7.10 HYDROPOWER

The impacts to hydropower are estimated using the traditional hydropower economic benefits analysis and using two other approaches to address concerns expressed by consumers of the hydropower. Traditionally, the Corps determines the economic value of hydropower by evaluating the total value of its production of both the capacity and energy components with respect to alternative replacement costs, as discussed in the Hydropower Economics technical report for the DEIS (Corps, 1994l). Section 7.10.1 reviews the differences in these hydropower benefits for the alternatives discussed in this chapter, examining average annual hydropower benefits and a breakdown of capacity and energy values. The capacity value represents the amount of generation capacity available from the hydropower units under various constraints. Energy is the amount of power generated during a specified time period.

Results of two additional analyses are discussed in this chapter. Section 7.10.2 presents an analysis of how much electric capacity and energy might be at risk in the basin during summer low-flow periods. This analysis looks at the hydropower generated at the six system dams and the electricity generated at the powerplants along the river that depend on the river for cooling of the thermal wastes resulting from the generation of the electricity. For Section 7.10.3, the Western Area Power Administration (WAPA), a cooperating agency in the preparation of the RDEIS and the Federal agency that markets the hydropower from the Mainstem Reservoir System, conducted a revenue analysis of the energy it would be able to market under the CWCP and each of the alternatives evaluated in detail in this chapter. WAPA takes the results of this analysis a step further and identifies the impacts of reduced revenues under each alternative in terms of what it might mean to electric customers that depend on hydropower for some or all of their electricity.

7.10.1 Hydropower Economic Benefits

This part of the hydropower discussion focuses on the National Economic Development (NED) benefits associated with hydropower generation by the Mainstem Reservoir System. It also includes the related information on the breakdown of these benefits between capacity and energy benefits. Data on capacity and energy are also presented.

It should be noted that the hydropower economic benefits presented in this RDEIS reflect a recent reanalysis of the basic unit values for capacity and energy. The basic application of these values in the hydropower economic impact model has not changed from that discussed in the Hydropower Economics technical report (Corps 1994l); only the unit values used in the analysis have been adjusted.

The total economic hydropower benefits for the alternatives are presented in Table 7.10-1 and shown in Figure 7.10-1. Table 7.10-1 also includes data for each of the six mainstem dams. The greatest total average annual benefits for the 100-year period of analysis occur under the GP1528 option ($758.76 million), and the least occur under the CWCP ($741.52 million), a difference of approximately 2.3 percent.

The CWCP has a flat release of 34.5 kcfs from Gavins Point during spring and summer of most years; during major droughts, this release is reduced to 28.5 kcfs. This operational pattern results in $741.52 million in total average annual benefits for the Mainstem Reservoir System hydropower production. The majority of the hydropower benefits come from two dams, Oahe (29.7 percent) and Garrison (20.6 percent). The contributions of the remaining four dams are as follows: Big Bend (17.8 percent), Fort Randall (16.6 percent), Fort Peck (9.5 percent), and Gavins Point (5.8 percent). This distribution of hydropower benefits remains consistent among the alternatives.

Table 7.10-1. Average annual hydropower benefits ($millions).

Alternative	Total	Fort Peck	Garrison	Oahe	Big Bend	Fort Randall	Gavins Point
CWCP	**741.52**	70.28	152.59	220.04	132.19	123.34	43.08
MCP	**747.42**	70.83	155.96	222.89	131.88	122.94	42.92
GP1528	**758.76**	71.53	160.25	225.66	133.36	123.64	44.32
GP2021	**754.83**	71.43	159.21	224.38	132.86	123.01	43.94
GP1521	**755.37**	71.44	159.14	224.80	132.99	123.02	43.98
GP2028	**758.01**	71.49	160.13	225.20	133.40	123.52	44.27

As depicted in Figure 7.10-1, the total average annual hydropower benefits of the alternatives fall into three groups. At $741.52 million per year, the CWCP has the lowest value. The next grouping includes only the MCP, which results in $5.90 million (0.8 percent) more benefits than the CWCP. The highest grouping comprises the set of GP options. One of the two components of these options, the summer low flow, provides a pattern within this cluster: the options with a 28.5-kcfs flat release result in greater benefits than the options with a split-season (21/25-kcfs) low flow. The GP2028 and GP1528 options result in 2.2 and 2.3 percent more total hydropower benefits than the CWCP, respectively. The GP2021 and GP1521 options result in 1.8 and 1.9 percent more total hydropower benefits than the CWCP, respectively.

To allow comparison of the effects of the alternatives addressed in this chapter to those of the submitted alternatives, Figure 7.10-1 includes the values for the alternatives addressed in Chapter 5. The four GP options provide hydropower benefits similar to those provided by the two alternatives submitted by the USFWS (the BIOP and FWS30 alternatives). The USFWS alternatives included different spring rises but the same variable summer low flows, thus the hydropower benefits provided by those alternatives are essentially the same as those provided by the GP options with the variable summer flow pattern (GP1521 and GP2021). Of all the alternatives, the greatest hydropower benefits occur under the GP1528 option.

The MCP differs from the CWCP in that it includes greater conservation measures during drought periods, unbalanced intrasystem regulation, and a spring rise downstream from Fort Peck Dam. These changes result in a 0.8 percent increase in total average annual hydropower benefits over those modeled for the CWCP. Compared to the GP options, this represents the lowest percent increase in total hydropower benefits over the CWCP. The bulk of the increase under the MCP comes from Garrison and Oahe Dams, which increase 2.2 percent and 1.3 percent, respectively. At the three lower dams (Big Bend, Fort Randall, and Gavins Point), this alternative results in decreases ranging from 0.2 to 0.5 percent in average annual hydropower benefits.

The GP options differ from the MCP by including spring rises and low summer releases at Gavins Point Dam. A potential starting point for this set of options (because it has the smallest changes at Gavins Point Dam of the four GP options), identified as the GP1528 option, includes a 15-kcfs spring rise and a 28.5-kcfs flat release during summer. These measures result in a 1.5 percent increase in total average annual hydropower benefits, compared to the MCP. Increases occur at all six dams, with the greatest relative increases at Gavins Point (3.3 percent) and Garrison (2.8 percent) Dams. Notably, all four options result in greater average annual hydropower benefits than the MCP, both in total and at each dam.

To provide a perspective for how hydropower benefits could change in the future if changes are made to the GP1528 option, the following paragraphs describe the changes relative to the GP1528 option. The greatest total percent decrease (0.5 percent decrease from those of the GP1528 option) in hydropower benefits occurs under the GP2021 option. The GP2021 option has the 20-kcfs spring rise and 25/21-kcfs split summer release from Gavins Point Dam. This combination of change, when made to the GP1528 option, decreases by 0.1 percent hydropower benefits at Fort Peck Dam, decreases 0.6 percent at Garrison Dam, decreases 0.6 percent at Oahe Dam, decreases 0.4 percent at Big Bend Dam, decreases 0.5 percent at Fort Randall Dam, and decreases 0.9 percent at Gavins Point Dam. In summary, changing both the spring rise and summer low flow at the same time under adaptive management results in a negative change in hydropower benefits at all six dams.

With a change in the summer low flow from minimum service to the 25/21-kcfs split from Gavins Point Dam, as with the GP1521 option, total hydropower benefits decrease by 0.4 percent compared to the GP1528 option. When only the summer flows are lowered from those of the GP1528 option, hydropower benefits decrease by 0.1 percent at Fort Peck Dam, decrease by 0.7 percent at Garrison Dam, decrease by 0.4 percent at Oahe Dam, decrease by 0.3 percent at Big Bend Dam, decrease by 0.5 percent at Fort Randall Dam, and decrease by 0.8 percent at Gavins Point Dam. In summary, changing summer low flows only under adaptive management results in a negative change in hydropower benefits at all six dams.

With a change in only the spring rise amount from 15 kcfs to 20 kcfs, as with the GP2028 option, total hydropower benefits decrease by 0.1 percent compared to the GP1528 option. When only the spring rise is increased over the GP1528 option, hydropower benefits decrease by 0.1 percent at Fort Peck Dam, decrease by 0.1 percent at Garrison Dam, decrease by 0.2 percent at Oahe Dam, decrease by 0.1 percent at Fort Randall Dam, and decrease by 0.1 percent at Gavins Point Dam. No change in benefits occurs at Big Bend Dam for the change in criteria. In summary, increasing the spring rise only under adaptive management results in a negative change in hydropower benefits at five dams and no change at one.

The annual values of total hydropower benefits for the alternatives are shown in Figures 7.10-2 through 7.10-4. Hydropower benefits are highly variable during the entire period of analysis, and none of the alternatives performs consistently better or worse than any of the others. As the figures show, the lowest total hydropower benefit values under all alternatives occur during the 1930 to 1941 drought. Additional low points occur during the late 1950s and late 1980s.

Figure 7.10-2 shows that the MCP and the GP1528 option, both of which feature increased drought conservation measures, differ from the CWCP most noticeably during and after periods of drought. The MCP produces higher annual hydropower benefits than the CWCP only during the 1930 to 1941 drought, while the GP1528 option does so during that period as well as the late 1950s and the late 1980s. As shown in Figures 7.10-3 and 7.10-4, there is very little difference in effects among the GP options. The GP1528 and GP2021 options are essentially identical for almost the entire 100-year period of analysis, with the GP1528 option producing higher benefits only in the late 1930s and the mid-1940s (Figure 7.10-3). This difference appears to be a result of the lower summer releases from Gavins Point Dam, because the options with the same summer releases match each other almost exactly (GP1528 and GP2028, Figure 7.10-4).

The month-to-month distributions of the average annual generating capacity values for the full 100-year period of analysis are presented in Table 7.10-2 and Figures 7.10-5 and 7.10-6. In general, the total generating capacity at the mainstem dams is at its highest level in the summer months. Under the CWCP and the MCP, the lowest levels of generating capacity occur during spring and fall, and an intermediate peak occurs during winter. Throughout the year, the MCP results in slightly higher generating capacity than the CWCP, consistently producing between 1.2 percent and 1.7 percent more hydropower capacity than the CWCP.

The four GP options result in a different annual pattern of generating capacity. Rather than having two peaks, each option has a single peak in summer, and then gradually drops off to a winter time low before increasing back to its summer peak. The effects of the four GP options are almost identical, differing from each other by no more than 0.5 percent at any time. Generally, all four options result in higher monthly average peaking capacity values than the CWCP and the MCP throughout the year. For most of the year, the two options with 28.5-kcfs summer releases (GP1528 and GP2028) produce the highest average hydropower peaking capacity, ranging between 0.3 percent and 0.4 percent above the options that feature variable summer flows. In late summer and autumn, this difference is reduced to less than 0.1 percent. Finally, for each set of GP options with the same summer flow, the option with the higher spring rise (20 kcfs spring rise) has very slightly lower capacity values in some months. This occurs because the lakes are drawn down slightly lower by the higher spring rise, which slightly reduces generating capacity because the head on the generators is lower.

Table 7.10-2. Monthly average hydropower peaking capacity (MW).

