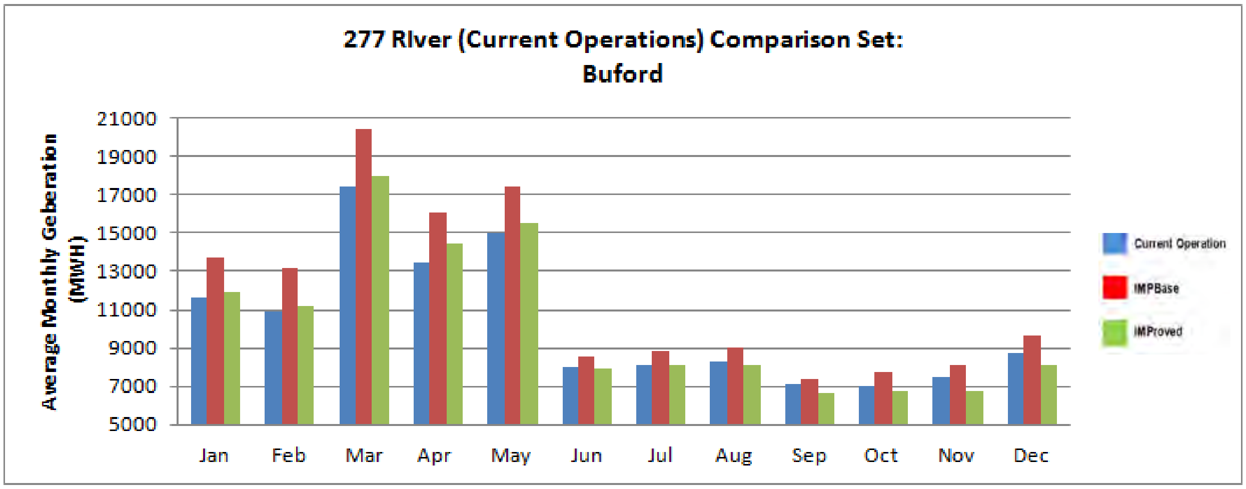


Figure 9. Average Buford Dam (Peak and Off-Peak) Monthly Generation for Alternatives in the 277 Comparison Set

5.1.2 Hydropower Generation for 2010:347 MGD River Withdrawal Comparisons

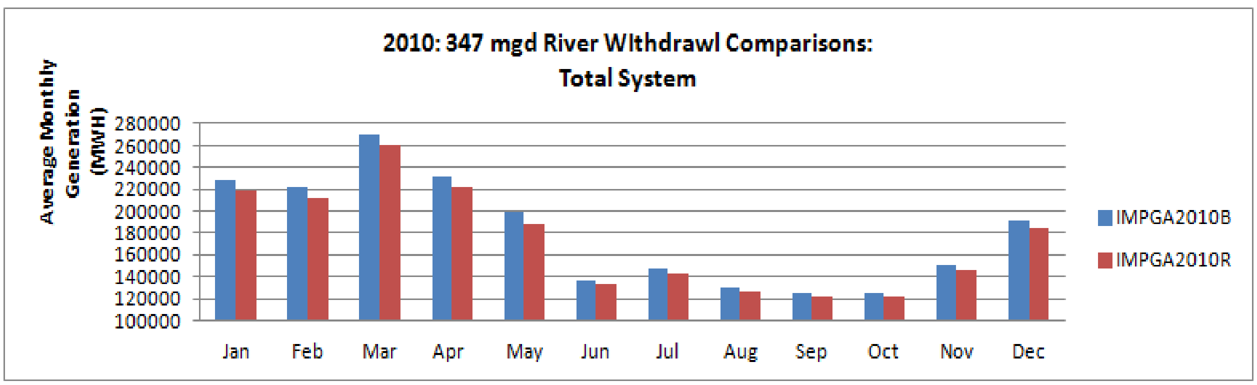


Figure 10. Average Total System (Peak and Off-Peak) Monthly Generation for Alternatives in the 2010:347 MGD River Withdrawal Comparison Set

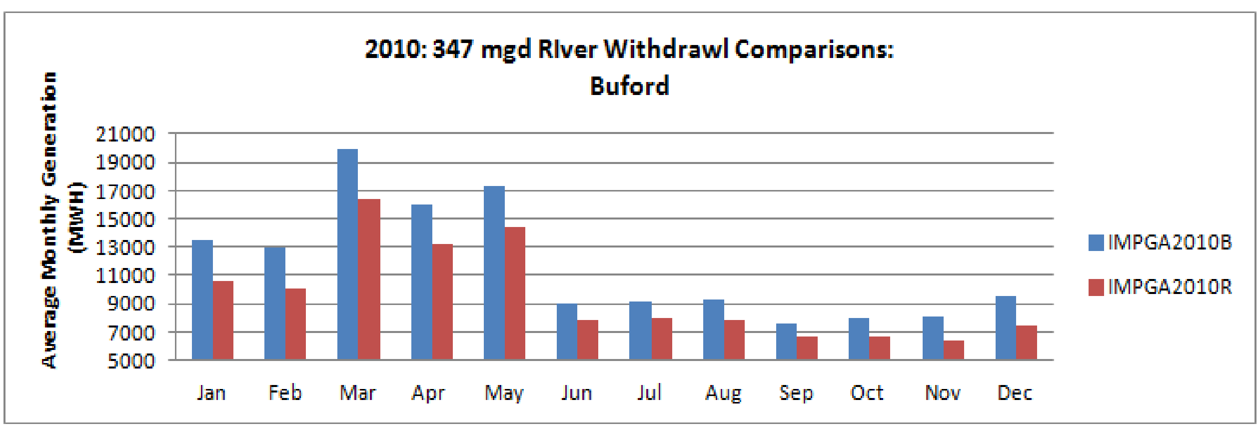


Figure 11. Average Buford Dam (Peak and Off-Peak) Monthly Generation for Alternatives in the 2010:347 River Withdrawal Comparison Set

5.1.3 Hydropower Generation for 2020:392 MGD Withdrawal Comparisons

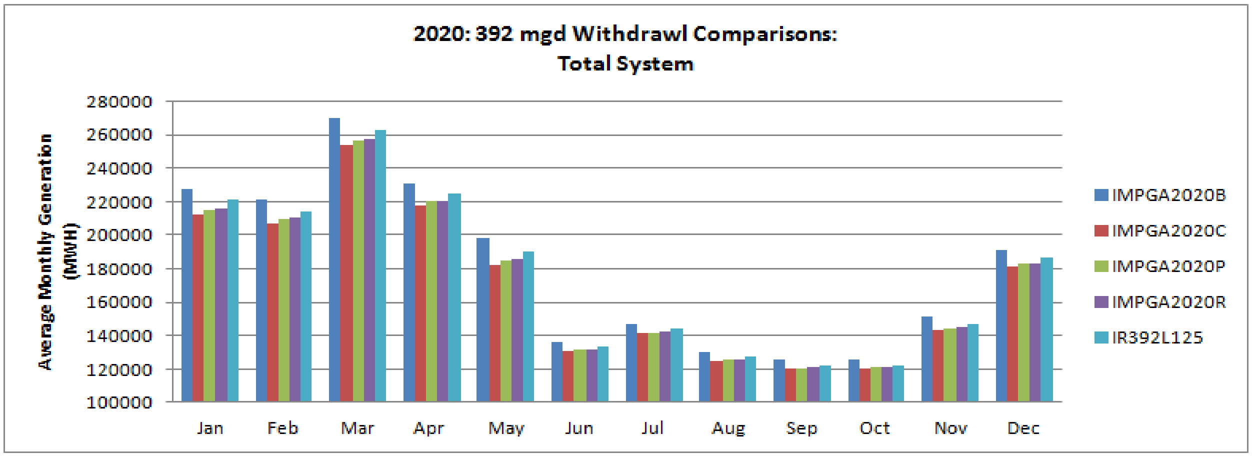


Figure 12. Average Total System (Peak and Off-Peak) Monthly Generation for Alternatives in the 2020:392 MGD Withdrawal Comparison Set

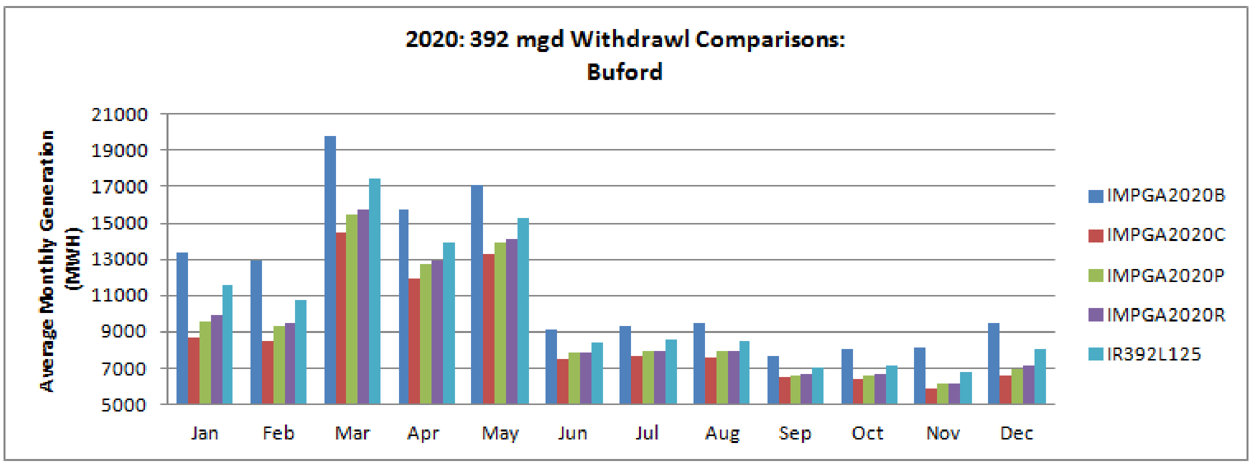


Figure 13. Average Buford Dam (Peak and Off-Peak) Monthly Generation for Alternatives in the 2020 and 392 Comparison Set

5.1.4 Hydropower Generation for 2030:408 MGD Withdrawal Comparisons

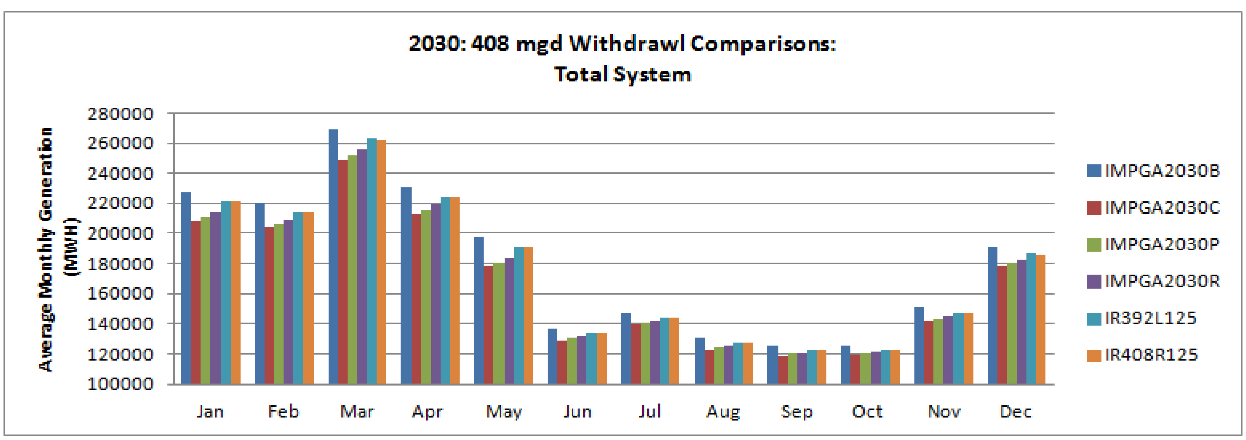


Figure 14. Average Total System (Peak and Off-Peak) Monthly Generation for Alternatives in the 2030:408 MGD Withdrawal Comparison Set

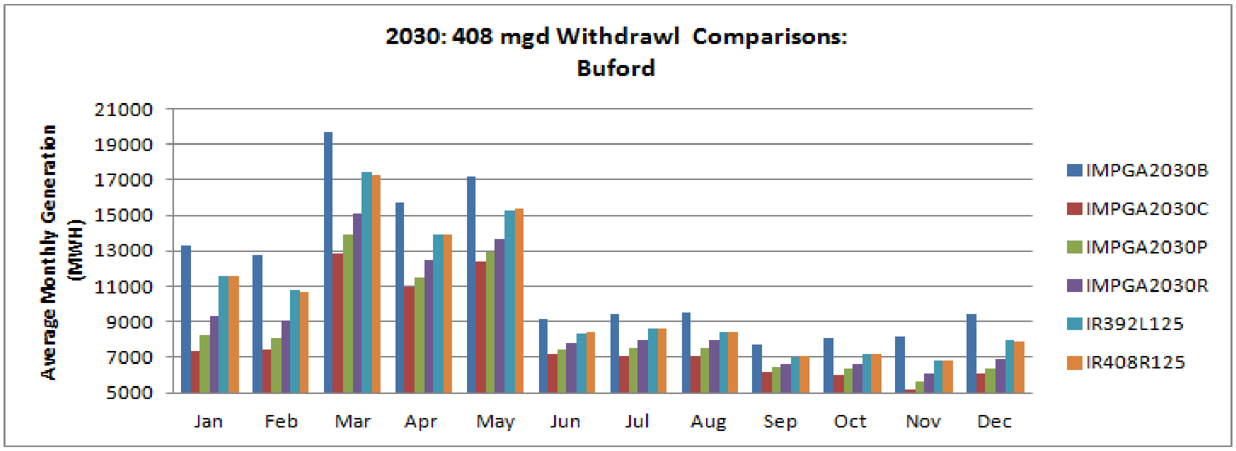


Figure 15. Average Buford Dam (Peak and Off-Peak) Monthly Generation for Alternatives in the 2030:408 MGD Withdrawal Comparison Set

6. ENERGY VALUE

Energy benefits are computed as the product of the energy loss in megawatt-hours and an energy unit value price ($/MWh). The energy price is based on the cost of energy from a combination of plants that would replace the lost energy from the hydropower plant due to operational and/or structural changes.

6.1 Energy Unit Value Prices

This analysis uses a simulation over the period of record to estimate the effects of changes in water management on hydropower production. However, in order to evaluate the resulting changes in hydropower benefits over a 50-year period of analysis, forecasts of future energy prices are needed.

Future energy values in this analysis are based on EIA forecasts from the supplemental tables of "Annual Energy Outlook" (AEO 2011) [1]. The EIA forecasts are developed with the Electricity Market Model (EMM) as part of the National Energy Modeling System (NEMS). The following description is from the model documentation report available on the EIA website:[2]

> *The National Energy Modeling System (NEMS) was developed to provide 20-to-25 year forecasts and analyses of energy-related activities. The NEMS uses a central database to store and pass inputs and outputs between the various components. The NEMS Electricity Market Module (EMM) provides a major link in the NEMS framework (Figure 1). In each model year, the EMM receives electricity demand from the NEMS demand modules, fuel prices from the NEMS*

[1] http://www.eia.gov/oiaf/aeo/supplement/sup_elec.xls, as of December 14, 2011.
[2] http://www.eia.gov/FTPROOT/modeldoc/m068(2011).pdf, as of December 14, 2011.

fuel supply modules, expectations from the NEMS system module, and macroeconomic parameters from the NEMS macroeconomic module. The EMM estimates the actions taken by electricity producers (electric utilities and nonutilities) to meet demand in the most economical manner. The EMM then outputs electricity prices to the demand modules, fuel consumption to the fuel supply modules, emissions to the integrating module, and capital requirements to the macroeconomic module. The model iterates until a solution is reached for each forecast year.

In addition to providing average annual energy forecasts of electrical generation prices through 2035, AEO 2011 also includes regional forecasts corresponding to North American Electric Reliability Corporation (NERC) regional entity sub-regions. Federal ACF hydropower plants are located in the southeastern sub-region of the Southeastern Reliability Corporation (SERC/S). Discussions with SEPA confirmed that most of the electrical generation from ACF plants is marketed through SERC/S, and that EIA forecasts of thermal generation prices for the SERC/S region was appropriate for this analysis.[3]

6.1.1 Shaping and System Lambda

Because EIA provides only a single average energy value for each future year through 2035, the EIA forecasts values were adjusted (shaped) to reflect both seasonal and daily variation in load and prices using data from Federal Energy Regulatory Commission (FERC) Form 714 reports. For utilities generating electricity from thermal plants, Form 714 requires reporting of hourly energy demand (load) and the hourly marginal cost (lambda) of generating one additional MW of electrical energy.

