RECLAMATION

Managing Water in the West

Hydropower Resource Assessment at Existing Reclamation Facilities

March 2011

U.S. Department of the Interior
Bureau of Reclamation

Hydropower Resource Assessment at Existing Reclamation Facilities

Prepared by

United States Department of the Interior
Bureau of Reclamation
Power Resources Office

U.S. Department of the Interior
Bureau of Reclamation
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Mission Statements

The mission of the Department of the Interior is to protect and provide access to our Nation's natural and cultural heritage and honor our trust responsibilities to Indian Tribes and our commitments to island communities.

The mission of the Bureau of Reclamation is to manage, develop, and protect water and related resources in an environmentally and economically sound manner in the interest of the American public.

Disclaimer Statement

The report contains no recommendations. Rather, it identifies a set of candidate sites based on explicit criteria that are general enough to address all sites across the geographically broad scope of the report. The report contains limited analysis of environmental and other potential constraints at the sites. The report must not be construed as advocating development of one site over another, or as any other site-specific support for development. There are no warranties, express or implied, for the accuracy or completeness of any information, tool, or process in this report.

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Abbreviations and Acronyms

BLM	Bureau of Land Management
cfs	cubic feet per second
CO	Colorado
Corps	United States Army Corps of Engineers
Council	Northwest Power and Conservation Council
DOA	Department of Army
DOE	Department of Energy
DOI	Department of the Interior
DSIRE	Database of State Incentives for Renewables and Efficiency
FERC	Federal Energy Regulatory Commission
GIS	Geographic Information System
GP	Great Plains
INL	Idaho National Engineering and Environmental Laboratory
IREC	Interstate Renewable Energy Council
IRR	internal rate of return
kV	kilo voltage
kWh	kilowatt hours
LC	Lower Colorado
MOU	Memorandum of Understanding
MP	Mid-Pacific
MT	Montana
MW	megawatt
MWh	megawatt hours
NPS	National Park Service
O&M	operation and maintenance
P&Gs	Economic and Environmental Principles and Guidelines for Water and Related Land Resources Implementation Studies
PN	Pacific Northwest
Reclamation	Bureau of Reclamation
Resource Assessment	Hydropower Resource Assessment at Existing Reclamation Facilities
T-line	transmission line
UC	Upper Colorado
USFS	United States Forest Service
USFWS	United States Fish and Wildlife Service
USGS	United States Geological Survey

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Executive Summary

Recent Federal policies and legislation focus on moving the nation towards a cleaner energy economy that includes developing environmentally appropriate renewable energy projects involving solar, wind and waves, geothermal, biofuels, and hydropower. The 2010 Federal Memorandum of Understanding for Hydropower and the Energy Policy Act of 2005 direct Reclamation to evaluate development of new hydropower projects at Federally-owned facilities and upgrade or rehabilitate existing hydropower generation facilities, as a contribution to the nation's clean energy goals. State policies are also starting to encourage renewable energy development. Some states have adopted renewable portfolio standards that require electricity providers to obtain a minimum percentage of their power from renewable energy resources by a certain date.

Recognizing the current national emphasis on renewable energy and its extensive existing water infrastructure systems, Reclamation is undertaking the *Hydropower Resource Assessment at Existing Reclamation Facilities* (Resource Assessment) to assess hydropower development at existing facilities to contribute to nationwide renewable energy strategies. Reclamation identified 530 sites, including reservoir dams, diversion dams, canals, tunnels, dikes and siphons, in Reclamation's five regions, comprised of the 17 western states, for analysis in the Resource Assessment. All 530 sites were considered in the analysis, of which, 191 sites were determined to have some level of hydropower potential.

Purpose

The purpose of the Resource Assessment is to provide information on whether or not hydropower development at existing Reclamation facilities would be economically viable and possibly warrant further investigation. The assessment is mainly targeted towards municipalities and private developers that could further evaluate the potential to increase hydropower production at Reclamation sites. Developers could use the information provided in this assessment to focus more detailed analysis on sites that demonstrate a reasonable potential for being economically and financially viable. The Resource Assessment is not intended to provide feasibility level analyses for the potential sites.

Site Identification and Data Collection

Reclamation initially identified 530 potential hydropower sites in the study entitled *Potential Hydroelectric Development at Existing Federal Facilities* (May 2007), developed to comply with Section 1834 of the Energy Policy Act of 2005. The same 530 sites are reevaluated in this Resource Assessment. The first step in the Resource Assessment was collecting available flow, head water and tail water elevation data for each site. Significant efforts were made to collect hydrologic data for all 530 sites, including obtaining data from existing stream gages, facility designs, Reclamation offices' and irrigation districts' records, and field staff knowledge. Minimum data required for analysis include the state the site is located in, a continuous period of daily flow records of at least 1 year (3 years recommended), defined head water and tail water elevations, and distance to the nearest transmission or distribution line.

Data collection indicated that each of the 530 sites were in one of the following data categories. Table ES-1 summarizes how the sites were categorized.

1) Site has some level of hydropower potential – Hydrologic data was collected for the site and the Hydropower Assessment Tool indicated that some level of hydropower could be generated at the site;

2) Site does not have hydropower potential – Local area knowledge or available hydrologic data indicated that the site does not have hydropower potential because flows or net head are too low or infrequent for hydropower development;

3) Canal or tunnel site that needs further analysis – All dams and diversion dams were evaluated for hydropower potential, but further analysis is needed to determine net head and seasonal flows at some canal and tunnel sites to determine hydropower potential. Reclamation canal and tunnel sites are being addressed in a separate ongoing analysis; or

4) Site should be removed from the analysis – The site was either a duplicate to another site identified, no longer a Reclamation-owned site, had hydropower already developed or hydropower was being developed at the site.

Table ES-1 Site Summary

	No. of Sites
Total Sites Identified	530
Sites with No Hydropower Potential	218
Total Sites with Hydropower Potential	191
Canal or Tunnel Sites (Separate Analysis In Progress)	52
Sites Removed from Analysis[1]	69
1 – Sites were removed from the analysis for various reasons, including duplicate to another site identified, no longer a Reclamation-owned site, hydropower already developed or being developed at the site.	

Because data varied substantially across all sites, Reclamation categorized data collected as high, medium, or low confidence based on data source, availability and consistency of data. High confidence data was assigned to sites with complete daily flow data, generally from stream gages, and recorded head and tail water elevations. Of the total 530 sites, 117 sites had high confidence data, 69 sites had medium confidence data, and 275 sites had low confidence data (note 69 sites were removed from the analysis, as described above, and not assigned confidence ratings). Low confidence sites include canals and tunnels that require further analysis. Results from low confidence data, though useful to analyze a site's potential at this preliminary level of investigation, should not be used for more detailed or feasibility level analyses. Efforts to collect more reliable data (i.e. higher confidence) should be made in subsequent analyses.

Hydropower Assessment Tool

Reclamation developed the Hydropower Assessment Tool to estimate potential energy generation and economic net benefits at the identified Reclamation facilities. The tool is an Excel spreadsheet model with embedded macro functions. Using the data inputs described above, the tool computes power generation, cost estimates, and economic benefits. The distance to the nearest transmission or distribution line allows for calculation of a cost of transmission, but does not necessarily indicate that an interconnection can be made with the transmission line. Further site specific analysis for transmission would be needed if a site is pursued.

To estimate power potential, the tool develops flow and net head exceedance curves and sets design flow and design net head at a 30 percent exceedance level to calculate installed capacity. The tool then assigns a Pelton, Kaplan, Francis, or low-head (modified Francis) turbine based on the installed head and flow capacity and general turbine operating ranges. Non-traditional turbine technologies for very low heads or flows were not considered. Monthly and annual energy generation is calculated based on the selected turbine, turbine efficiency, and daily hydrologic data.

For the economic calculations, cost curves are embedded in the model to estimate total construction, development (includes construction, licensing and mitigation), and annual operation and maintenance costs. Economic benefits from power generation are based on current and forecasted energy prices. The benefits analysis also incorporates green incentives available from existing Federal and state programs. After estimating annual and total benefits and costs, the tool calculates a benefit cost ratio and internal rate of return (IRR) for each site as an indicator of economic feasibility. The benefit cost ratio and IRR are based on a 50 year period of analysis using the Fiscal Year 2010 Federal discount rate of 4.375 percent. The interest rate can be easily modified in the Hydropower Assessment Tool.

The Hydropower Assessment Tool is intended for use as a preliminary evaluation of potential hydropower sites and is valuable for informational purposes to support further evaluation of a potential site. The tool allows for the user to change assumptions, such as turbine selection, flow exceedance, or costs, if additional site specific information is available. The tool does not substitute the need for a feasibility study.

Site Evaluation and Results

Table ES-2 summarizes economic results, indicated by number of sites within specified benefit cost ratio ranges, and total power capacity and energy production for the 191 sites with hydropower potential. Sites with lower benefit cost ratios would be less economic to develop. In general, sites with a higher benefit cost ratio had higher installed capacities (measured in megawatts [MW]) and more annual energy production potential (measured in megawatt hours [MWh]).

Table ES-2 Sites with Hydropower Potential within Benefit Cost Ratio (with Green Incentives) Ranges

Benefit Cost Ratio Range	No. of Sites	Total Installed Capacity (MW)	Total Annual Production (MWh)
0 to 0.25	62	10.4	35,041
0.25 to 0.5	35	15.7	57,955
0.5 to 0.75	24	17	67,375
0.75 to 1.0	27	40.5	147,871
1.0 to 2.0	36	79.9	375,353
Greater than or equal to 2.0	7	104.8	484,653
Total	191	268.3	1,168,248

Table ES-3 (at the end of this summary) shows 70 sites with benefit cost ratios (with green incentives) greater than 0.75. Although the standard for economic viability is a benefit cost ratio of greater than 1.0, sites with benefit cost ratios of 0.75 and higher were ranked given the preliminary nature of the analysis. The results show a potential of approximately 225MW of installed capacity and 1.0 million MWh of energy could be produced annually at existing Reclamation facilities if all sites with a benefit cost ratio greater than 0.75 are summed. Individual sites range from a 125 kW installed capacity to about 26 MW installed capacity.

Because of the uncertainty in green energy incentive prices, benefit cost ratios with and without green incentives are calculated. Of the 17 western states, state level green incentive programs were identified in Arizona, California, and Washington. Federal green incentives are also available. The benefits analysis includes available state and Federal green incentives to calculate economic benefits, and the resulting benefit cost ratios.

The Resource Assessment considers potential regulatory constraints related to water supply, fish and wildlife considerations, and effects on Native Americans, water quality, and recreation. Constraints can either block development completely or add significant costs for mitigation, permitting, or further investigation of the site. Table ES-3 identifies if a potential constraint was applicable to a site. Mitigation costs were added to the total development costs of the site for any applicable constraints. For this preliminary analysis, constraints and mitigation costs are identified and added primarily to indicate that a potential constraint exists and should be further investigated if the site is pursued for development. Additional constraints could be present at any of the sites identified in this analysis. Depending on specific environmental and regulatory issues at a particular site, costs could differ significantly from those used in the analysis or development may be prohibited. As mentioned above, costs in the Hydropower Assessment Tool can be easily modified and rerun to estimate costs.

The last column in Table ES-3 identifies the confidence level in the hydrologic data collected for the site. It is important to note that results for sites with low confidence data may not be as reliable as sites with higher confidence data. There are ten sites with low confidence data in the table, including the third and fourth ranked sites.

The site evaluation results are based on design flow and design head set at 30 percent exceedance level. Different exceedance percentages can be selected for sizing the hydropower plant, which could increase or decrease the plant capacity. Changing the plant capacity would effectively change the amount of energy the plant can generate and the costs to develop, operate, and maintain the plant. Reclamation performed a sensitivity analysis on varying the exceedance level for sites with benefit cost ratios close to or greater than 1.0 and sites with seasonal flows, which typically had a benefit cost ratio much lower than 1.0. For most sites that would be economical for hydropower development at the 30 percent exceedance level, the benefit cost ratio decreased at the 20 percent exceedance level, indicating that the costs of adding capacity were rising faster than the revenues (energy production) of the added capacity. For sites with seasonal flows, designing the plant at a lower exceedance level would slightly increase the benefit cost ratio relative to the 30 percent exceedance design because of increased revenues from more energy production, but the plant would continue to be uneconomical to develop (the benefit cost ratio remains less than 1.0; and, for most seasonal sites, less than 0.75).

The Resource Assessment consistently used a 30 percent exceedance, which resulted in more sites having higher benefit cost ratios. Using a 20 percent exceedance could have resulted in higher installed capacities and more energy generation, but the number of economically feasible projects, based on the benefit cost ratios, would decrease. During feasibility analysis of a potential site, the developer should analyze different plant sizes to evaluate the most economic plant size.

Conclusions

The Resource Assessment concludes that substantial hydropower potential exists at Reclamation sites. Some site analyses are based on over 20 years of hydrologic data that indicate a high likelihood of generation capability. Table ES-3 presents 70 of the 530 sites that could be economically feasible to develop based on available data and study assumptions; of which 36 sites used high confidence data for the analysis.

The results of the Resource Assessment will be of value to public municipalities and private developers seeking to add power to their load area or for investment purposes. It provides a valuable database in which potential sites can be viewed to help determine whether or not to proceed with a feasibility study. For many of these Reclamation sites, development would proceed under a Lease of Power Privilege Agreement as opposed to a Federal Energy Regulatory Commission (FERC) license. A lease of power privilege (lease) is a contractual right of up to 40 years given to a non-Federal entity to use a Reclamation facility for electric power generation. It is an alternative to federal power development where Reclamation has the authority to develop power on a federal project. The selection of a Lessee is done through a public process to ensure fair and open competition though preference is given through the Reclamation Project Act of 1939 to municipalities, other public corporations or agencies, and also to cooperatives and other nonprofit organizations financed through the Rural Electrification Act of 1936. In order to proceed under a lease, the project must have adequate design information, satisfactory environmental analysis/impacts, and cannot be detrimental to the existing project. Some sites in the analysis are already being pursued by public or private entities. Reclamation does not intend to interfere with existing plans for site development. Reclamation selected sites for this analysis that do not have existing hydropower facilities; although some may have FERC preliminary permits issued. The reports notes sites that have a FERC preliminary permit issued or are being pursued by other means.

The results could also be used to support an incentive program for hydropower as a renewable energy source. A large number of projects fall in the gray area of being economically feasible. The Resource Assessment shows that green incentives for hydropower development are largely not available in individual states, but, when they are, can contribute substantially to the economic viability of a project. For example, state-sponsored programs in Arizona and California can, in some instances, double the benefit cost ratio for a site. Washington also has a green incentive program that can contribute to the economic viability of hydropower development. For the 14 remaining states, renewable energy incentives for hydropower are not available at the state level. A Federal incentive program exists, but does not contribute significantly to economic benefits. Further, if sites are developed by Reclamation, they would not be eligible for the Federal incentive, but could qualify for state-sponsored incentives. This analysis could be useful in promoting hydropower at existing facilities as a low cost and low impact renewable energy source and determining incentives that would be necessary to stimulate investment.

The Hydropower Assessment Tool is also a valuable product of this analysis. The tool provides a first step in identifying if sites should be further analyzed or if there is clearly no hydropower potential at the site. The tool requires relatively simple inputs of daily flows, head water elevations, and tail water elevation and the results are valid information on potential hydropower production and economic viability. Any site with available flow, head and tail water elevation data can be analyzed with the tool. It is a time-saving, effective tool to determine if a site should be further pursued for hydropower development.

Table ES-3 Sites with Benefit Cost Ratios (with Green Incentives) Greater than 0.75

Site ID	Site Name	State	Project	Installed Capacity (kW)	Annual Production (MWh)	Benefit Cost Ratio With Green	Benefit Cost Ratio Without Green	Constraint (see legend)	Data Confidence
LC-6	Bartlett Dam	Arizona	Salt River Project	7,529	36,880	3.5	2.25	F&W; REC	Medium
GP-146	Yellowtail Afterbay Dam	Montana	PSMBP - Yellowtail	9,203	68,261	3.05	2.86	-	Medium
UC-141	Sixth Water Flow Control	Utah	Central Utah Project - Bonneville Unit	25,800	114,420	3.02	2.84	F&W; REC	Medium
LC-20	Horseshoe Dam	Arizona	Salt River Project	13,857	59,854	2.98	1.93	F&W; REC	Low
GP-125	Twin Buttes Dam	Texas	San Angelo	23,124	97,457	2.61	2.46	-	Low
UC-185	Upper Diamond Fork Flow Control Structure	Utah	Central Utah Project - Bonneville Unit	12,214	52,161	2.36	2.22	F&W; REC	Medium
GP-99	Pueblo Dam	Colorado	Fryingpan-Arkansas	13,027	55,620	2.34	2.2	F&W	High
MP-30	Prosser Creek Dam	California	Washoe	872	3,819	1.98	1.06	-	High
PN-6	Arthur R. Bowman Dam	Oregon	Crooked River	3,293	18,282	1.9	1.79	REC	High
UC-89	M&D Canal-Shavano Falls	Colorado	Uncompahgre	2,862	15,419	1.88	1.77	-	Low
GP-56	Huntley Diversion Dam	Montana	Huntley	2,426	17,430	1.86	1.74	-	Medium
MP-2	Boca Dam	California	Truckee Storage	1,184	4,370	1.68	0.89	REC; H&A	High
PN-31	Easton Diversion Dam	Washington	Yakima	1,057	7,400	1.68	1.58	-	High
UC-159	Spanish Fork Flow Control Structure	Utah	Central Utah Project - Bonneville Unit	8,114	22,920	1.66	1.57	F&W	Medium
LC-21	Imperial Dam	Arizona-California	Boulder Canyon Project	1,079	5,325	1.61	1.05	F&W	Low
GP-46	Gray Reef Dam	Wyoming	PSMBP - Glendo	2,067	13,059	1.58	1.49	FP	High
MP-8	Casitas Dam	California	Ventura River	1,042	3,280	1.57	0.84	-	High
UC-49	Grand Valley Diversion Dam	Colorado	Grand Valley	1,979	14,246	1.55	1.45	F&W; REC; H&A	Medium
UC-52	Gunnison Tunnel	Colorado	Uncompahgre	3,830	19,057	1.55	1.45	-	Medium
GP-23	Clark Canyon Dam	Montana	PSMBP - East Bench	3,078	13,689	1.52	1.42	WQ	High
UC-19	Caballo Dam	New Mexico	Rio Grande	3,260	15,095	1.45	1.36	F&W	Low

Table ES-3 Sites with Benefit Cost Ratios (with Green Incentives) Greater than 0.75