Alternative	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
CWCP	2,146	2,148	2,053	2,009	2,130	2,244	2,270	2,255	2,089	2,071	2,150	2,141
MCP	2,180	2,185	2,086	2,037	2,163	2,277	2,300	2,287	2,119	2,096	2,182	2,175
GP1528	2,231	2,234	2,245	2,263	2,262	2,288	2,319	2,314	2,293	2,267	2,239	2,226
GP2021	2,221	2,224	2,236	2,253	2,251	2,276	2,310	2,310	2,292	2,267	2,233	2,216
GP1521	2,222	2,224	2,236	2,254	2,253	2,279	2,313	2,312	2,294	2,268	2,234	2,216
GP2028	2,230	2,232	2,244	2,262	2,261	2,286	2,317	2,310	2,291	2,265	2,237	2,224

Table 7.10-3. Monthly average hydropower energy values (GWh).

Alternative	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
CWCP	729	637	554	711	928	912	1,023	1,053	973	928	857	722
MCP	710	611	550	740	929	921	1,027	1,054	1,016	977	776	727
GP1528	743	610	561	802	1,028	924	980	970	1,018	960	772	716
GP2021	739	607	560	805	1,052	914	869	894	1,033	984	868	716
GP1521	741	608	560	809	1,025	900	872	901	1,044	994	874	719
GP2028	739	609	559	797	1,050	933	980	967	1,011	954	765	713

The energy distributions, in thousands of megawatt-hours, or gigawatt-hours (GWh), are presented in Table 7.10-3 and in Figures 7.10-7 and 7.10-8. Overall, the annual patterns of the alternatives fall into two groups. Under all of the alternatives, average hydropower energy values are lowest in March and highest in late spring or summer. The greatest values under the CWCP and the MCP occur in August, while the GP options exhibit two peaks, in May and September. Compared to the CWCP, the increased drought conservation measures of the MCP generally result in lower energy values during the winter months, but higher values during spring, summer, and autumn. The GP options result in higher values than the CWCP and the MCP in spring and autumn, and lower values in summer and winter. The lowest average summer hydropower energy values occur under the two options with variable (25/21-kcfs) summer flows.

For the region in which the Mainstem Reservoir System hydropower facilities operate, Federal hydroelectric generating capacity is marketed based on the peak season firm demand, in both the summer and winter seasons. In the early 1980s, WAPA chose to use 1961 water conditions to determine adverse-year capability for the sale of firm capacity. The lowest peak capacities in the summer and winter periods for the Corps' 1961 annual operating year (March 1961 through February 1962) represent the criteria that determine the capacities marketed by WAPA. Table 7.10-4 presents the summer and winter values for dependable capacity in 1961 for all alternatives. This table also presents the currently marketed capacities in both seasons.

Under current depletion levels, the CWCP does not meet the currently marketed levels identified in the early 1980s at depletion levels assumed at that time. The CWCP almost meets the level in the summer (-2 megawatt [MW]), but falls much shorter of meeting the level in the winter (-37 MW). The increased drought conservation measures of the MCP and the four GP options allow these alternatives to exceed the currently marketed hydropower capacity level both in summer and winter. The greatest increases above currently marketed levels occur under the four GP options, all of which are within 0.5 percent of each other in both summer and winter.

Table 7.10-4. Marketable capacity from the Mainstem Reservoir System hydropower facilities (MW).

	1961 Operating Year Minimum Capacity	
Alternative	**Summer Season**	**Winter Season**
Currently marketed	2,070	2,010
CWCP	2,068	1,973
MCP	2,102	2,015
GP1528	2,177	2,108
GP2021	2,177	2,099
GP1521	2,178	2,099
GP2028	2,176	2,107

7.10.2 Power at Risk

Thermal capacity and energy impacts were analyzed for the CWCP, the MCP, and the GP options during the month of July at power-generating facilities that use the Missouri River for cooling. These facilities are identified in the Water Supply Economics Technical Report (Corps 1994g). July was selected as the month for this assessment because it is one of the peak power demand months and the river flows are most constant for the alternatives considered in this chapter. The analysis was conducted assuming the purchase of replacement capacity or energy once water quality permits could not be met. The thermal capacity and energy at-risk results were combined with the differences in hydropower generation to come up with the combined at-risk values for the Missouri River region of the United States.

Thermal Capacity at Risk

As flows drop on the river reaches, powerplants may have to cut back on their generating capacity to limit the amount of heated wastewater entering the river from their cooling facilities. Potential cutbacks were determined using the water supply model developed to identify the water supply benefits of the alternatives. An analysis was conducted that assumes that if flows are insufficient to meet water quality permit requirements, the impacted plant capacity must be replaced by purchased capacity from another facility. As part of determining the economic impacts on the powerplants under the water supply (and water quality, as both were combined into one analysis to ensure that the economic impacts to the powerplants were not double counted), the capacity and energy shortfall is computed. The capacity data were retrieved from the model to be used in the analysis of capacity effects, which is referred to as capacity at risk during the Gavins Point low-flow release period.

Figure 7.10-9 illustrates the relationship between capacity-at-risk and the Gavins Point Dam releases. Capacity at risk appears to be highly correlated (R squared value near 1.0) and increases exponentially as Gavins Point Dam releases decrease during July. The CWCP with a capacity at risk of about 34 MW and the MCP with a capacity at risk of about 68 MW both have July flows of about 34.5 kcfs, or full service navigation, except during drought. The GP options with a minimum navigation service release (GP1528 and GP2028) have an average summer release of about 28.5 kcfs and a capacity at risk of about 70 MW. The GP options with a split navigation season (GP1521 and GP2021) have an average July target release of about 23 kcfs and a capacity at risk of about 278 MW. To assist with the analysis, the ARNRC alternative, one of the submitted alternatives discussed in Chapter 5, has a July release of 18 kcfs and a capacity at risk of over 750 MW, which is also plotted. From this figure, the potential capacity at risk for a release of 21 kcfs is 387 MW of generating capability. This value is more indicative of the impacts of the GP1521 and GP2021 options for the second half of July and the first half of August, when the Gavins Point Dam release is generally 21 kcfs.

Average annual capacity at risk during July at the river thermal plants is presented in Table 7.10-5, and the annual July values over the period of record are presented in Figures 7.10-10 through 7.10-12. The capacity at risk is predominantly from powerplants in the Sioux City reach, with most of the remaining capacity at risk in plants located in the reach downstream of Garrison Dam and in the Omaha, Nebraska City, and Hermann reaches.

Table 7.10-5. Potential capacity at risk in July at powerplants using Missouri River water for cooling (MW).

	Reach[1/]									
Alternative	**GARR**	**DS_G**	**SUX**	**OMA**	**NCNE**	**STJ**	**MKC**	**BN**	**HE**	**Total**
CWCP	4.37	12.38	10.49	3.88	2.38	0.02	0.19	0.00	0.00	**33.70**
MCP	0.00	20.81	28.62	7.65	5.36	0.03	0.12	0.00	5.09	**67.68**
GP1528	0.00	26.27	30.80	5.97	3.86	0.02	0.08	0.00	3.67	**70.66**
GP2021	0.00	24.79	219.90	18.15	10.58	0.04	0.25	0.00	4.56	**278.26**
GP1521	0.00	24.10	219.90	18.15	10.58	0.04	0.25	0.00	4.56	**277.58**
GP2028	0.00	25.50	30.80	5.97	3.86	0.02	0.08	0.00	3.67	**69.90**
ARNRC	0.00	15.10	555.49	111.64	49.31	0.48	3.10	0.00	44.15	**779.28**

1/ Reach names are abbreviated as follows: GARR = Garrison; DS_G = downstream Garrison; SUX = Sioux City; OMA = Omaha; NCNE = Nebraska City; STJ = Saint Joseph; MKC = Kansas City; BN = Boonville; HE = Hermann.

The CWCP minimizes the average annual July thermal capacity at risk at about 34 MW. Capacity at risk for the CWCP is primarily during the single nonnavigation season, which occurred in 1937 in the model simulation. About two-thirds of the capacity at risk is at powerplants in the Sioux City and downstream Garrison reaches, with most of the remaining capacity at risk in plants located in the Omaha and Nebraska City reaches.

Three of the alternatives, the MCP, the GP1528 option, and the GP2028 option maintain at least minimum navigation service throughout the summer and place similar amounts of capacity at risk, predominantly during years of no navigation during the 1930 to 1941 drought. These alternatives have 5 to 6 nonnavigation seasons during this period compared to the single nonnavigation season for the CWCP. These three alternatives about double the average annual capacity at risk compared to the CWCP. About 75 to 80 percent of the capacity at risk for these alternatives is at powerplants in the Sioux City and downstream Garrison reaches, with most of the remaining capacity at risk at powerplants located in the Omaha, Nebraska City, and Hermann reaches.

In comparison, the GP1521 and GP2021 options, both with a split in the navigation season, increase the amount of capacity at risk by more than 8 times the CWCP or about four times GP1528. For the GP1521 and GP2021 options, the potential capacity loss occurs in all years except during years with high downstream inflow that keeps the average July flow above the threshold flow below which water quality temperature standards may not be met. For these alternatives, nearly 80 percent of the capacity at risk is from thermal plants in the Sioux City reach.

Figure 7.10-13 shows the duration of the impacts. The CWCP has a 100-MW impact in fewer than 5 percent of the years, the MCP has a 100-MW impact in fewer than 10 percent of the years, and the minimum service summer flow options have impacts exceeding 100-MW in fewer than 15 percent of the years. In contrast, the split season options (GP1521 and GP2021) have a 300-MW impact in nearly 60 percent of the years and the ARNRC alternative has a 500-MW impact in nearly 90 percent of the years.

The total average capacity at risk considering the mainstem hydropower plants and the thermal plants using Missouri River water for cooling is summarized in Table 7.10-6 and by year in Figure 7.10-14. Persistence of the capacity at risk for the GP options with summer flows below minimum navigation service (GP1521 and GP2021) is highlighted in the figure. The table shows that the capacity at risk at thermal plants is only partially offset by increases in mainstem hydropower capacity due to higher average pool elevations with increased conservation included in the alternatives to the CWCP. The GP1528 and GP2028 options have net gains in generating capacity in July, whereas the GP1521 and GP2021 options and the ARNRC alternative have net losses. The MCP shows essentially no change.

Energy at Risk

When generating capacity has to be cut back to limit the impact of heated wastewater on the Missouri River, the amount of energy generated is adversely affected. Effects on the ability to generate energy were also identified using an analysis similar to that described for the capacity effects. These effects are also combined with the changes in energy availability at the mainstem hydropower facilities.

Similar to the capacity-at-risk relationship with flows, energy at risk appears to be highly correlated and increases exponentially as Gavins Point Dam releases decrease during July, as shown by Figure 7.10-15. Impacts increase from about 35 GWh for the MCP with full service navigation flows in July to over 300 GWh for the ARNRC alternative that

Table 7.10-6. Potential total thermal and hydropower average capacity at risk in July compared to the CWCP (MW).