The following explanation of how lambda was calculated is from the FERC Form 714 report, Part II, Schedule 6, filed for 2010 by Southern Company:

The Southern Company system lambda is determined hourly and is based on the variable costs of the resources that serve the load obligations of the Operating Companies plus any sales to third parties. The variable costs of the resources include the components listed below, and may also reflect the cost of purchases. The economic dispatch formula used to dispatch Southern's generating resources on the basis of their variable cost components is as follows:

$$\lambda = [\{(2aP + b) * (FC + EC)\} + VOM + FH] * TPF$$

Where:

[3] Email correspondence between Douglas Symes, USACE, and Douglas Spencer, SEPA, December 14, 2011.

λ	= *System lambda*
a, b	= *Incremental heat rate coefficients*
P	= *Generation level*
FC	= *Marginal replacement fuel costs*
EC	= *Marginal replacement emission allowance costs*
VOM	= *Variable operations and maintenance expenses*
FH	= *In-plant fuel handling expenses*
TPF	= *Incremental transmission losses (penalty factors)*

Form 714 reports are available online for the five Southern Company utilities that generate thermal power in SERC/S for the years 2001 through 2010: Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power. The five Southern Company utilities represent about three quarters of the fossil fuel generating capacity in the SERC/S sub-region and about 92 percent of the fossil generation for which system lambda is reported to FERC. While system lambda and load were also reported during this period by Southern Mississippi Electric Power Cooperative and Alabama Electric Cooperative, formatted data from these companies was not available for the entire period and therefore was not included in the calculations described below.

For each year of the 2001 - 2010 period, average load-weighted lambda for each month was calculated for on-peak and off-peak hours. The proportion of each of these monthly average weighted lambda values to the total year’s average weighted lambda was calculated for each year, and then averaged over the 10-year period. These proportions are presented in Table 5.

The proportions in Table 6 were then multiplied by the EIA forecast energy value for each year to obtain estimates of monthly on-peak and off-peak values. For instance, the Annual Energy Outlook (AEO) forecast of the SERC/S average generation price of one MW of electricity in 2025 is $62.05 indexed to Fiscal Year (FY) 2012 dollars. To calculate the estimated average January on-peak energy price for 2025, the calculation is $62.05 x 1.31 = $81.29. The estimated on-peak and off-peak energy prices for all 12 months of 2025 are presented in Table 5.

Table 5. Average Monthly On-Peak and Off-Peak Load-Weighted Lambda as a Proportion of Average Yearly Load-Weighted Lambda

	On-Peak	Off-Peak
January	1.31	0.95
February	1.14	0.86
March	1.12	0.87
April	1.28	0.91
May	1.23	0.85
June	1.45	0.93
July	1.49	0.96
August	1.56	1.02
September	1.36	0.91
October	1.17	0.88
November	1.01	0.81
December	1.12	0.87

Table 6. Average Monthly On-Peak and Off-Peak System Lambda for 2025

	On-Peak	Off-Peak
January	$81.29	$60.24
February	$70.99	$60.53
March	$69.67	$54.28
April	$79.45	$55.60
May	$76.44	$50.62
June	$90.22	$55.86
July	$92.60	$58.34
August	$96.89	$57.23
September	$84.68	$44.11
October	$72.98	$45.40
November	$62.77	$48.15
December	$69.86	$55.37

Figure 16 shows the EIA forecasts of average annual all-hour wholesale energy generation prices for the period 2012 through 2035, indexed to constant FY 2012 dollars[4], and also applies the proportions in Table 4 to the EIA forecast values to derive monthly values for on-peak and off-peak energy. After 2035, monthly prices are assumed to be constant in FY 2012 dollars through 2061.

To develop the annualized prices for each calendar month, the present values of on-peak and off-peak prices for each month of the 50-year period of analysis were calculated using the federal discount rate of four percent. The resulting 50 present values were then summed and amortized over the 50-year period of analysis at the Federal discount rate. The resulting annualized prices are shown in Table 7.

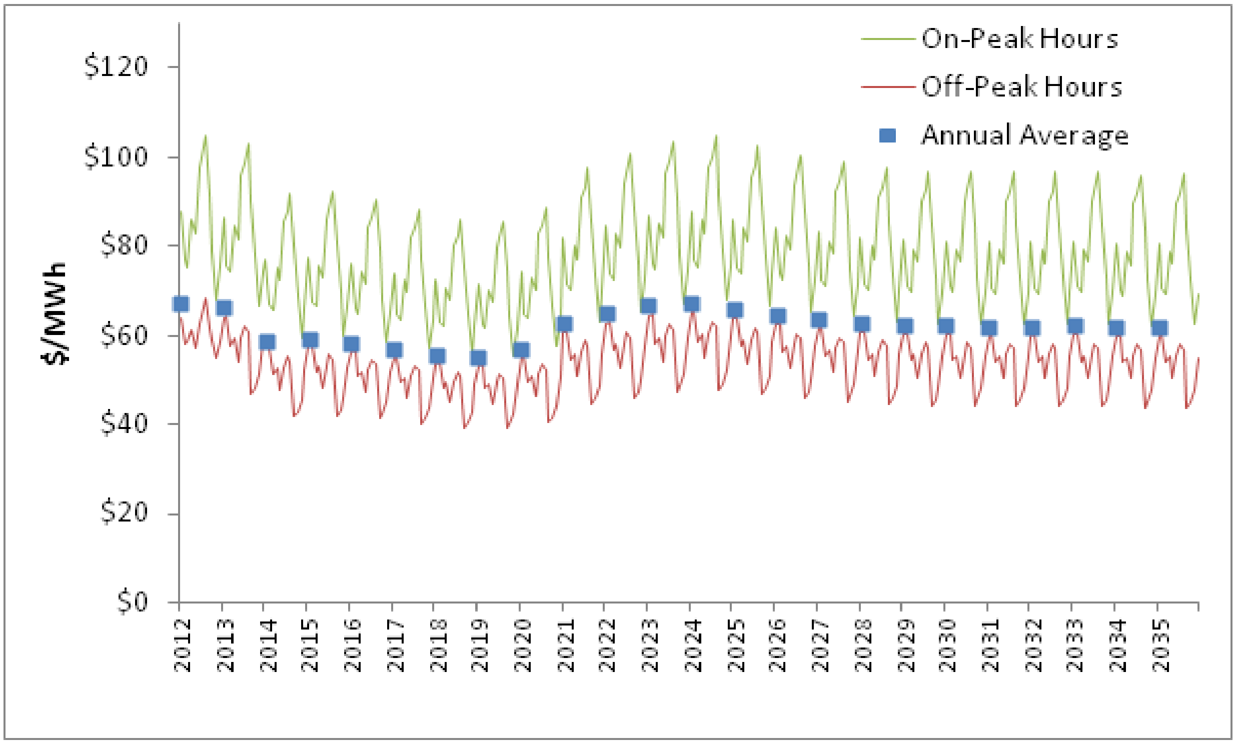


Figure 16. Forecasts On-Peak and Off-Peak Energy Prices 2012-2035

[4] EIA average annual all-hours wholesale generations prices for SPP/S are reported in Annual Energy Outlook 2011 in 2009 constant dollars. These values are indexed to 2012 constant dollars using the GDP Deflator (http://www.whitehouse.gov/omb/budget/Historicals as of October 21, 2011).

Table 7. Average Annual On-Peak and Off-Peak Energy Prices by Month

	On-Peak	Off-Peak
January	$83.44	$61.78
February	$72.86	$61.83
March	$71.51	$55.70
April	$81.55	$57.11
May	$78.46	$52.06
June	$92.60	$57.42
July	$95.05	$59.94
August	$99.46	$59.01
September	$86.92	$45.83
October	$74.91	$47.01
November	$64.43	$49.53
December	$71.71	$56.77

6.2 Average Annual Energy Value Calculations

If the price of energy was constant throughout both the day and seasons, daily energy values could be computed simply as the product of total generation (in MWh) and a static energy price ($/MWh). In this case the annual energy value would just be sum of those daily values over the entire year. However energy prices are dynamic on both a seasonal and hourly scale. A more accurate approach then would be to assign a different energy price to each month's generation, in effect modeling the seasonal changes. This still does not incorporate the hourly differences between peak and off-peak generation. This section explains the methodology used to estimate the amount of daily peak and off-peak generation, and eventually the annual energy value of an alternative.

Although all plants in this system except for Jim Woodruff are defined as peaking plants, actual hydropower operations of the individual power plants can vary significantly. For example some plants may turn completely off and then back on again during peak demand periods, while others may have a minimum flow requirement that constantly generates a small amount of electricity with a maximum generation occurring during peak demand periods. Unfortunately, the detailed hourly generation information required from each non-Federal plant to determine the daily peak and off-peak percentage of total generation is not available because the ResSim model is run with a daily time step. To calculate the energy value, the methodology assumes that plants will operate to maximize energy benefits; that is, to generate the maximum amount of energy during periods of peak demand.

To better illustrate this assumption an example daily calculation has been prepared.

For each day in the simulation period the ResSim model outputs a plant's total generation in MWh and a plant capability in MW. The plants capability estimates the operational capacity of the plant as a function of head. In this example, Buford Dam has a simulated generation of 1370 MWh for May 5 under the current operations alternative and an estimated plant capability of 115.24 MW.

The maximum amount of peak generation in MWh defined for that day will be the simulated plant capability multiplied by the daily number of peak hours defined for the month as confirmed by the SEPA for the region. For the winter period of October 1 through March 31, eleven (11) daily peaking hours were defined. These hours can be roughly estimated as 5:00 a.m. to 9:00 a.m. and 3:00 p.m. to 10:00 p.m., Monday through Friday. For the summer period from April 1 to September 30, six daily peaking hours were defined. With the hours roughly estimated as 1:00 p.m. to 7:00 p.m., Monday through Friday. Weekends are defined as off-peak.

A simulated hourly generation pattern for the Buford Dam example is shown in Figure 17. To make up the total 1370 MWh generated that day, a maximum of 6*115.24=691.44 MW could be defined as peaking with the remaining 678.56 defined as off-peak, which makes up almost an additional six hours of off-peak generation. Each hour of generation is assigned the associated energy price from Table 7 also shown in Figure 17. It is important to realize that the exact hour representation of the generation and energy prices are only meant as a visual tool. The exact timing of when the peaking hours occur may change from day-to-day or year-to-year.

The product of the hourly MWh generated by the associated energy price gives the hourly energy value for the plant (Figure 18). The sum of both the peak and off-peak hourly energy values results in the daily energy value. For this example the daily energy value totaled nearly $90,000.00. Annual energy values are computed as the sum of daily values for a given simulation year. Average annual energy values are the average over each simulated annual energy value. Table 8 provides the average annual energy value for each plant and alternative considered in this analysis.

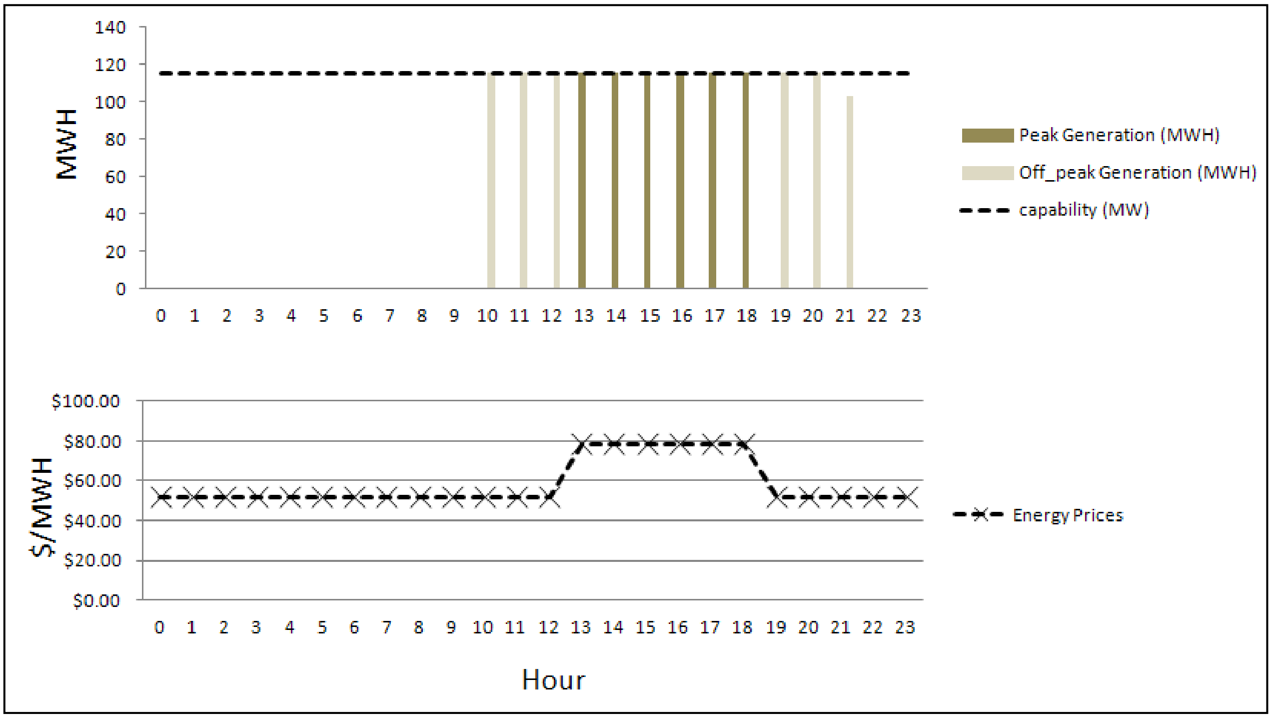


Figure 17. Simulated Hourly Generation and Energy Prices for Buford Dam for the Simulated Date May 5, 1945. Total Daily Generation 1370 MWh with an Estimated Plant Capacity 115.24 MW.

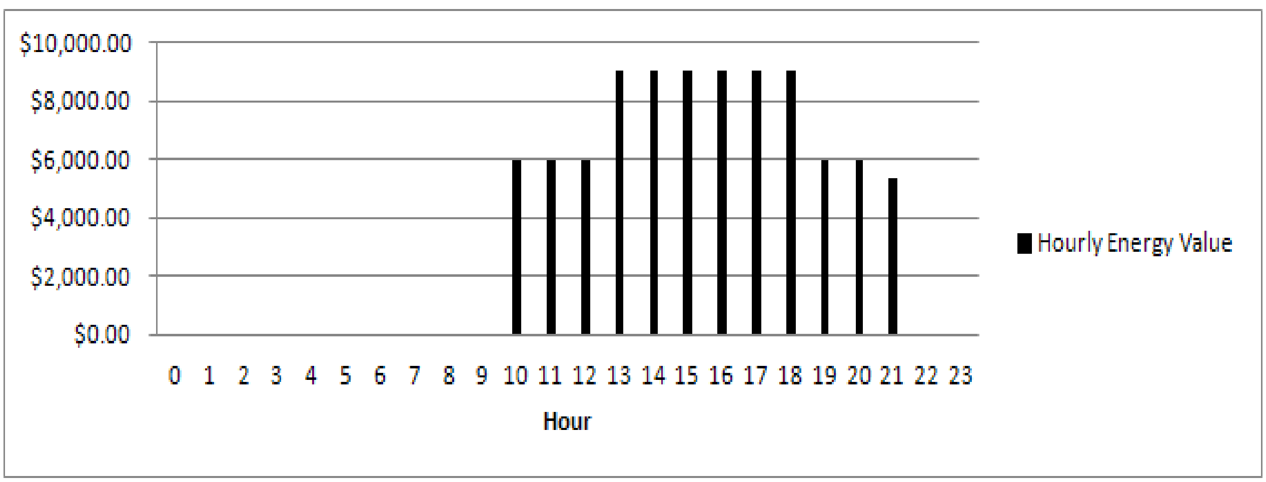


Figure 18. Simulated Hourly Energy Value for Buford Dam for May 5, 1945.