Site ID	Site Name	State	Project	Installed Capacity (kW)	Annual Production (MWh)	Benefit Cost Ratio With Green	Benefit Cost Ratio Without Green	Constraint (see legend)	Data Confidence
UC-147	South Canal, Sta. 181+10, "Site #4"	Colorado	Uncompahgre	3,046	15,536	1.44	1.35	-	Medium
PN-95	Sunnyside Dam	Washington	Yakima	1,362	10,182	1.43	1.35	H&A	Medium
UC-144	Soldier Creek Dam	Utah	Central Utah Project - Bonneville Unit	444	2,909	1.39	1.31	F&W	High
GP-52	Helena Valley Pumping Plant	Montana	PSMBP - Helena Valley	2,626	9,608	1.38	1.29	-	High
UC-131	Ridgway Dam	Colorado	Dallas Creek	3,366	14,040	1.35	1.27	F&W	High
GP-41	Gibson Dam	Montana	Sun River	8,521	30,774	1.32	1.23	-	High
UC-146	South Canal, Sta 19+ 10 "Site #1"	Colorado	Uncompahgre	2,465	12,576	1.32	1.24	-	Medium
UC-51	Gunnison Diversion Dam	Colorado	Uncompahgre	1,435	9,220	1.28	1.2	F&W	Medium
PN-88	Scootney Wasteway	Washington	Columbia Basin	2,276	11,238	1.26	1.18	-	Low
UC-150	South Canal, Sta.106+65, "Site #3"	Colorado	Uncompahgre	2,224	11,343	1.26	1.18	-	Medium
GP-126	Twin Lakes Dam (USBR)	Colorado	Fryingpan-Arkansas	981	5,648	1.24	1.17	F&W	High
GP-95	Pathfinder Dam	Wyoming	North Platte	743	5,508	1.23	1.16	REC; FP	High
UC-162	Starvation Dam	Utah	Central Utah Project - Bonneville Unit	3,043	13,168	1.23	1.15	F&W	High
LC-15	Gila Gravity Main Canal Headworks	Arizona	Gila	223	1,548	1.17	0.75	-	Medium
GP-43	Granby Dam	Colorado	Colorado-Big Thompson	484	2,854	1.16	1.09	F&W	High
MP-32	Putah Diversion Dam	California	Solano	363	1,924	1.16	0.62	F&W	Medium
UC-179	Taylor Park Dam	Colorado	Uncompahgre	2,543	12,488	1.12	1.05	F&W	High
GP-136	Willwood Diversion Dam	Wyoming	Shoshone	1,062	6,337	1.1	1.03	FP	High
GP-93	Pactola Dam	South Dakota	PSMBP - Rapid Valley	596	2,725	1.07	1.01	REC	High
UC-57	Heron Dam	New Mexico	San Juan-Chama	2,701	8,874	1.06	1	F&W	Medium
UC-154	Southside Canal, Sta 171+ 90 thru 200+ 67 (2 canal	Colorado	Collbran	2,026	6,557	1.05	0.99	-	Low

Table ES-3 Sites with Benefit Cost Ratios (with Green Incentives) Greater than 0.75

Site ID	Site Name	State	Project	Installed Capacity (kW)	Annual Production (MWh)	Benefit Cost Ratio With Green	Benefit Cost Ratio Without Green	Constraint (see legend)	Data Confidence
	drops)								
UC-148	South Canal, Sta. 472+00, "Site #5"	Colorado	Uncompahgre	1,354	6,905	1.05	0.98	-	Medium
PN-34	Emigrant Dam	Oregon	Rogue River Basin	733	2,619	0.99	0.93	-	High
UC-177	Syar Tunnel	Utah	Central Utah Project - Bonneville Unit	1,762	7,982	0.99	0.93	F&W; REC	Medium
PN-104	Wickiup Dam	Oregon	Deschutes	3,950	15,650	0.98	0.92	REC	High
UC-174	Sumner Dam	New Mexico	Carlsbad	822	4,300	0.98	0.92	F&W	Medium
GP-34	East Portal Diversion Dam	Colorado	Colorado-Big Thompson	283	1,799	0.96	0.9	-	High
PN-12	Cle Elum Dam	Washington	Yakima	7,249	14,911	0.94	0.89	-	High
PN-80	Ririe Dam	Idaho	Ririe River	993	3,778	0.94	0.89	-	High
UC-155	Southside Canal, Sta 349+ 05 thru 375+ 42 (3 canal drops)	Colorado	Collbran	1,651	5,344	0.93	0.88	-	Low
PN-87	Scoggins Dam	Oregon	Tualatin	955	3,683	0.92	0.86	-	High
UC-132	Rifle Gap Dam	Colorado	Silt	341	1,740	0.92	0.86	F&W	High
GP-5	Angostura Dam	South Dakota	PSMBP Cheyenne Diversion	947	3,218	0.9	0.84	-	Low
MP-17	John Franchi Dam	California	Central Valley	469	1,863	0.9	0.48	F&W	Low
GP-39	Fresno Dam	Montana	Milk River	1,661	6,268	0.88	0.82	-	High
GP-129	Virginia Smith Dam	Nebraska	PSMBP - North Loup	1,607	9,799	0.88	0.82	-	Low
PN-59	McKay Dam	Oregon	Umatilla	1,362	4,344	0.88	0.83	-	High
GP-128	Vandalia Diversion Dam	Montana	Mild River	326	1,907	0.87	0.82	-	Medium
PN-49	Keechelus Dam	Washington	Yakima	2,394	6,746	0.87	0.81	REC	High
PN-44	Haystack	Oregon	Deschutes	805	3,738	0.85	0.8	-	High
UC-72	Joes Valley Dam	Utah	Emery County	1,624	6,596	0.85	0.8	F&W; REC	High
UC-145	South Canal Tunnels	Colorado	Uncompahgre	884	4,497	0.84	0.79	-	Medium

Table ES-3 Sites with Benefit Cost Ratios (with Green Incentives) Greater than 0.75

Site ID	Site Name	State	Project	Installed Capacity (kW)	Annual Production (MWh)	Benefit Cost Ratio With Green	Benefit Cost Ratio Without Green	Constraint (see legend)	Data Confidence
MP-24	Marble Bluff Dam	Nevada	Washoe	1,153	5,624	0.83	0.78	H&A	High
GP-92	Olympus Dam	Colorado	Colorado-Big Thompson	284	1,549	0.82	0.77	-	High
GP-117	St. Mary Canal - Drop 4	Montana	Milk River	2,569	8,919	0.82	0.77	H&A	High
GP-42	Glen Elder Dam	Montana	Sun River	1,008	3,713	0.81	0.76	-	High
UC-117	Paonia Dam	Colorado	Paonia	1,582	5,821	0.79	0.74	F&W	Medium
PN-48	Kachess Dam	Washington	Yakima	1,227	3,877	0.77	0.72	-	Medium
GP-118	St. Mary Canal - Drop 5	Montana	Milk River	1,901	7,586	0.75	0.70	H&A	High

Constraint Legend:

Fish and Wildlife - F&W; Recreation – REC; Historical and Archaeological - H&A ; Water Quality – WQ; Fish Passage - FP

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Chapter 1 Introduction

The Bureau of Reclamation (Reclamation) is the largest water supplier in the United States, owning and operating 188 water projects across the western states with dams, reservoirs, canals, diversion dams, pipelines, and other distribution infrastructure. Reclamation also produces hydropower through 58 power plants and 194 generating units in operation at Reclamation-owned facilities. Reclamation is the second largest producer of hydropower in the U.S., behind the U.S. Army Corps of Engineers (Corps); however, many opportunities remain at existing Reclamation facilities to produce additional hydropower. Recognizing the current national emphasis on renewable energy and its extensive existing water infrastructure, Reclamation is undertaking the *Hydropower Resource Assessment at Existing Reclamation Facilities* (Resource Assessment) to evaluate hydropower development potential to contribute to nationwide renewable energy strategies.

1.1 Background

Historically, the primary purposes of Reclamation projects have been agricultural irrigation and provision of water for municipal and industrial use. Because of water infrastructure facilities, hydropower has been prominent in Reclamation's projects. According to the Federal *Economic and Environmental Principles and Guidelines for Water and Related Land Resources Implementation Studies* (P&Gs), power can be included in multipurpose Federal Reclamation projects when it is in the national interest, economically justified, and feasible by engineering and environmental standards. In past studies, hydropower has often shown clear economic benefits and financial capability of repaying its share of the Federal investment. Reclamation currently generates over 40 billion kilowatt hours (kWh) of hydroelectric energy at existing facilities.

Recent Federal policies and legislation focus on moving the nation towards a cleaner energy economy that includes developing environmentally appropriate renewable energy projects involving solar, wind and waves, geothermal, biofuels, and hydropower. The 2010 Federal Memorandum of Understanding (MOU) for Hydropower and the Energy Policy Act of 2005, described below, direct Reclamation to evaluate development of new hydropower projects at Federally-owned facilities and upgrade or rehabilitate existing hydropower generation facilities, as a contribution to the nation's clean energy goals.

State policies are also starting to encourage renewable energy development. Many states are implementing financial incentives programs targeted to developers of renewable energy; however, hydropower is not always eligible for financial incentives. Most programs focus on solar, wind, and geothermal power sources. Incentive programs vary by state, but provide a financial mechanism to make hydropower development more economical.

1.1.1 Federal Memorandum of Understanding for Hydropower

On March 24, 2010, an MOU for Hydropower was signed between the Department of the Interior (DOI), the Department of Energy (DOE), and the Department of Army (DOA) that represents a new approach to hydropower development – a strategy that can increase the production of clean, renewable power while avoiding or reducing environmental impacts and enhancing the viability of ecosystems. By signing the MOU, the Federal agencies agree to focus on increasing energy generation at Federally-owned facilities and explore opportunities for new development of low-impact hydropower. The MOU aims to increase communication among Federal agencies and strengthen the long-term relationship among them to prioritize the generation and development of sustainable hydropower.

Objectives of the MOU include:

- Identify specific Federal facilities that are well-suited as sites for sustainable hydropower;
- Upgrade facilities and demonstrate new technologies at existing hydropower locations;
- Coordinate research and development on advanced hydropower technologies;
- Increase hydropower generation through low-impact and environmentally sustainable approaches;
- Integrate policies at the Federal level; and
- Collaborate to identify total incremental hydropower resources at federal facilities.

1.1.2 Section 1834 of the Energy Policy Act of 2005

Section 1834 of the Energy Policy Act of 2005 (Section 1834) required the DOI, DOA, and DOE to "jointly conduct a study assessing the potential for increasing electric power production at federally owned or operated water regulation, storage, and conveyance facilities." The agencies completed the study entitled "Potential Hydroelectric Development at Existing Federal Facilities" (1834 Study) in May 2007. The 1834 Study inventoried sites that have potential, with or without modification, of producing additional hydroelectric power for public consumption. The initial sites for the DOI included 530 sites at Reclamation facilities and 123 sites at Bureau of Indian Affairs facilities. The 1834 Study also analyzed 218 sites at Corps facilities. The Corps represented the DOA in the study.

The analysis in the 1834 Study applied three screenings to identify sites with the most hydropower development potential. Sites were screened out if analysis indicated that sites 1) produced less than 1 megawatt (MW) capacity or had less than 10 feet of hydraulic head; 2) conflicted with water and land use legislations; and 3) had a calculated benefit cost ratio less than 1.0. In the 1834 Study, 80 of the 530 Reclamation sites made it to the third screening step and had a power production and benefit-cost analysis completed. Of the 80 sites, 6 sites had a benefit cost ratio greater than 1.0. The sites were Prosser Creek Dam, Rye Patch Dam, and Bradbury Dam in the Mid-Pacific Region, Helena Valley Pumping Plant and Yellowtail Afterbay Dam in the Great Plains Region, and the Sixth Water Flow Control Structure in the Upper Colorado Region.

In summary, the 1834 Study provided an indication of remaining potential for hydropower development on Federal facilities. With further investigation, these sites may be viable to produce hydropower in the future.

1.1.3 Renewable Energy Incentive Programs

Many state governments have reported goals of increasing the percentage of renewable energy in the state's electricity portfolio. To help meet this goal, states are implementing financial incentive programs to encourage development and use of renewable energy. Incentives are available in various forms. Some states offer performance-based incentives that generally include a utility providing cash payment to a renewable energy developer based on the amount of kWh of renewable energy generated. Most state programs are installation-based meaning developers receive a one-time payment, rebate, or tax credit for installing a renewable energy facility. Although most states have implemented renewable energy programs, the eligibility of hydropower to receive financial renewable energy incentives, in particular, is very limited.

The Federal government also offers renewable energy tax incentives. The primary incentives available for renewable energy on a federal basis are the Production Tax Credit, a performance-based credit, or Investment Tax Credit, an installation-based credit. Federal incentives apply to hydropower.

1.2 Purpose and Objectives

Due to increased Federal and state renewable energy interests, Reclamation is reevaluating potential hydropower development at Reclamation-owned facilities. Numerous sites analyzed in the 1834 Study were either removed by the various screening processes or were not found to have net benefits but are actively being developed by private entities. Some sites have been developed, including Jordanelle Dam in Utah, Pineview Dam in Utah, Arrowrock Dam in Idaho, Quincy Chute in Washington, and others. Increased power value forecasts and renewable energy incentives could be enticing private entities to pursue hydropower projects. As a result, the Commissioner of Reclamation has directed the Power Resources Office to update and expand the scope and economic analysis of the original 1834 Study.

The *Hydropower Resource Assessment at Existing Reclamation Facilities* has the following study objectives:

- Assess the potential for developing new hydropower capacity and generation at existing Reclamation facilities.
- Determine the economic viability of hydropower production at existing Reclamation facilities.
- Document economically viable opportunities for future hydroelectric power development.

The assessment is mainly targeted towards providing preliminary information for municipalities and private developers that could further evaluate the potential to increase hydropower production at Reclamation sites. Developers could use the information provided in this assessment to focus more detailed analysis on sites that demonstrate a reasonable potential for being economically and financially viable.

1.3 Resource Assessment Overview

The 530 Reclamation-owned sites identified in the 1834 Study are used as the starting point for the Resource Assessment. The sites are spread throughout Reclamation's five regions (Great Plains, Lower Colorado, Mid-Pacific, Pacific Northwest, and Upper Colorado) covering 17 western states. Figure 1-1 shows the distribution of the 530 sites, which makes up the assessment study area.

Rather than applying a screening process as used in the 1834 Study, the Resource Assessment evaluates all 530 sites, including those with low hydraulic head, low capacity, or regulatory conflicts, as potential for new hydropower development. For this assessment, Reclamation developed and applied the Hydropower Assessment Tool, an Excel-based model, to evaluate power potential and economic benefits and costs of each site. In addition to analysis of each site, the Resource Assessment also added some key components to the analysis not included in the 1834 Study, including:

- Green incentives in the economic benefits analysis.
- Turbine types and efficiency specified for each site as indicated by the available hydraulic head and flow.

- Actual or estimated distances and costs of transmission lines.
- Calculation of the internal rates of return.
- Maps of each site to identify locations related to potential sensitive water and land use areas that may preclude or constrain development.

The Resource Assessment provides a "big picture" analysis of potential hydropower sites. Because of the geographic scope of the analysis, many general assumptions had to be applied to determine hydropower production potential and estimate economic benefits and costs. The analysis provides preliminary comparison among potential sites, which gives Reclamation further understanding of hydropower development potential at existing facilities. All sites would have to be investigated in further detail through feasibility, environmental, design, and permitting studies.

1.4 Public Input

The public has had the opportunity to provide input and comments on the Resource Assessment Draft Report. As part of the public process, Reclamation published a notice in the Federal Register on November 4, 2010 soliciting public comments on the draft report. The public comment period was scheduled through December 3, 2010. On December 28, 2010, Reclamation reissued a notice in the Federal Register extending the comment period through January 27, 2011, in response to public requests for an extension. Appendix G summarizes and includes public comments received.

1.5 Report Content

This report is organized into the following chapters.

Chapter 1 Introduction: Presents the background, purpose and objectives, and overview for the *Hydropower Resource Assessment at Existing Reclamation Facilities*.

Chapter 2 Hydropower Site Data Collection: Discusses methods to collect head water elevation, tail water elevation, and flow data for the 530 sites in study area.

Chapter 3 Site Analysis Methods and Assumptions: Summarizes methods to estimate potential energy generation at each site, economic benefits related to power production and green incentives, site development and operation and maintenance (O&M) costs, and potential environmental and regulatory constraints.

Chapter 4 Hydropower Assessment Tool: Describes components and application of the Hydropower Assessment Tool developed for this study to evaluate power production potential, benefit cost ratio, and internal rate of return (IRR) of potential hydropower sites.

Chapter 5 Site Evaluation Results: Presents results of the Resource Assessment, organized by Reclamation region, and sensitivity analyses.

Chapter 6 Conclusions: Summarizes study results and conclusions, and uses for future hydropower analyses.

Chapter 7 References: Lists references used to develop the report.

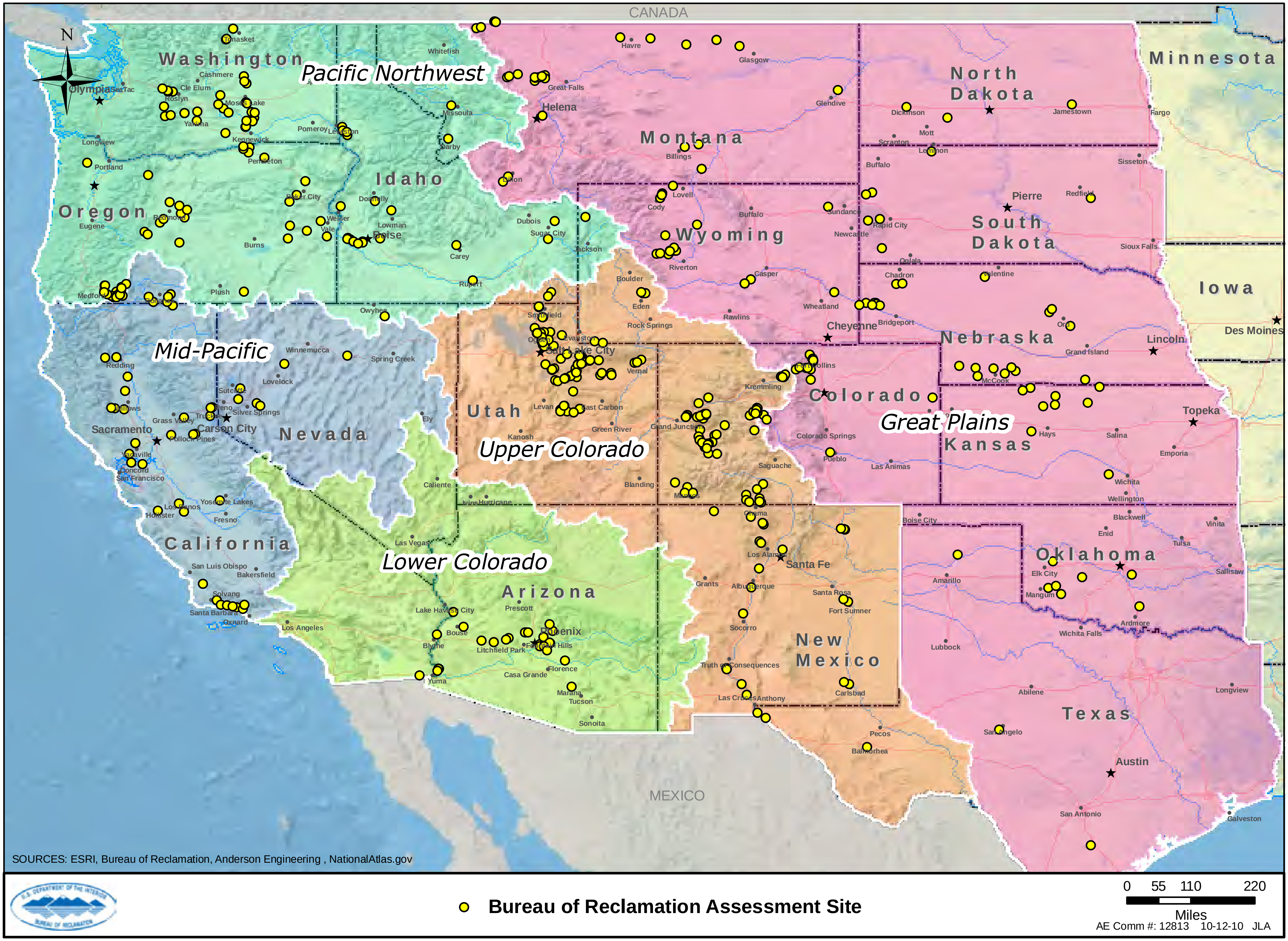

Figure 1-1 : Resource Assessment Site Locations

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Chapter 2 Hydropower Site Data Collection

The Resource Assessment evaluates potential hydropower development at the 530 Reclamation facilities inventoried in the 1834 Study. Table 2-1 summarizes the number of sites in each Reclamation region. For analysis purposes, each site is labeled with the region initials and a number, based on alphabetical order of the sites in the region. Table 2-4 (at the end of this section) lists the sites and identification numbers and Appendix A lists the sites, state, Reclamation project, and assigned site identification numbers.