Alternative	Hydropower	Thermal Power	Total
MCP	+ 30	- 34	- 4
GP1528	+ 49	- 37	+ 12
GP2021	+ 40	- 245	- 204
GP1521	+ 43	- 244	- 201
GP2028	+ 47	- 36	+ 11
ARNRC	+ 52	- 746	- 694

Table 7.10-7. Potential energy at risk in July at the powerplants using Missouri River water for cooling (GWh).

	Reach[1/]									
Alternative	**GARR**	**DS_G**	**SUX**	**OMA**	**NCNE**	**STJ**	**MKC**	**BNM**	**HEM**	**Total**
CWCP	2.20	6.33	4.62	2.12	1.45	0.01	0.09	0.00	0.00	**16.82**
MCP	0.00	10.48	11.68	4.34	3.51	0.00	0.06	0.00	4.84	**34.91**
GP1528	0.00	13.24	12.38	3.40	2.53	0.00	0.03	0.00	3.05	**34.63**
GP2021	0.00	12.48	83.83	10.32	6.95	0.00	0.11	0.00	6.55	**120.24**
GP1521	0.00	12.14	83.83	10.32	6.95	0.00	0.11	0.00	6.55	**119.90**
GP2028	0.00	12.82	12.38	3.40	2.53	0.00	0.03	0.00	3.05	**34.21**
ARNRC	0.00	7.65	229.08	62.99	31.93	0.20	1.39	0.00	30.26	**363.50**

1/ Reach names are abbreviated as follows: GARR = Garrison; DS_G = downstream Garrison; SUX = Sioux City; OMA = Omaha; NCNE = Nebraska City; STJ = Saint Joseph; MKC = Kansas City; BN = Boonville; HE = Hermann

has Gavins Point Dam releases in July of 18 kcfs, about 17 kcfs below full service navigation.

Average annual energy at risk during July at river thermal plants is presented in Table 7.10-7 and by year in Figures 7.10-16 through 7.10-18.

The CWCP minimizes energy at risk at about 17 GWh. Energy at risk is primarily during the single nonnavigation season. Nearly two-thirds of the energy at risk is at powerplants in the Sioux City and downstream Garrison reaches.

The MCP together with the GP1528 and GP2028 options about double the energy at risk. This doubling is based on the 5 to 6 nonnavigation seasons for these alternatives in the 1930 to 1941 drought compared to the single nonnavigation season for the CWCP. Most of the energy at risk for these alternatives is from powerplants in the Sioux City and downstream Garrison reaches.

The GP1521 and GP2021 options increase the amount of energy at risk by more than 7 times that of the CWCP, or about 3.5 times that of the GP1528 option. The energy at risk is predominantly produced in the Sioux City reach, with most of the remaining energy at risk at powerplants located in the reach downstream of Garrison Dam and in the Omaha, Nebraska City, and Hermann reaches. The analysis assumes that if flows are insufficient to allow the powerplants to meet water quality temperature standards, the impacted powerplant capacity must be replaced by purchased energy. In contrast to the CWCP, the MCP, and the GP1528 and GP 2028 options, where the potential energy losses are predominantly during years of no navigation service, the GP1521 and GP2021options have potential energy losses in almost all years. The exceptions occur in years with high downstream inflow that keeps the average July flow above the threshold flow below which water quality temperature standards may not be met.

The duration plot of energy at risk is presented in Figure 7.10-19. The CWCP shows potential thermal energy at risk of less than 50 GWh in less than 5 percent of the years. The MCP has 50 GWh at risk in less than 10 percent of the years, and the minimum service options (GP1528 and GP2028) have 50 GWh at risk in less than 15 percent of the years. In contrast, the split season options, GP1521 and GP2021, show more than 100 GWh at risk in more than 50 percent of the years, and the ARNRC alternative has over 200 GWh at risk in over 90 percent of the years.

The total energy at risk considering the mainstem hydropower facilities and the thermal plants using Missouri River water for cooling is summarized on an average annual basis in Table 7.10-8 and on a yearly basis in Figure 7.10-20. The potential energy loss at the thermal plants is compounded by

Table 7.10-8. Potential total thermal and hydropower energy impacts in July compared to the CWCP (GWh).

Alternative	Hydropower	Thermal Power	Total
MCP	+ 4	- 18	- 14
GP1528	- 43	- 18	- 61
GP2021	- 151	- 103	- 254
GP1521	- 43	- 17	- 60
GP2028	- 154	- 103	- 257
ARNRC	- 291	- 347	- 638

hydropower energy losses at the mainstem hydropower plants, except for the MCP, which shows a small hydropower energy gain. Hydropower energy at risk compared to the CWCP is greater than the thermal energy at risk for all the GP options.

7.10.3 Hydropower Revenue Impacts to the Upper Great Plains Region of WAPA and its Customers

The Upper Great Plains Region of WAPA calculated revenue impacts of the CWCP, the MCP, and the GP options on the Pick-Sloan Missouri Basin—Eastern Division. Power from Federal generation resources in the Upper Great Plains region has been allocated through a succession of marketing plans. The marketing plans result in an amount of power that WAPA has agreed to provide (firm commitments). Water levels and releases fluctuate hour to hour, month to month, season to season, and year to year. Because of these fluctuations, WAPA may need to purchase power to fulfill its firm commitments or it may have power to sell after fulfilling its firm commitments. The monthly 100-year average generation was calculated for the CWCP, the MCP, and the four GP options (GP1528, GP2028, GP1521, and GP2021). Generation is compared to the firm commitments. If power is available beyond the firm commitments, it is sold. If there is not sufficient power generated to fulfill the firm commitments, additional power is purchased. Based on the Post-2000 Marketing Plan for the Pick-Sloan Missouri Basin Program—Eastern Division, these sales or purchases are made on the energy market. For this analysis, the sales and purchases were priced according to the monthly Cinergy Rates of January 30, 2001. (Cinergy provides monthly rate values for the upcoming at the end of each month.)

The 100-year average sales and purchases for each alternative are shown in the Table 7.10-9. The MCP generates slightly more net revenue than the CWCP. The minimum navigation service options (GP1528 and GP2028) provide almost $9 million less average annual revenue than the CWCP, and the split season options (GP1521 and GP2021) provide nearly $30 million less revenue than the CWCP.

Sales and purchases were totaled for each alternative resulting in the 100-year average monthly sales (+) and purchases (-). The MCP and the GP options are compared to the CWCP to obtain the increase or decrease in revenue. This comparison shows the overall impact to the Pick-Sloan Missouri Basin—Eastern Division firm power and is shown in Figure 7.10-21. July and August are notable as the only months where the alternatives deliver the distinctly different net revenue. In July, the CWCP and the MCP provide about $40 million in average net revenue; the minimum navigation service alternatives, GP1528 and GP2028, deliver less than $35 million average revenue. The split season alternatives, GP1521 and GP2021, provide less than $20 million in average revenue. The pattern is much the same in August, except GP1528 and GP2028 provide less than $30 million in revenue. Revenue in November also varies by alternative, but while the percentage differences between alternatives are great, the average dollar differences are less than $5 million between alternatives.

The Upper Great Plains Region of WAPA serves customers across more than 378,000 square miles in the northern Rocky Mountain and WAPA Great Plains states. Power is delivered through 98 substations across approximately 7,745 miles of Federal transmission lines, which connect with other regional transmission systems.

The Region's 300-plus customers include rural electric cooperatives, municipalities, public utility districts, irrigation districts, Native American Tribes, and Federal and State agencies. The Upper Great Plains Region markets the power from six Corps mainstem dams and powerplants.

Table 7.10-9. Average annual impact to WAPA for meeting Pick-Sloan firm power commitments ($millions).

	CWCP	MCP	GP1528	GP2021	GP1521	GP2028
Sales Revenue (+)	144.9	148.6	136.9	116.0	116.3	137.3
Purchase Cost (-)	25.2	27.3	25.8	26.2	26.0	26.3
Net Revenues	119.7	121.3	111.1	89.8	90.3	111.0
Lost Revenues Compared to CWCP	0.0	-1.6	8.6	29.9	29.4	8.7

To analyze the impact of the proposals on Upper Great Plains Region Customers (a capital C is used when referring to a direct Customer of the Upper Great Plains Region), a representative sample of Customers was selected. To be representative, the sampling needed a Customer from each of the six states in which the Region provides service. Customers receiving approximately 10, 40, 60, 70, and 100 percent of their load were selected. The Customer sample includes Customers from each of the different types of entities receiving power from WAPA.

An example of one of the Region's Customers receiving 10 percent of its power and energy resources from Federal generation is a rural electric cooperative with offices in Bismarck, North Dakota. This cooperative has about 9,247 customers, and 8,264 of these are residential customers. This rural electric cooperative operates in four counties in south-central North Dakota. The summer peak is about 32 MW and the winter peak is about 29 MW. Another example of a 10 percent Customer would be a municipality in northeastern Nebraska with 1,844 customers, 1,461 of which are residential. The summer peak is 11 MW and the winter peak is 9 MW.

An example of a 40 percent load Customer is a municipality in northwestern Iowa with 1,306 customers, 1,105 of which are residential. The summer peak is 7 MW and the winter peak is 6 MW. Another 40 percent load Customer is a rural electric cooperative in Montana with a summer peak of 147 MW and a winter peak of 186 MW. A final example of a 40 percent load Customer is a rural electric cooperative in South Dakota, with 24 wholesale customers, a summer peak of 300 MW, and a winter peak of 314 MW.

An example of a 70 percent load Customer is a municipality in west-central Minnesota with 750 customers, 654 of which are residential. The summer peak is 2.6 MW and the winter peak is 3.2 MW. Another example of a 70 percent load Customer is a municipality in WAPA South Dakota with 622 residential customers, a summer peak of 2.6 MW, and a winter peak of 2.5 MW.

One hundred percent load Customers include a municipality in northwest South Dakota, with 305 customers, of which 248 are residential customers. The summer peak is 1.2 MW and the winter peak is 1.5 MW. Another 100 percent load Customer is a municipality in Iowa with 881 customers, of which 728 are residential. The service area includes a town in northwestern Iowa. The summer peak is 5.25 MW and the winter peak is 5.43 MW.

A representative Tribal Customer is a Tribe in South Dakota receiving 60 percent of its power from Federal resources. It covers 2.8 million acres and has a population of 14,861 people.

The increase or decrease in revenue from the 100-year averages compared to the firm commitments is applied to the power repayment study to determine the rate impact for each alternative water control plan. After selecting representative Customers, the increased or decreased rate for each proposal is then applied to the amount of power purchased from WAPA by these representative Customers. The increase or decrease in purchase power from WAPA is divided by the Customer's total purchase power cost to determine the percentage of change from their purchases under the CWCP. The above procedure was applied to all of the sample Customers. Figure 7.10-22 indicates the percentage increase in purchase power costs that would be experienced by each of the five sample Customers for the GP options.

Analyzing the sample Customers shows that the 100 percent load Customer impacts are increases of about 20 percent for GP1521. For the 10 percent load Customers, impacts are increases of about 1 percent. The analysis of the GP2021 option is almost identical to GP1521. The magnitude is smaller for the GP1528 and GP2028 options. One hundred percent Customer impacts are increases of about 6 percent. For the 10 percent load Customers, increases are about 0.3 percent for the GP1528 and GP2028 options.