Table 8. Average Annual Energy Values for ACF Hydropower System by Alternative

	Buford	Morgan Falls	West Point	Bartlett	Goat Rock	Oliver	North Highlands	Walter F George	Jim Woodruff	Total Energy Value
Current	$9,227,000	$4,138,000	$12,793,000	$30,394,000	$13,488,000	$16,319,000	$9,508,000	$33,579,000	$16,499,000	$145,946,000
IMP_Power	$10,493,000	$4,383,000	$13,270,000	$31,226,000	$13,777,000	$16,672,000	$9,705,000	$34,101,000	$16,543,000	$150,169,000
IMPBase	$10,388,000	$4,352,000	$13,171,000	$31,113,000	$13,707,000	$16,592,000	$9,656,000	$33,992,000	$16,503,000	$149,474,000
IMPGA2010B	$10,359,000	$4,537,000	$13,129,000	$31,001,000	$13,689,000	$16,557,000	$9,639,000	$33,941,000	$16,517,000	$149,369,000
IMPGA2010R	$8,597,000	$4,213,000	$12,530,000	$29,918,000	$13,361,000	$16,123,000	$9,403,000	$33,276,000	$16,471,000	$143,892,000
IMPGA2020B	$10,347,000	$4,542,000	$13,096,000	$30,934,000	$13,669,000	$16,532,000	$9,626,000	$33,907,000	$16,518,000	$149,172,000
IMPGA2020C	$7,824,000	$4,086,000	$12,267,000	$29,433,000	$13,224,000	$15,931,000	$9,300,000	$32,981,000	$16,475,000	$141,522,000
IMPGA2020P	$8,262,000	$4,163,000	$12,404,000	$29,680,000	$13,294,000	$16,030,000	$9,354,000	$33,142,000	$16,475,000	$142,804,000
IMPGA2020R	$8,372,000	$4,183,000	$12,437,000	$29,741,000	$13,312,000	$16,055,000	$9,367,000	$33,173,000	$16,476,000	$143,117,000
IMPGA2030B	$10,337,000	$4,543,000	$13,082,000	$30,906,000	$13,663,000	$16,523,000	$9,622,000	$33,887,000	$16,517,000	$149,079,000
IMPGA2030C	$7,157,000	$3,973,000	$12,050,000	$29,042,000	$13,104,000	$15,771,000	$9,214,000	$32,738,000	$16,467,000	$139,516,000
IMPGA2030P	$7,608,000	$4,055,000	$12,197,000	$29,301,000	$13,187,000	$15,879,000	$9,273,000	$32,902,000	$16,474,000	$140,876,000
IMPGA2030R	$8,158,000	$4,149,000	$12,364,000	$29,606,000	$13,276,000	$16,003,000	$9,340,000	$33,089,000	$16,479,000	$142,463,000
IMPMaxRHA	$10,190,000	$4,605,000	$12,953,000	$30,589,000	$13,621,000	$16,444,000	$9,587,000	$33,742,000	$16,568,000	$148,299,000
IMProved	$9,219,000	$4,126,000	$12,750,000	$30,361,000	$13,469,000	$16,283,000	$9,487,000	$33,524,000	$16,463,000	$145,682,000
IR392L125	$9,147,000	$4,325,000	$12,689,000	$30,195,000	$13,446,000	$16,236,000	$9,465,000	$33,447,000	$16,488,000	$145,439,000
IR408LMAX	$7,459,000	$4,029,000	$12,150,000	$29,220,000	$13,160,000	$15,843,000	$9,253,000	$32,850,000	$16,472,000	$140,436,000
IR408R125	$9,138,000	$4,327,000	$12,679,000	$30,176,000	$13,443,000	$16,230,000	$9,462,000	$33,439,000	$16,485,000	$145,379,000

7. DEPENDABLE CAPACITY MEASUREMENTS AND VALUE

The dependable capacity of a hydropower project is a measure of the amount of capacity that the project can reliably contribute towards meeting system peak power demands. If a hydropower project always maintains approximately the same head, and there is always an adequate supply of stream flow so that there is enough generation for the full capacity to be usable in the system load, the full installed generator capacity can be considered dependable. In some cases even the overload capacity is dependable.

At storage projects, normal reservoir drawdown can result in a reduction of capacity due to a loss in head. At other times, diminished stream flows during low flow periods may result in insufficient generation to support the marketable capacity of the load. Dependable capacity accounts for these factors by giving a measure of the amount of capacity that can be provided on average during peak demand periods.

There is an important subtle distinction between dependable capacity and marketable capacity. The marketable capacity listed for the Federal plants in Table 1 has been defined by SEPA to represent the amount of capacity that is available under the low hydrologic regime of 1981 in meeting the peak demands of the summer months. SEPA uses this value to market firm energy to their customers. Dependable capacity on the other hand represents the average capacity that is available during the summer months over the entire simulation period. Extreme events are not given any higher weight compared to average years in the calculation of dependable capacity.

7.1 Average Dependable Capacity Measurement

Dependable capacity can be computed in several ways. The method that is most appropriate for evaluating the dependable capacity of a hydropower plant in a predominantly thermal-based power system like the ACF River Basin is the average availability method. This method is described in Section 6-7g of EM 1110-2-1701, *HYDROPOWER Engineering and Design*, dated 31 December 1985. The occasional unavailability of a portion of a hydropower project's generating capacity due to hydrologic variations can be treated in the same manner as the occasional unavailability of all or part of a thermal plant's generating capacity due to forced outages.

In order to evaluate the average dependable capacity for a project, a long-term record of project operation must be used. Actual project operating records would be most desirable; however, certain factors may preclude the use of these records. The period of operation may not be long enough to give a statistically reliable value. Furthermore, operating changes may have occurred over the life of the project, which would make actual data not representative of the current operating strategies. In order to assure the greatest possible consistency in this calculation, the 70-year ResSim simulation for the ACF River Basin was used.

The dependable capacity calculation procedure for the ACF River Basin projects began by approximating each project's contribution (weekly hours operating on peak) in meeting the system capacity requirements demand for the regional critical year. This contribution estimate was determined by first calculating each project's weekly average energy produced (in MWh) for the annual critical months of mid-May through mid-September of 1981, SEPA's defined critical year from the ResSim baseline model run. This number was then divided by SEPA's defined marketable capacity (in MW). The baseline alternative is used because it most closely represents current operations in which SEPA has defined the marketable capacity. This gave an estimate of weekly hours on-peak for each project for the current operations. Coordination with SEPA confirmed marketable capacity values for the Corps hydropower plants and the critical water year of 1981. Installed capacity was assumed to be the same as marketable capacity for all non-Corps plants.

Next, each project's weekly average energy (in MWh) produced during the peak demand months was calculated for each simulated year. Dividing these values by each project's weekly average hours (H) on-peak (as determined in the previous step) yielded an array of yearly dependable capacity values. The average across the array is each project's average dependable capacity.

This process is repeated for each alternative flow simulated by the ResSim model output. The average dependable capacity for each plant and alternative is given Table 9.

Table 9. Average Annual Dependable Capacity (MW) for Plants in ACF Hydropower System by Alternative

	Buford	Morgan Falls	West Point	Bartlett	Goat Rock	Oliver	North Highlands	Walter F George	Jim Woodruff	total (MW)
Current	110.24	16.44	83.38	198.36	39.09	56.14	32.79	163.76	39.76	739.98
IMP_Power	114.24	16.78	84.6	200.18	39.41	56.61	33.03	164.54	39.88	749.26
IMPBase	111.43	16.51	83.32	198.69	39.14	56.22	32.81	163.32	39.79	741.24
IMPGA2010B	113.03	16.75	83.71	199.1	39.21	56.32	32.87	163.54	39.8	744.34
IMPGA2010R	106.87	16.67	83.56	198.67	39.14	56.22	32.83	164.02	39.79	737.77
IMPGA2020B	113.6	16.79	83.84	199.32	39.25	56.38	32.91	163.72	39.8	745.62
IMPGA2020C	105.28	16.76	83.96	199.15	39.23	56.35	32.91	164.2	39.83	737.65
IMPGA2020P	106.29	16.76	83.89	198.99	39.2	56.31	32.88	164.17	39.79	738.28
IMPGA2020R	106.59	16.76	83.85	198.92	39.19	56.29	32.87	164.18	39.81	738.45
IMPGA2030B	113.62	16.79	83.91	199.28	39.25	56.37	32.9	163.63	39.79	745.53
IMPGA2030C	101.91	16.76	83.9	198.99	39.2	56.31	32.9	164.16	39.82	733.95
IMPGA2030P	104.72	16.78	83.99	199.15	39.23	56.35	32.91	164.22	39.82	737.18
IMPGA2030R	106.76	16.78	83.98	199.22	39.24	56.37	32.92	164.19	39.82	739.28
IMPMaxRHA	113.04	16.79	85.05	201.63	39.76	57.11	33.34	164.85	39.93	751.52
IMProved	109.77	16.42	83.17	198.24	39.06	56.11	32.76	163.44	39.78	738.76
IR392L125	109.99	16.77	83.66	198.81	39.16	56.26	32.85	163.81	39.81	741.12
IR408LMAX	103.64	16.78	83.98	199.12	39.23	56.34	32.91	164.22	39.82	736.04
IR408R125	110.21	16.79	83.87	199.2	39.24	56.36	32.91	164.09	39.81	742.48

7.2 Dependable Capacity Unit-Value Calculation

Capacity unit values represent the capital cost and the fixed operations and maintenance (O&M) cost of the most likely thermal generation alternative that would carry the same increment of load as the proposed hydropower project or modification. As discussed below in the screening curve analysis description, the cost effectiveness of the different thermal resources depends on how and when the resource is used. For example, coal fired plants may be used to replace a base loading hydropower plant while a gas fired turbine plant may be used to replace a peaking hydropower operation. A combined cycle plant would be used in an intermediate mode of load-following. In this section the process of determining the least costly, most likely combination of thermal generation resources, which comprise the thermal alternative to hydropower, is described. Next, the method calculating the capacity unit-value is presented.

7.2.1 Total System and Buford Duration Curves

To establish the most likely thermal alternative, an analysis of how the hydropower system is currently operated is performed. The goal of this analysis is to show how much capacity can be defined as base load, how much can be defined as intermediate load, and how much can be defined as peaking.

The first step in this process is to create a load duration curve. This curve, typically created from historical records of hourly generation, illustrates the portion of time different levels of cumulative system generation are each hour in a typical year. In this study hourly generation data for the four Corps plants for a typical year were available. However for the remaining non-Corps plants in the ACF System, the hourly generation was assumed to act similarly to the nearest upstream Corps plant. This assumption is reasonable since the non-Corps plants are defined as modified run-of-river plants acting to smooth out discharges from the larger upstream Corps reservoirs.

To produce the total system duration curve, a further assumption was made that all of the hydropower plants' typical year, hourly generation occurred concurrently. The hourly generation for all of the hydropower plants in the basin were added together to form a total system hourly generation. The duration curve developed from this process is shown in Figure 19. The load duration curve for Buford Dam is illustrated in Figure 20.

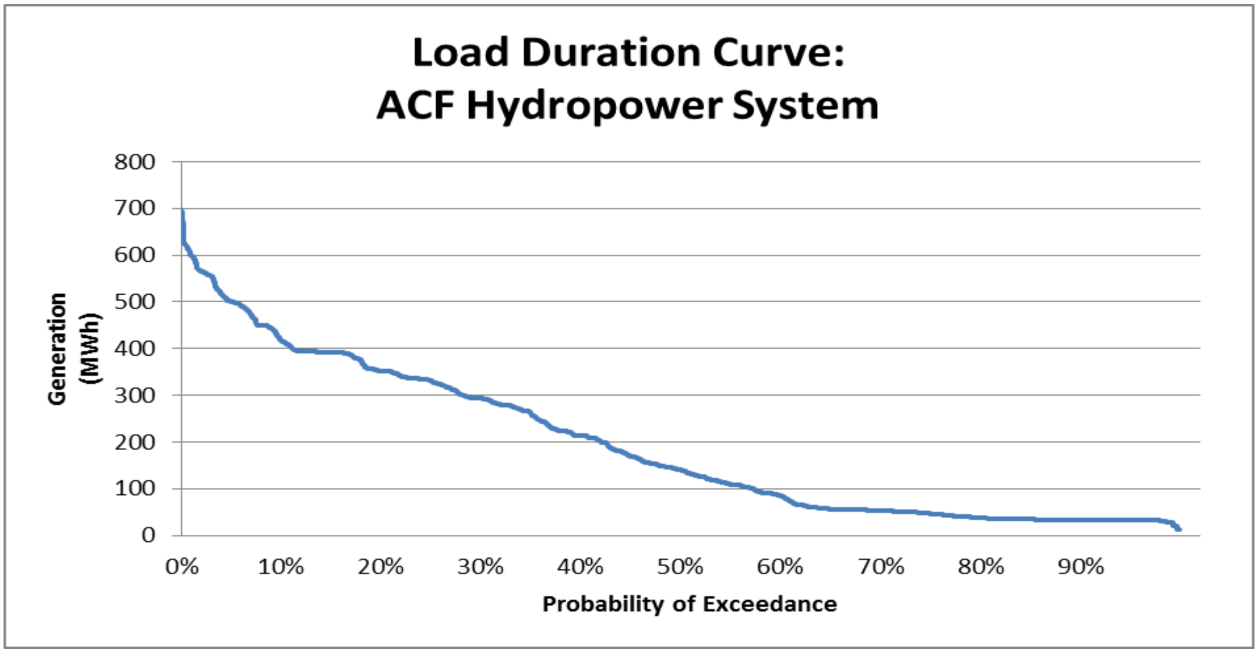


Figure 19. Load Duration Curve for entire ACF Hydropower System. This curve is derived from hourly generation data for a plants typical year. .

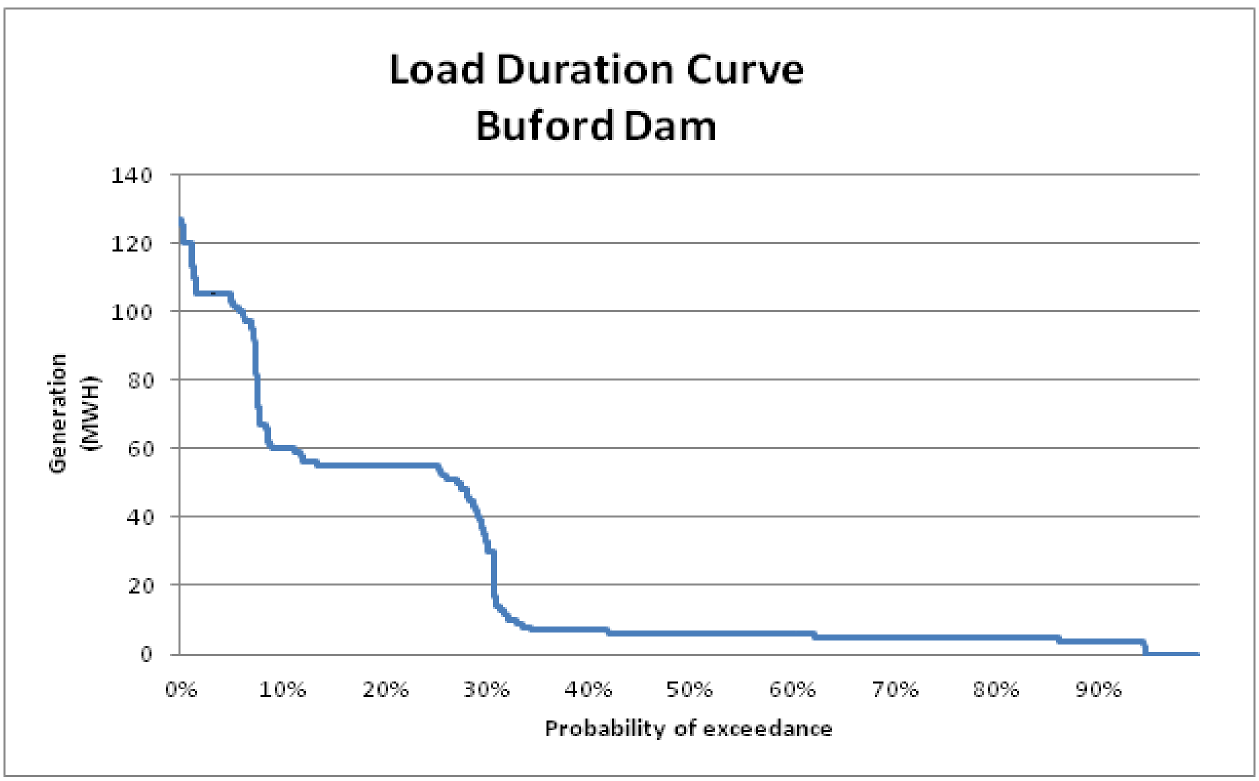


Figure 20. Load Duration Curve for Buford Dam. This curve is derived from hourly generation for a typical year for Buford Dam.

7.2.2 Screening Curve

A screening curve is a plot of annual total plant costs for a thermal generating plant [fixed (capacity) cost plus variable (operating) cost] versus annual plant factor (plant utilization factor). When this is applied to multiple types of thermal generation resources, the screening curve provides an algebraic way to show which type of thermal generation is the least cost alternative for each plant factor range.

The screening curve assumes a linear function defined by the following equation:

$$AC = CV + (EV * 0.0876 * PF)$$

where: AC = annual thermal generating plant total cost ($/kW-year)

CV = thermal generating plant capacity cost ($/KkW-year)

EV = thermal generating plant operating cost ($/MWh)

Capacity unit values for coal-fired steam, gas-fired combined cycle and combustion turbine plants were computed using procedures developed by FERC. Results of executing the FERC procedures can be found in Appendix B. Capacity values were computed for Alabama and Georgia in the SEPA region based on a 4.0 percent interest rate and 2012 price levels. Adjusted capacity values are shown in Table 10. The adjusted capacity values incorporate adjustments to account for differences in reliability and operating flexibility between hydropower and thermal generating power plants. See EM 1110-2-1701, *HYDROPOWER Engineering and Design*, Section 9-5c for further discussion of the capacity value FERC adjustments.