Table 2-1 Number of Sites in Each Reclamation Region

Reclamation Region	Number of Sites	Site Identification Numbering
Great Plains (GP)	146	GP-1 to GP-146
Lower Colorado (LC)	30	LC-1 to LC-30
Mid-Pacific (MP)	44	MP-1 to MP-44
Pacific Northwest (PN)	105	PN-1 to PN-105
Upper Colorado (UC)	205	UC-1 to UC-205
Total	**530**	-

Extensive data is needed for a complete hydropower analysis of each site, including site coordinates, proximity to transmission lines, daily flows for at least a 1-year period, and head water and tail water elevations. This section describes data necessary to complete the analysis, data sources, and confidence levels in the data collected.

Data availability varied per site. For the majority of sites, a complete data set, as listed above, was available. For some sites, a complete data set was not available after extensive data collection efforts. The sites with incomplete data were still tested for hydropower potential using available data; however, the analysis indicates that the data confidence level is low. Further analysis, including site visits and monitoring, which are out of the scope of this analysis, could identify potential hydropower development at sites with currently low confidence data.

2.1 Site Location and Proximity Data

Reclamation operates 188 projects within the 17 western states. Potential hydropower sites are distributed among these projects and states. The 1834 Study identified potential hydropower sites by name of the canal, dam, siphon, or other infrastructure, the associated Reclamation project, and the state.

Site coordinates were also collected for the majority of sites. Figures 2-1 through 2-10 show the distribution and location of sites, with available coordinate data, for each region. Regions are split among the figures because of the region size and to better show site locations.

The Idaho National Engineering and Environmental Laboratory (INL) provided proximity data related to site locations, based on the site coordinates. Proximity data include distance of site to nearest population center, road, substation, and transmission line. INL also provided the voltage of nearest transmission or distribution lines, power line operator and substation name.

The distance from the site to transmission line and transmission line voltage were used in estimating costs of potential hydropower development at a site. If INL did not have transmission data available for a particular site, a 5.0 mile default distance from the site to the transmission line was used in the analysis. This reflects an average transmission line distance based on the available data for the remainder of sites. The default transmission voltage value used was 115 kilo voltage (kV), which is considered an average kV for transmission lines. Data for transmission or distribution line kV provided by INL went from 35 kV up to 500 kV. The distance to the nearest transmission line does not necessarily indicate that an interconnection can be made with the transmission line. Further site specific analysis for transmission would be needed if a site is pursued. Chapter 3 discusses cost estimating methods and assumptions for transmission.

2.2 Site Hydrologic Data

Hydrologic data, including flow and net hydraulic head (net head), are necessary to calculate potential power generation at a site. Net head is the difference between head water and tail water elevations. Power generation can be estimated using the following formula:

Power [kW] = (Flow [cfs] * Net Head [feet] * Efficiency)/11.8[1]

Flow, head water and tail water data are typically available from flow meter or gage measurements, reservoir elevations, and project design specifications. Efficiency is dependent on the turbine design capacity, operating capacity[2], and turbine type. Chapter 3 discusses efficiency assumptions used in the power generation analysis of the Hydropower Assessment Tool. The following sections describe flow and net head data required and available for the analysis.

[1] 11.8 is a constant factor that is a combination of a constant and unit conversion factors.
[2] Turbine design capacity is the nameplate design for the turbine and operating capacity is the nameplate capacity less losses due to operational conditions (changes in heads or flows).