As a result of the marketing plans and other events in the Upper Great Plains Region, those Customers that have 100 percent of their load served from Federal resources tend to be the smaller, poorer customers. These Customers have not had any load growth and may have, in fact, seen a reduction in load. On the other hand, those with less than 40 percent of their load furnished by Federal resources have seen load growth and thus the percentage of load served by Federal resources has decreased. The largest impact of any increase in the cost of the Federal resources greatly burdens the 100 percent load, small customer. The 10 percent load customer spreads the increase over a larger load base, making a 20 percent increase in the Federal resource price much less noticeable.

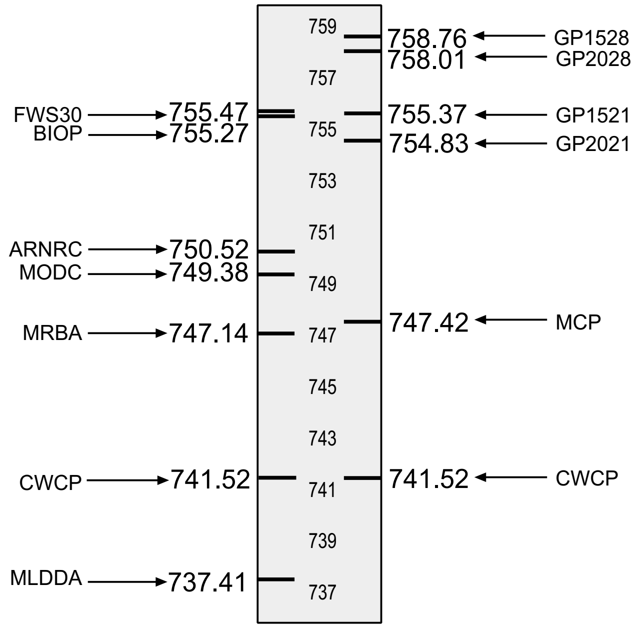

Figure 7.10-1. Average annual hydropower benefits for submitted alternatives and the alternatives ($millions).

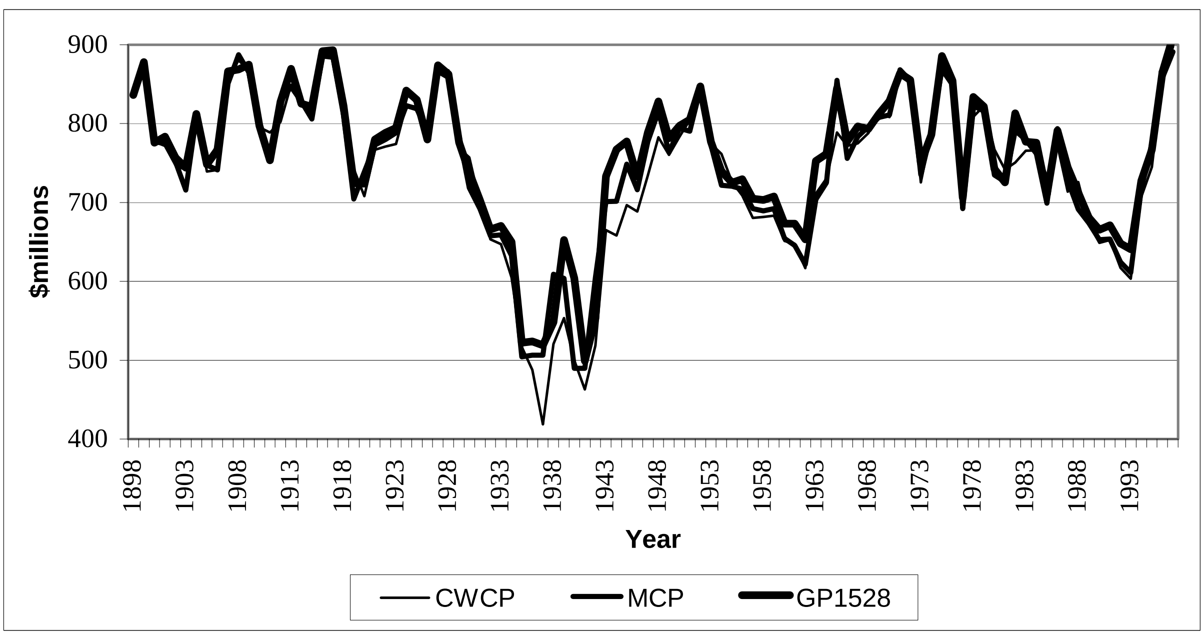

Figure 7.10-2. Average annual hydropower benefits for CWCP, MCP, and GP1528.

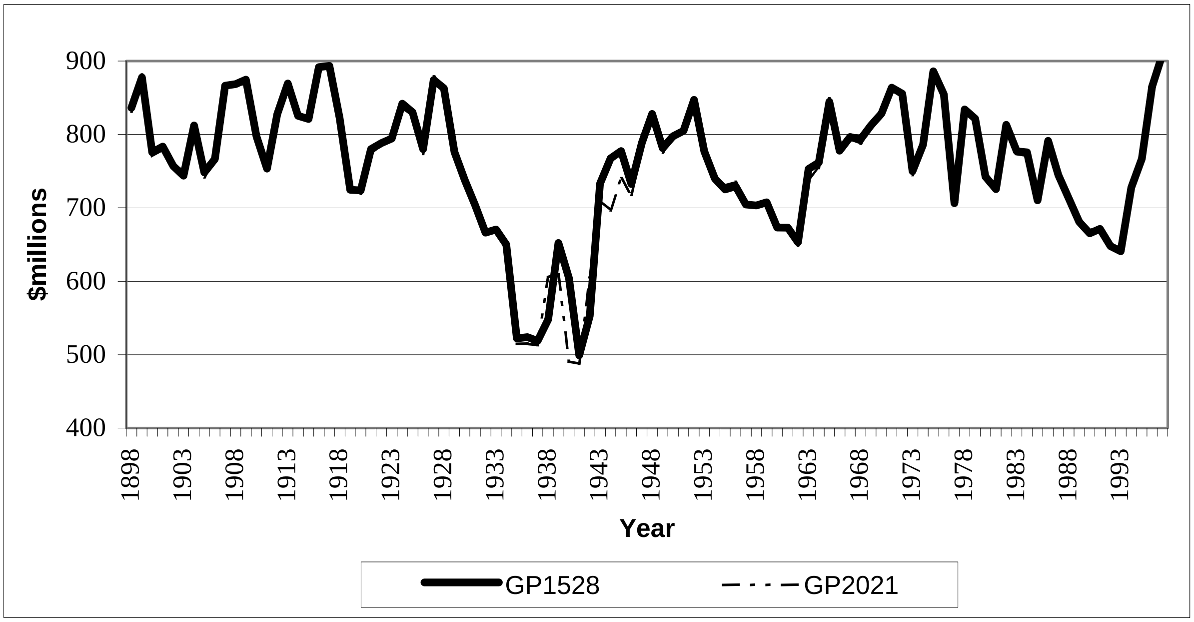

Figure 7.10-3. Average annual hydropower benefits for GP1528 and GP2021.

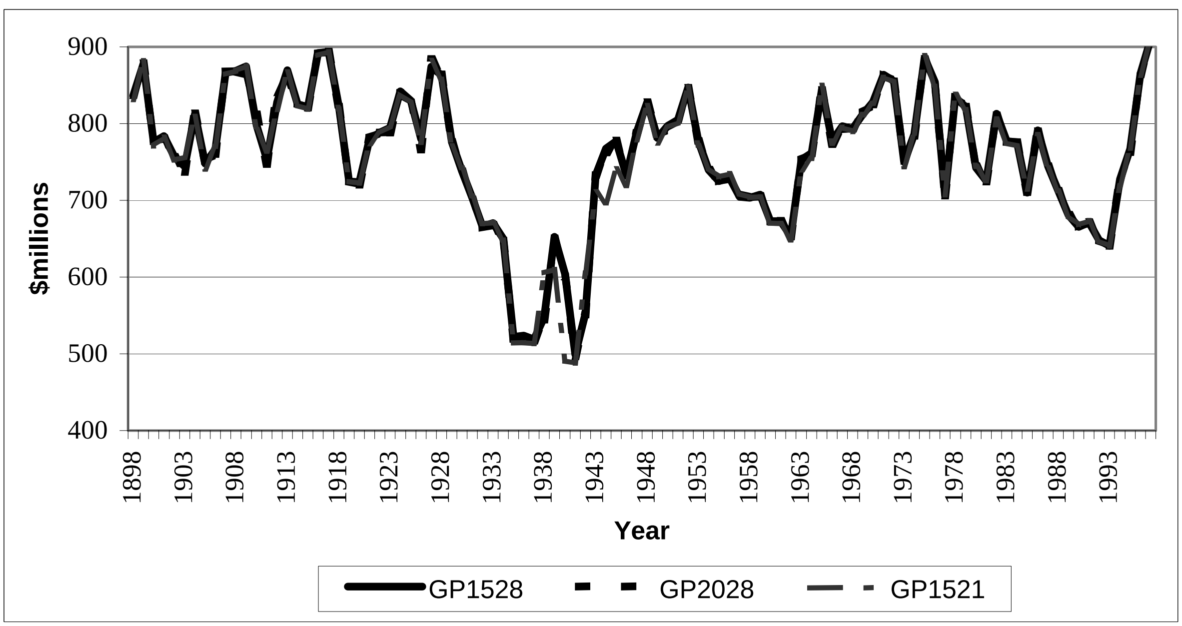

Figure 7.10-4. Average annual hydropower benefits for GP1528, GP2028, and GP1521.

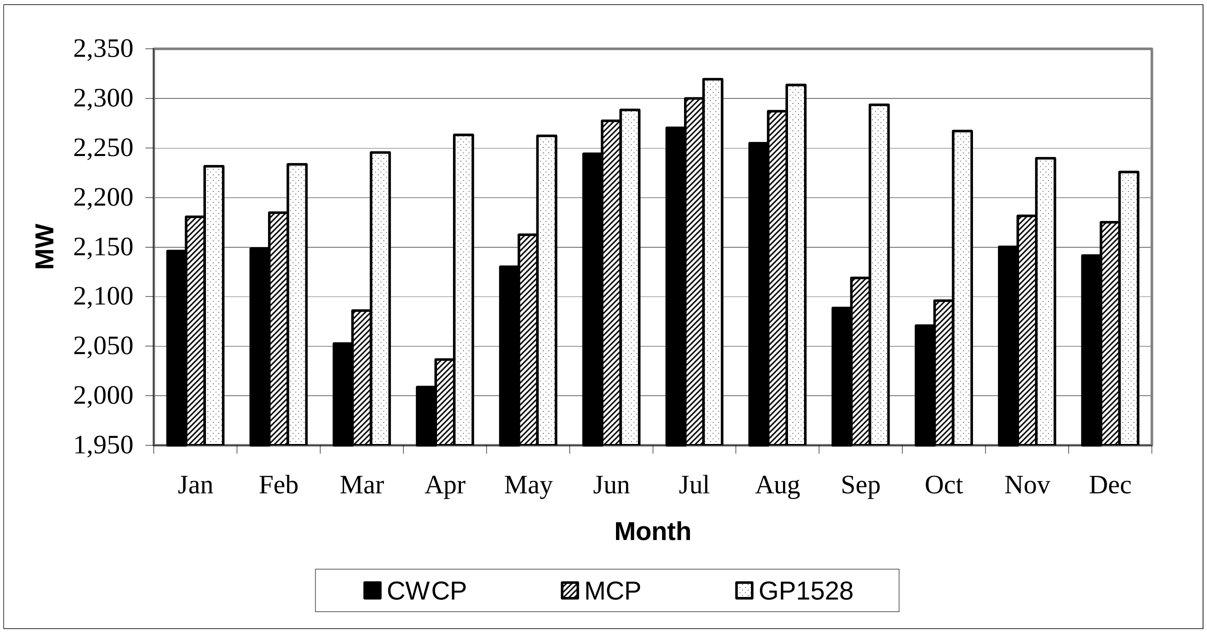

Figure 7.10-5. Monthly average hydropower peaking capacity for CWCP, MCP, and GP1528.