Table 10. Adjusted Capacity and Operating Costs for SEPA Region

Thermal Generating Plant Type	Adjusted Capacity Cost	Operating Cost
	$/KW-Year	$/MWh
Coal-Fired Steam	$198.82	$29.08
Combined Cycle	$121.15	$53.05
Combustion Turbine	$57.76	$85.19

Operating costs for coal-fired steam (CO), gas-fired combined cycle (CC) and gas-fired combustion turbine (CT) plants were developed using information obtained from the publication *EIA Electric Power Monthly (DOE/EIA-0226)* and other sources. The information obtained included fuel costs, heat rates and variable O&M costs. The resulting values, based on 2012 price levels, are shown in Table 7. Since current Corps policy does not allow the use of real fuel cost escalation, these values were assumed to apply over the entire period of analysis.

The plot for each thermal generation type was developed by computing the annual plant cost for various plant factors ranging from zero to 100 percent. As shown in Figure 21, CT had the lowest over all capacity cost up to the first breakpoint with a plant factor of 22.6 percent. After that CC had the lowest cost from a plant factor of 22.6 up to a plant factor of 36.8 percent. For plant factors greater than 36.8 percent, coal had the lowest cost.

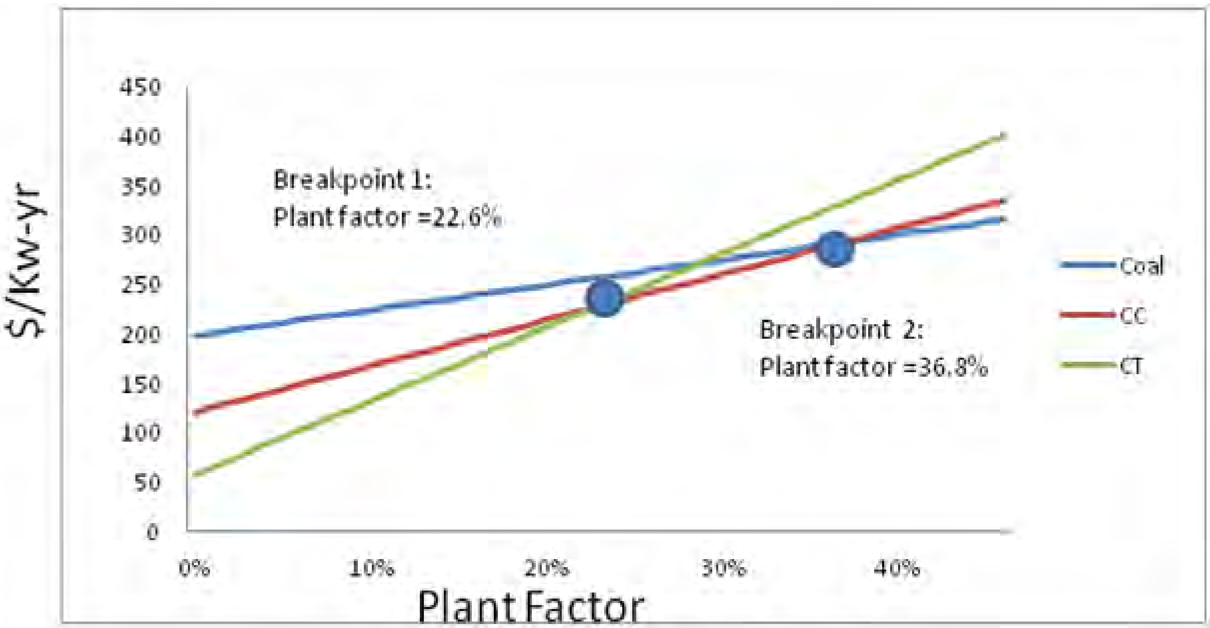


Figure 21. Screen Curve Analysis for SEPA Region.

7.2.3 Composite Unit Capacity Value

The process for calculating the composite unit capacity value for the ACF River Basin System is described by the following algorithm and is illustrated in Figure 22 and for Buford Dam individually in Figure 23.

7.2.4 Computation Algorithm of Composite Unit Capacity Value

The following is the algorithm used to compute composite unit capacity.

1. From the screening curve, determine the “breakpoints” (the plant factors at which the least cost plant type changes).
2. Find the points on the generation-duration curve where the percent of time generation is numerically identical to the plant factor breakpoints defined in the preceding step; these intersection points define the portion of the

generation capacity (MW) that would be carried by each thermal generation plant type.

3. Calculate percent of total generating capacity for each thermal alternative using the portions defined in Step 2.
4. Calculate the composite unit capacity value of the system as an average of each the thermal alternative's capacity cost weighted by their percent of total generating capacity defined in Step 3.

The results of the composite unit capacity value for both the entire ACF Hydropower System and Buford Dam are listed in Tables 11 and 12. As illustrated in these tables, Buford Dam has a lower composite unit capacity value then the entire system. This can be explained by comparing Figures 22 and 23. In Figure 23, Buford Dam, 94 percent of the plant's capacity is utilized less than the second break point plant factor of 36 percent, while on the other hand for the entire system only 68 percent of the total systems capacity falls below that second break point. This implies that the total system acts somewhat more like a baseload plant, which would require a more expensive coal capacity value then for Buford Dam. Results for other Corps plants for the system are listed in Appendix C.

The final dependable capacity value for each plant is found by multiplying the plants dependable capacity by the composite unit capacity value. The results for each of the alternatives for the entire ACF Hydropower System can be found in Table 13. The results of Buford Dam by itself can be found in Table 14. The results for the other individual Corps projects can be found in Appendix C.1 through Appendix C.3

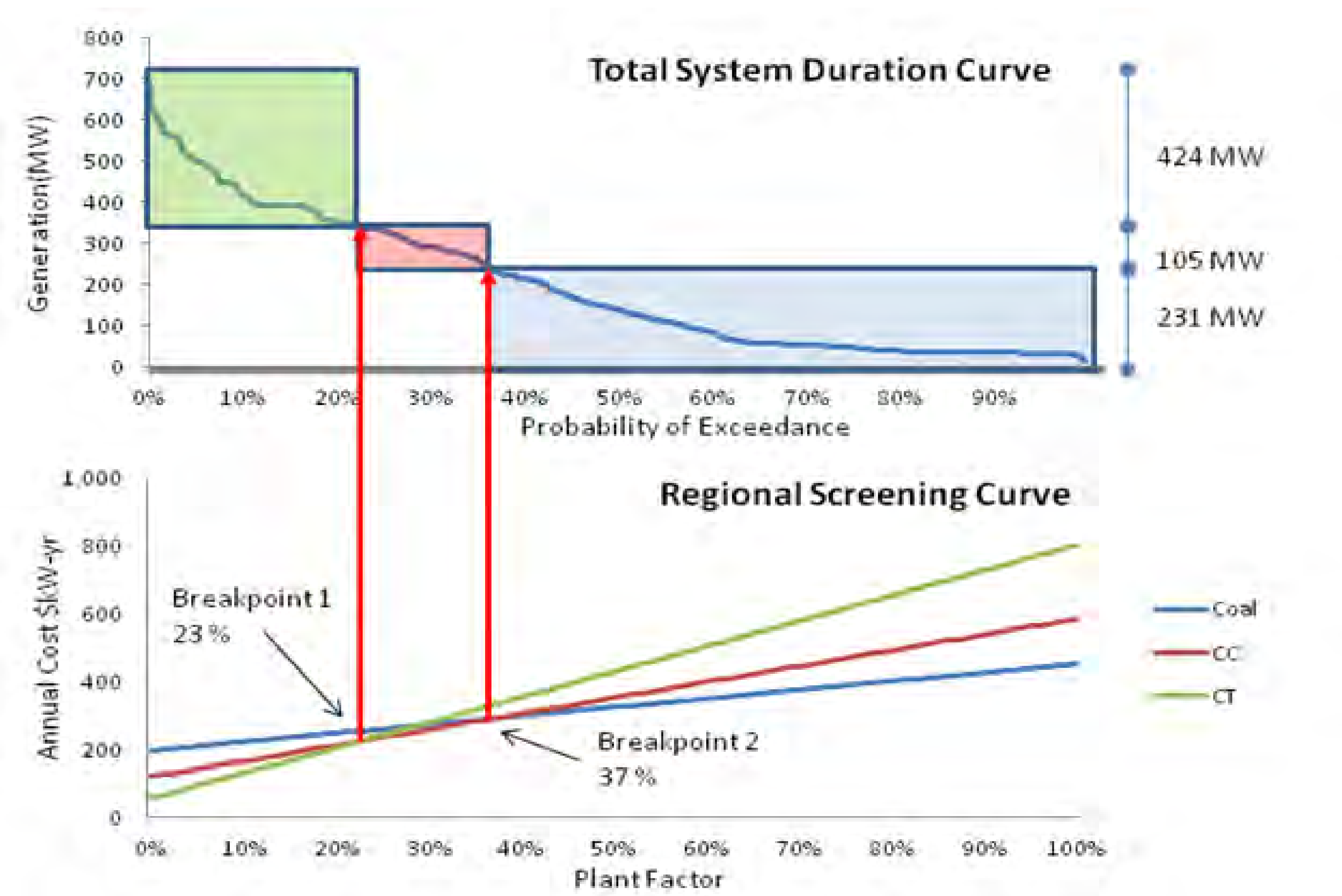


Figure 22. Illustrative Example of Composite Unit Capacity Value for ACF River Basin Hydropower System.

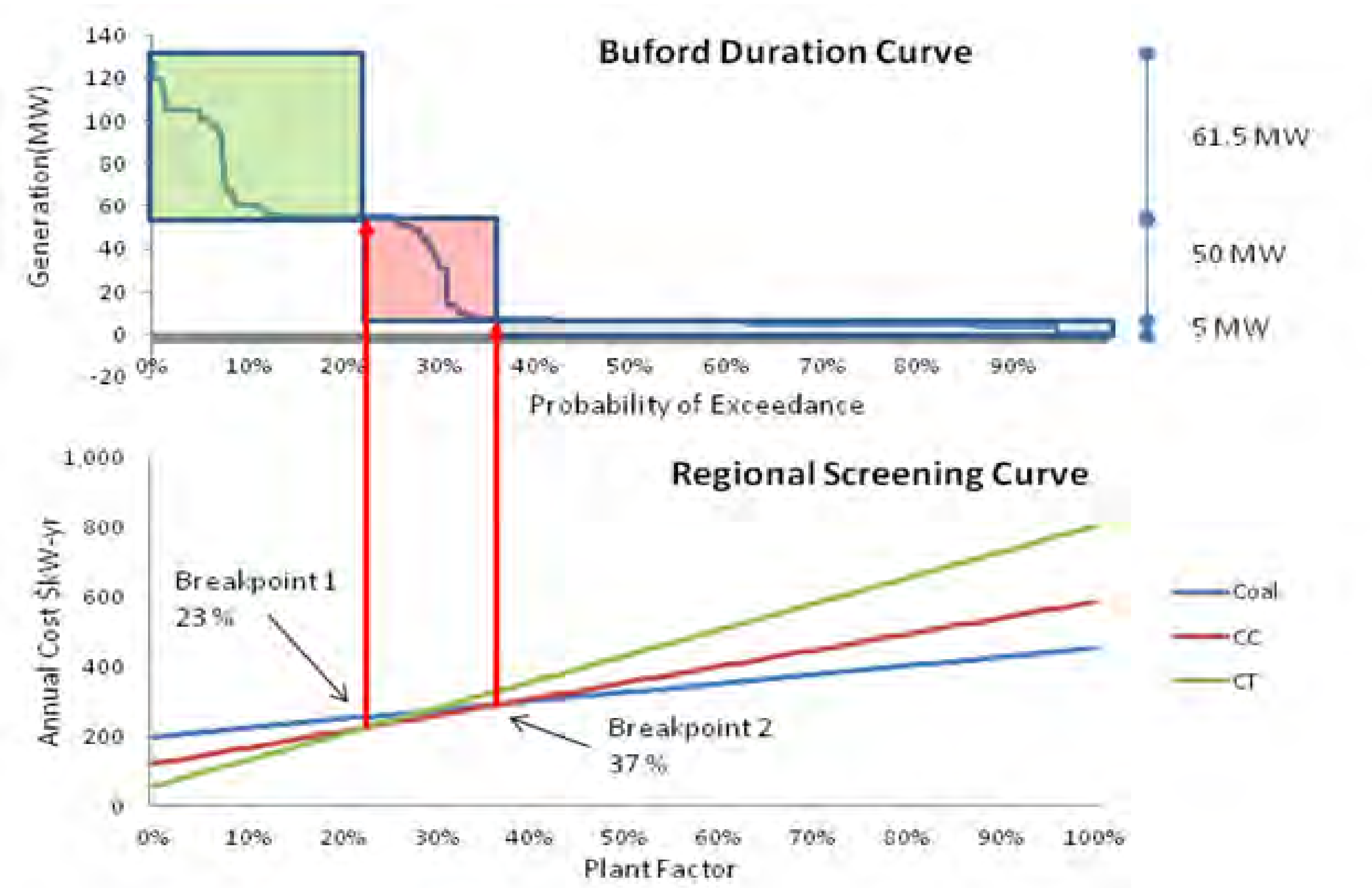


Figure 23. Illustrative Example of Composite Unit Capacity Value for Buford Dam.

Table 11. Composite Unit Capacity Value for Total ACF Hydropower System

Total System	Estimated Replacement Capacity (MW)	Percentage of total Generating Capacity (MW)	Capacity Cost ($/KW-yr)	Weighted Value ($)	
Combustion Turbine	424.44	56%	57.76	32.23	
Combined Cycle	105.00	14%	121.15	16.72	
Coal	231.00	30%	198.82	60.39	
				109.36	weighted average ($/KW-yr)

Table 12. Composite Unit Capacity Value for Buford Dam System

Buford	Estimated Replacement Capacity (MW)	Percentage of total Generating Capacity (MW)	Capacity Cost ($/KW-yr)	Weighted Value ($)	
Combustion Turbine	61.50	53%	57.76	30.48	
Combined Cycle	50.00	43%	121.15	51.99	
Coal	5.00	4%	198.82	8.53	
				91.02	weighted average ($/KW-yr)

.

Table 13

Average Annual Dependable Capacity Value For Entire ACF Hydropower System by Alternative

	Total ACF Hydropower System Dependable Capacity (MW)	Capacity Value $/MW-yr	Total Capacity Value
Current	739.98	$109,360	$80,924,000
IMP_Power	749.26	$109,360	$81,940,000
IMPBase	741.24	$109,360	$81,062,000
IMPGA2010B	744.34	$109,360	$81,401,000
IMPGA2010R	737.77	$109,360	$80,682,000
IMPGA2020B	745.62	$109,360	$81,541,000
IMPGA2020C	737.65	$109,360	$80,670,000
IMPGA2020P	738.28	$109,360	$80,739,000
IMPGA2020R	738.45	$109,360	$80,757,000
IMPGA2030B	745.53	$109,360	$81,532,000
IMPGA2030C	733.95	$109,360	$80,264,000
IMPGA2030P	737.18	$109,360	$80,618,000
IMPGA2030R	739.28	$109,360	$80,847,000
IMPMaxRHA	751.52	$109,360	$82,186,000
IMProved	738.76	$109,360	$80,790,000
IR392L125	741.12	$109,360	$81,049,000
IR408LMAX	736.04	$109,360	$80,493,000
IR408R125	742.48	$109,360	$81,198,000

Table 14. Dependable Capacity Value for Buford Dam by Alternative

	Total Buford Dam Dependable Capacity (MW)	Capacity Value $/MW-yr	Total Capacity Value
Current	110.24	$91,020	$10,034,000
IMP_Power	114.24	$91,020	$10,398,000
IMPBase	111.43	$91,020	$10,143,000
IMPGA2010B	113.03	$91,020	$10,288,000
IMPGA2010R	106.87	$91,020	$9,727,000
IMPGA2020B	113.6	$91,020	$10,340,000
IMPGA2020C	105.28	$91,020	$9,582,000
IMPGA2020P	106.29	$91,020	$9,675,000
IMPGA2020R	106.59	$91,020	$9,701,000
IMPGA2030B	113.62	$91,020	$10,341,000
IMPGA2030C	101.91	$91,020	$9,275,000
IMPGA2030P	104.72	$91,020	$9,532,000
IMPGA2030R	106.76	$91,020	$9,717,000
IMPMaxRHA	113.04	$91,020	$10,289,000
IMProved	109.77	$91,020	$9,992,000
IR392L125	109.99	$91,020	$10,011,000
IR392L125	103.64	$91,020	$9,433,000
IR408R125	110.21	$91,020	$10,032,000

8. HYDROPOWER BENEFITS BY COMPARISON SET

Hydropower benefits for each comparison set are determined by computing the difference from alternative to the baseline of that comparison set for both the energy values found in Table 8 and the dependable capacity values found in Tables 13 and 14.

Table 15 shows the energy benefits for the RHA comparison set.