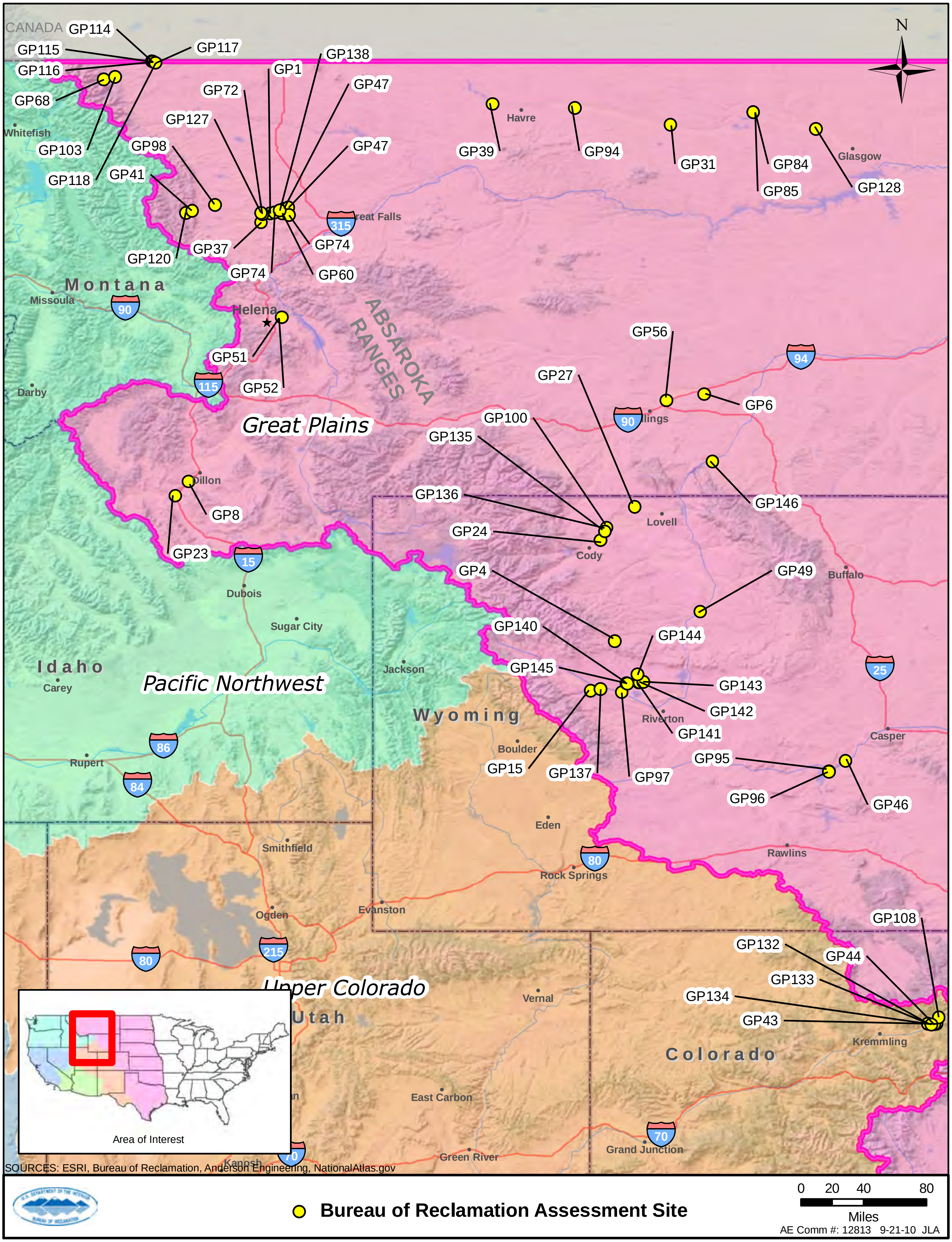


Figure 2-1 : Great Plains Region (Northwest) Assessment Site Location Map

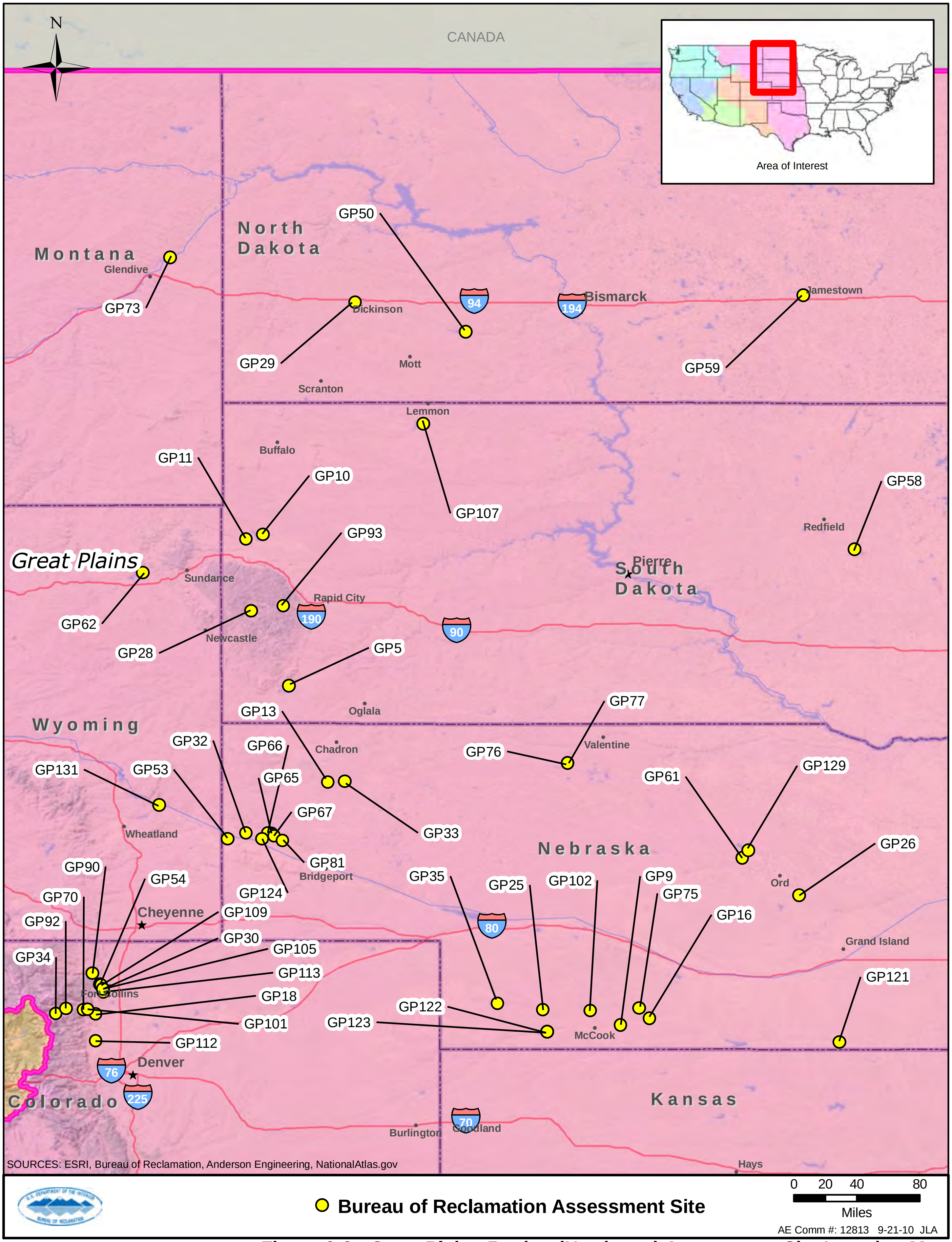


Figure 2-2 : Great Plains Region (Northeast) Assessment Site Location Map

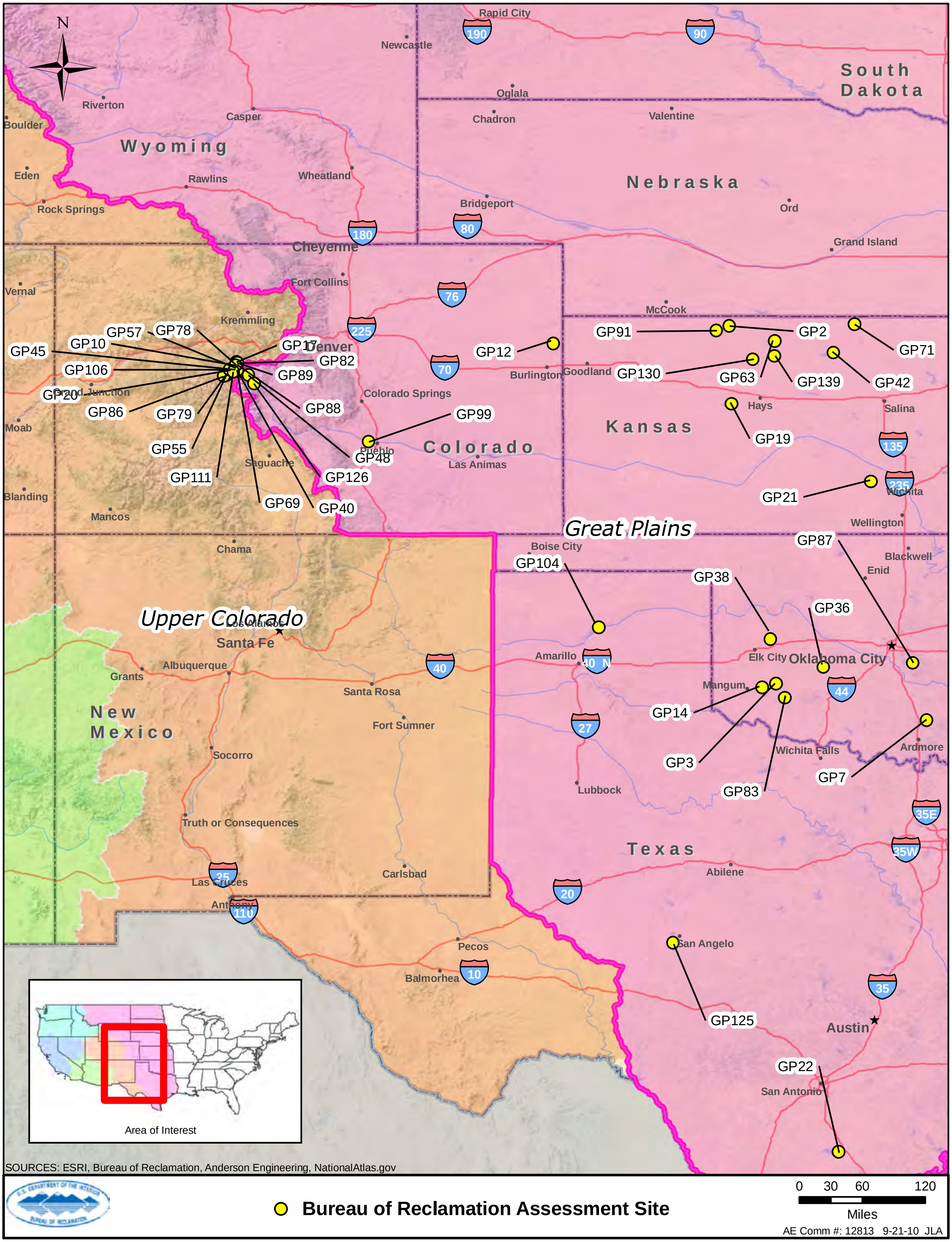


Figure 2-3 : Great Plains Region (South) Assessment Site Location Map

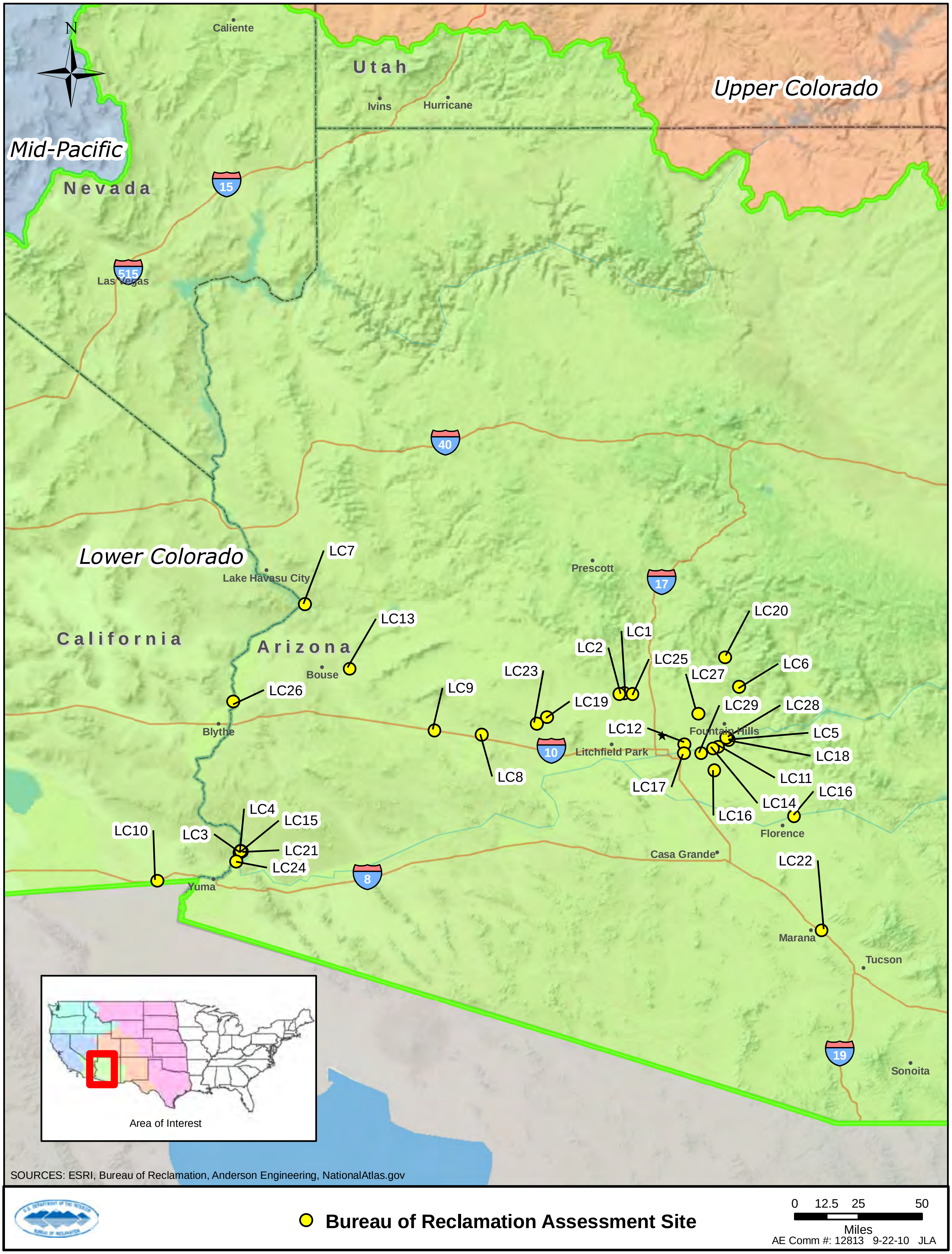


Figure 2-4 : Lower Colorado Region Assessment Site Location Map

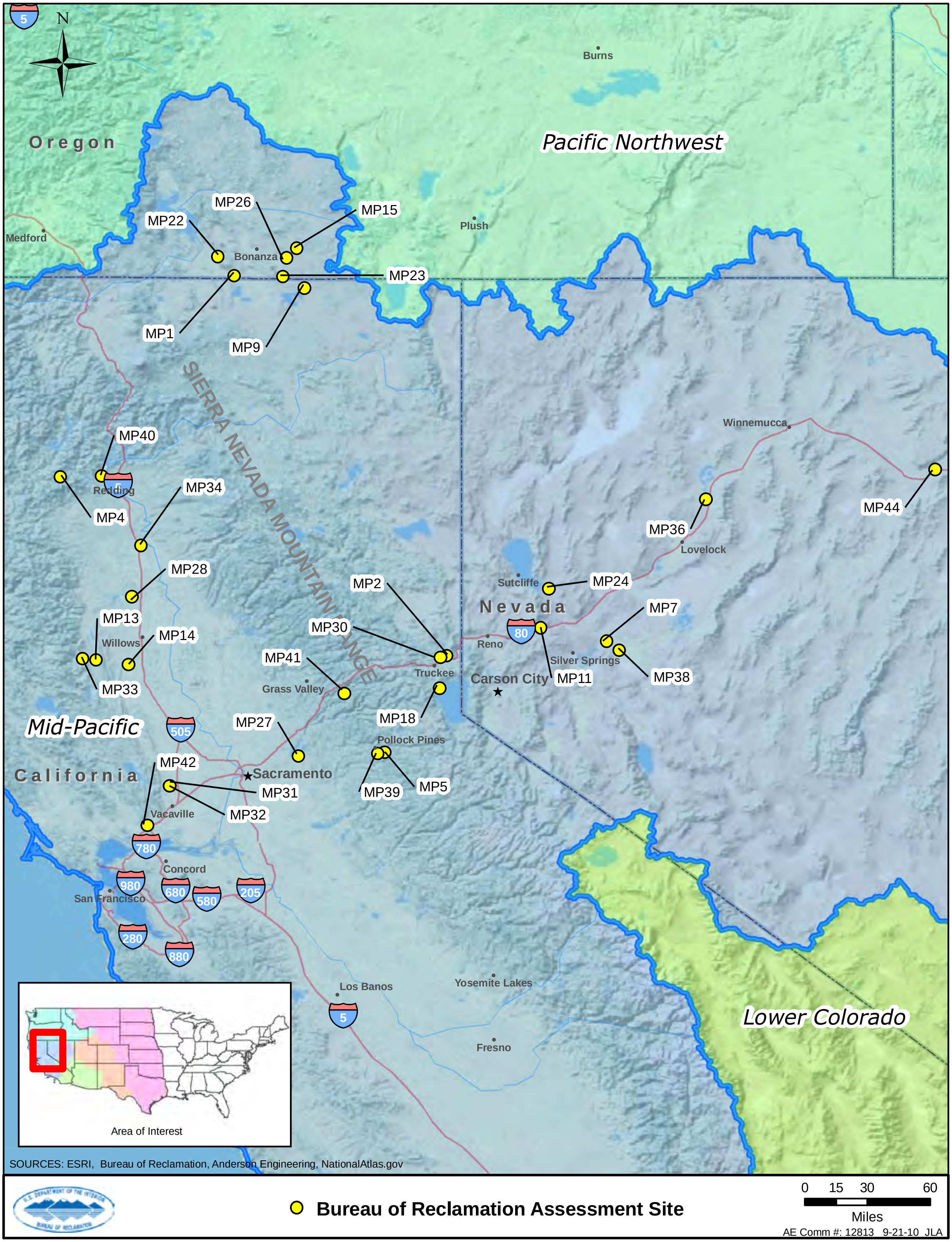


Figure 2-5 : Mid-Pacific Region (North) Assessment Site Location Map

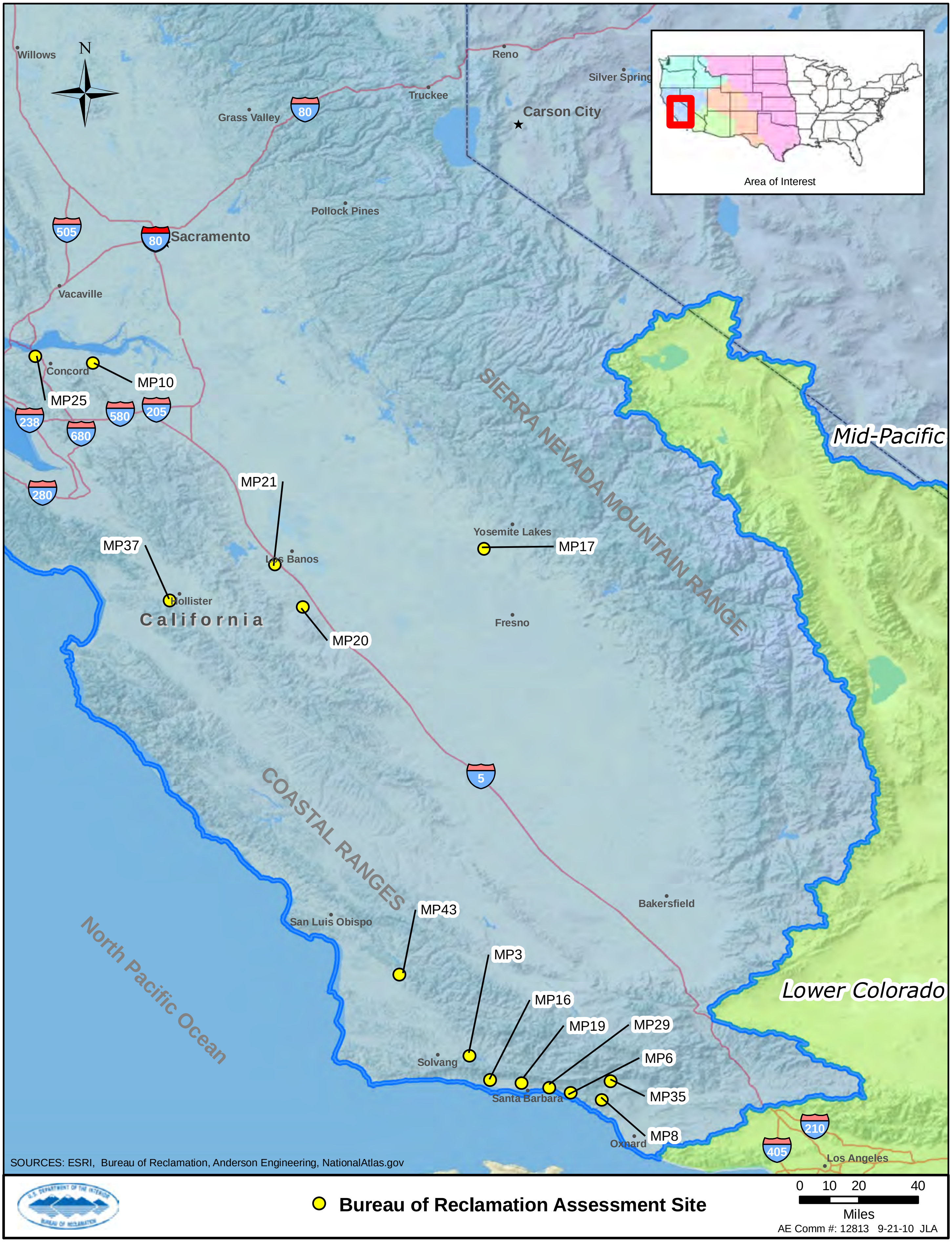
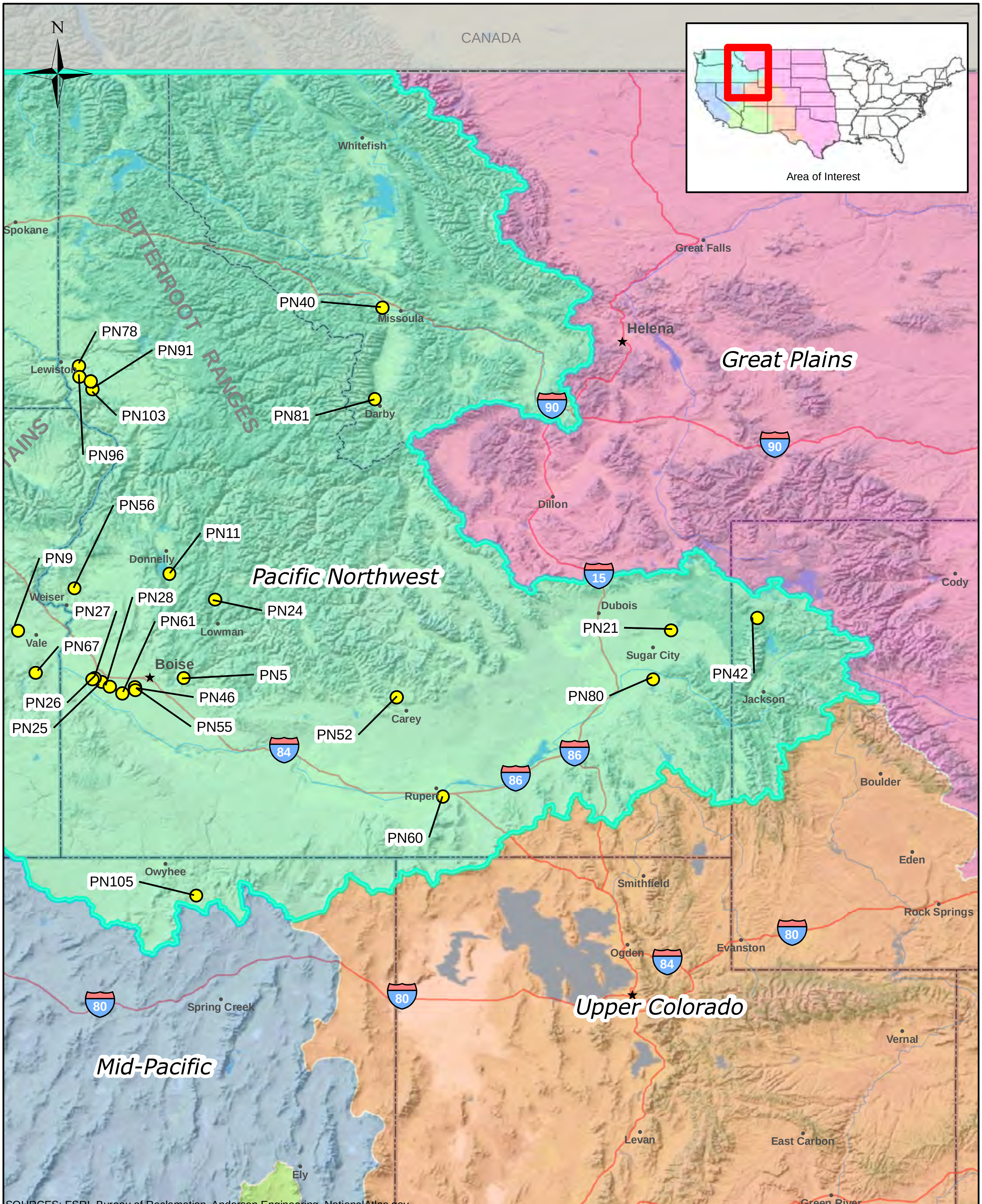


Figure 2-6 : Mid-Pacific Region (South) Assessment Site Location Map

Figure 2-7 : Pacific Northwest Region (West) Assessment Site Location Map



Bureau of Reclamation Assessment Site

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Figure 2-8 : Pacific Northwest Region (East) Assessment Site Location Map

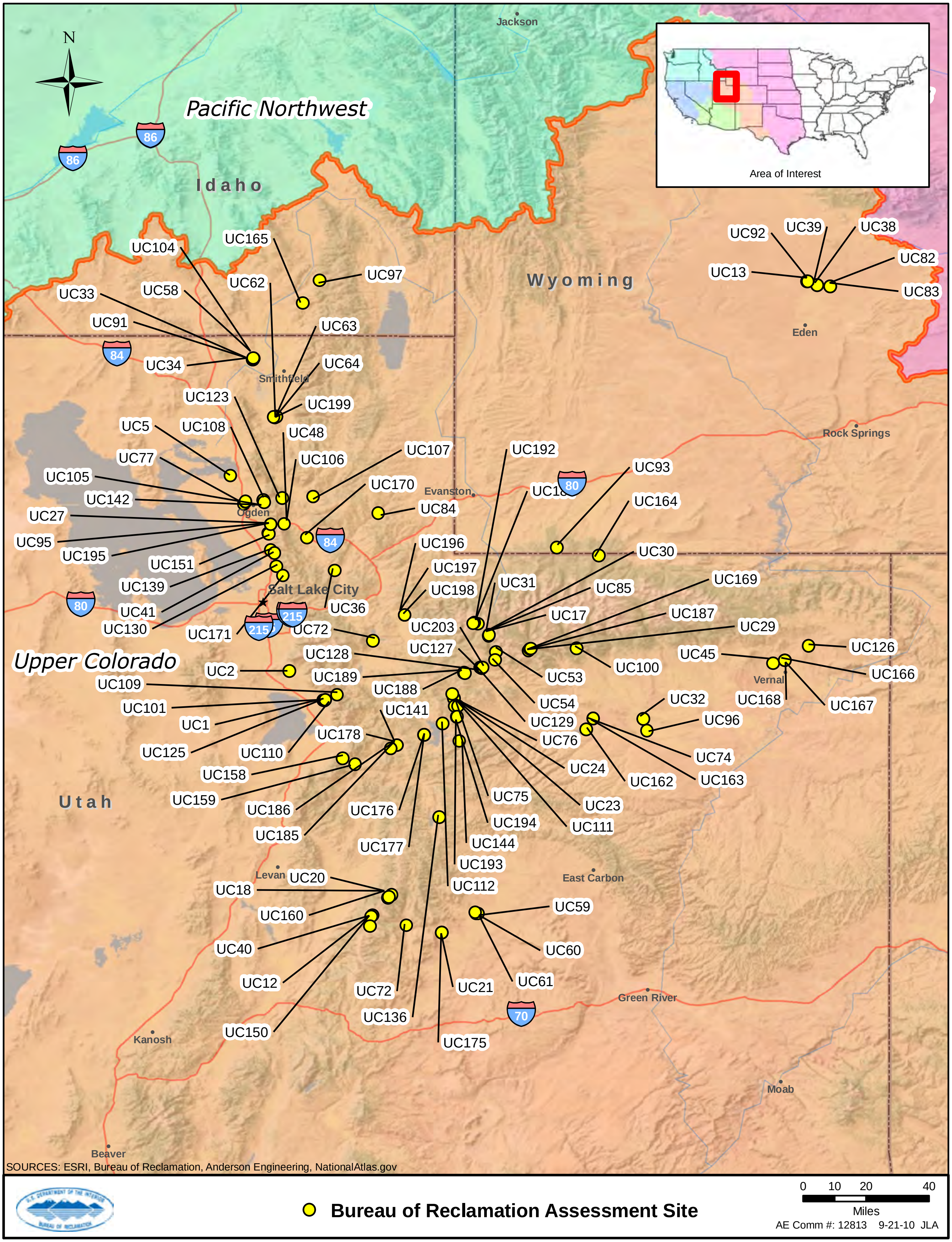

Figure 2-9 : Upper Colorado Region (West) Assessment Site Location Map

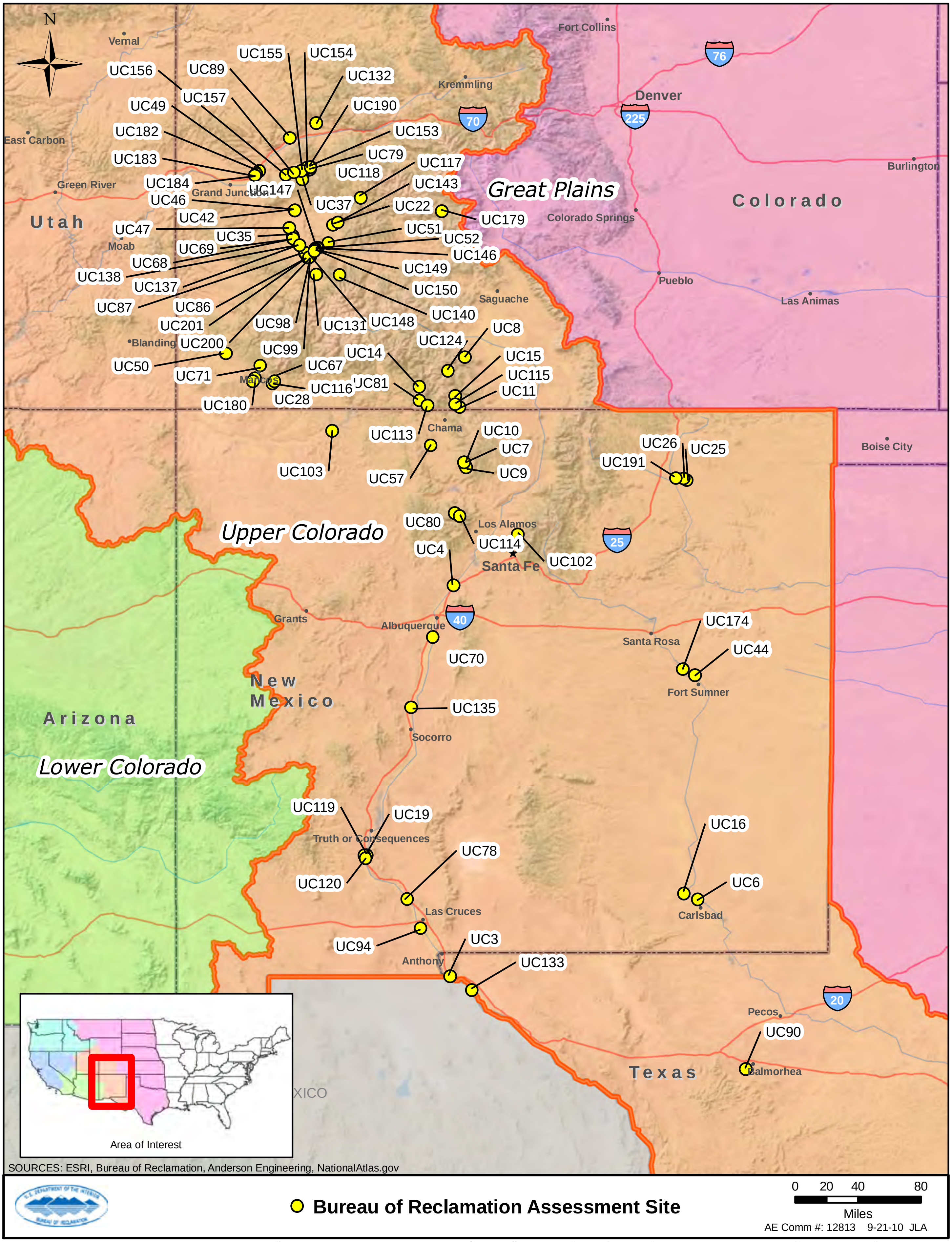

Figure 2-10 : Upper Colorado Region (East) Assessment Site Location Map

2.2.1 Flow

The analysis requires daily flow data measured in cubic feet per second (cfs). Historic flow records for the sites were used, as available. A minimum of 1 year of flow records was required for analysis. Sites with data that indicated zero flows would not have any power potential and were not carried forward in the analysis. The 530 sites analyzed are either dams/diversion dams (spillways or outlet works) or canal/tunnels or dikes/siphons, which have different flow regimes, as described in the following sections.

Reservoir Dams and Diversion Dams

Flows are typically measured as releases from the reservoir or diversions from a main canal or water way. Some of the diversion dams in the analysis are used for irrigation purposes and divert during the irrigation season; therefore, there are about 6 months of flow through the facility.

Flows through spillways or outlet works are typically monitored and recorded by the operating facilities; these data sources were used for the analysis. If no recorded data was available at the site, local knowledge was used to estimate the average flow through the facility. In some cases, particularly where the site uses flows from a flood control channel, the local representatives with knowledge of the site indicated that flow through the site was too sporadic or low for hydropower generation. In these instances, it was documented that the site had “no hydropower potential” and the site was not further analyzed.