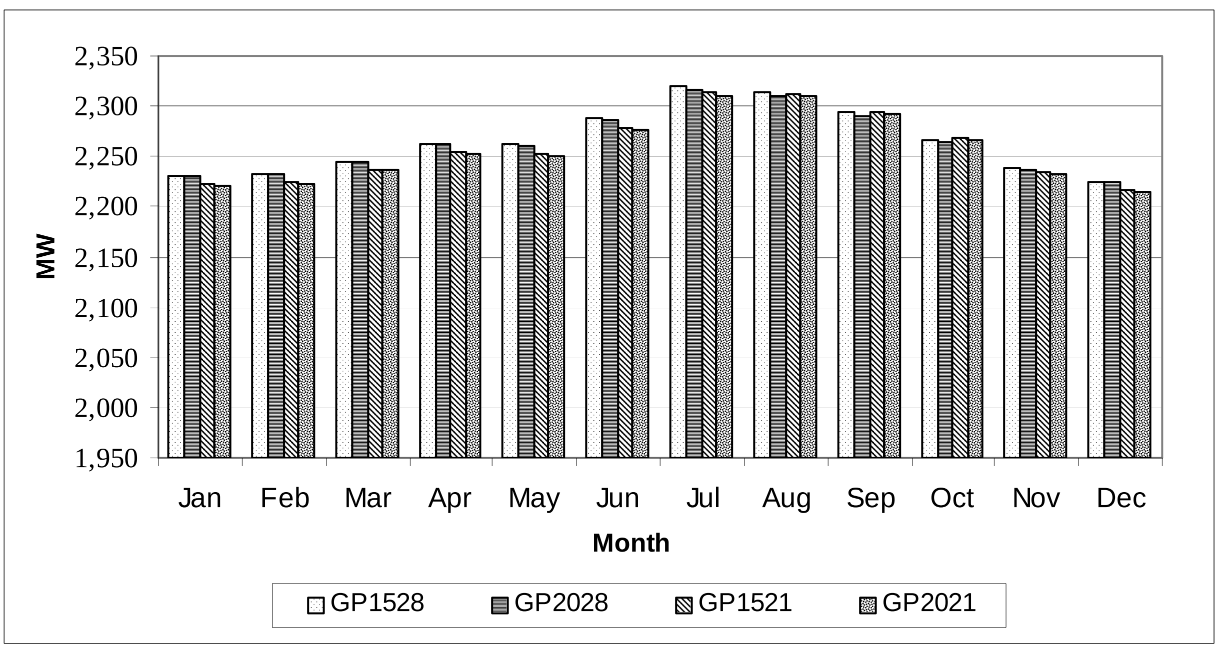

Figure 7.10-6. Monthly average hydropower peaking capacity for GP1528, GP2028, GP1521, and GP2021.

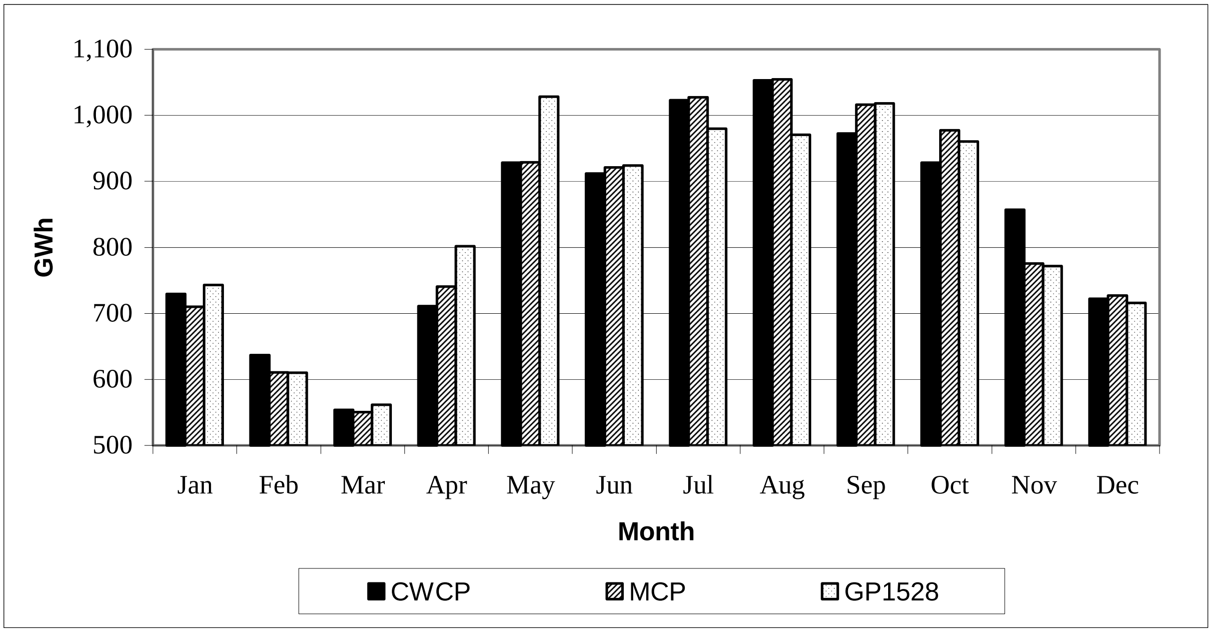

Figure 7.10-7. Monthly average hydropower energy values for CWCP, MCP, and GP1528.

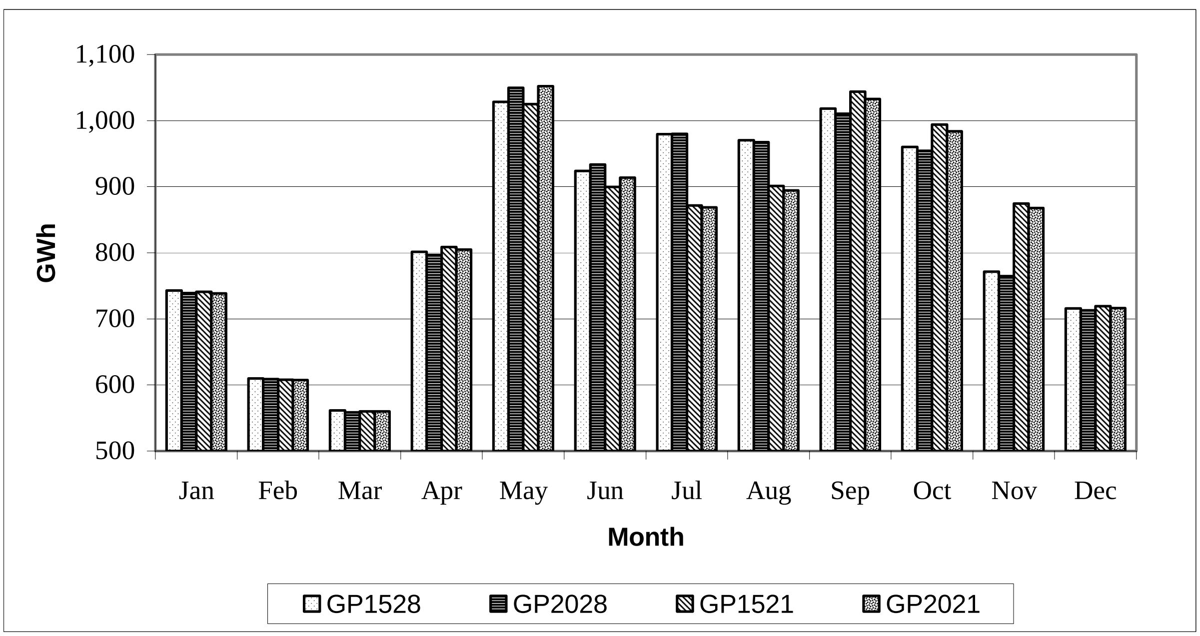

Figure 7.10-8. Monthly average hydropower energy values for GP1528, GP2028, GP1521, and GP2021.

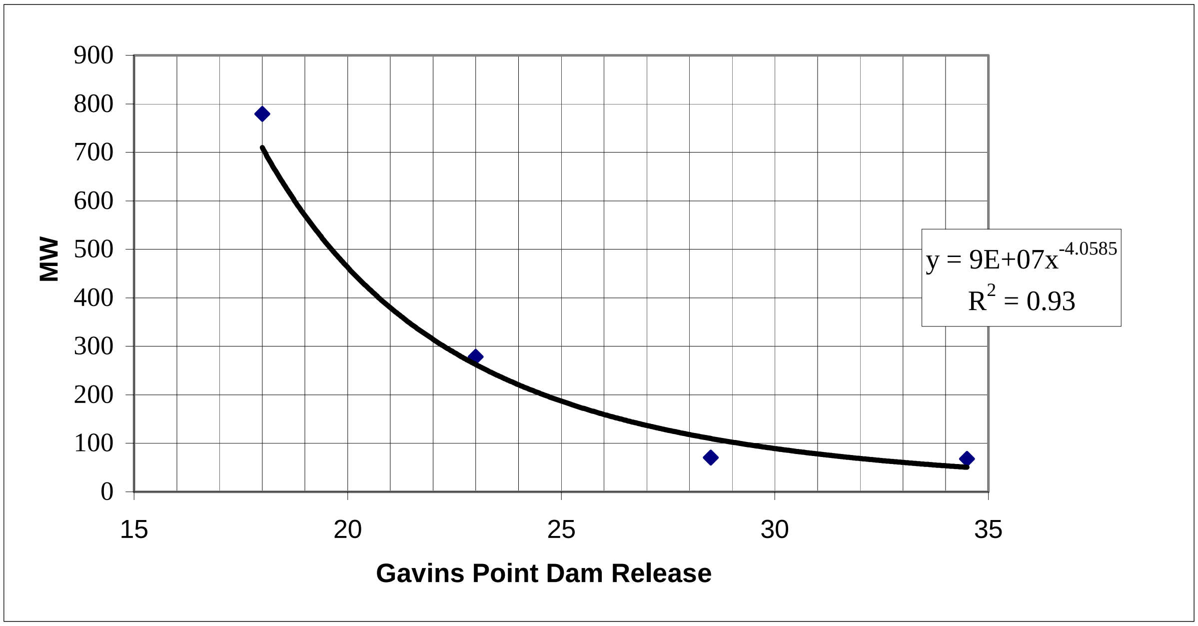

Figure 7.10-9. Missouri River thermal powerplants, capacity at risk in July.