Table 15. Energy Benefits for Total ACF Hydropower System

	Average Annual Energy Value	Energy Benefits
IMP_Power	$150,169,000	$0
IMPBase	$149,474,000	-$695,000
IMPGA2010B	$149,369,000	-$800,000
IMPGA2020B	$149,172,000	-$997,000
IMPGA2030B	$149,079,000	-$1,090,000
IMPMaxRHA	$148,299,000	-$1,870,000

In Table 15 Energy Benefits are computed as an average annual value. Another approach in comparing the baseline alternative with the other alternatives in the comparison set is looking at each spread of each yearly difference over the entire 70-year ResSim output. In Figure 24, a box and whisker plot for the annual difference for the RHA comparison set. The box represents the second and third quartiles, while the error bar stretches from the median to the maximum and minimum benefits. The red 'X' in the figure represents the average annual energy benefit.

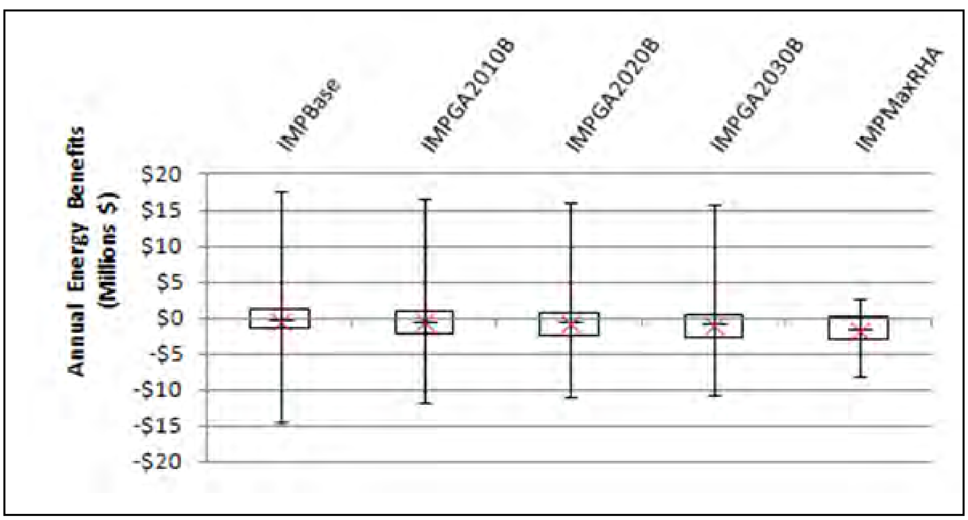


Figure 24. Box and Whisker Plot for Annual Energy Benefits for the RHA Comparison Set.

The capacity benefits for the entire ACF Hydropower System is shown in Table 16. Capacity Benefits for the individual Buford Dam is found using Table 14.

Table 16. Total ACF Hydropower System Dependable Capacity Benefits for RHA Comparison Set

	Dependable Capacity (MW)	Difference From Baseline	Capacity Value ($/MW-yr)	Capacity Benefits
IMP_Power	749.26	0	$109,360	$0
IMPBase	741.24	-8.03	$109,360	-$878,000
IMPGA2010B	744.34	-4.92	$109,360	-$538,000
IMPGA2020B	745.62	-3.65	$109,360	-$399,000
IMPGA2030B	745.53	-3.73	$109,360	-$408,000
IMPMaxRHA	751.52	2.25	$109,360	$246,000

The remaining parts in this section provide energy and dependable capacity values for each comparison set. In Section 8.1 we compute the total ACF Hydropower System benefits. In Section 8.2 the benefits from Buford Dam are displayed. Benefits for other Corps plants are found in Appendix C.

8.1 Total ACF Hydropower System Benefits

Alternative Set: RHA Comparisons

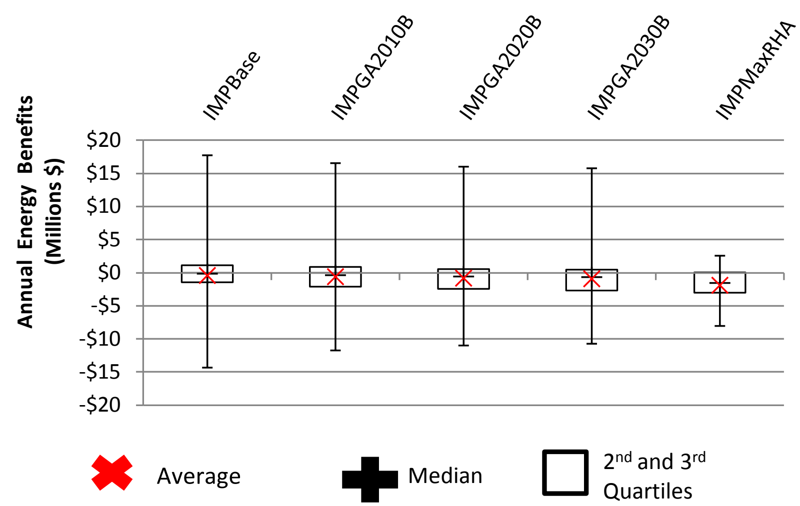
Alternatives

IMP_Power	IMPBase	IMPGA2010B	IMPGA2020B	IMPGA2030B	IMPMaxRHA
Baseline					

Energy Benefits:

	Average Annual Energy Value	Energy Benefits
IMP_Power	$150,169,000	$0
IMPBase	$149,474,000	-$695,000
IMPGA2010B	$149,369,000	-$800,000
IMPGA2020B	$149,172,000	-$997,000
IMPGA2030B	$149,079,000	-$1,090,000
IMPMaxRHA	$148,299,000	-$1,870,000

Annual Energy Benefit Distribution



Capacity Benefits:

	Dependable Capacity (MW)	Difference From Baseline	Capacity Value ($/MW-yr)	Capacity Benefits
IMP_Power	749.26	0.00	$109,360	$0
IMPBase	741.24	-8.03	$109,360	-$878,000
IMPGA2010B	744.34	-4.92	$109,360	-$538,000
IMPGA2020B	745.62	-3.65	$109,360	-$399,000
IMPGA2030B	745.53	-3.73	$109,360	-$408,000
IMPMaxRHA	751.52	2.25	$109,360	$246,000

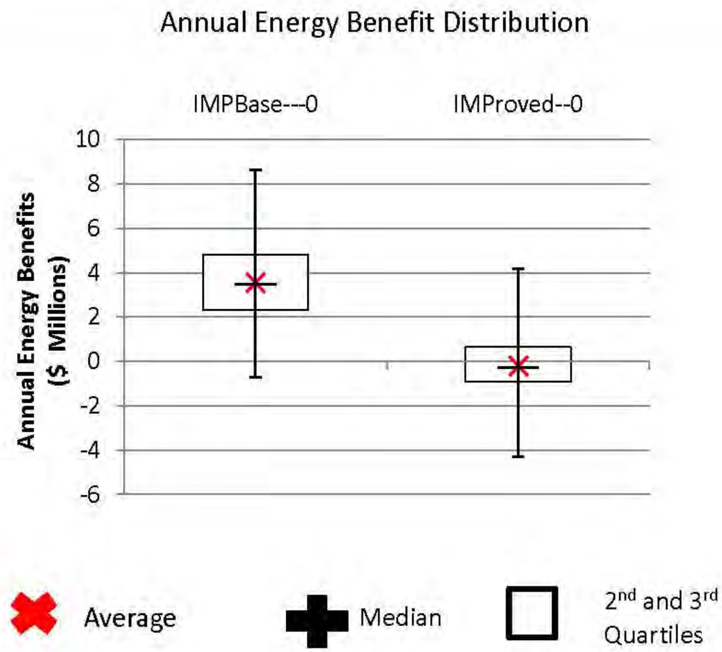
277 River (Current Operations) Withdrawal Comparisons

Alternatives

Current	IMPBase	IMProved
Baseline		

Energy Benefits:

	Average Annual Energy Value	Energy Benefits
Current	$145,946,000	$0
IMPBase	$149,474,000	$3,528,000
IMProved	$145,682,000	-$264,000



Capacity Benefits:

	Dependable Capacity (MW)	Difference From Baseline	Capacity Value ($/MW-yr)	Capacity Benefits
Current	739.98	0.00	$109,360	$0
IMPBase	741.24	1.26	$109,360	$137,000
IMProved	738.76	-1.23	$109,360	-$134,000

2010: 347 mgd River Withdrawal Comparisons

Alternatives

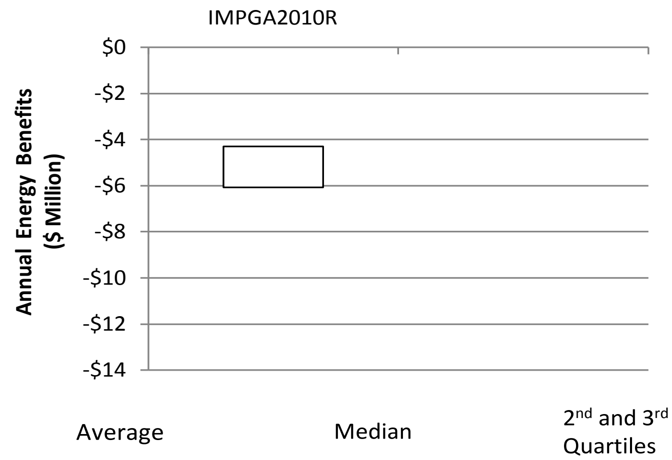
IMPGA2010B IMPGA2010R

Baseline

Energy Benefits:

	Average Annual Energy Value	Energy Benefits
IMPGA2010B	$149,369,000	$0
IMPGA2010R	$143,892,000	-$5,477,000

Annual Energy Benefit Distribution



Capacity Benefits:

	Dependable Capacity (MW)	Difference From Baseline	Capacity Value ($/MW-yr)	Capacity Benefits
IMPGA2010B	744.34	0.00	$109,360	$0
IMPGA2010R	737.77	-6.58	$109,360	-$719,000

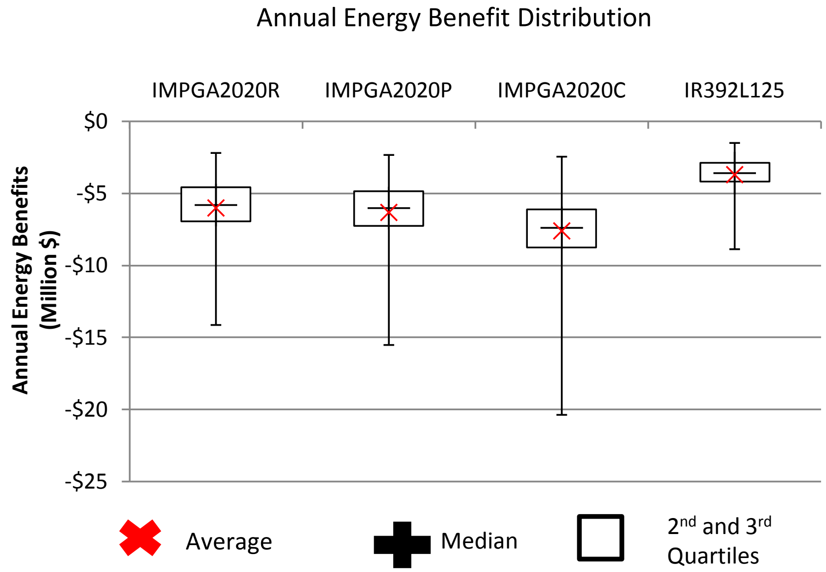
2020: 392 mgd Withdrawal Comparisons

Alternatives

IMPGA2020B	IMPGA2020R	IMPGA2020P	IMPGA2020C	IR392L125
Baseline				

Energy Benefits:

	Average Annual Energy Value	Energy Benefits
IMPGA2020B	$149,172,000	$0
IMPGA2020R	$143,117,000	-$6,055,000
IMPGA2020P	$142,804,000	-$6,368,000
IMPGA2020C	$141,522,000	-$7,650,000
IR392L125	$145,439,000	-$3,733,000



Capacity Benefits:

	Dependable Capacity (MW)	Difference From Baseline	Capacity Value ($/MW-yr)	Capacity Benefits
IMPGA2020B	745.62	0.00	$109,360	$0
IMPGA2020R	738.45	-7.17	$109,360	-$784,000
IMPGA2020P	738.28	-7.33	$109,360	-$802,000
IMPGA2020C	737.65	-7.97	$109,360	-$871,000
IR392L125	741.12	-4.50	$109,360	-$492,000

2030: 408 mgd Withdrawal Comparisons

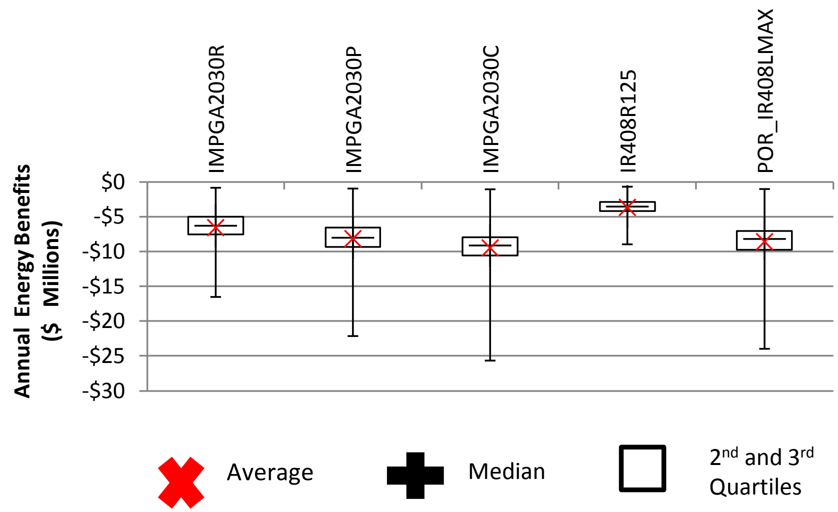
Alternatives

IMPGA2030B	IMPGA2030R	IMPGA2030P	IMPGA2030C	IR408R125	IR408LMAX
Baseline					

Energy Benefits:

	Average Annual Energy Value	Energy Benefits
IMPGA2030B	$149,079,000	$0
IMPGA2030R	$142,463,000	-$6,616,000
IMPGA2030P	$140,876,000	-$8,203,000
IMPGA2030C	$139,516,000	-$9,563,000
IR408R125	$145,379,000	-$3,700,000
IR408LMAX	$140,436,000	-$8,643,000

Annual Energy Benefit Distribution



Capacity Benefits:

	Dependable Capacity (MW)	Difference From Baseline	Capacity Value ($/MW-yr)	Capacity Benefits
IMPGA2030B	745.53	0.00	$109,360	$0
IMPGA2030R	739.28	-6.26	$109,360	-$684,000
IMPGA2030P	737.18	-8.35	$109,360	-$913,000
IMPGA2030C	733.95	-11.59	$109,360	-$1,267,000
IR408R125	742.48	-3.05	$109,360	-$334,000
IR408LMAX	736.04	-9.50	$109,360	-$1,039,000

8.2 Buford Dam Hydropower Benefits

8.2.1 RHA Comparison Set

Table 17. Buford Energy Benefits across the RHA Comparison Set

Baseline Comparisons:	Energy Value	Energy Benefits
IMP_Power	$10,493,000	$0
IMPBase	$10,388,000	-$105,000
IMPGA2010B	$10,359,000	-$134,000
IMPGA2020B	$10,347,000	-$146,000
IMPGA2030B	$10,337,000	-$156,000
IMPMAXRHA	$10,190,000	-$303,000

Table 18. Buford Dependable Capacity Benefits across the RHA Comparison Set

Baseline Comparisons:	Dependable Capacity Value (MW)	Change in Dependable Capacity (MW)	$/ Unit of Capacity	Capacity Value
IMP_Power	114.24	0.00	$91,020	$0
IMPBase	111.43	-2.80	$91,020	-$255,000
IMPGA2010B	113.03	-1.21	$91,020	-$110,000
IMPGA2020B	113.60	-0.64	$91,020	-$58,000
IMPGA2030B	113.62	-0.62	$91,020	-$56,000
IMPMAXRHA	113.04	-1.20	$91,020	$109,000

8.2.2 277 River Comparison Set

Table 19. Buford Energy Benefits across the 277 River Comparison Set

277 River (Current Operations) Comparison Set	Energy Value	Energy Benefits
Current	$9,227,000	$0
IMPBase	$10,388,000	$1,161,000
IMProved	$9,219,000	-$8,000

Table 20. Buford Dependable Capacity Benefits across the 277 River Comparison Set

277 River (Current Operations) Comparison Set	Dependable Capacity Value (MW)	Change in Dependable Capacity (MW)	$/ Unit of Capacity	Capacity Value
Current	110.24	0.00	$91,020	$0
IMPBase	111.43	1.19	$91,020	$108,000
IMProved	109.77	-0.47	$91,020	-$43,000

8.2.3 2010:347 MGD River Withdrawal Comparison Set

Table 21. Buford Energy Benefits across the 2010:347 MGD River Withdrawal Comparison Set