Canals and Tunnels

Sites on canals and tunnels consist of elevation drops in the canal where head can be captured to generate power, or at a turnout or siphon used to move water from a larger canal into laterals or smaller canals for delivery. For some of these points of delivery, hydraulic head needs to be reduced to manage the flow of water. Similar to diversion dams, some of the canals and tunnels are also for irrigation purposes with only seasonal flows.

Flow records through canals and tunnels are usually recorded and monitored by Reclamation, U.S. Geological Survey (USGS) gages or by the operating entity. Reclamation owned canals are often operated and maintained by local irrigation districts, and in sites without readily available flow data, local authorities or irrigation districts were contacted for estimates on flow. In some instances, local districts had hard copy, written flow data that was used for the analysis. Local officials also provided information about some sites, particularly if they had sporadic or no flows for hydropower production. If the sites were determined to have no flows, it was noted to have “no hydropower potential” and was not further analyzed. For some canal and tunnel sites flow data were not available. Reclamation is conducting a separate study to further analyze canals and tunnels for hydropower potential, and this study will include collecting seasonal flow data and estimating net head through field investigations.

Dikes and Siphons

Some sites identified in the 1834 Study are dikes. Dikes typically impound water and do not have any flow releases. As a result, the dikes included in this study were assumed to have "no hydropower potential" because of zero flows. If a local representative had data indicating the site was not a typical dike and did have flows, then it was documented and carried forward in the analysis. The same approach applied to sites that were siphons.

2.2.2 Net Hydraulic Head

In addition to flow, sites require a positive net head for hydropower development. Net head is calculated as the difference between head water and tail water elevation. In general, a minimum of 3 feet of head is required to generate some hydropower. For some sites without historic records, local staff was able to provide information about available head at the sites. If sites had minimal head available (i.e., less than 3 feet), which occurred mostly in canals and tunnels, they were noted to have "no hydropower potential" due to the limited head available to move water within the canal or tunnel.

For reservoir dams and diversion dams, the recorded variable reservoir elevations at the site were used as the head water elevation and the tail water elevation was estimated from record drawings. Tail water elevation was a constant.

For most canals and tunnels, net head was a constant reflecting the elevation drop in the facilities. Some canals had similar elevation data as reservoirs where head water elevation varied and tail water elevation was constant.

2.3 Data for Canals and Tunnels

Many of the sites with further data needs are canals and tunnels. For some canals, maximum flow data design capacity was available, but seasonal variations in flow and net head data was not available. Seasonal flow distribution can significantly affect hydropower potential at a site. Many Reclamation canals are used for irrigation purposes and only carry flows during the irrigation season. Irrigation demands can also vary monthly, so canals may not be operating at peak capacity during the entire irrigation season. As a result, using design capacity flow data to calculate hydropower production is not an accurate representation of hydropower potential; daily flow data is best.

Further, hydropower potential cannot be estimated without data on net head. A large portion of the canals listed in the 1834 Study did not identify a specific drop or drops in the canal. Instead they simply listed the head differential along the entire stretch of the canal (sometimes over tens of miles). Elevation changes in canals and tunnels can occur over short or long distances, and for some sites field investigations are needed to determine net head. The scope of this Resource Assessment does not include site visits for evaluating net head, and at the level of analysis of this study it was difficult to estimate potential changes in net head in these canals and tunnels. Reclamation is conducting a separate study to further analyze canals and tunnels for hydropower potential; this study includes collecting seasonal flow data and estimating net head through field investigations.

2.4 Data Sources

Various data sources provided flow, head water and tail water data for the analysis. For many sites, Reclamation owns the site but has transferred operation and maintenance to a local irrigation district. Therefore, local irrigation districts assisted in data collection.

- Hydromet – Reclamation operates a network of automated hydrologic and meteorologic monitoring stations throughout the Pacific Northwest and Great Plains region. Hydromet collects remote field data and transmits it via satellite to provide real-time water management capability. Hydromet data is then integrated with other sources of information to provide streamflow forecasting and current runoff conditions for river and reservoir operations. Hydromet provides daily flow and elevation data.

- USGS Water Data - USGS surface-water data includes more than 850,000 station years of time-series data that describe stream levels, streamflow, reservoir and lake levels, surface-water quality, and rainfall. The data are collected by automatic recorders and manual measurements. Data is available real-time, daily, monthly, and annually. Daily data is available at 25,290 surface water sites.

- 1834 Study – Efforts to complete the 1834 Study included data collection for the 530 sites. Hydrologic data required for the 1834 Study is the same as data needed for the Resource Assessment. As a result of screening criteria, hydrologic data was not collected on many of the sites. However, sites that made it to the final phase of analysis in the 1834 Study had hydrologic data available.

- Project Data Book – The *Water and Power Resources Service Project Data* (1981) (Project Data Book) contains descriptive and technical information for existing Reclamation water projects and facilities, including engineering designs. The Project Data Book was used to identify tail water elevation for most sites and head water elevation for some sites, if it were not available through other sources. Tail water elevation was identified based on elevation of outlet works in the design drawings.

- Reclamation Area Offices' or Irrigation Districts' records – Reclamation's area offices or irrigation districts operating the site maintain flow data for some sites. Daily data was provided in Excel files or in written records.

- Reclamation Area Offices' and Irrigation Districts' staff knowledge - Area office and irrigation district staff had local knowledge of some sites through operation, maintenance, or inspection and could provide general knowledge on flow and head data. This local information was applied, as necessary and applicable, to some sites and assigned a "low confidence" in the analysis (see below). Most often, staff knowledge was applied if the site did not have hydropower potential, as staff generally knew about flow magnitude and frequency and if head was available for hydropower production.

2.5 Data Collection and Confidence Levels

The Resource Assessment is very data-intensive. Reclamation made significant efforts to research and find hydrologic data for all 530 sites. Reclamation Technical Service Center staff coordinated closely with area offices in each region to collect data. Reclamation's field offices and local irrigation districts were also consulted for hydrologic data.

Best efforts were made to collect complete data for all 530 sites; however, some sites had missing or incomplete data. In most instances, incomplete data was manipulated in order to be adequate for the planning level of analysis in the Resource Assessment. As a result of the variability in data, Reclamation has assigned confidence ratings to data collected for each site based on the source, availability and consistency of data. Data was classified as high, medium, or low confidence, defined below. Table 2-1 shows the number of high, medium and low confidence data by region.

- **High Confidence**: assigned to data downloaded from Hydromet, USGS gages, or data collected from the previously conducted 1834 Study. Data has continuous daily data sets for a minimum of three years.

- **Medium Confidence**: assigned to data downloaded from Hydromet or USGS that had data gaps. Some of the data downloaded from the Hydromet or USGS sites had missing data points, either single data points or weeks to months of missing data. This data was still valuable and adequate to use for the planning level analysis in the Resource Assessment; therefore, data gaps were filled in using best professional judgment. For example, for single gaps, the previous data point could be repeated and for consecutive gaps, linear interpolation could be applied. Medium confidence was also assigned to data provided as monthly averages for flow and net head from irrigation records. The monthly averages were used as daily data points in order to run the Hydropower Assessment Tool.

- **Low Confidence**: assigned to sites where no historical hydrologic records were available. Local area office staff were contacted and provided estimates on flow and head available for hydropower generation based on local knowledge of the site. If staff had local knowledge of the site, it was included as information available on the site, but assigned a low confidence rating. Low confidence was also assigned to sites that had data available, but the local staff suspected inaccuracies in the data based on local knowledge. Sites with unique data issues, such as only monthly flows or design flow capacity available, but still used for analysis, were also given a low confidence rating.

Table 2-2 Number of High, Medium, and Low Confidence Sites per Region

	High Confidence	Medium Confidence	Low Confidence
Great Plains	56	15	66
Lower Colorado	0	2	26
Mid-Pacific	5	10	25
Pacific Northwest	28	7	48
Upper Colorado	28	35	110
Total	**117**	**69**	**275**

Results from low confidence data, though useful to analyze a site's potential at this preliminary level of investigation, should not be used for more detailed or feasibility level analyses. Efforts to collect more reliable data (i.e. higher confidence) should be made in subsequent analyses.

2.6 Site Data Summary

Site location, proximity, and hydrologic data are unique to each of the 530 sites. Reclamation was able to collect data needed for the Hydropower Assessment Tool for the majority of sites. Table 2-3 summarizes hydropower potential and data confidence levels for the 530 sites. The hydropower potential column indicates if any hydropower potential exists at the site based on data from Reclamation staff or model estimates; however, a "yes" does not mean that the site is economically viable. Further, hydropower potential from model estimates is based on the 30 percent flow exceedance level. If the model determined flows were too low or infrequent for hydropower generation based on the 30 percent exceedance level, then the 20 percent flow exceedance level is noted to give an indication of flow magnitude and duration at the site.

Dash marks indicate sites that were removed from the analysis or a canal or tunnel site that requires further analysis. Sites were removed from the analysis because of various reasons, including if the site was duplicate to another, if hydropower was already developed or being developed, or if Reclamation no longer owned the site. These sites were identified and not further analyzed in the Resource Assessment. The notes column indicates the reasons why sites were removed, reasons for no hydropower potential, or additional notes on data availability or site characteristics.

Table 2-3 Site Data and Hydropower Potential Summary

Site ID	Site Name	Hydropower Potential (yes/no) [1]	Data Confidence Level	Notes (including reason for no hydropower potential)
GP-1	A-Drop Project, Greenfield Main Canal Drop	No[2]	High	Site has seasonal flows about 4 months per year, model estimated that flows are too low and infrequent for economical hydropower development at 30 percent flow exceedance, 20 percent flow exceedance would be 1,090 cfs
GP-2	Almena Diversion Dam	No	Low	Data indicates there is no drop into the canal; therefore, no head is available for hydropower development
GP-3	Altus Dam	No	Medium	Site has seasonal flows about 2 months per year, model estimated that flows are too low and infrequent for hydropower development at 30 percent flow exceedance, 20 percent flow exceedance would be 2 cfs
GP-4	Anchor Dam	Yes	High	
GP-5	Angostura Dam	Yes	Low	Flow data includes some flood releases
GP-6	Anita Dam	No	Low	Facility only operates seasonally and has limited flows for hydropower development
GP-7	Arbuckle Dam	No	Low	Data indicates flows are too low for hydropower development, about 1 cfs constant downstream release
GP-8	Barretts Diversion Dam	Yes	Medium	
GP-9	Bartley Diversion Dam	No	Low	Data indicates there is no drop into the canal; therefore, no head is available for hydropower development
GP-10	Belle Fourche Dam	Yes	High	Site has seasonal flows
GP-11	Belle Fourche Diversion Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development
GP-12	Bonny Dam	Yes	High	
GP-13	Box Butte Dam	No	Low	Site has some seasonal flows about 1-2 months per year, model estimated that flows are too low and infrequent for hydropower development at 30 percent flow exceedance, 20 percent flow exceedance would be 2 cfs
GP-14	Bretch Diversion Canal	Yes	Low	Site has less than 10 feet of head, has infrequent higher flows during 1-2 months per year
GP-15	Bull Lake Dam	Yes	High	Site has seasonal flows
GP-16	Cambridge Diversion Dam	No	Low	Data indicates there is no drop into the canal; therefore, no head is available for hydropower development
GP-17	Carter Creek Diversion Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development
GP-18	Carter Lake Dam No. 1	Yes	High	Site has seasonal flows
GP-19	Cedar Bluff Dam	No	High	Site has some seasonal flows about 1-2 months per year, model estimated that flows are too low and infrequent for hydropower development at 30 percent flow exceedance, 20 percent flow exceedance would also be 0 cfs
GP-20	Chapman Diversion Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development
GP-21	Cheney Dam	No[2]	Low	Flow data includes some flood releases. Site has infrequent high flows in some

Table 2-3 Site Data and Hydropower Potential Summary

Site ID	Site Name	Hydropower Potential (yes/no) [1]	Data Confidence Level	Notes (including reason for no hydropower potential)
				months, model estimated that flows are too low and infrequent for economical hydropower development at 30 percent flow exceedance, 20 percent flow exceedance would be 200 cfs
GP-22	Choke Canyon Dam	Yes	Low	Flow data includes some flow releases, steady state flows around 30 cfs
GP-23	Clark Canyon Dam	Yes	High	
GP-24	Corbett Diversion Dam	Yes	High	Site has seasonal flows
GP-25	Culbertson Diversion Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development
GP-26	Davis Creek Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development
GP-27	Deaver Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development
GP-28	Deerfield Dam	Yes	High	
GP-29	Dickinson Dam	Yes	High	Site has low seasonal flows
GP-30	Dixon Canyon Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development
GP-31	Dodson Diversion Dam	Yes	Low	
GP-32	Dry Spotted Tail Diversion Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development
GP-33	Dunlap Diversion Dam	No	Low	Data indicates there is no drop into the canal; therefore, no head is available for hydropower development
GP-34	East Portal Diversion Dam	Yes	High	
GP-35	Enders Dam	Yes	High	Site has some seasonal flow in July and August, low to no flow the rest of the year
GP-36	Fort Cobb Dam	No	Low	Site has some infrequent flows 1 month per year, model estimated that flows are too low and infrequent for hydropower development at 30 percent flow exceedance, 20 percent flow exceedance would be 21 cfs
GP-37	Fort Shaw Diversion Dam	Yes	Medium	
GP-38	Foss Dam	Yes	Low	
GP-39	Fresno Dam	Yes	High	Site has year round flows with high seasonal flows May through September
GP-40	Fryingpan Diversion Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development
GP-41	Gibson Dam	Yes	High	
GP-42	Glen Elder Dam	Yes	High	
GP-43	Granby Dam	Yes	High	
GP-44	Granby Dikes 1-4	No	Low	Dike structure, no flows available for hydropower generation
GP-45	Granite Creek Diversion Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development
GP-46	Gray Reef Dam	Yes	High	

Table 2-3 Site Data and Hydropower Potential Summary

Site ID	Site Name	Hydropower Potential (yes/no) [1]	Data Confidence Level	Notes (including reason for no hydropower potential)
GP-47	Greenfield Project, Greenfield Main Canal Drop	Yes	Low	
GP-48	Halfmoon Creek Diversion Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development
GP-49	Hanover Diversion Dam	-	-	Reclamation does not own the site
GP-50	Heart Butte Dam	Yes	High	
GP-51	Helena Valley Dam	Yes	High	
GP-52	Helena Valley Pumping Plant	Yes	High	
GP-53	Horse Creek Diversion Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development
GP-54	Horsetooth Dam	Yes	High	Site has seasonal flows
GP-55	Hunter Creek Diversion Dam	No	Medium	Site has some seasonal flows about 1-2 months per year, model estimated that flows are too low and infrequent for hydropower development at 30 percent flow exceedance, 20 percent flow exceedance would also be 0 cfs
GP-56	Huntley Diversion Dam	Yes	Medium	
GP-57	Ivanhoe Diversion Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development
GP-58	James Diversion Dam	Yes	High	Consistent months of high flows in most years, head is 5 feet
GP-59	Jamestown Dam	Yes	High	
GP-60	Johnson Project, Greenfield Main Canal Drop	Yes	Medium	Site has seasonal flows
GP-61	Kent Diversion Dam	No	Low	Data indicates there is no drop into the canal; therefore, no head is available for hydropower development
GP-62	Keyhole Dam	No	High	Site has some seasonal flows about 2-3 months per year, model estimated that flows are too low and infrequent for hydropower development at 30 percent flow exceedance, 20 percent flow exceedance would also be 0 cfs
GP-63	Kirwin Dam	Yes	High	
GP-64	Knights Project, Greenfield Main Canal Drop	No[2]	Medium	Site has seasonal flows about 4 months per year, model estimated that flows are too low and infrequent for hydropower development at 30 percent flow exceedance, 20 percent flow exceedance would be 35 cfs
GP-65	Lake Alice Lower 1-1/2 Dam	No	Low	Site has no head for hydropower development
GP-66	Lake Alice No. 1 Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development
GP-67	Lake Alice No. 2 Dam	Yes	Medium	Design head is 3 feet.
GP-68	Lake Sherburne Dam	Yes	Medium	Site has seasonal flows
GP-69	Lily Pad Diversion Dam	no	Low	Model estimated that flows are too low for hydropower development, flows less

Table 2-3 Site Data and Hydropower Potential Summary

Site ID	Site Name	Hydropower Potential (yes/no) [1]	Data Confidence Level	Notes (including reason for no hydropower potential)
				than 10 cfs 95% of the time
GP-70	Little Hell Creek Diversion Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development
GP-71	Lovewell Dam	No[2]	High	Site has seasonal flows about 5-6 months per year, model estimated that flows are too low and infrequent for economical hydropower development at 30 percent flow exceedance, 20 percent flow exceedance would be 100 cfs
GP-72	Lower Turnbull Drop Structure	-	-	Site already has hydropower developed or being developed
GP-73	Lower Yellowstone Diversion Dam	-	-	Reclamation and Corps are working on improved fish passage at the dam, no potential for hydropower development
GP-74	Mary Taylor Drop Structure	No[2]	Medium	Site has seasonal flows about 5 months per year, model estimated that flows are too low and infrequent for economical hydropower development at 30 percent flow exceedance, 20 percent flow exceedance would be 123 cfs
GP-75	Medicine Creek Dam	Yes	High	
GP-76	Merritt Dam	Yes	Low	
GP-77	Merritt Dam	-	-	Duplicate site, same as Merritt Dam
GP-78	Middle Cunningham Creek Diversion Dam	No	Low	Model estimated that flows and head are too low for hydropower development, flows less than 21 cfs 95% of the time and head is 7.5 feet
GP-79	Midway Creek Diversion Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development
GP-80	Mill Coulee Canal Drop, Upper and Lower Drops Combined	No	Medium	Site has seasonal flow for 4 months in some years, model estimated that flows are too low and infrequent for hydropower development at 30 percent flow exceedance, 20 percent flow exceedance would be 0 cfs
GP-81	Minatare Dam	No[2]	High	Site has seasonal flow for 3 months per year, model estimated that flows are too low and infrequent for economical hydropower development at 30 percent flow exceedance, 20 percent flow exceedance would be 160 cfs
GP-82	Mormon Creek Diversion Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development
GP-83	Mountain Park Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development
GP-84	Nelson Dikes C	No	High	Site has some seasonal flows about 1-2 months per year, model estimated that flows are too low and infrequent for hydropower development at 30 percent flow exceedance, 20 percent flow exceedance would also be 0 cfs
GP-85	Nelson Dikes DA	Yes	High	
GP-86	No Name Creek Diversion Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development
GP-87	Norman Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development
GP-88	North Cunningham Creek Diversion Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development
GP-89	North Fork Diversion Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development