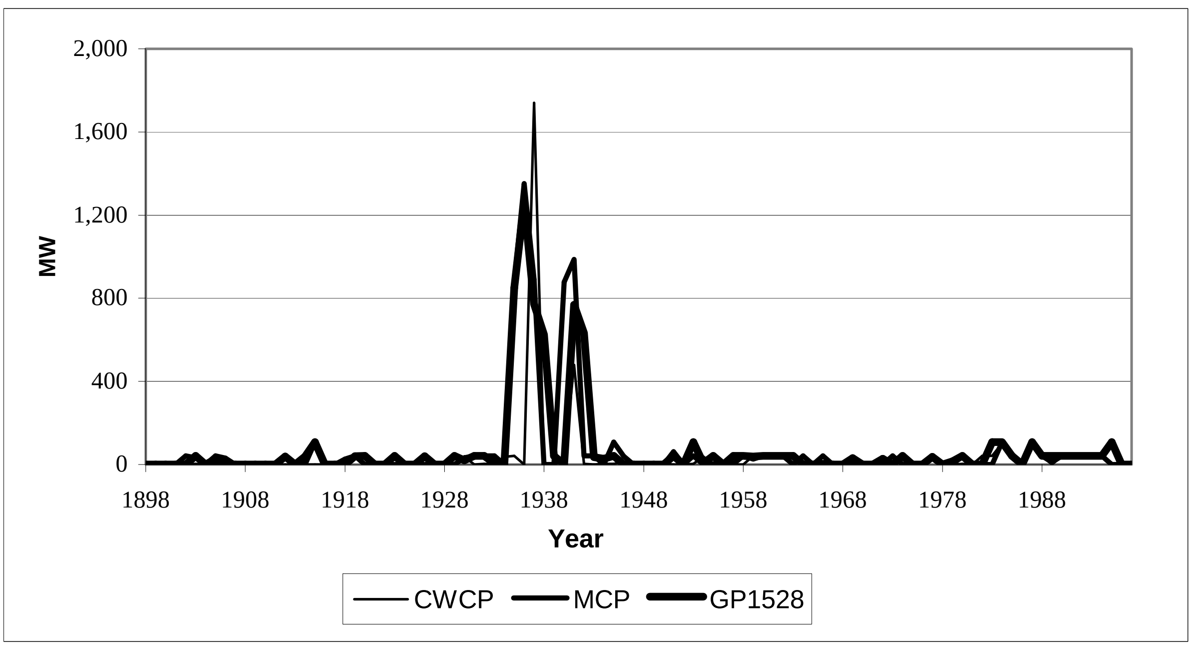

Figure 7.10-10. Potential capacity loss for CWCP, MCP, and GP1528 in July (1898 to 1997).

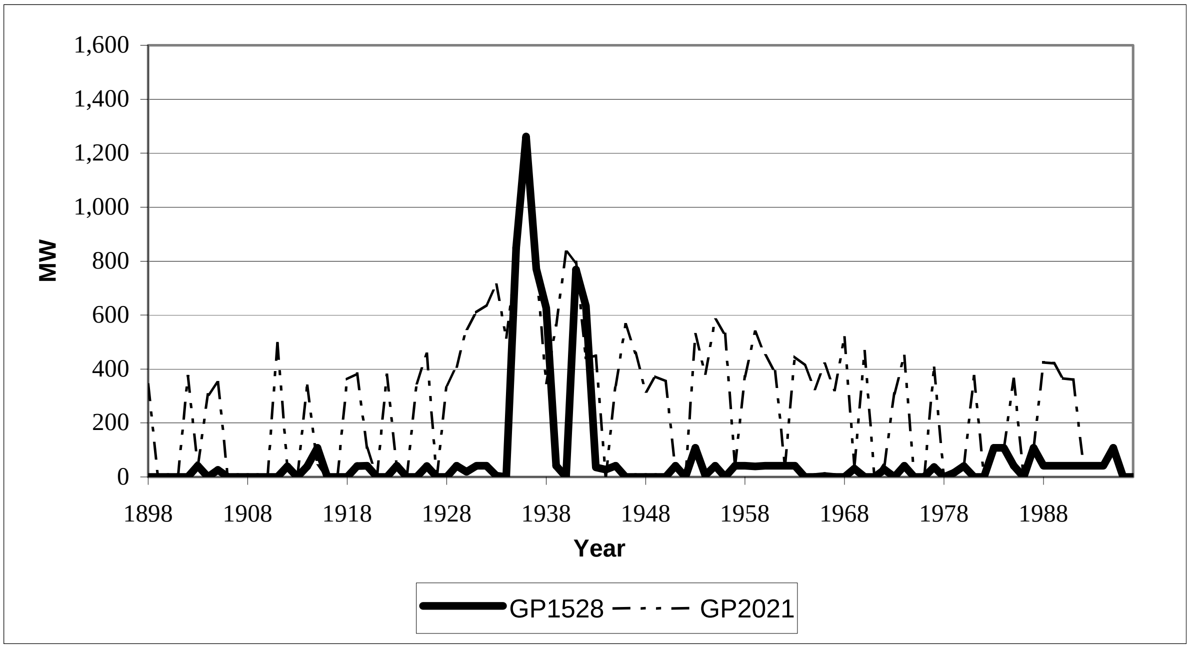

Figure 7.10-11. Potential capacity loss for GP1528 and GP2021 in July (1898 to 1997).

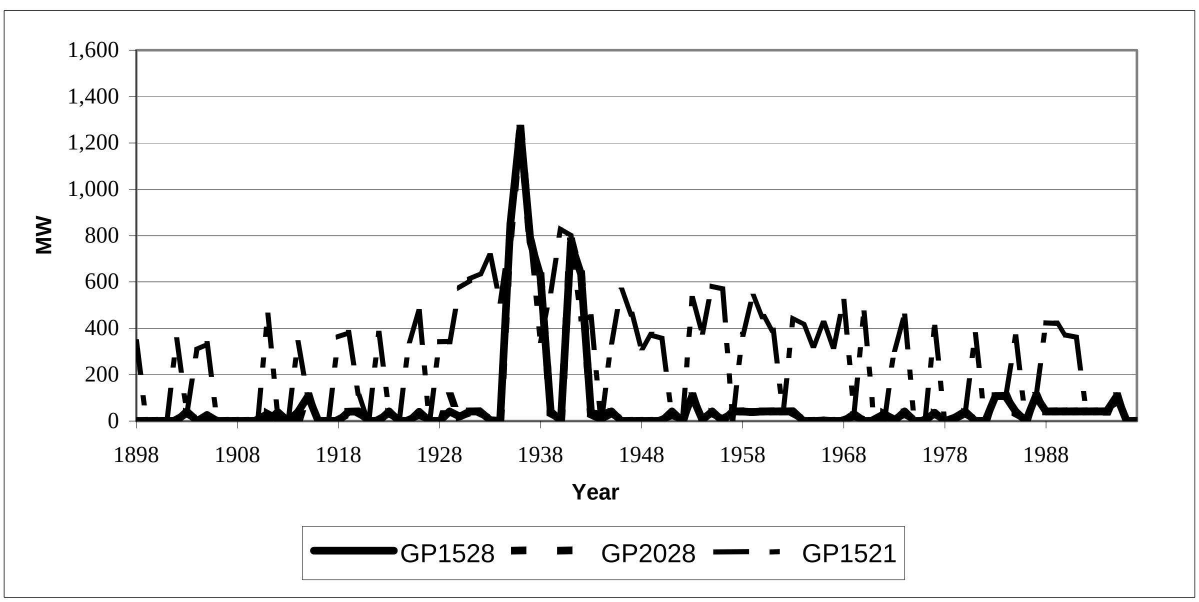

Figure 7.10-12. Potential capacity loss for GP1528, GP2028, and GP1521 in July (1898 to 1997).

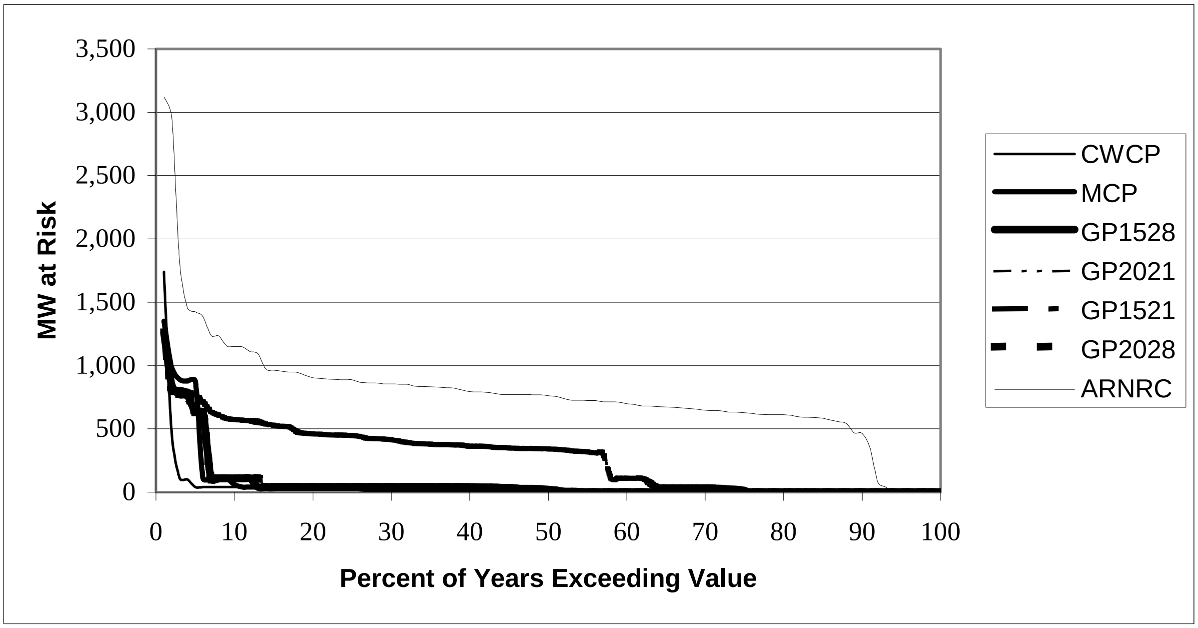

Figure 7.10-13. Potential thermal capacity at risk in July, duration plot.