2010:347 MGD River Withdrawal Comparisons	Energy Value	Energy Benefits
IMPGA2010B	$10,359,000	$0
IMPGA2010R	$8,597,000	-$1,762,000

Table 22. Buford Dependable Capacity Benefits across the 2010:347 MGD River Withdrawal Comparison Set

2010:347 MGD River Withdrawal Comparisons	Dependable Capacity Value (MW)	Change in Dependable Capacity (MW)	$/ Unit of Capacity	Capacity Value
IMPGA2010B	113.03	0.00	$91,020	$0
IMPGA2010R	106.87	-616	$91,020	-$561,000

8.2.4 2020:392 MGD Withdrawal Comparison Set

Table 23. Buford Energy Benefits across the 2020:392 Withdrawal Comparison Set

2010:392 MGD River Withdrawal Comparisons	Energy Value	Energy Benefits
IMPGA2020B	$10,347,000	$0
IMPGA2020R	$8,372,000	-$1,975,000
IMPGA2020P	$8,262,000	-$2,085,000
IMPGA2020C	$7,824,000	-$2,523,000
IR392L125	$9,147,000	-$1,200,000

Table 24. Dependable Capacity Benefits across the 2020:392 Withdrawal Comparison Set

2020:392 MGD Withdrawal Comparisons	Dependable Capacity Value (MW)	Change in Dependable Capacity (MW)	$/ Unit of Capacity	Capacity Value
IMPGA2020B	113.60	0.00	$91,020	$0
IMPGA2020R	106.59	-7.01	$91,020	-$638,000
IMPGA2020P	106.29	-7.30	$91,020	-$665,000
IMPGA2020C	105.28	-8.32	$91,020	-$757,000
IR392L125	109.99	-3.61	$91,020	-$329,000

8.2.5 2030:408 MGD Withdrawal Comparison Set

Table 25. Dependable Energy Benefits across the 2030:408 Withdrawal Comparison Set

2030:408 MGD Withdrawal Comparisons	Energy Value	Energy Benefits
IMPGA2030B	$10,337,000	$0
IMPGA2030R	$8,158,000	-$2,179,000
IMPGA2030P	$7,608,000	-$2,729,000
IMPGA2030C	$7,157,000	-$3,180,000
IR408L125	$9,138,000	-$1,199,000
IR408LMAX	$7,459,000	-$2,878,000

Table 26. Buford Capacity Benefits across the 2030:408 Withdrawal Comparison Set

2030:408 MGD Withdrawal Comparisons	Dependable Capacity Value (MW)	Change in Dependable Capacity (MW)	$/ Unit of Capacity	Capacity Value
IMPGA2030B	113.62	0.00	$91,020	$0
IMPGA2030R	106.76	-6.86	$91,020	-$624,000
IMPGA2030P	104.72	-8.90	$91,020	-$810,000
IMPGA2030C	101.91	-11.71	$91,020	- $1,066,000
IR408L125	110.21	-3.40	$91,020	-$310,000
IR408LMAX	103.64	-9.97	$91,020	-$908,000

APPENDIX A

ALTERNATIVE DESCRIPTIONS

	A	B	C	D	E	F	G	H	I	J	K	Q	R	S	T	U
1	**System Output Matrix**															
2	***Scenario***			***Withdrawals***								**Alternative Components**				
3	**Alternative**	**Description**	**Operation Set**	**Gross Lake Withdrawal (mgd)**	**Lake Return Rate**	**Lake Net Withdrawal (mgd)**	**Gross River Withdrawal (mgd)**	**River Return Rate**	**River Net Withdrawal (mgd)**	**Total Gross (mgd)**	**Total Net (mgd)**	**Action Zones**	**Hydropower**	**ESA Operations**	**Navigation**	
4	IMP_Power	Improved operations*; no releases for downstream water supply**; 20 mgd water supply withdrawals from Lanier, 600 cfs/388 mgd off-peak releases thru Buford's small turbine; 13.5 hrs/weekday of peaking hydropower generation.	IMProved	20***	0%	20	Incidental**	0%	0	Incidental + 20	20.0	Improved	13.5 hours peaking Monday-Friday at Buford, with current operations at Federal hydropower facilities in the rest of the ACF	Modified RIOP****	5 month season (Jan-May), 7 ft channel	
5	Current***** (Baseline 1)	Current operations; downstream water supply incidental to hydropower generation; water supply withdrawals from Lanier as reported for year 2007; 600 cfs/388 mgd off-peak (weekend) release thru Buford's small turbine; river withdrawal and river and lake return rates as reported by State of Georgia.	Current	134.4	7%	125	277	76%	66	411.4	191.5	Current	Current	2008 RIOP	Incidental*	
6	IMPBase (Baseline 2)	Improved operations*; downstream water supply incidental to hydropower generation; 20 mgd water supply withdrawals from Lanier; river withdrawal and return rate as reported by State of Georgia. Baseline for improved operation set(s)	IMProved	20	0%	20	277	76%	66	297.0	86.5	Improved	Current	Modified RIOP	5 month season (Jan-May), 7 ft channel	
7	IMProved	Improved operations*; downstream water supply incidental to hydropower generation; water supply withdrawals from Lanier as reported for year 2007; 600 cfs/388 mgd off-peak (weekend) release thru Buford's small turbine; river withdrawal, river and lake return rates as reported by State of Georgia.	IMProved	134.4	7%	125	277	76%	66	411.4	191.5	Improved	Current	Modified RIOP	5 month season (Jan-May), 7 ft channel	
8	IMPGA2010B (Baseline 3)	Improved operations*; downstream water supply using 2010 river withdrawal volumes in GA 2000 reallocation request; 20 mgd water supply withdrawals from Lanier; peaking hydropower generation derivative of operations for downstream water supply; river return rate based on State of Georgia reported return rates. Baseline for Georgia's 2010 water volume request.	IMProved	20	0%	20	347	76%	83	367.0	103.3	Improved	Current	Modified RIOP	5 month season (Jan-May), 7 ft channel	
9	IMPGA2010R	Improved operations*; peaking hydropower generation derivative of operations for downstream water supply; downstream water supply using 2010 river withdrawal volumes in GA 2000 reallocation request; Lanier water supply using 2010 lake withdrawal volumes in GA 2000 reallocation request; lake return rates using 2010 return volumes in GA 2000 reallocation request; river return rate based on State of Georgia reported return rates.	IMProved	202	15%	172	347	76%	83	549.0	255.0	Improved	Current	Modified RIOP	5 month season (Jan-May), 7 ft channel	
10	IMPGA2020B (Baseline 4)	Improved operations*; downstream water supply using 2020 river withdrawal volumes in GA 2000 reallocation request; 20 mgd water supply withdrawals from Lanier; peaking hydropower generation derivative of operations for downstream water supply; river return rate based on State of Georgia reported return rates. Baseline for Georgia's 2020 water volume request.	IMProved	20	0%	20	392	76%	94	412.0	114.1	Improved	Current	Modified RIOP	5 month season (Jan-May), 7 ft channel	

	A	B	C	D	E	F	G	H	I	J	K	Q	R	S	T	U
11	IMPGA2020R	Improved operations*; downstream water supply using 2020 river withdrawal volumes in GA 2000 reallocation request; Lanier water supply using 2020 lake withdrawal volumes in GA 2000 reallocation request; peaking hydropower generation derivative of operations for downstream water supply; lake return rate using 2020 lake return volumes in GA 2000 reallocation request; river return rate based on State of Georgia reported return rates.	IMProved	256	27%	187	392	76%	94	648.0	281.0	Improved	Current	Modified RIOP	5 month season (Jan-May), 7 ft channel	
12	IMPGA2020P	Improved operations*; downstream water supply using 2020 river withdrawal volumes in GA 2000 reallocation request; Lanier water supply using 2020 lake withdrawal volumes in GA 2000 reallocation request; peaking hydropower generation derivative of operations for downstream water supply; lake return rate based on return rates specified in withdrawal permit(s); river return rate based on State of Georgia reported return rates.	IMProved	256	23%	197	392	76%	94	648.0	291.2	Improved	Current	Modified RIOP	5 month season (Jan-May), 7 ft channel	
13	IMPGA2020C	Improved operations*; downstream water supply using 2020 river withdrawal volumes in GA 2000 reallocation request; Lanier water supply using 2020 lake withdrawal volumes in GA 2000 reallocation request; peaking hydropower generation derivative of operations for downstream water supply; lake and river return rates based on State of Georgia reported return rates.	IMProved	256	7%	238	392	76%	94	648.0	332.2	Improved	Current	Modified RIOP	5 month season (Jan-May), 7 ft channel	
14	IR392L125	Improved operations*; downstream water supply using 2020 river withdrawal volumes in GA 2000 reallocation request; water supply withdrawals from Lanier in 2007; peaking hydropower generation derivative of operations for downstream water supply; lake and river return rate based State or Georgia reported return rates.	IMProved	134.4	7%	125	392	76%	94	526.4	219.1	Improved	Current	Modified RIOP	5 month season (Jan-May), 7 ft channel	
15	IMPGA2030B (Baseline 5)	Improved operations*; downstream water supply using 2030 river withdrawal volumes in GA 2000 reallocation request; 20 mgd water supply withdrawals from Lanier; peaking hydropower generation derivative of operations for downstream water supply; river return rate based on State of Georgia reported return rates. Baseline for Georgia's 2030 water volume request.	IMProved	20	0%	20	408	76%	98	428.0	117.9	Improved	Current	Modified RIOP	5 month season (Jan-May), 7 ft channel	
16	IMPGA2030R	Improved operations*; downstream water supply using 2030 river withdrawal volumes in GA 2000 reallocation request; Lanier water supply using 2030 lake withdrawal volumes in GA 2000 reallocation request; peaking hydropower generation derivative of operations for downstream water supply; lake return rate using 2030 lake return rates in GA 2000 reallocation request; river return rate based State of Georgia reported return rates.	IMProved	297	36%	190	408	76%	98	705.0	288.0	Improved	Current	Modified RIOP	5 month season (Jan-May), 7 ft channel	

	A	B	C	D	E	F	G	H	I	J	K	Q	R	S	T	U
17	IMPGA2030P	Improved operations*; downstream water supply using 2030 river withdrawal volumes in GA 2000 reallocation request; Lanier water supply using 2030 lake withdrawal volumes in GA 2000 reallocation request; peaking hydropower generation derivative of operations for downstream water supply; lake return rate based on return rates specified in withdrawal permit(s); river return rate based on State of Georgia reported return rates	IMProved	297	20%	238	408	76%	98	705.0	335.5	Improved	Current	Modified RIOP	5 month season (Jan-May), 7 ft channel	
18	IMPGA2030C	Improved operations*; downstream water supply using 2030 river withdrawal volumes in GA 2000 reallocation request; Lanier water supply using 2030 lake withdrawal volumes in GA 2000 reallocation request; peaking hydropower generation derivative of operations for downstream water supply; lake and river return rate based on State of Georgia reported return rates.	IMProved	297	7%	276	408	76%	98	705.0	374.1	Improved	Current	Modified RIOP	5 month season (Jan-May), 7 ft channel	
19	IR408L125	Improved operations*; downstream water supply using 2030 river withdrawal volumes in GA 2000 reallocation request; water supply withdrawals from Lanier in 2007; peaking hydropower generation derivative of operations for downstream water supply; lake and river return rate based on State of Georgia reported return rates.	IMProved	134.4	7%	125	408	76%	98	542.4	222.9	Improved	Current	Modified RIOP	5 month season (Jan-May), 7 ft channel	
20	IR408LMAX	Improved operations*; downstream water supply using 2030 river withdrawal volumes in GA 2000 reallocation request; total water supply withdrawal from Lanier is the amount over 408 mgd that can be made without reducing conversation pool storage below its bottom elevation of 1035'; peaking hydropower generation derivative of operations for downstream water supply; lake and river return rate based on State of Georgia reported return rates.	IMProved	290.3	7%	270	408	76%	98	698.3	367.9	Improved	Current	Modified RIOP	5 month season (Jan-May), 7 ft channel	
21	IMPMAXRHA	Improved operations*; downstream water supply using 2030 river withdrawal volumes in GA 2000 reallocation request plus the amount over 408 that can be released without reducing conversation pool storage below its bottom elevation of 1035'; total water supply withdrawal from Lanier is 20 mdg; river return rate based on State of Georgia reported return rate.	IMProved	20	0%	20	685	76%	164	705.0	184.4	Improved	Current	Modified RIOP	5 month season (Jan-May), 7 ft channel	

*Improved Operations: An operations set that includes revised project action zones, revised hydropower generation schedule, a modified Revised Interim Operating Procedures (Improved RIOP) and a 5 month (Jan-May) navigation season with a 7-foot channel.

**Incidental: No specific operations are executed to make the resource available; the availability, amount and quality of the resource is a by-product of other operations and/or natural conditions.

***20 mgd: Represents the volumes of withdrawals authorized by the River and Harbors Act of 1946 (8 mgd for the City of Gainesville, Georgia and 2 mgd for the City of Buford, Georgia) and 1956 Act (10 mgd for the City of Gainesville, Georgia)

****Modified RIOP: Recalculated system composite storage zones based upon revised project action zones (reference IMProved), Emergency Drought Operations (EDO) triggered when composite storage falls into Composite Storage Zone 4, EDO suspended upon composite storage recovery to Composite Storage Zone 1, elimination of volumetric balancing,minimum releases between June and February matching 7-day basin inflow at values of 5,000 to 10,000 cfs, matching 7-day basin inflow when revised ramping rates above Jim Woodfuff powerhouse capacity to match 1-day basin flows between 16,000 and 30,000 cfs; no ramping when flows are above 30,000 cfs.

*****Current: Operations as excuted in 2012, including action zones and hydropower generation schedules in accordance with the Draft Apalachicola-Chattahoochee-Flint Water Control Manual dated 1989, navigation incidental to available flows and the Revised Interim Operating Procedures dated 2008.

APPENDIX B

FEDERAL ENERGY REGULATORY COMMISSION (FERC) SPREADSHEET MODEL RESULTS

COMBINED CYCLE POWER VALUE				01/11/12
	LOCATION:	Georgia		
	FINANCING:	FEDERAL @	4.00%	
Capacity Value		**$121.15**	**per kW-yr**	
Energy Value		**$57.72**	**per MWh**	
PROGRAM INPUT DATA			State Index Number	11
			State Abbr. (exact)	GA
Cost Level Date	10/1/2011		H-W Index Reg No	2
Single unit capacity	150		ROW ($/acre)	0
Capacity factor	0.20		Clearing % of ROW	0.60
Trans Voltage	230		Rec Sub Land Cost	0
Transformer MVA	200		Plant Invest	883
No of Trans	1		FC Mov-Ave Time Frame	60
No of Trans Positions	1		Fuel Cost	718.8
Single or Three Phase	3		Heat Rate	8030
Length Line 1	0		Variable O&M	0.00
Length Line 2	0		Fixed O&M	49.57
Line 1: Total Circuits	2		O&M update	3.07
No of Single Circ	2		Plant update	2.98
No of Double Circ	0		Transmission update	2.75
Line 2: Total Circuits	0		Depreciation Plant (%)	1.78
No of Single Circ	0		Deprec Sub (%)	1.78
No of Double Circ	0		Deprec Trans Tower (%)	0.66
			Deprec Trans Pole (%)	1.78
Cost of Money (%)	4.000			
Plant Life	30		Fed Inc Tax (%)	0.000
Substation Life	30		Fed Misc Tax (%)	0.000
Trans (towers) Life	50		State & Local Tax (%)	0.000
Trans (poles) life	30			
			Hydro Flex Adjust	0.025
Plant insurance (%)	0.25		Alt Mechanical Avail	0.900
Trans Insurance (%)	0.10		Hydro Mech Avail	0.980
Sub insurance (%)	0.25		Mech Avail Adjust	0.089

COMBINED CYCLE POWER VALUE				01/11/12
	LOCATION:	Alabama		
	FINANCING:	FEDERAL @	4.00%	
Capacity Value		**$121.15**	**per kW-yr**	
Energy Value		**$48.58**	**per MWh**	
PROGRAM INPUT DATA			State Index Number	1
			State Abbr. (exact)	AL
Cost Level Date	10/1/2011		H-W Index Reg No	2
Single unit capacity	150		ROW ($/acre)	0
Capacity factor	0.20		Clearing % of ROW	0.60
Trans Voltage	230		Rec Sub Land Cost	0
Transformer MVA	200		Plant Invest	883
No of Trans	1		FC Mov-Ave Time Frame	60
No of Trans Positions	1		Fuel Cost	605.0
Single or Three Phase	3		Heat Rate	8030
Length Line 1	0		Variable O&M	0.00
Length Line 2	0		Fixed O&M	49.57
Line 1: Total Circuits	2		O&M update	3.07
No of Single Circ	2		Plant update	2.98
No of Double Circ	0		Transmission update	2.75
Line 2: Total Circuits	0		Depreciation Plant (%)	1.78
No of Single Circ	0		Deprec Sub (%)	1.78
No of Double Circ	0		Deprec Trans Tower (%)	0.66
			Deprec Trans Pole (%)	1.78
Cost of Money (%)	4.000			
Plant Life	30		Fed Inc Tax (%)	0.000
Substation Life	30		Fed Misc Tax (%)	0.000
Trans (towers) Life	50		State & Local Tax (%)	0.000
Trans (poles) life	30			
			Hydro Flex Adjust	0.025
Plant insurance (%)	0.25		Alt Mechanical Avail	0.900
Trans Insurance (%)	0.10		Hydro Mech Avail	0.980
Sub insurance (%)	0.25		Mech Avail Adjust	0.089