Table 2-3 Site Data and Hydropower Potential Summary

Site ID	Site Name	Hydropower Potential (yes/no) [1]	Data Confidence Level	Notes (including reason for no hydropower potential)
GP-90	North Poudre Diversion Dam	-	-	Reclamation does not own the site
GP-91	Norton Dam	Yes	High	
GP-92	Olympus Dam	Yes	High	
GP-93	Pactola Dam	Yes	High	
GP-94	Paradise Diversion Dam	No[2]	High	Site has seasonal flow for 3 months per year, model estimated that flows are too low and infrequent for economical hydropower development at 30 percent flow exceedance, 20 percent flow exceedance would be 90 cfs
GP-95	Pathfinder Dam	Yes	High	
GP-96	Pathfinder Dike	No	Low	Dike structure, no flows available for hydropower generation
GP-97	Pilot Butte Dam	-	-	Reclamation has an existing 1,600 kW plant at Pilot Butte Dam that is currently not in operation
GP-98	Pishkun Dike - No. 4	Yes	High	Site has seasonal flows
GP-99	Pueblo Dam	Yes	High	
GP-100	Ralston Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development
GP-101	Rattlesnake Dam	No	High	Model estimated that flows are too low for hydropower development , site has 1 cfs flow consistently
GP-102	Red Willow Dam	Yes	High	
GP-103	Saint Mary Diversion Dam	Yes	High	
GP-104	Sanford Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development
GP-105	Satanka Dike	No	Low	Dike structure, no flows available for hydropower generation
GP-106	Sawyer Creek Diversion Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development
GP-107	Shadehill Dam	Yes	High	
GP-108	Shadow Mountain Dam	Yes	High	
GP-109	Soldier Canyon Dam	No	High	Model estimated that flows and head are too low for hydropower development, flows less than 2 cfs 95% of the time
GP-110	South Cunningham Creek Diversion Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development
GP-111	South Fork Diversion Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development
GP-112	South Platte Supply Canal Diverion Dam	-	-	Reclamation does not own the site
GP-113	Spring Canyon Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development
GP-114	St. Mary Canal - Drop 1	Yes	High	Site has seasonal flows
GP-115	St. Mary Canal - Drop 2	Yes	High	Site has seasonal flows

Table 2-3 Site Data and Hydropower Potential Summary

Site ID	Site Name	Hydropower Potential (yes/no) [1]	Data Confidence Level	Notes (including reason for no hydropower potential)
GP-116	St. Mary Canal - Drop 3	Yes	High	Site has seasonal flows
GP-117	St. Mary Canal - Drop 4	Yes	High	Site has seasonal flows
GP-118	St. Mary Canal - Drop 5	Yes	High	Site has seasonal flows
GP-119	St. Vrain Canal	-	-	Reclamation does not own the site
GP-120	Sun River Diversion Dam	Yes	High	Site has seasonal flows
GP-121	Superior-Courtland Diversion Dam	No	Low	Data indicates there is no drop into the canal; therefore, no head is available for hydropower development
GP-122	Trenton Dam	Yes	High	
GP-123	Trenton Dam	-	-	Duplicate site, same as Trenton Dam
GP-124	Tub Springs Creek Diversion Dam	No	Low	Site has no flow available for hydropower during irrigation season; structures are open during remainder of year with no available head for hydropower development
GP-125	Twin Buttes Dam	Yes	Low	
GP-126	Twin Lakes Dam (USBR)	Yes	High	
GP-127	Upper Turnbull Drop Structure	-	-	Site already has hydropower developed or being developed
GP-128	Vandalia Diversion Dam	Yes	Medium	
GP-129	Virginia Smith Dam	Yes	Low	
GP-130	Webster Dam	Yes	High	
GP-131	Whalen Diversion Dam	Yes	High	Site has only one year of data available. Based on one year data, hydropower may be a potential at the site
GP-132	Willow Creek Dam	Yes	High	
GP-133	Willow Creek Dam (MT)	No	Medium	Site has some seasonal flows about 1-2 months per year, model estimated that flows are too low and infrequent for hydropower development at 30 percent flow exceedance, 20 percent flow exceedance would also be 0 cfs
GP-134	Willow Creek Forebay Diversion Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development
GP-135	Willwood Canal	Yes	Medium	Site has seasonal flows
GP-136	Willwood Diversion Dam	Yes	High	
GP-137	Wind River Diversion Dam	Yes	High	Site has seasonal flows
GP-138	Woods Project, Greenfield Main Canal Drop	Yes	Low	
GP-139	Woodston Diversion Dam	No	Low	Data indicates there is no drop into the canal; therefore, no head is available for hydropower development

Table 2-3 Site Data and Hydropower Potential Summary

Site ID	Site Name	Hydropower Potential (yes/no) [1]	Data Confidence Level	Notes (including reason for no hydropower potential)
GP-140	Wyoming Canal - Sta 1016	Yes	Low	
GP-141	Wyoming Canal - Sta 1490	Yes	Low	
GP-142	Wyoming Canal - Sta 1520	Yes	Low	
GP-143	Wyoming Canal - Sta 1626	Yes	Low	
GP-144	Wyoming Canal - Sta 1972	Yes	Low	
GP-145	Wyoming Canal - Sta 997	Yes	Low	
GP-146	Yellowtail Afterbay Dam	Yes	Medium	Crow Tribe has exclusive right to develop power at this Site as part of the "Claims Resolution Act of 2010" (P.L. 111-291) that was signed into law by President Obama on December 8, 2010
LC-1	Agua Fria River Siphon	No	Low	Site is a siphon entrance, data indicates flows are too low for hydropower development (approximately 25 cfs)
LC-2	Agua Fria Tunnel	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 3,000 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this tunnel site to determine hydropower potential
LC-3	All American Canal	No	Low	Data indicates no head is available for hydropower development (approximately 1.97 feet of head); many power plants already exist on the canal
LC-4	All American Canal Headworks	-	-	Duplicate site
LC-5	Arizona Canal	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 2,000 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this canal site to determine hydropower potential
LC-6	Bartlett Dam	Yes	Medium	
LC-7	Buckskin Mountain Tunnel	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 3,000 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this tunnel site to determine hydropower potential
LC-8	Burnt Mountain Tunnel	-	Low	Further analysis needs to be conducted at this site to determine hydropower potential
LC-9	Centennial Wash Siphon	No	Low	Data indicates no head is available for hydropower development
LC-10	Coachella Canal	No	Low	Data indicates no head is available for hydropower development (16.8 feet of head over 123 miles). Field representatives indicated that flows at site are unreliable and insufficient for hydropower development.
LC-11	Consolidated Canal	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 550 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this canal site to determine hydropower

Table 2-3 Site Data and Hydropower Potential Summary

Site ID	Site Name	Hydropower Potential (yes/no) [1]	Data Confidence Level	Notes (including reason for no hydropower potential)
				potential
LC-12	Cross Cut Canal	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 400 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this canal site to determine hydropower potential
LC-13	Cunningham Wash Siphon	No	Low	Data indicates no head is available for hydropower development
LC-14	Eastern Canal	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 360 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this canal site to determine hydropower potential
LC-15	Gila Gravity Main Canal Headworks	Yes	Medium	
LC-16	Gila River Siphon	No	Low	Data indicates no head is available for hydropower development (3.3 feet of head)
LC-17	Grand Canal	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 625 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this canal site to determine hydropower potential
LC-18	Granite Reef Diversion Dam	No	Low	Data indicates no head is available for hydropower development (1.5 feet of head)
LC-19	Hassayampa River Siphon	No	Low	Data indicates no head is available for hydropower development
LC-20	Horseshoe Dam	Yes	Low	Site has seasonal flows
LC-21	Imperial Dam	Yes	Low	Site has seasonal flows
LC-22	Interstate Highway Siphon	No	Low	Data indicates no head is available for hydropower development
LC-23	Jackrabbit Wash Siphon	No	Low	Data indicates no head is available for hydropower development
LC-24	Laguna Dam	Yes	Low	Facility is silted in currently and dredging will be required to have the dam fully functional. Data indicates about 200 cfs flow (assumed seasonal flow during the irrigation season)
LC-25	New River Siphon	No	Low	Data indicates no head is available for hydropower development
LC-26	Palo Verde Diversion Dam	-	-	Reclamation does not own the site
LC-27	Reach 11 Dike	No	Low	Dike structure, no flows available for hydropower generation
LC-28	Salt River Siphon Blowoff	No	Low	Data indicates no head is available for hydropower development
LC-29	Tempe Canal	No	Low	Data indicates no head is available for hydropower development
LC-30	Western Canal	No	Low	Data indicates no head is available for hydropower development
MP-1	Anderson-Rose Dam	Yes	Medium	

Table 2-3 Site Data and Hydropower Potential Summary

Site ID	Site Name	Hydropower Potential (yes/no) [1]	Data Confidence Level	Notes (including reason for no hydropower potential)
MP-2	Boca Dam	Yes	High	
MP-3	Bradbury Dam	Yes	Medium	
MP-4	Buckhorn Dam (Reclamation)	No	Low	Data indicates flows are too low or infrequent for hydropower development
MP-5	Camp Creek Dam	No	Low	Data indicates there is no effective flow through the facility; it is diversion dam collecting runoff
MP-6	Carpenteria	No	Low	Data indicates there is no effective flow through the facility; it is a regulating dam
MP-7	Carson River Dam	No	Low	Data indicates approximately 14 feet of head; field representatives indicated that flows at site are unreliable and insufficient for hydropower development.
MP-8	Casitas Dam	Yes	High	
MP-9	Clear Lake Dam	No	Medium	Model estimated that no heads is available for hydropower development
MP-10	Contra Loma Dam	No	Low	Site is used solely for recreation and emergency municipal water supply should there be a failure in the system. It is not suitable for hydroelectric generation
MP-11	Derby Dam	No	Low	Data indicates no head is available for hydropower development ; all the head is being used to move the water from Truckee River to Lahontan dam
MP-12	Dressler Dam	-	-	Site was de-authorized and was not built
MP-13	East Park Dam	No	Low	Site is a very old facility built in 1908 and has unconventional outlet works
MP-14	Funks Dam	No	Low	Dam is a widening in the canal, there is no flow to capture for hydropower development
MP-15	Gerber Dam	Yes	Medium	Site has seasonal flows
MP-16	Glen Anne Dam	No	Low	Site is a regulating reservoir with a Safety of Dams restriction on use of the dam. Little inflows other than local drainage which gets released into a creek
MP-17	John Franchi Dam	Yes	Low	Site has seasonal flows
MP-18	Lake Tahoe Dam	Yes	High	
MP-19	Lauro Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development
MP-20	Little Panoche Detention Dam	No	Low	Site is a detention dam and only discharges stream flows of only a few cfs during the winter/spring with occasional increases based on rainfall in watershed
MP-21	Los Banos Creek Detention Dam	No	Low	Site is a detention dam operated under Corps flood operating criteria. Infrequent discharges of 100 to 400 cfs are made through outlet works
MP-22	Lost River Diversion Dam	No	Low	Site has no effective head and water is rarely put down the river. Water flows through the canal to the Klamath Project and refuges. There is no generation potential at the site
MP-23	Malone Diversion Dam	Yes	Medium	
MP-24	Marble Bluff Dam	Yes	High	
MP-25	Martinez Dam	No	Low	Site is a terminal reservoir for the Contra Costa Canal and supplies water to the

Table 2-3 Site Data and Hydropower Potential Summary

Site ID	Site Name	Hydropower Potential (yes/no) [1]	Data Confidence Level	Notes (including reason for no hydropower potential)
				City of Martinez and Shell Oil under pressure; would not want to lose any head for hydropower development
MP-26	Miller Dam	No	Low	Data indicates approximately 5 feet of head available at site; field representative indicated that there is no flow at this site for 6 months in most years. Not enough flow and head at site for hydropower development.
MP-27	Mormon Island Auxiliary Dike	No	Low	Data indicates flows are too low or infrequent for hydropower development
MP-28	Northside	No	Low	Data indicates no head is available for hydropower development
MP-29	Ortega Dam	No	Low	Data indicates flows are too low for hydropower development, site is a small regulating reservoir
MP-30	Prosser Creek Dam	Yes	High	
MP-31	Putah Creek Dam	Yes	Medium	
MP-32	Putah Diversion Dam	Yes	Medium	
MP-33	Rainbow Dam	Yes	Medium	
MP-34	Red Bluff Dam	No	Low	
MP-35	Robles Dam	No	Low	Data indicates no flow or head is available for hydropower development, site is a diversion structure
MP-36	Rye Patch Dam	-	-	Title transfers are in progress, no longer a Reclamation site
MP-37	San Justo Dam	No	Low	Site is a terminal/balancing reservoir; reservoir head is needed to deliver water in the system
MP-38	Sheckler Dam	No	Low	Flows to this site are limited and low for hydropower development. The site is also remote (7.1 miles of transmission line distance), which would increase development costs
MP-39	Sly Park Dam	-	-	Reclamation does not own the site
MP-40	Spring Creek Debris Dam	No	Low	Site holds back contaminated water from past mining; not a source for hydropower development
MP-41	Sugar Pine	-	-	Reclamation does not own the site
MP-42	Terminal Dam	No	Low	Data indicates flows are too low for hydropower development, site is a siphon diversion
MP-43	Twitchell Dam	No[2]	Medium	Site has inconsistent flows 2-3 months in some years, model estimated that flows are too low and infrequent for hydropower development at 30 percent flow exceedance, 20 percent flow exceedance would be 150 cfs, site has only 3 years data
MP-44	Upper Slaven Dam	Yes	Medium	
PN-1	Agate Dam	Yes	High	
PN-2	Agency Valley	Yes	High	

Table 2-3 Site Data and Hydropower Potential Summary

Site ID	Site Name	Hydropower Potential (yes/no) [1]	Data Confidence Level	Notes (including reason for no hydropower potential)
PN-3	Antelope Creek	No	Low	Data indicates no head is available for hydropower development, irrigation turnout
PN-4	Arnold Dam	No	Low	Data indicates no head is available for hydropower development, site is a check structure
PN-5	Arrowrock Dam	-	-	Site exempted - FERC docket number 4656
PN-6	Arthur R. Bowman Dam	Yes	High	
PN-7	Ashland Lateral	No	Low	Data indicates no flow or head is available for hydropower development
PN-8	Beaver Dam Creek	No	Low	Data indicates no head is available for hydropower development
PN-9	Bully Creek	Yes	High	
PN-10	Bumping Lake	Yes	High	
PN-11	Cascade Creek	No	Low	Data indicates flows are too low for hydropower development, site is very remote and difficult to access
PN-12	Cle Elum Dam	Yes	High	
PN-13	Clear Creek	No	Low	Data indicates flows are too low or infrequent for hydropower development; site is also called Clear Lake
PN-14	Col W.W. No 4	No	Low	Site is a waste way with no recorded flow data; hydropower potential is not likely
PN-15	Cold Springs Dam	Yes	High	
PN-16	Conconully	No	Low	Data indicates flows are too low or infrequent for hydropower development
PN-17	Conde Creek	No	Low	Data indicates flows are too low for hydropower development, site is a collection dam for Howard Prairie Dam
PN-18	Cowiche	-	-	Site exempted - FERC docket number 7337
PN-19	Crab Creek Lateral #4	-	Low	Further analysis needs to be conducted at this lateral to determine hydropower potential
PN-20	Crane Prairie	Yes	High	
PN-21	Cross Cut	-	-	Site exempted - FERC docket number 3991
PN-22	Daley Creek	No	Low	Data indicates no head is available for hydropower development , site is very remote and difficult to access
PN-23	Dead Indian	No	Low	Data indicates flows are too low for hydropower development, no diversion at the site
PN-24	Deadwood Dam	Yes	High	
PN-25	Deer Flat East Dike	No	Low	Dike structure, no flows available for hydropower generation
PN-26	Deer Flat Middle	No	Low	Dike structure, no flows available for hydropower generation
PN-27	Deer Flat North Lower	No	Low	Dike structure, no flows available for hydropower generation

Table 2-3 Site Data and Hydropower Potential Summary

Site ID	Site Name	Hydropower Potential (yes/no) [1]	Data Confidence Level	Notes (including reason for no hydropower potential)
PN-28	Deer Flat Upper	No	Low	Dike structure, no flows available for hydropower generation
PN-29	Diversion Canal Headworks	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 160 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this canal site to determine hydropower potential
PN-30	Dry Falls - Main Canal Headworks	-	-	Site exempted - FERC docket number 2849
PN-31	Easton Diversion Dam	Yes	High	
PN-32	Eltopia Branch Canal	-	-	Site exempted - FERC docket number 3842
PN-33	Eltopia Branch Canal 4.6	-	-	Site exempted - FERC docket number 3842
PN-34	Emigrant Dam	Yes	High	
PN-35	Esquatzel Canal	-	Low	Further analysis needs to be conducted at this canal to determine hydropower potential
PN-36	Feed Canal	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 350 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this canal site to determine hydropower potential
PN-37	Fish Lake	Yes	High	
PN-38	Fourmile Lake	-	-	Reclamation does not own the site
PN-39	French Canyon	No	Low	Site has very limited storage area and no available hydrologic data
PN-40	Frenchtown	No	Low	Data indicates 13 feet of head available at site; field representatives indicated that flows at site are unreliable and insufficient for hydropower development.
PN-41	Golden Gate Canal	Yes	Low	Development right issued to Boise Project Board of Control, FERC docket number 5056, site has seasonal flows
PN-42	Grassy Lake	No	High	Site has seasonal flow for 3 months in some years, model estimated that flows are too low and infrequent for hydropower development at 30 percent flow exceedance, 20 percent flow exceedance would also be 0 cfs
PN-43	Harper Dam	Yes	Low	Site has seasonal flows
PN-44	Haystack Canal	Yes	High	Site has seasonal flows
PN-45	Howard Prairie Dam	No	High	Model estimated that flows and head are too low for hydropower development, flows less than 5 cfs 95% of the time
PN-46	Hubbard Dam	No	Low	Data indicates no flow or head is available for hydropower development, site is a very shallow and small regulating pond. Available net head is approximately 5 feet and has no flow for most of the year
PN-47	Hyatt Dam	No	Low	Data indicates flows are too low for hydropower development, site is a reregulating reservoir with very low flows

Table 2-3 Site Data and Hydropower Potential Summary

Site ID	Site Name	Hydropower Potential (yes/no) [1]	Data Confidence Level	Notes (including reason for no hydropower potential)
PN-48	Kachess Dam	Yes	Medium	
PN-49	Keechelus Dam	Yes	High	
PN-50	Keene Creek	-	-	Site already has hydropower developed or being developed
PN-51	Little Beaver Creek	No	Low	Data indicates no head is available for hydropower development. Remote site with limited accessibility; diverts water into Howard Prairie
PN-52	Little Wood River Dam	Yes	High	
PN-53	Lytle Creek	Yes	Low	
PN-54	Main Canal No. 10	-	Low	Further analysis needs to be conducted at this canal to determine hydropower potential
PN-55	Main Canal No. 6	-	Low	Further analysis needs to be conducted at this canal to determine hydropower potential
PN-56	Mann Creek	Yes	High	
PN-57	Mason Dam	Yes	High	Site has seasonal flows
PN-58	Maxwell Dam	Yes	Medium	
PN-59	McKay Dam	Yes	High	
PN-60	Mile 28 - on Milner Gooding Canal	-	-	Site already has hydropower developed or being developed
PN-61	Mora Canal Drop	-	-	Site exempted - FERC docket number 3403
PN-62	North Canal Diversion Dam	-	-	Reclamation does not own the site; preliminary permit has been issued for the North Unit
PN-63	North Unit Main Canal	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 1,000 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this canal site to determine hydropower potential
PN-64	Oak Street	No	Low	Data indicates no head is available for hydropower development, site is a diversion structure with approximately 1 foot of available head
PN-65	Ochoco Dam	Yes	High	
PN-66	Orchard Avenue	-	-	Site already has hydropower developed or being developed
PN-67	Owyhee Tunnel No. 1	-	-	Site exempted - FERC docket number 4359
PN-68	PEC Mile 26.3	-	Low	Further analysis needs to be conducted at this canal to determine hydropower potential
PN-69	Phoenix Canal	No	Low	Data indicates no head is available for hydropower development , very small drop over weir
PN-70	Pilot Butte Canal	-	Low	Further analysis needs to be conducted at this canal to determine hydropower potential