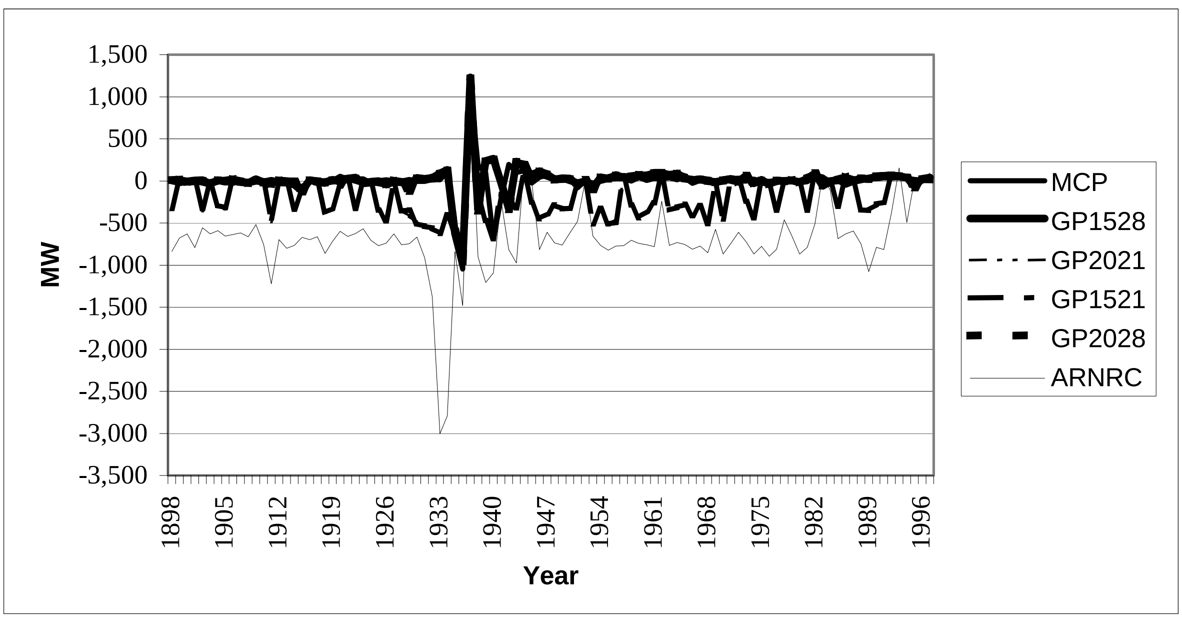

Figure 7.10-14. Total hydropower and thermal power capacity change from CWCP in July.

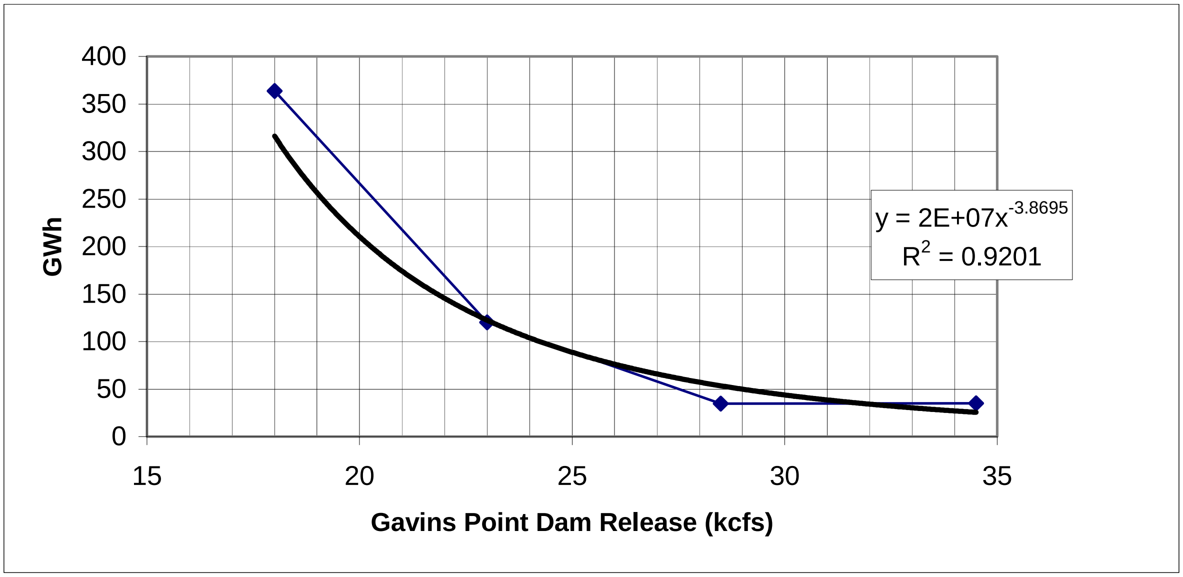

Figure 7.10-15. Missouri River thermal powerplants, energy at risk in July.

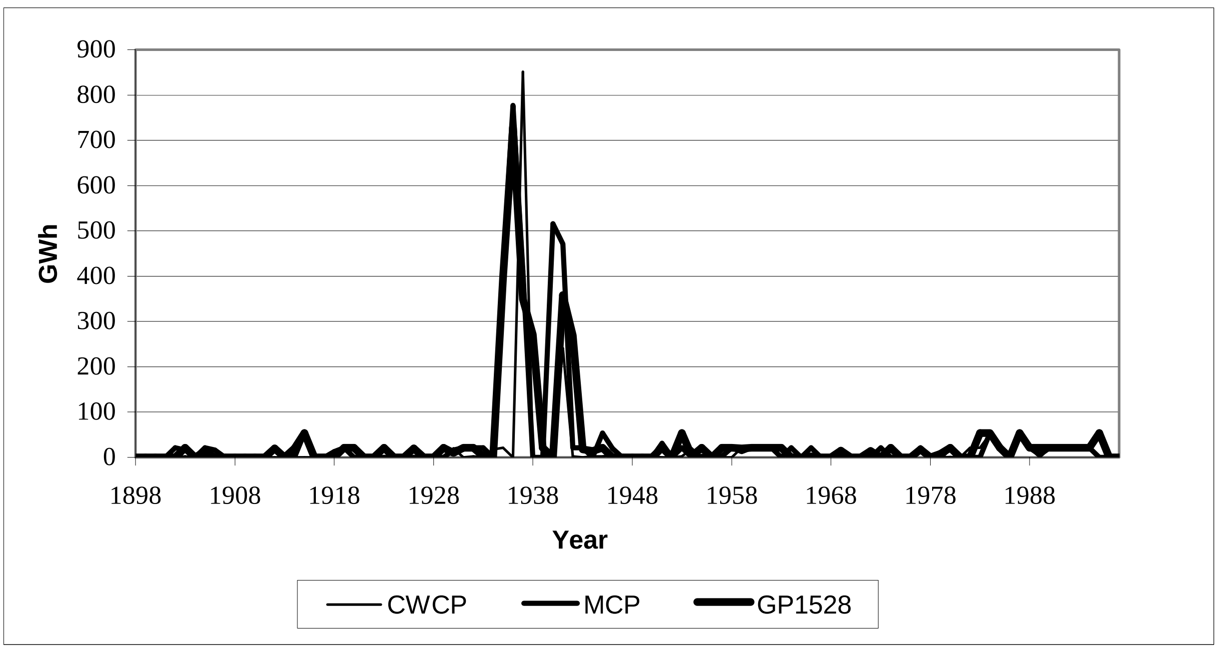

Figure 7.10-16. Potential energy loss for CWCP, MCP, and GP1528 in July (1898 to 1997).

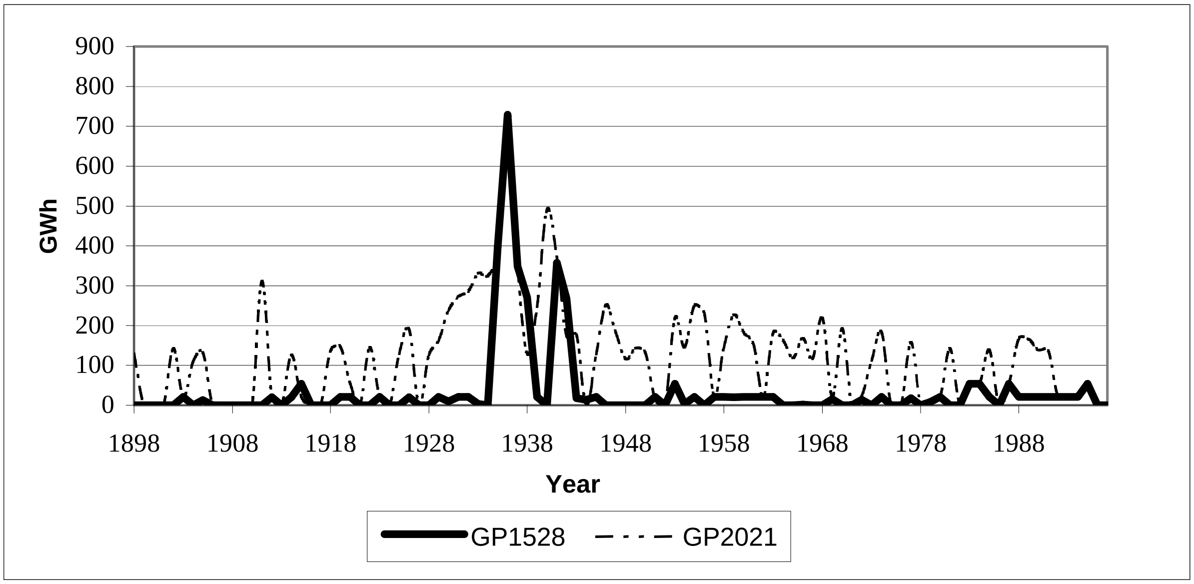

Figure 7.10-17. Potential energy loss for GP1528 and GP2021 in July (1898 to 1997).

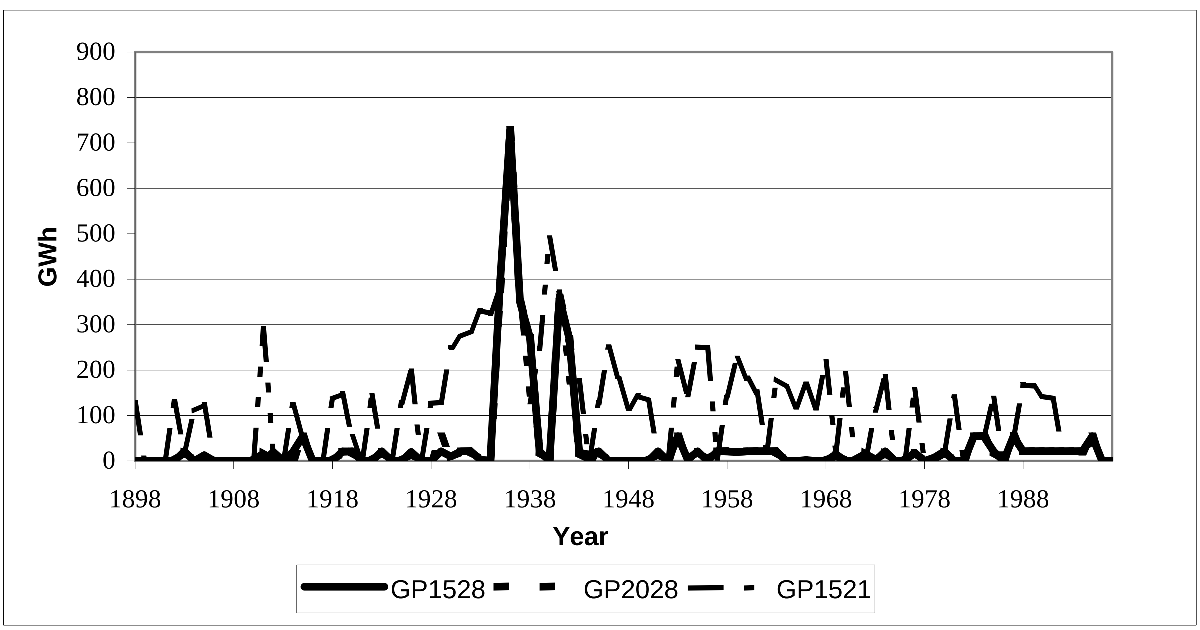

Figure 7.10-18. Potential energy loss for GP1528, GP2028, and GP1521 in July (1898 to 1997).