COMBUSTION TURBINE POWER VALUE				01/11/12
	LOCATION:	Georgia		
	FINANCING:	FEDERAL @	4.00%	
Capacity Value		$57.76	per kW-yr	
Energy Value		$92.51	per MWh	
PROGRAM INPUT DATA			State Index Number	11
			State Location	GA
Cost Level Date	10/1/2011		H-W Index Reg No	2
Single unit capacity	100		ROW ($/acre)	2274
Capacity Factor	0.10		Clearing % of ROW	0.60
Transmission Voltage	230		Rec Sub Land Cost	21467
Transformer MVA	125		Plant Invest	463
No of Trans	2		FC Mov-Ave Time Frame	60
No of Trans Pos	2		Fuel Cost	718.8
Single or Three Phase	3		Heat Rate	12870
Length Line 1	0		Variable O&M	0.00
Length Line 2	0		Fixed O&M	16.26
Line 1: Total Circuits	2		O&M update	3.07
No of Single Circ	2		Plant update	2.98
No of Double Circ	0		Transmission update	2.75
Line 2: Total Circuits	0		Depreciation Plant (%)	1.78
No of Single Circ	0		Deprec Sub (%)	1.78
No of Double Circ	0		Deprec Trans Tower (%)	0.66
			Deprec Trans Pole (%)	1.78
Cost of Money (%)	4.000			
Plant Life	30		Fed Inc Tax (%)	0.000
Substation Life	30		Fed Misc Tax (%)	0.000
Trans (towers) Life	50		State & Local Tax (%)	0.000
Trans (poles) life	30			
			Hydro Flex Adjust	0.025
Plant insurance (%)	0.25		Alt Mechanical Avail	0.900
Trans Insurance (%)	0.10		Hydro Mechanical Avail	0.980
Sub insurance (%)	0.25		Mech Avail Adjust	0.089

COMBUSTION TURBINE POWER VALUE				01/11/12
	LOCATION:	Alabama		
	FINANCING:	FEDERAL @	4.00%	
Capacity Value		**$57.76**	per kW-yr	
Energy Value		**$77.86**	per MWh	
PROGRAM INPUT DATA			State Index Number	1
			State Location	AL
Cost Level Date	10/1/2011		H-W Index Reg No	2
Single unit capacity	100		ROW ($/acre)	2274
Capacity Factor	0.10		Clearing % of ROW	0.60
Transmission Voltage	230		Rec Sub Land Cost	21467
Transformer MVA	125		Plant Invest	463
No of Trans	2		FC Mov-Ave Time Frame	60
No of Trans Pos	2		Fuel Cost	605.0
Single or Three Phase	3		Heat Rate	12870
Length Line 1	0		Variable O&M	0.00
Length Line 2	0		Fixed O&M	16.26
Line 1: Total Circuits	2		O&M update	3.07
No of Single Circ	2		Plant update	2.98
No of Double Circ	0		Transmission update	2.75
Line 2: Total Circuits	0		Depreciation Plant (%)	1.78
No of Single Circ	0		Deprec Sub (%)	1.78
No of Double Circ	0		Deprec Trans Tower (%)	0.66
			Deprec Trans Pole (%)	1.78
Cost of Money (%)	4.000			
Plant Life	30		Fed Inc Tax (%)	0.000
Substation Life	30		Fed Misc Tax (%)	0.000
Trans (towers) Life	50		State & Local Tax (%)	0.000
Trans (poles) life	30			
			Hydro Flex Adjust	0.025
Plant insurance (%)	0.25		Alt Mechanical Avail	0.900
Trans Insurance (%)	0.10		Hydro Mechanical Avail	0.980
Sub insurance (%)	0.25		Mech Avail Adjust	0.089

COAL-FIRED STEAM POWER VALUE				01/11/12
	LOCATION:	Alabama		
	FINANCING:	FEDERAL @	4.00 %	
Capacity Value		**$198.66**	per kW-yr	
Energy Value		**$25.62**	per MWh	
PROGRAM INPUT DATA			State Index Number	1
			State Location	AL
Cost Level Date	10/1/2011		H-W Index Reg No	2
Single unit capacity	600		ROW ($/acre)	0
Capacity factor	0.65		Clearing % of ROW	0.60
Trans Voltage	345		Rec Sub Land Cost	0
Transformer MVA	200		Plant Invest	1330
No of Trans	6		FC Mov-Ave Time Frame	60
No of Trans Pos	2		Fuel Cost	260.6
Single or Three Phase	1		Heat Rate	9830
Length Line 1	50		Variable O&M	0.00
Length Line 2	0		Fixed O&M	62.89
Line 1: Total Circuits	3		O&M update	3.07
No of Single Circ	1		Plant update	2.98
No of Double Circ	1		Transmission update	2.75
Line 2: Total Circuits	0		Depreciation Plant (%)	1.78
No of Single Circ	0		Deprec Sub (%)	1.78
No of Double Circ	0		Deprec Trans Tower (%)	0.66
			Deprec Trans Pole (%)	1.78
Cost of Money (%)	4.000			
Plant Life	30		Fed Inc Tax (%)	0.000
Substation Life	30		Fed Misc Tax (%)	0.000
Trans (towers) Life	50		State & Local Tax (%)	0.000
Trans (poles) life	30			
			Hydro Flex Adjust	0.050
Plant insurance (%)	0.25		Alt Mechanical Avail	0.850
Trans Insurance (%)	0.10		Hydro Mech Avail	0.980
Sub insurance (%)	0.25		Mech Avail Adjust	0.153

COAL-FIRED STEAM POWER VALUE				01/11/12
	LOCATION:	Georgia		
	FINANCING:	FEDERAL @	4.00 %	
Capacity Value		**$198.98**	per kW-yr	
Energy Value		**$32.54**	per MWh	
PROGRAM INPUT DATA			State Index Number	11
			State Location	GA
Cost Level Date	10/1/2011		H-W Index Reg No	2
Single unit capacity	600		ROW ($/acre)	0
Capacity factor	0.65		Clearing % of ROW	0.60
Trans Voltage	345		Rec Sub Land Cost	0
Transformer MVA	200		Plant Invest	1330
No of Trans	6		FC Mov-Ave Time Frame	60
No of Trans Pos	2		Fuel Cost	331.0
Single or Three Phase	1		Heat Rate	9830
Length Line 1	50		Variable O&M	0.00
Length Line 2	0		Fixed O&M	62.89
Line 1: Total Circuits	3		O&M update	3.07
No of Single Circ	1		Plant update	2.98
No of Double Circ	1		Transmission update	2.75
Line 2: Total Circuits	0		Depreciation Plant (%)	1.78
No of Single Circ	0		Deprec Sub (%)	1.78
No of Double Circ	0		Deprec Trans Tower (%)	0.66
			Deprec Trans Pole (%)	1.78
Cost of Money (%)	4.000			
Plant Life	30		Fed Inc Tax (%)	0.000
Substation Life	30		Fed Misc Tax (%)	0.000
Trans (towers) Life	50		State & Local Tax (%)	0.000
Trans (poles) life	30			
			Hydro Flex Adjust	0.050
Plant insurance (%)	0.25		Alt Mechanical Avail	0.850
Trans Insurance (%)	0.10		Hydro Mech Avail	0.980
Sub insurance (%)	0.25		Mech Avail Adjust	0.153

APPENDIX C

FEDERAL PLANTS BENEFITS
(BUFORD DAM IS IN TEXT)

C.1 West Point

C.1.1 West Point Energy Benefits

RHA Comparisons:	Energy Value	Energy Benefits
IMP_Power	$13,270,000	$0
IMP Base	$13,171,000	-$99,000
IMPGA2010B	$13,129,000	-$141,000
IMPGA2020B	$13,096,000	-$174,000
IMPGA2030B	$13,082,000	-$188,000
IMPMAXRHA	$12,953,000	-$317,000

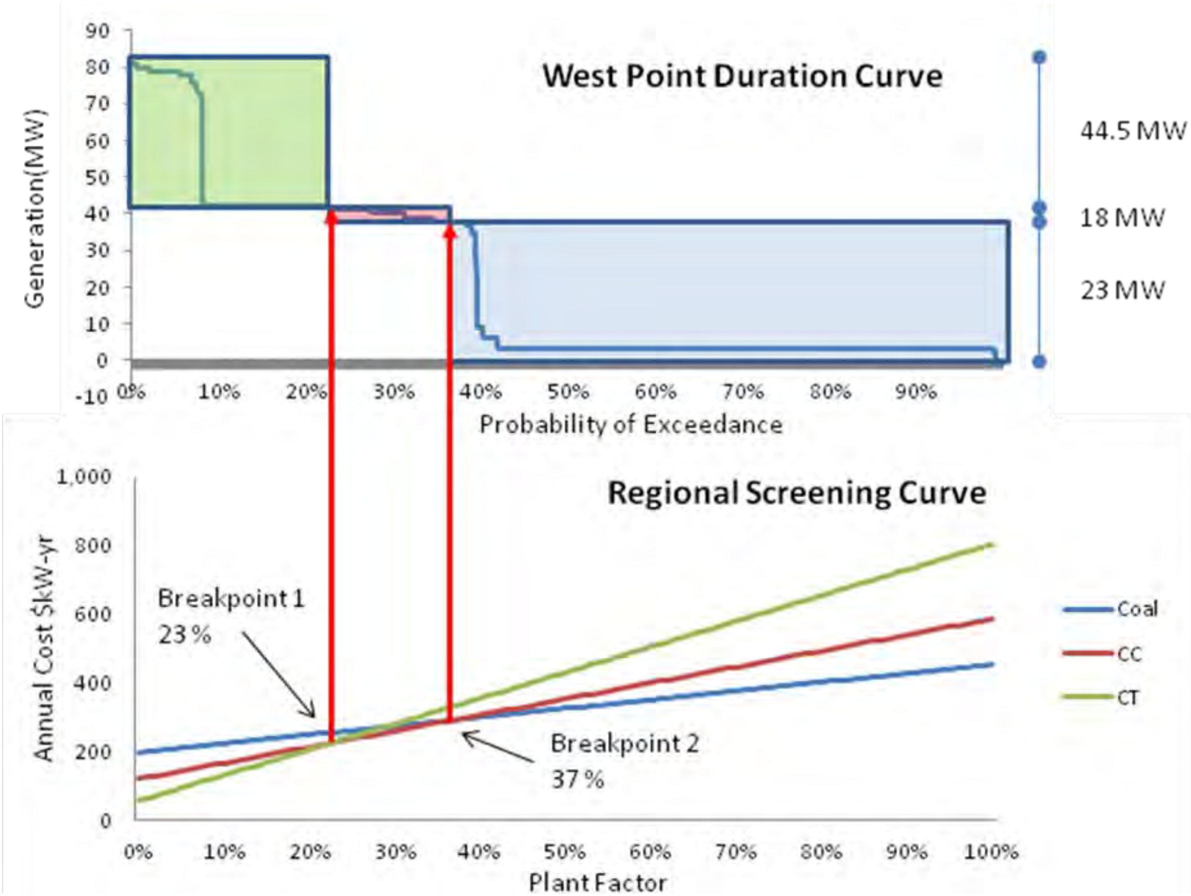
2010:347 mgd River Withdrawal Comparisons	Energy Value	Energy Benefits
IMPGA2010B	$13,129,000	$0
IMPGA2010R	$12,530,000	-$599,000

277 River (Current Operations) Comparison Set	Energy Value	Energy Benefits
Current	$12,793,000	$0
IMPBase	$13,171,000	$378,000
IMProved	$12,750,000	-$43,000

2020:392 mgd Withdrawal Comparisons	Energy Value	Energy Benefits
IMPGA2020B	$13,096,000	$0
IMPGA2020R	$12,437,000	-$659,000
IMPGA2020P	$12,404,000	-$692,000
IMPGA2020C	$12,267,000	-$829,000
IR392L125	$12,689,000	-$407,000

2030:408 mgd Withdrawal Comparisons	Energy Value	Energy Benefits
IMPGA2030B	$13,082,000	$0
IMPGA2030R	$12,364,000	-$718,000
IMPGA2030P	$12,197,000	-$885,000
IMPGA2030BC	$12,050,000	-$1,032,000
IR408L125	$12,679,000	-$403,000
IR408LMAX	$12,150,000	-$932,000

C.1.2 West Point Screening Curve Analysis



West Point	Estimated Replacement Capacity (MW)	Percentage of total Generating Capacity (MW)	Capacity Cost ($/KW-yr)	Weighted Value ($)	
Combustion Turbine	44.5	52%	$57.76	$30.06	
Combined Cycle	18	21%	$121.15	$25.51	
Coal	23	27%	$198.82	$53.48	
				$109.05	weighted average ($/KW-yr)

C.1.3 West Point Capacity Benefits

RHA Comparisons:	Dependable Capacity Value (MW)	Change in Dependable Capacity (MW)	$/ Unit of Capacity	Capacity Value
IMP_Power	84.50	0.00	$109,050	$0
IMP Base	83.32	-1.28	$109,050	-$139,000
IMPGA2010B	83.71	-0.89	$109,050	-$97,000
IMPGA2020B	83.84	-0.75	$109,050	-$82,000
IMPGA2030B	83.91	-0.68	$109,050	-$74,000
IMPMAXRHA	85.05	0.46	$109,050	$50,000

2010:347 mgd River Withdrawal Comparisons	Dependable Capacity Value (MW)	Change in Dependable Capacity (MW)	$/ Unit of capacity	Capacity Value
IMPGA2010B	83.71	0.00	$109,050	$0
IMPGA2010R	83.56	-0.15	$109,050	-$17,000

277 River (Current Operations) Comparison Set	Dependable Capacity Value (MW)	Change in Dependable Capacity (MW)	$/ Unit of Capacity	Capacity Value
Current	83.38	0.00	$109,050	$0
IMPBase	83.32	-0.06	$109,050	-$7,000
IMProved	83.17	-0.21	$109,050	-$23,000

2020:392 mgd Withdrawal Comparisons	Dependable Capacity Value (MW)	Change in Dependable Capacity (MW)	$/ Unit of capacity	Capacity Value
IMPGA2020B	83.84	0.00	$109,050	$0
IMPGA2020R	83.85	0.00	$109,050	$0
IMPGA2020P	83.89	0.04	$109,050	$5,000
IMPGA2020C	83.96	0.11	$109,050	$13,000
IR392L125	83.66	-0.19	$109,050	-$20,000

2030:408 mgd Withdrawal Comparisons	Dependable Capacity Value (MW)	Change in Dependable Capacity (MW)	$/ Unit of capacity	Capacity Value
IMPGA2030B	83.91	0.00	$109,050	$0
IMPGA2030R	83.98	0.06	$109,050	$7,000
IMPGA2030P	83.99	0.08	$109,050	$9,000
IMPGA2030C	83.90	-0.01	$109,050	-$1,000
IR408L125	83.87	-0.04	$109,050	-$4,000
IR408LMAX	83.98	0.07	$109,050	$7,000

C.2 Walter F George

C.2.1 Walter F George Energy Benefits

RHA Comparisons:	Energy Value	Energy Benefits
IMP_Power	$34,101,000	$0
IMP Base	$33,992,000	-$109,000
IMPGA2010B	$33,941,000	-$160,000
IMPGA2020B	$33,907,000	-$194,000
IMPGA2030B	$33,887,000	-$214,000
IMPMAXRHA	$33,742,000	-$359,000