Table 2-3 Site Data and Hydropower Potential Summary

Site ID	Site Name	Hydropower Potential (yes/no) [1]	Data Confidence Level	Notes (including reason for no hydropower potential)
PN-71	Pinto Dam	No	Low	Data indicates no flow available for hydropower development.
PN-72	Potholes Canal Headworks	-	-	Site exempted - FERC docket number P-2840
PN-73	Potholes East Canal - PEC 66.0	-	-	Site exempted - FERC docket number P-3843
PN-74	Potholes East Canal 66.0	-	-	Site exempted - FERC docket number 3843
PN-75	Prosser Dam	-	-	Site already has hydropower developed or being developed
PN-76	Quincy Chute Hydroelectric	-	-	Site exempted - FERC docket number 2937
PN-77	RB4C W. W. Hwy26 Culvert	No	Low	Site is a road culvert, a penstock would be necessary for hydropower generation
PN-78	Reservoir "A"	Yes	High	
PN-79	Ringold W. W.	No	Low	Site is a waste way with no recorded flow data; hydropower development is not likely
PN-80	Ririe Dam	Yes	High	
PN-81	Rock Creek	No	Low	Data indicates no head is available for hydropower development. Very small structure with approximately 2 feet of available head
PN-82	Roza Diversion Dam	No	Low	Site receives excess flows from Yakima project with a drop of 20-25 feet. Available flows used for existing Reclamation power plant and fish mitigation
PN-83	Russel D Smith Dam	-	-	Site already has hydropower developed or being developed
PN-84	Saddle Mountain W. W.	No	Low	Site includes 9 drop structures with less than 2 feet of head available at each drop. Estimating piping distance to be 5 miles for 5 feet of head, project considered uneconomical based on estimated data
PN-85	Salmon Creek	-	-	Duplicate site, same as Salmon Lake
PN-86	Salmon Lake	No	Low	Data indicates there are no flows for hydropower development
PN-87	Scoggins Dam	Yes	High	
PN-88	Scootney Wasteway	Yes	Low	Site has seasonal flows
PN-89	Soda Creek	No	Medium	Model estimated that flows and head are too low for hydropower development, flows less than 9 cfs 95% of the time, head is 1 foot
PN-90	Soda Lake Dike	No	Low	Data indicates no head is available for hydropower development, site is a reregulating dike
PN-91	Soldier´s Meadow Dam	No	Medium	Model estimated that flows are too low for hydropower development, flows less than 12 cfs 95% of the time
PN-92	South Fork Little Butte Creek	No	Low	Data indicates flows are too low for hydropower development, estimate of 10 cfs for 4 months of the year with 5 feet of head
PN-93	Spectacle Lake Dike	No	Low	All available flows through the site are used for irrigation
PN-94	Summer Falls on Main Canal	-	-	Site already has hydropower developed or being developed
PN-95	Sunnyside Dam	Yes	Medium	

Table 2-3 Site Data and Hydropower Potential Summary

Site ID	Site Name	Hydropower Potential (yes/no) [1]	Data Confidence Level	Notes (including reason for no hydropower potential)
PN-96	Sweetwater Canal	No	Low	Data indicates no head is available for hydropower development , irrigation structure with head less than 2 feet available
PN-97	Thief Valley Dam	Yes	Medium	
PN-98	Three Mile Falls	No	Low	Site has a prime anadromous fish spotting facility with no flow available for generation
PN-99	Tieton Diversion	-	-	Site already has hydropower developed or being developed
PN-100	Unity Dam	Yes	Medium	
PN-101	Warm Springs Dam	Yes	High	
PN-102	Wasco Dam	No	High	Model estimated that flows are too low for hydropower development, flows less than 20 cfs 95% of the time
PN-103	Webb Creek	No	Low	Data indicates no head is available for hydropower development , site is a small diversion structure with less than 2 feet of head available
PN-104	Wickiup Dam	Yes	High	
PN-105	Wild Horse - BIA	Yes	High	Site has seasonal flows
UC-1	Alpine Tunnel	No	Low	Data indicates no head is available for hydropower development, site is underground
UC-2	Alpine-Draper Tunnel	-	-	Reclamation does not own the site
UC-3	American Diversion Dam	-	-	Reclamation does not own the site, site is owned by a State department
UC-4	Angostura Diversion	Yes	High	
UC-5	Arthur V. Watkins Dam	Yes	High	
UC-6	Avalon Dam	Yes	High	
UC-7	Azeotea Creek and Willow Creek Conveyance Channel Station 1565+00	Yes	Low	Site has seasonal flows
UC-8	Azeotea Creek and Willow Creek Conveyance Channel Station 1702+75	Yes	Low	Site has seasonal flows
UC-9	Azeotea Creek and Willow Creek Conveyance Channel Station 1831+17	Yes	Low	Site has seasonal flows
UC-10	Azotea Creek and Willow Creek Conveyance Channel Outlet	No	Low	Model estimated that head is too low for hydropower development, less than 5 feet
UC-11	Azotea Tunnel	Yes	High	Site has seasonal flows
UC-12	Beck's Feeder Canal	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 94 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this canal site to determine hydropower potential. The site is also remote (11.3 miles of transmission line distance), which would increase development costs

Table 2-3 Site Data and Hydropower Potential Summary

Site ID	Site Name	Hydropower Potential (yes/no) [1]	Data Confidence Level	Notes (including reason for no hydropower potential)
UC-13	Big Sandy Dam	Yes	Medium	
UC-14	Blanco Diversion Dam	Yes	Medium	Site has seasonal flows
UC-15	Blanco Tunnel	Yes	Medium	Site has seasonal flows
UC-16	Brantley Dam	Yes	Medium	
UC-17	Broadhead Diversion Dam	No	Low	Data indicates 5 feet of head available at site; not enough head for hydropower development
UC-18	Brough's Fork Feeder Canal	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 32 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this canal site to determine hydropower potential
UC-19	Caballo Dam	Yes	Low	
UC-20	Cedar Creek Feeder Canal	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 66 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this canal site to determine hydropower potential
UC-21	Cottonwood Creek/Huntington Canal	-	-	Duplicate site, same as Swasey Diversion
UC-22	Crawford Dam	Yes	High	
UC-23	Currant Creek Dam	Yes	High	
UC-24	Currant Tunnel	No	Low	Data indicates no head is available for hydropower development, site is underground
UC-25	Dam No. 13	-	-	Title transfers are in progress, no longer a Reclamation site
UC-26	Dam No. 2	-	-	Title transfers are in progress , no longer a Reclamation site
UC-27	Davis Aqueduct	No	Low	Not a feasible site
UC-28	Dolores Tunnel	Yes	Medium	
UC-29	Docs Diversion Dam	No	Low	Data indicates flows are too low or infrequent for hydropower development
UC-30	Duchesne Diversion Dam	-	-	Duplicate site, same as Duchesne Tunnel
UC-31	Duchesne Tunnel	No[2]	Medium	Site has seasonal flow for 2 months per year, model estimated that flows are too low and infrequent for economical hydropower development at 30 percent flow exceedance, 20 percent flow exceedance would be 64 cfs
UC-32	Duschense Feeder Canal	-	-	Reclamation does not own the site, it is a BIA structure
UC-33	East Canal	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 160 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this canal site to determine hydropower potential

Table 2-3 Site Data and Hydropower Potential Summary

Site ID	Site Name	Hydropower Potential (yes/no) [1]	Data Confidence Level	Notes (including reason for no hydropower potential)
UC-34	East Canal	No	Medium	Site has 2 feet head and low and infrequent flows for economical hydropower development
UC-35	East Canal Diversion Dam	No	Low	Data indicates 8 feet of head available at site; field representatives indicated that flows at site are unreliable and insufficient for hydropower development.
UC-36	East Canyon Dam	Yes	High	
UC-37	East Fork Diversion Dam	No	Low	Data indicates 8 feet of head available at site with a diversion capacity of 30 cfs. Flow and head not enough for hydropower development
UC-38	Eden Canal	No	Low	Data indicates no head is available for hydropower development , all the head available is being used to move water in the canal
UC-39	Eden Dam	No	High	Site has seasonal flows about 1-2 months per year, model estimated that flows are too low and infrequent for economical hydropower development at 30 percent flow exceedance, 20 percent flow exceedance would be 25 cfs
UC-40	Ephraim Tunnel	-	Low	Tunnel is designed to carry 95 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this tunnel site to determine hydropower potential .The site is also remote (11.9 miles of transmission line distance), which would increase development costs
UC-41	Farmington Creek Stream Inlet	-	Low	Further analysis needs to be conducted at this inlet to determine hydropower potential
UC-42	Fire Mountain Diversion Dam	No	Low	Data indicates no head is available for hydropower development
UC-43	Florida Farmers Diversion Dam	No	Low	Data indicates 14 feet of head available at site; field representatives indicated that flows at site are unreliable and insufficient for hydropower development.
UC-44	Fort Sumner Diversion Dam	Yes	High	
UC-45	Fort Thornburgh Diversion Dam	No	Low	Data indicates 9 feet of head available at site;field representatives indicated that flows at site are unreliable and insufficient for hydropower development.
UC-46	Fruitgrowers Dam	Yes	High	
UC-47	Garnet Diversion Dam	No	Medium	Site has 2 feet head and low and infrequent flows for economical hydropower development
UC-48	Gateway Tunnel	No	Low	Data indicates no head is available for hydropower development , site is a 3.2-mile long tunnel
UC-49	Grand Valley Diversion Dam	Yes	Medium	
UC-50	Great Cut Dike	No	Low	Dike structure, no flows available for hydropower generation
UC-51	Gunnison Diversion Dam	Yes	Medium	
UC-52	Gunnison Tunnel	Yes	Medium	
UC-53	Hades Creek Diversion Dam	No	Low	Data indicates no head is available for hydropower development
UC-54	Hades Tunnel	No	Low	Data indicates no head is available for hydropower development, site is underground

Table 2-3 Site Data and Hydropower Potential Summary

Site ID	Site Name	Hydropower Potential (yes/no) [1]	Data Confidence Level	Notes (including reason for no hydropower potential)
UC-55	Haights Creek Stream Inlet	-	Low	Further analysis needs to be conducted at this inlet to determine hydropower potential
UC-56	Hammond Diversion Dam	Yes	Medium	
UC-57	Heron Dam	Yes	Medium	
UC-58	Highline Canal	No	Low	Data indicates canal capacity is approximately 8 cfs; not enough flow available at site for hydropower development
UC-59	Huntington North Dam	Yes	High	
UC-60	Huntington North Feeder Canal	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 100 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this canal site to determine hydropower potential
UC-61	Huntington North Service Canal	-	-	Duplicate site, same Huntington North Dam
UC-62	Hyrum Dam	Yes	High	
UC-63	Hyrum Feeder Canal	No	Low	Data indicates canal capacity is approximately 9 cfs; not enough flow available at site for hydropower development
UC-64	Hyrum-Mendon Canal	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 90 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this canal site to determine hydropower potential
UC-65	Indian Creek Crossing Div. Dam	-	-	Site no longer exists
UC-66	Indian Creek Dike	-	-	Site no longer exists
UC-67	Inlet Canal	Yes	Medium	
UC-68	Ironstone Canal	No	Low	Model estimated that no head is available for hydropower development
UC-69	Ironstone Diversion Dam	No	Low	Data indicates 13 feet of head available at site; field representatives indicated that flows at site are unreliable and insufficient for hydropower development.
UC-70	Isleta Diversion Dam	No	Low	Model estimated that no head is available for hydropower development, head ranges from 0 to 2 feet
UC-71	Jackson Gulch Dam	-	-	Site already has hydropower developed or being developed
UC-72	Joes Valley Dam	Yes	High	Site has seasonal flows
UC-73	Jordanelle Dam	-	-	Site already has hydropower developed or being developed
UC-74	Knight Diversion Dam	No	Low	Data indicates no head is available for hydropower development
UC-75	Layout Creek Diversion Dam	No	Low	Model estimated that flows are too low for hydropower development, flows less than 2 cfs 95% of the time
UC-76	Layout Creek Tunnel	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 620 cfs. Further analysis needs to be conducted to collect seasonal flow

Table 2-3 Site Data and Hydropower Potential Summary

Site ID	Site Name	Hydropower Potential (yes/no) [1]	Data Confidence Level	Notes (including reason for no hydropower potential)
				distribution and net head data at this tunnel site to determine hydropower potential
UC-77	Layton Canal	No	Low	Data indicates no head is available for hydropower development , all the head available is being used to move water in the canal
UC-78	Leasburg Diversion Dam	No	Low	Data indicates 7 feet of head available at site; field representatives indicated that flows at site are unreliable and insufficient for hydropower development.
UC-79	Leon Creek Diversion Dam	No	Low	Data indicates 10 feet of head available at site; field representatives indicated that flows at site are unreliable and insufficient for hydropower development.
UC-80	Little Navajo River Siphon	No	Low	Site is a buried siphon structure that offers no effective access and no potential for hydropower development. Redesign and construction would be needed to maintain design flow, available head is approximately 7 feet
UC-81	Little Oso Diversion Dam	No	Medium	Site has 9 feet head and low and infrequent flows for economical hydropower development.
UC-82	Little Sandy Diversion Dam	No	Low	Data indicates 5 feet of head available at site; not enough head for hydropower development
UC-83	Little Sandy Feeder Canal	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 150 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this canal site to determine hydropower potential. The site is also remote (15.7 miles of transmission line distance), which would increase development costs
UC-84	Lost Creek Dam	Yes	High	
UC-85	Lost Lake Dam	No	Low	Site has less than 15 feet head and low and infrequent flows for economical hydropower development
UC-86	Loutzenheizer Canal	No	Low	Data indicates no head is available for hydropower development
UC-87	Loutzenheizer Diversion Dam	No	Low	Model estimated no head is available for hydropower development
UC-88	Lucero Dike	No	Low	Dike structure, no flows available for hydropower generation
UC-89	M&D Canal-Shavano Falls	Yes	Low	Site has less than 3 years of data available
UC-90	Madera Diversion Dam	No	Low	Data indicates 13 feet of head available at site; field representatives indicated that flows at site are unreliable and insufficient for hydropower development.
UC-91	Main Canal	-	-	Duplicate site, same as Newton Dam
UC-92	Means Canal	-	-	Duplicate site, same as Big Sandy Dam
UC-93	Meeks Cabin Dam	Yes	High	Site has seasonal flows
UC-94	Mesilla Diversion Dam	No	Low	Data indicates 10 feet of head available at site; field representatives indicated that flows at site are unreliable and insufficient for hydropower development.
UC-95	Middle Fork Kays Creek Stream Inlet	-	Low	Further analysis needs to be conducted at this inlet to determine hydropower potential

Table 2-3 Site Data and Hydropower Potential Summary

Site ID	Site Name	Hydropower Potential (yes/no) [1]	Data Confidence Level	Notes (including reason for no hydropower potential)
UC-96	Midview Dam	-	-	Reclamation does not own the site, it is a BIA structure
UC-97	Mink Creek Canal	No	Low	Data indicates canal capacity is approximately 36 cfs; not enough flow available at site for hydropower development
UC-98	Montrose and Delta Canal	Yes	Low	
UC-99	Montrose and Delta Div. Dam	No	Low	Data indicates 10 feet of head available at site; field representatives indicated that flows at site are unreliable and insufficient for hydropower development.
UC-100	Moon Lake Dam	Yes	High	
UC-101	Murdock Diversion Dam	-	-	Title transfers are in progress, no longer Reclamation sites
UC-102	Nambe Falls Dam	Yes	Low	
UC-103	Navajo Dam Diversion Works	-	-	Title transfers are in progress; site will no longer be a Reclamation site after transfer is complete
UC-104	Newton Dam	No	High	Site has low seasonal flow for 5 months per year, model estimated that flows are too low and infrequent for hydropower development at 30 percent flow exceedance, 20 percent flow exceedance would be 6 cfs
UC-105	Ogden Brigham Canal	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 120 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this canal site to determine hydropower potential
UC-106	Ogden Valley Canal	-	-	Duplicate site, same as Ogden Valley Diversion Dam
UC-107	Ogden Valley Diversion Dam	No	Low	Site has 6 feet head and low and infrequent flows for economical hydropower development
UC-108	Ogden-Brigham Canal	-	-	Duplicate site
UC-109	Olmstead Diversion Dam	-	-	Site already has hydropower developed or being developed
UC-110	Olmsted Tunnel	-	-	Title transfers are in progress, no longer a Reclamation site
UC-111	Open Channel #1	-	-	Duplicate site, same flow as Vat Tunnel (Baffled channels)
UC-112	Open Channel #2	-	-	Duplicate site, same flow as Water Hollow Tunnel
UC-113	Oso Diversion Dam	No	Medium	Model estimated that no head is available for hydropower development
UC-114	Oso Feeder Conduit	-	Low	Closed conduit with a diversion capacity of 150 cfs. Diverts water from Little Navajo River to Oso Tunnel. No available head data. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this canal site to determine hydropower
UC-115	Oso Tunnel	-	Low	Data available indicates that 72 feet of head available at site. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this canal site to determine hydropower potential
UC-116	Outlet Canal	Yes	Medium	Site has seasonal flows

Table 2-3 Site Data and Hydropower Potential Summary

Site ID	Site Name	Hydropower Potential (yes/no) [1]	Data Confidence Level	Notes (including reason for no hydropower potential)
UC-117	Paonia Dam	Yes	Medium	
UC-118	Park Creek Diversion Dam	No	Low	Data indicates 8 feet of head available at site; field representatives indicated that flows at site are unreliable and insufficient for hydropower development.
UC-119	Percha Arroyo Diversion Dam	No	Low	Data indicates flows are too low for hydropower development, diverts only seasonal storm water flow
UC-120	Percha Diversion Dam	No	Low	Data indicates 8 feet of head available at site; field representatives indicated that flows at site are unreliable and insufficient for hydropower development.
UC-121	Picacho North Dam	No	Low	Data indicates flows are too low for hydropower development, diverts only seasonal storm water flow
UC-122	Picacho South Dam	No	Low	Data indicates flows are too low for hydropower development, diverts only seasonal storm water flow
UC-123	Pineview Dam	-	-	Site already has hydropower developed or being developed
UC-124	Platoro Dam	Yes	High	Site has seasonal flows
UC-125	Provo Reservoir Canal	-	-	Title transfers are in progress, no longer a Reclamation site
UC-126	Red Fleet Dam	Yes	High	
UC-127	Rhodes Diversion Dam	No	Low	Model estimated that flows and head are too low for hydropower development, flows are less than 24 cfs 95% of the time and head is 7 feet
UC-128	Rhodes Flow Control Structure	No	Low	Structure is a valve and not a viable site for hydropower development
UC-129	Rhodes Tunnel	No	Low	Data indicates no head is available for hydropower development , site is underground
UC-130	Ricks Creek Stream Inlet	-	Low	Further analysis needs to be conducted at this inlet to determine hydropower potential
UC-131	Ridgway Dam	Yes	High	
UC-132	Rifle Gap Dam	Yes	High	
UC-133	Riverside Diversion Dam	No	Low	Site has dam safety issues, not a feasible site due to safety concerns
UC-134	S. Ogden Highline Canal Div. Dam	No	Low	Data indicates no head is available for hydropower development
UC-135	San Acacia Diversion Dam	Yes	Medium	
UC-136	Scofield Dam	Yes	High	Site has seasonal flows
UC-137	Selig Canal	Yes	Low	Site has seasonal flows
UC-138	Selig Diversion Dam	No	Low	Data indicates 10 feet of head available at site; field representatives indicated that flows at site are unreliable and insufficient for hydropower development.
UC-139	Sheppard Creek Stream Inlet	-	Low	Further analysis needs to be conducted at this inlet to determine hydropower potential
UC-140	Silver Jack Dam	Yes	High	