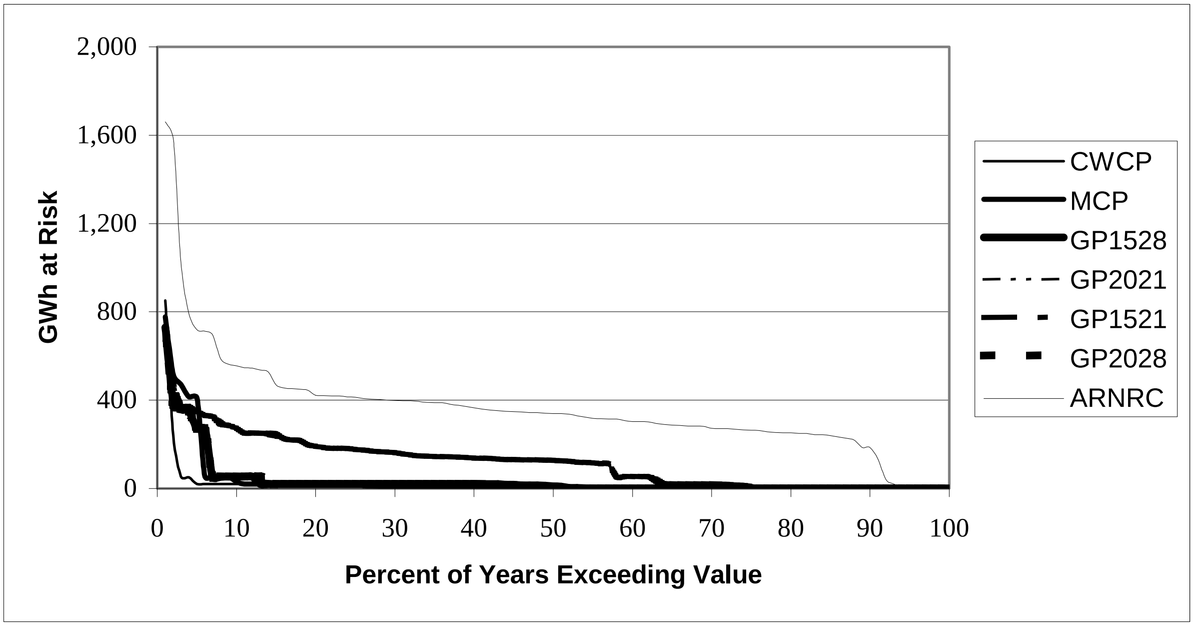

Figure 7.10-19. Thermal energy at risk in July, duration plot.

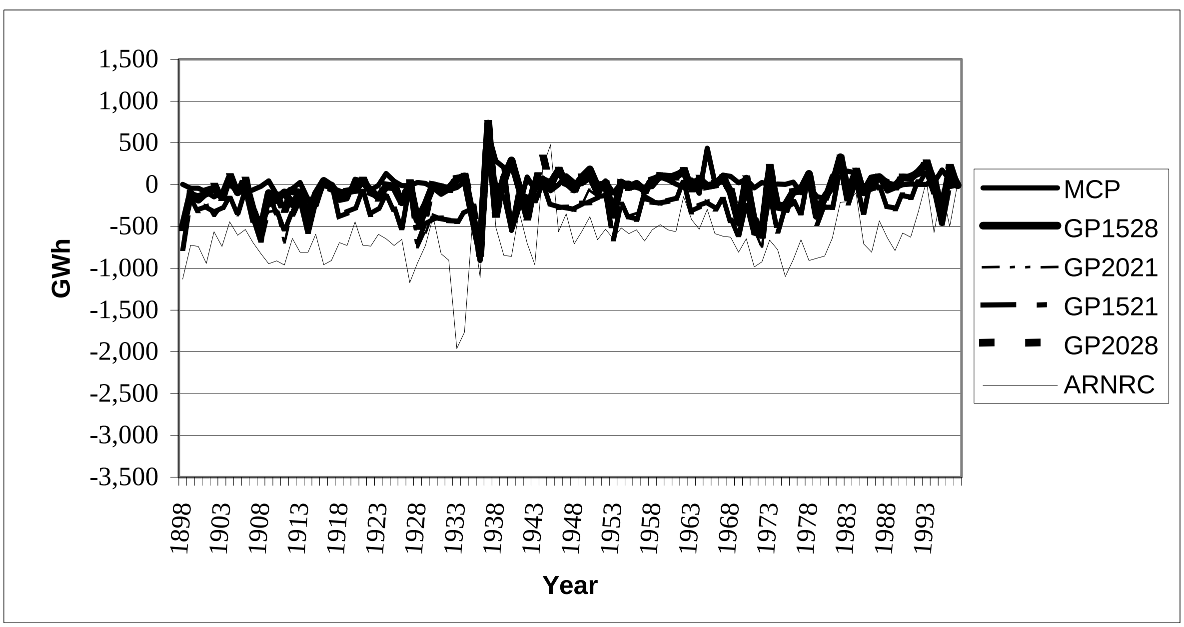

Figure 7.10-20. Total hydropower and thermal energy change in July from the CWCP.

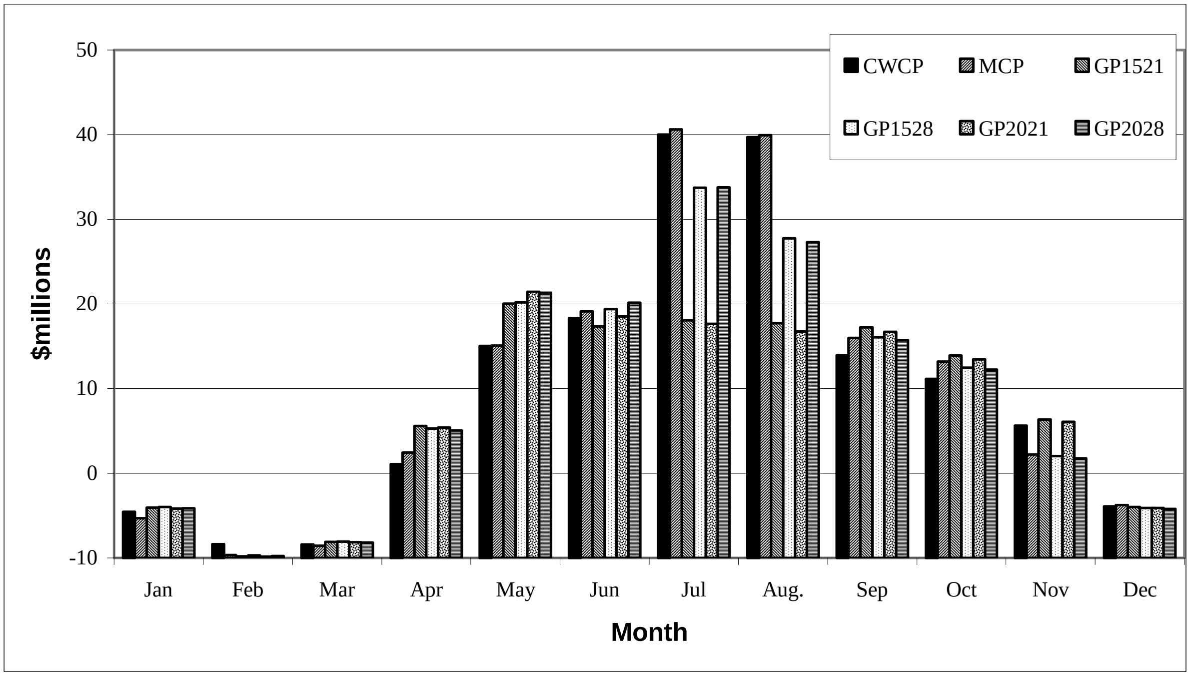

Figure 7.10-21. Net revenue: Pick-Sloan firm power marketing, 100-year monthly average at Cinergy Rates (Jan. 30, 2001).

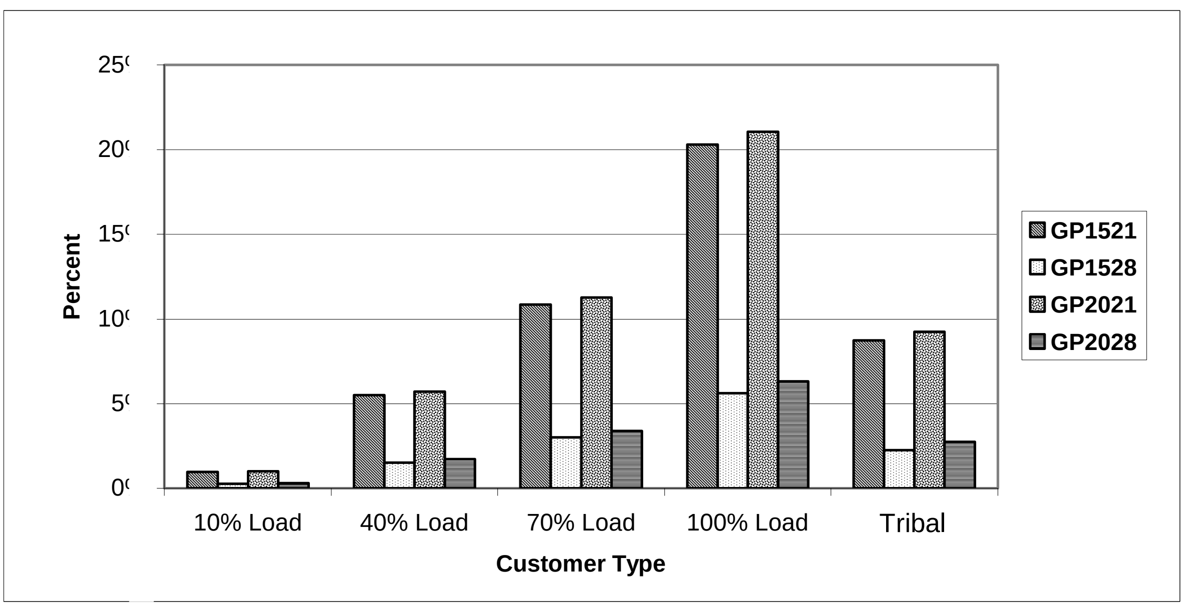

Figure 7.10-22. Percent increase in purchase power cost.