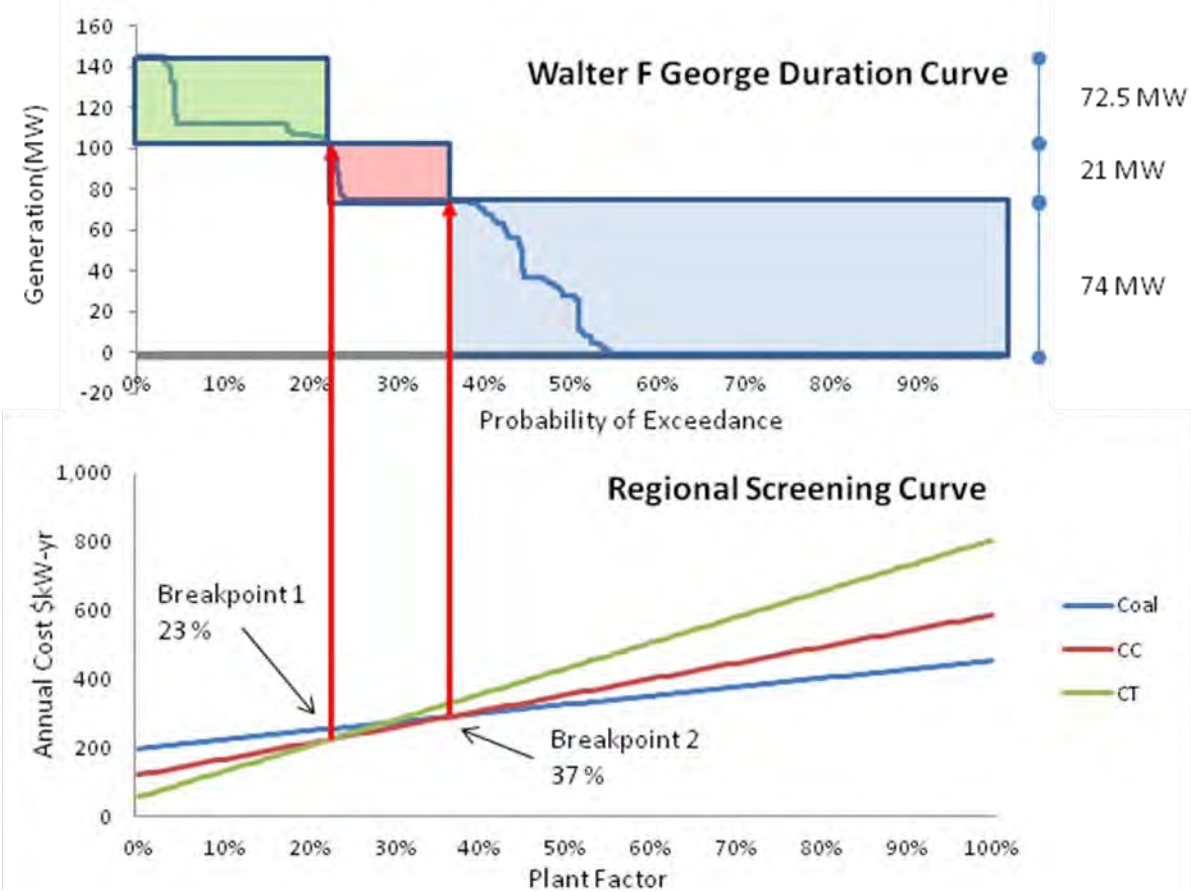
2010:347 mgd River Withdrawal	Energy Value	Energy Benefits
IMPGA2010B	$33,941,000	$0
IMPGA2010R	$33,276,000	-$665,000

277 River (Current Operations)	Energy Value	Energy Benefits
Current	$33,579,000	$0
IMPBase	$33,992,000	$413,000
IMProved	$33,524,000	-$55,000

2020:392 mgd Withdrawal Comparisons	Energy Value	Energy Benefits
IMPGA2020B	$33,907,000	$0
IMPGA2020R	$33,173,000	-$734,000
IMPGA2020P	$33,142,000	-$765,000
IMPGA2020C	$32,981,000	-$926,000
IR392L125	$33,447,000	-$460,000

2030:408 mgd Withdrawal Comparisons	Energy Value	Energy Benefits
IMPGA2030B	$33,887,000	$0
IMPGA2030R	$33,089,000	-$798,000
IMPGA2030P	$32,902,000	-$985,000
IMPGA2030BC	$32,738,000	-$1,149,000
IR408L125	$33,439,000	-$448,000
IR408LMAX	$32,850,000	-$1,037,000

C.2.2 Walter F. George Screening Curve Analysis



Walter F George	Estimated Replacement Capacity (MW)	Percentage of total Generating Capacity (MW)	Capacity Cost ($/KW-yr)	Weighted Value ($)	
Combustion Turbine	72.5	43%	$57.76	$25.00	
Combined Cycle	21	13%	$121.15	$15.19	
Coal	74	44%	$198.82	$87.84	
				$128.03	weighted average ($/KW-yr)

C.2.3 Walter F George Capacity Benefits

RHA Comparisons:	Dependable Capacity Value (MW)	Change in Dependable Capacity (MW)	$/ Unit of Capacity	Capacity Value
IMP_Power	164.54	0.00	$128,025	$0
IMP Base	163.32	-1.22	$128,025	-$157,000
IMPGA2010B	163.54	-1.00	$128,025	-$128,000
IMPGA2020B	163.72	-0.82	$128,025	-$105,000
IMPGA2030B	163.63	-0.92	$128,025	-$117,000
IMPMAXRHA	164.85	0.31	$128,025	$40,000

2010:347 mgd River Withdrawal Comparisons	Dependable Capacity Value (MW)	Change in Dependable Capacity (MW)	$/ Unit of capacity	Capacity Value
IMPGA2010B	163.54	0.00	$128,025	$0
IMPGA2010R	164.02	0.48	$128,025	$61,000

277 River (Current Operations) Comparison Set	Dependable Capacity Value (MW)	Change in Dependable Capacity (MW)	$/ Unit of Capacity	Capacity Value
Current	163.76	0.00	$128,025	$0
IMPBase	163.32	-0.44	$128,025	-$57,000
IMProved	163.44	-0.32	$128,025	-$41,000

2020:392 mgd Withdrawal Comparisons	Dependable Capacity Value (MW)	Change in Dependable Capacity (MW)	$/ Unit of capacity	Capacity Value
IMPGA2020B	163.72	0.00	$128,025	$0
IMPGA2020R	164.18	0.46	$128,025	$59,000
IMPGA2020P	164.17	0.45	$128,025	$57,000
IMPGA2020C	164.20	0.48	$128,025	$61,000
IR392L125	163.81	0.09	$128,025	$12,000

2030:408 mgd Withdrawal Comparisons	Dependable Capacity Value (MW)	Change in Dependable Capacity (MW)	$/ Unit of capacity	Capacity Value
IMPGA2030B	163.63	0.00	$128,025	$0
IMPGA2030R	164.19	0.56	$128,025	$72,000
IMPGA2030P	164.22	0.59	$128,025	$76,000
IMPGA2030C	164.16	0.53	$128,025	$68,000
IR408L125	164.09	0.47	$128,025	$60,000
IR408LMAX	164.22	0.59	$128,025	$75,000

C.3 Jim Woodruff

C.3.1 Jim Woodruff Energy Benefits

RHA Comparisons:	Energy Value	Energy Benefits
IMP_Power	$16,543,000	$0
IMP Base	$16,503,000	-$40,000
IMPGA2010B	$16,517,000	-$26,000
IMPGA2020B	$16,518,000	-$25,000
IMPGA2030B	$16,517,000	-$26,000
IMPMAXRHA	$16,568,000	-$25,000

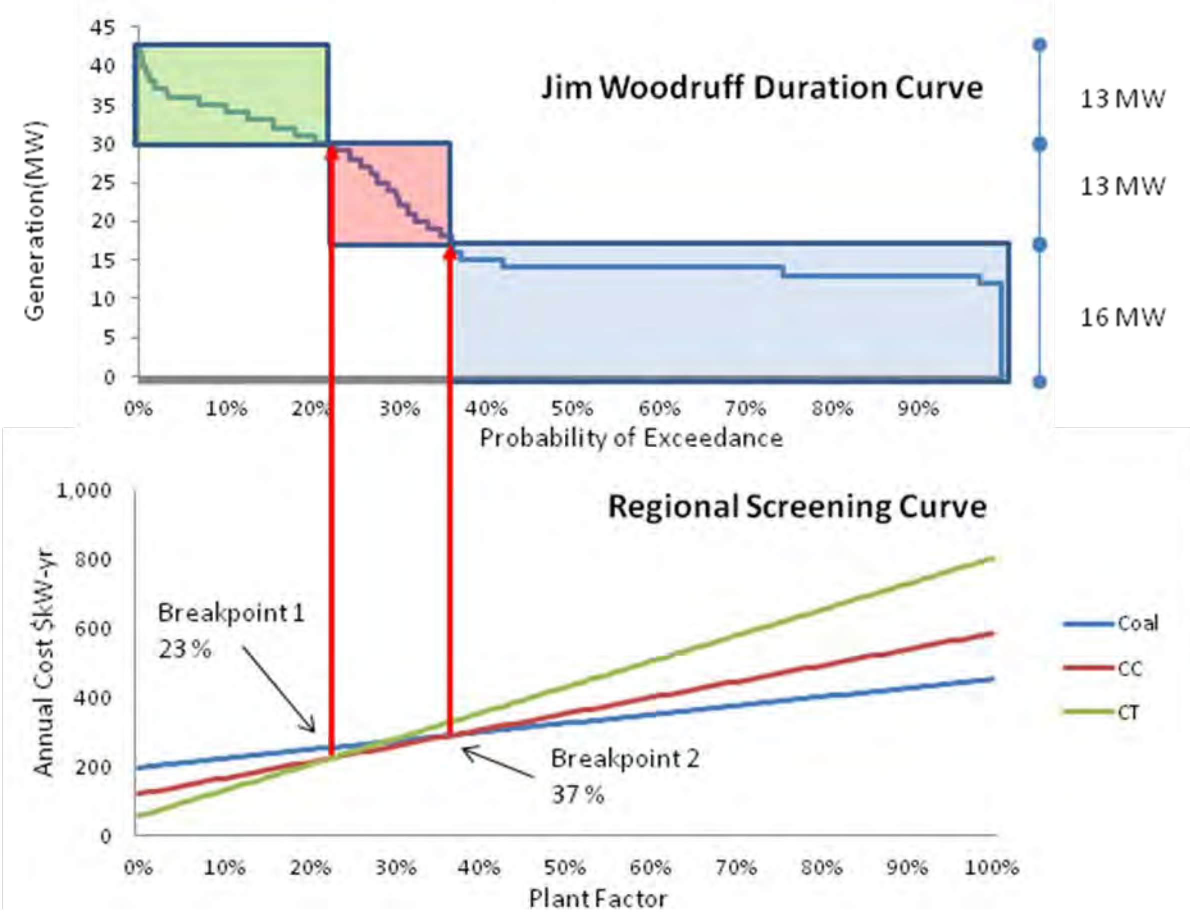
2010:347 mgd River Withdrawal Comparisons	Energy Value	Energy Benefits
IMPGA2010B	$16,517,000	$0
IMPGA2010R	$16,471,000	-$46,000

277 River (Current Operations)	Energy Value	Energy Benefits
Current	$16,499,000	$0
IMPBase	$16,503,000	$4,000
IMProved	$16,463,000	-$36,000

2020:392 mgd Withdrawal Comparisons	Energy Value	Energy Benefits
IMPGA2020B	$16,518,000	$0
IMPGA2020R	$16,476,000	-$42,000
IMPGA2020P	$16,475,000	-$43,000
IMPGA2020C	$16,475,000	-$43,000
IR392L125	$16,488,000	-$30,000

2030:408 mgd Withdrawal Comparisons	Energy Value	Energy Benefits
IMPGA2030B	$16,517,000	$0
IMPGA2030R	$16,479,000	-$38,000
IMPGA2030P	$16,474,000	-$43,000
IMPGA2030BC	$16,467,000	-$50,000
IR408L125	$16,485,000	-$32,000
IR408LMAX	$16,472,000	-$45,000

C.3.2 Jim Woodruff Screening Curve Analysis



Woodruff	Estimated Replacement Capacity (MW)	Percentage of total Generating Capacity (MW)	Capacity Cost ($/KW-yr)	Weighted Value ($)	
Combustion Turbine	13	31%	$57.76	$17.88	
Combined Cycle	13	31%	$121.15	$37.50	
Coal	16	38%	$198.82	$75.74	
				$131.12	weighted average ($/KW-yr)

C.3.3 Jim Woodruff Capacity Benefits

RHA Comparisons:	Dependable Capacity Value (MW)	Change in Dependable Capacity (MW)	$/ Unit of Capacity	Capacity Value
IMP_Power	39.88	0.00	$131,117	$0
IMP Base	39.79	-0.09	$131,117	-$11,000
IMPGA2010B	39.80	-0.08	$131,117	-$11,000
IMPGA2020B	39.80	-0.08	$131,117	-$10,000
IMPGA2030B	39.79	-0.09	$131,117	-$12,000
IMPMAXRHA	39.93	0.06	$131,117	$7,000

2010:347 mgd River Withdrawal Comparisons	Dependable Capacity Value (MW)	Change in Dependable Capacity (MW)	$/ Unit of capacity	Capacity Value
IMPGA2010B	39.80	0.00	$131,117	$0
IMPGA2010R	39.79	-0.01	$131,117	-$2,000

277 River (Current Operations) Comparison Set	Dependable Capacity Value (MW)	Change in Dependable Capacity (MW)	$/ Unit of Capacity	Capacity Value
Current	39.76	0.00	$131,117	$0
IMPBase	39.79	0.03	$131,117	$4,000
IMProved	163.44	0.02	$131,117	$2,000

2020:392 mgd Withdrawal Comparisons	Dependable Capacity Value (MW)	Change in Dependable Capacity (MW)	$/ Unit of capacity	Capacity Value
IMPGA2020B	39.80	0.00	$131,117	$0
IMPGA2020R	39.81	0.01	$131,117	$1,000
IMPGA2020P	39.79	-0.01	$131,117	-$2,000
IMPGA2020C	39.83	0.03	$131,117	$3,000
IR392L125	39.81	0.01	$131,117	$1,000

2030:408 mgd Withdrawal Comparisons	Dependable Capacity Value (MW)	Change in Dependable Capacity (MW)	$/ Unit of capacity	Capacity Value
IMPGA2030B	39.79	0.00	$131,117	$0
IMPGA2030R	39.82	0.03	$131,117	$4,000
IMPGA2030P	39.82	0.03	$131,117	$4,000
IMPGA2030C	39.82	0.03	$131,117	$4,000
IR408L125	39.81	0.02	$131,117	$2,000
IR408LMAX	39.82	0.03	$131,117	$4,000

APPENDIX D

AVERAGE ANNUAL SYSTEM GENERATION BY ALTERNATIVE

Table D-1. Total Average Annual System Generation (MWh) (Peak and Off-peak) by Alternative

Alternative	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Average Annual Generation (MWh)
Current	220,000	217,000	265,000	223,000	186,000	133,000	144,000	128,000	112,000	121,000	163,000	190,000	2,101,000
IMP_Power	231,000	224,000	272,000	231,000	197,000	135,000	146,000	130,000	124,000	126,000	153,000	196,000	2,166,000
IMProved	225,000	217,000	267,000	227,000	193,000	132,000	143,000	126,000	119,000	120,000	146,000	186,000	2,100,000
IMPBase	231,000	224,000	274,000	234,000	200,000	135,000	146,000	128,000	122,000	124,000	150,000	192,000	2,159,000
IMPGA2010B	228,000	222,000	271,000	232,000	199,000	136,000	147,000	130,000	125,000	125,000	151,000	192,000	2,158,000
IMPGA2010R	218,000	212,000	260,000	222,000	188,000	132,000	142,000	126,000	121,000	121,000	146,000	184,000	2,072,000
IMPGA2020B	228,000	221,000	270,000	231,000	198,000	136,000	147,000	130,000	125,000	125,000	151,000	191,000	2,154,000
IMPGA2020C	212,000	207,000	254,000	217,000	182,000	131,000	141,000	125,000	120,000	120,000	144,000	182,000	2,035,000
IMPGA2020P	215,000	210,000	257,000	220,000	185,000	132,000	142,000	126,000	121,000	121,000	145,000	183,000	2,055,000
IMPGA2020R	216,000	210,000	258,000	221,000	186,000	132,000	142,000	126,000	121,000	121,000	145,000	183,000	2,060,000
IR392L125	221,000	214,000	263,000	224,000	191,000	134,000	144,000	127,000	122,000	123,000	147,000	186,000	2,096,000
IMPGA2030B	227,000	221,000	269,000	231,000	198,000	136,000	147,000	130,000	125,000	125,000	151,000	191,000	2,153,000
IMPGA2030C	208,000	204,000	249,000	214,000	179,000	129,000	139,000	123,000	119,000	119,000	142,000	179,000	2,004,000
IMPGA2030P	211,000	206,000	252,000	216,000	181,000	130,000	141,000	124,000	120,000	120,000	143,000	181,000	2,025,000
IMPGA2030R	214,000	209,000	256,000	219,000	184,000	131,000	142,000	126,000	121,000	121,000	145,000	183,000	2,050,000
IR408R125	221,000	214,000	262,000	224,000	190,000	134,000	144,000	127,000	122,000	123,000	147,000	186,000	2,095,000
IMPMaxRHA	223,000	215,000	263,000	225,000	192,000	138,000	149,000	133,000	129,000	128,000	152,000	190,000	2,138,000
IR408LMAX	210,000	206,000	251,000	215,000	180,000	130,000	140,000	124,000	120,000	120,000	143,000	180,000	2,018,000