Table 2-3 Site Data and Hydropower Potential Summary

Site ID	Site Name	Hydropower Potential (yes/no) [1]	Data Confidence Level	Notes (including reason for no hydropower potential)
UC-141	Sixth Water Flow Control	Yes	Medium	
UC-142	Slaterville Diversion Dam	No	Low	Site has 8 feet head and low and infrequent flows for economical hydropower development
UC-143	Smith Fork Diversion Dam	No	Low	Site has 10 feet head and low and infrequent flows for economical hydropower development
UC-144	Soldier Creek Dam	Yes	High	
UC-145	South Canal Tunnels	Yes	Medium	
UC-146	South Canal, Sta 19+ 10 "Site #1"	Yes	Medium	
UC-147	South Canal, Sta. 181+10, "Site #4"	Yes	Medium	
UC-148	South Canal, Sta. 472+00, "Site #5"	Yes	Medium	
UC-149	South Canal, Sta. 72+50, Site #2"	-	Low	No flow data was available for Fairview, which feeds water into the South Canal Site #2. Further analysis needs to be conducted at this canal to determine hydropower potential
UC-150	South Canal, Sta.106+65, "Site #3"	Yes	Medium	
UC-151	South Feeder Canal	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 60 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this canal site to determine hydropower potential. The site is also remote (14.1 miles of transmission line distance), which would increase development costs
UC-152	South Fork Kays Creek Stream Inlet	-	Low	Further analysis needs to be conducted at this inlet to determine hydropower potential
UC-153	Southside Canal	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 240 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this canal site to determine hydropower potential
UC-154	Southside Canal, Sta 171+ 90 thru 200+ 67 (2 canal drops)	Yes	Low	Less than 3 years of data
UC-155	Southside Canal, Sta 349+ 05 thru 375+ 42 (3 canal drops)	Yes	Low	Less than 3 years of data
UC-156	Southside Canal, Station 1245 + 56	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 240 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this canal site to determine hydropower potential
UC-157	Southside Canal, Station 902 + 28	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 240 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this canal site to determine hydropower

Table 2-3 Site Data and Hydropower Potential Summary

Site ID	Site Name	Hydropower Potential (yes/no) [1]	Data Confidence Level	Notes (including reason for no hydropower potential)
				potential
UC-158	Spanish Fork Diversion Dam	No	Low	Data indicates 13 feet of head available at site; field representatives indicated that flows at site are unreliable and insufficient for hydropower development.
UC-159	Spanish Fork Flow Control Structure	Yes	Medium	
UC-160	Spring City Tunnel	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 95 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this tunnel site to determine hydropower potential.
UC-161	Staight Creek Stream Inlet	-	Low	Further analysis needs to be conducted at this inlet to determine hydropower potential
UC-162	Starvation Dam	Yes	High	
UC-163	Starvation Feeder Conduit Tunnel	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 300 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this tunnel site to determine hydropower potential. The site is also remote (7.6 miles of transmission line distance), which would increase development costs
UC-164	Stateline Dam	Yes	High	
UC-165	Station Creek Tunnel	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 250 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this tunnel site to determine hydropower potential
UC-166	Steinaker Dam	Yes	High	Site has seasonal flows
UC-167	Steinaker Feeder Canal	No	Low	Data indicates no head is available for hydropower development , all the head available is being used to move water in the canal
UC-168	Steinaker Service Canal	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 300 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this canal site to determine hydropower potential
UC-169	Stillwater Tunnel	Yes	Medium	
UC-170	Stoddard Diversion Dam	No	Low	Data indicates 8 feet of head available at site; field representatives indicated that flows at site are unreliable and insufficient for hydropower development.
UC-171	Stone Creek Stream Inlet	-	Low	Further analysis needs to be conducted at this inlet to determine hydropower potential
UC-172	Strawberry Tunnel Turnout	No	Low	Model estimated that head and flow is too low for hydropower development, 6-8 cfs flow and 2 feet of head
UC-173	Stubblefield Dam	-	-	Title transfers are in progress, no longer a Reclamation site

Table 2-3 Site Data and Hydropower Potential Summary

Site ID	Site Name	Hydropower Potential (yes/no) [1]	Data Confidence Level	Notes (including reason for no hydropower potential)
UC-174	Sumner Dam	Yes	Medium	
UC-175	Swasey Diversion Dam	No	Medium	Site has low seasonal flows about 4-5 months per year, model estimated that flows are too low and infrequent for economical hydropower development at 30 percent flow exceedance, 20 percent flow exceedance would be 47 cfs, head is 5 feet
UC-176	Syar Inlet	-	-	Duplicate site, same as Syar Tunnel
UC-177	Syar Tunnel	Yes	Medium	
UC-178	Tanner Ridge Tunnel	-	Low	This site is remote (6.1 miles of transmission line distance), which would increase development costs. Further analysis needs to be conducted at this tunnel site to determine hydropower potential
UC-179	Taylor Park Dam	Yes	High	
UC-180	Towoac Canal	-	Low	Further analysis needs to be conducted at this canal to determine hydropower potential
UC-181	Trial Lake Dam	No	Low	Site has low seasonal flows about 1-2 months per year, model estimated that flows are too low and infrequent for economical hydropower development at 30 percent flow exceedance, 20 percent flow exceedance would be 9 cfs,
UC-182	Tunnel #1	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 1,675 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this tunnel site to determine hydropower potential
UC-183	Tunnel #2	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 1,675 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this tunnel site to determine hydropower potential
UC-184	Tunnel #3	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 730 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this tunnel site to determine hydropower potential
UC-185	Upper Diamond Fork Flow Control Structure	Yes	Medium	
UC-186	Upper Diamond Fork Tunnel	-	-	Duplicate site, same Upper Diamond Fork Flow Control Structure
UC-187	Upper Stillwater Dam	Yes	Medium	
UC-188	Vat Diversion Dam	No	Medium	Site has low seasonal flows about 3-5 months per year, model estimated that flows are too low and infrequent for hydropower development at 30 percent flow exceedance, 20 percent flow exceedance would be 2 cfs
UC-189	Vat Tunnel	No	Low	Data indicates no head is available for hydropower development , all the head available is being used to move water in the tunnel

Table 2-3 Site Data and Hydropower Potential Summary

Site ID	Site Name	Hydropower Potential (yes/no) [1]	Data Confidence Level	Notes (including reason for no hydropower potential)
UC-190	Vega Dam	Yes	Medium	Site has seasonal flows
UC-191	Vermejo Diversion Dam	-	-	Title transfers are in progress, no longer a Reclamation site
UC-192	Washington Lake Dam	No	Low	Site has low and infrequent flows for economical hydropower development, flows are less than 20 cfs 95% of the time
UC-193	Water Hollow Diversion Dam	No	Low	Model estimated that flows and head are too low for hydropower development, flows are less than 6 cfs 95% of the time and head is 15 feet
UC-194	Water Hollow Tunnel	-	-	Duplicate site, same as Open Channel 2
UC-195	Weber Aqueduct	No	Low	Data indicates no head is available for hydropower development
UC-196	Weber-Provo Canal	Yes	Low	
UC-197	Weber-Provo Diversion Canal	Yes	Medium	
UC-198	Weber-Provo Diversion Dam	-	-	Duplicate site, same as Weber-Provo Canal
UC-199	Wellsville Canal	No	Low	Data indicates canal capacity is approximately 15 cfs; not enough flow available at site for hydropower development
UC-200	West Canal	No	Low	Model estimated that head is too low for hydropower development
UC-201	West Canal Tunnel	-	-	Duplicate site, same as West Canal
UC-202	Willard Canal	No	Low	Data indicates no head is available for hydropower development , all the head available is being used to move water in the canal
UC-203	Win Diversion Dam	No	Low	Data indicates no head is available for hydropower development
UC-204	Win Flow Control Structure	No	Low	Structure is a valve, not a viable site for hydropower development
UC-205	Yellowstone Feeder Canal	-	Low	Data available indicates that the maximum flow based on design capacity at this site is 88 cfs. Further analysis needs to be conducted to collect seasonal flow distribution and net head data at this canal site to determine hydropower potential

[1] Model estimated hydropower potential at 30% flow exceedance
[2] Sites have no potential at 30% flow exceedance. See “Notes” column and Chapter 5-Section 5.8 for information on hydropower potential at 20% exceedance

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Chapter 3 Site Analysis Methods and Assumptions

This chapter describes the methods and assumptions used for the sites' power potential and economic analysis. Figure 3-1 shows the general steps of the analysis.

This analysis estimates power production, economic benefits, and costs of the potential hydropower development at the sites, described in Sections 3.1, 3.2, and 3.3. The final calculation is a benefit cost ratio and internal rate of return (IRR) to evaluate the overall economic effectiveness of power production at each site, described in Section 3.4. The analysis is conducted using the Hydropower Assessment Tool, which is described in Chapter 4. The Boca Dam site in California in the Mid Pacific region is used as an example in this chapter to further explain how methods and assumptions were applied.

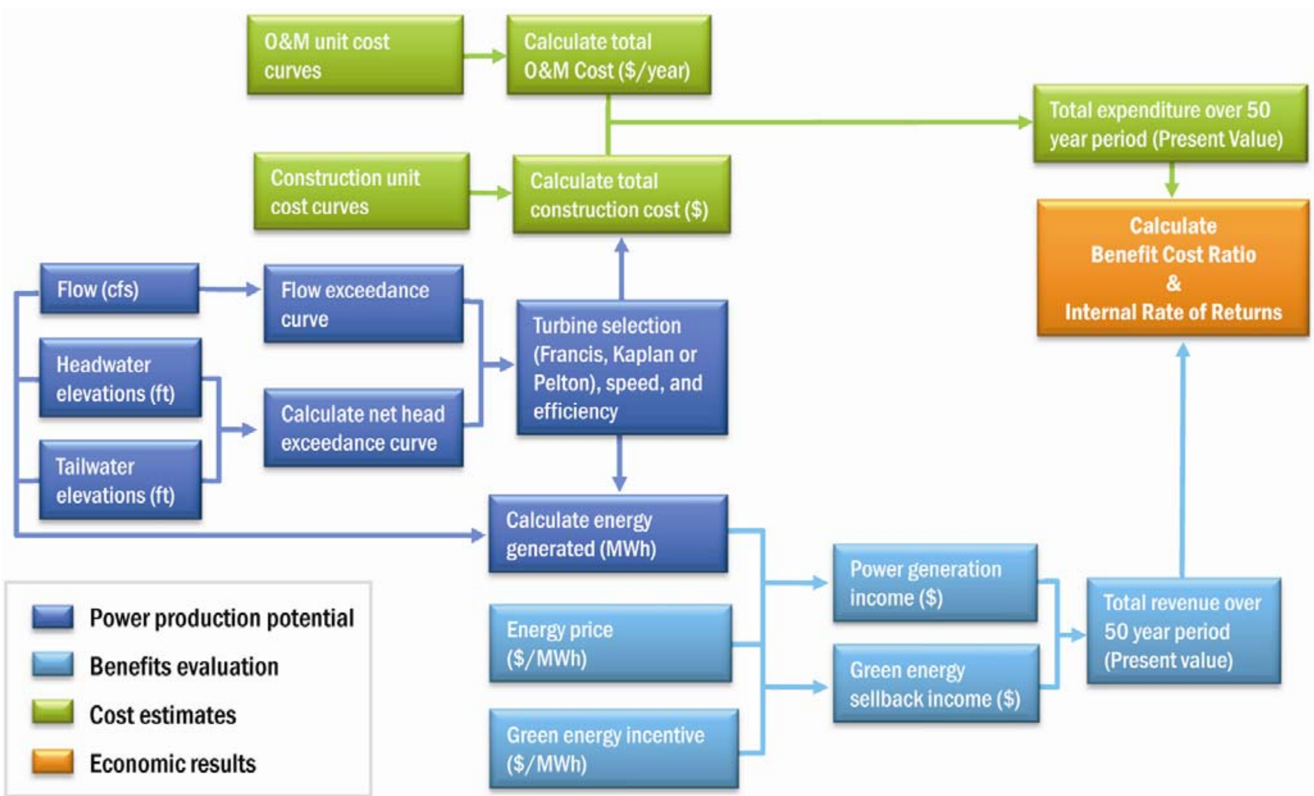

Figure 3-1 Resource Assessment Process Flow Chart

3.1 Power Production Potential

The first step to assess the feasibility of hydropower at a site is to determine the amount of power that can be produced at the site, which is primarily a product of the flow rate and head. Higher flow and higher head mean more available power. Data collection efforts described in Chapter 2 provided the flow and net head data needed to determine the power production potential. Flow rate and head measurements are used to define the hydropower system, including turbine capacity, type, and efficiency. Because of the broad geographic scope and preliminary planning level assessment, this analysis assumes that the hydropower plant would be located at the site (i.e., no extensive penstocks are assumed) and there would be one turbine operating unit. These assumptions should be revisited if a particular site if further analyzed. The following sections describe design factors and assumptions applied in the power production analysis.

3.1.1 Design Head and Flow

The analysis develops flow and net head exceedance curves using flow, head water, and tail water input data. Figures 3-2 and 3-3 show example flow and net head exceedance curves for the Boca Dam. Exceedance curves indicate the percentage of time a particular flow or head is possible for a given set of historic hydrologic and head data.

For this analysis, design flow and design head for the turbine are set at the 30 percent exceedance level. For purposes of this analysis, the 30 percent exceedance level represents a generally held industry standard which would result in an estimate in the range of the optimal installed capacity per dollar of capital investment. A lower exceedance level can be used, such as 20 percent, which would typically result in a higher installed capacity for the site; however it may also cause incremental costs to increase faster than incremental energy generated. Section 5.7 presents a sensitivity analysis of using a 20 percent exceedance level for selected sites.

For the Boca Dam site, based on the exceedance curves in Figures 3-2 and 3-3, 30 percent flow exceedance is 179 cfs and 30 percent net head exceedance is 91.5 feet. The installed capacity of the turbine is selected based on this flow and net head.

3.1.2 Turbine Selection and Efficiency

After the design flow and head are calculated for each site, a specific turbine type is selected for the site. In general, turbines can be classified as impulse turbines or reaction turbines. Impulse turbines operate in air, driven by one or more high velocity jets of water. Impulse turbines are typically used with high-head systems and use nozzles to produce high velocity jets. Reaction turbines run fully immersed in water and are typically used in lower-head systems.

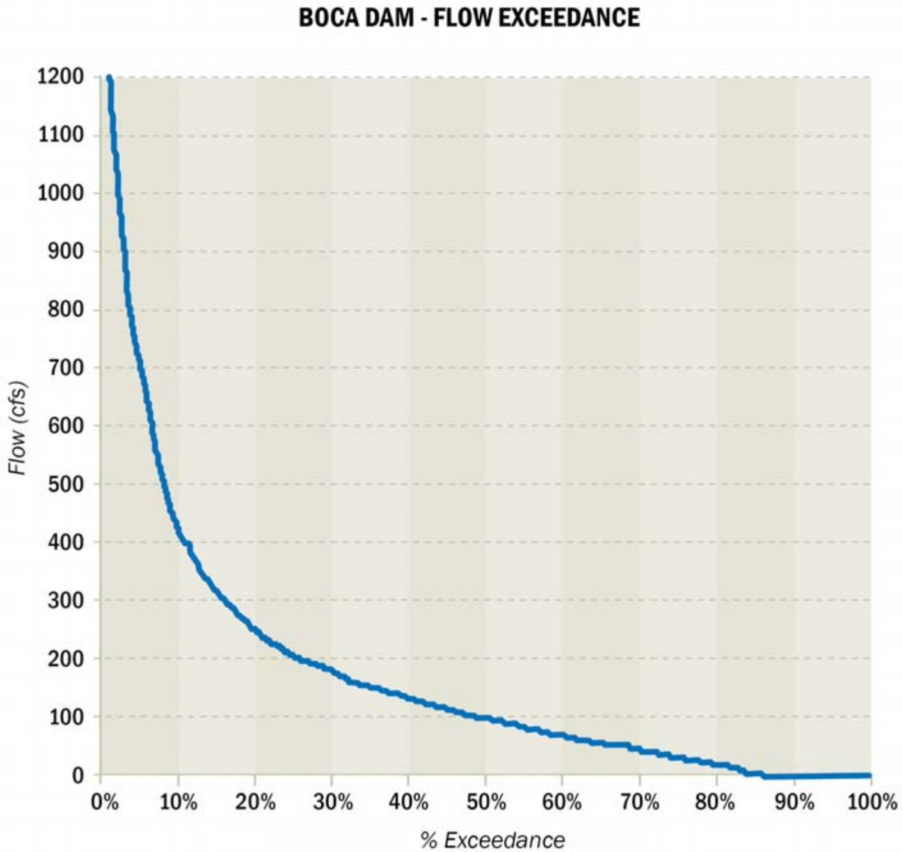

Figure 3-2 Boca Dam Flow Exceedance Curve

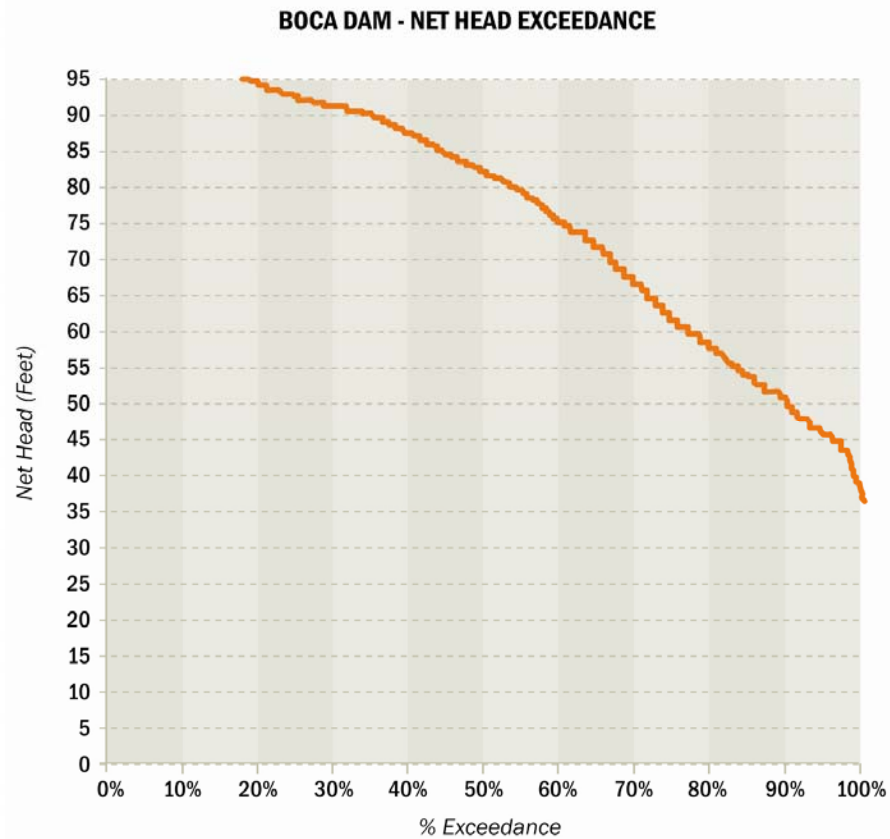

Figure 3-3 Boca Dam Net Head Exceedance Curve

In most cases, the impulse and reaction turbines in use today are designs named after their inventors. Examples of impulse turbines include Pelton and Turgo. Examples of reaction turbines include Francis, Kaplan, and Propeller. This analysis assigns Pelton, Kaplan, Francis turbine to each potential hydropower site based on the design head and flow and typical operating ranges of the turbine types.

Figure 3-4 is the turbine selection matrix used in the analysis. The matrix also includes a low-head turbine, which, for this analysis, is considered a modified Francis turbine. Based on the calculated design head of 91.5 feet and design flow of 179 cfs at the Boca Dam site, the turbine selection matrix indicates that a Francis turbine should be selected for this site.

Turbines operate at varying efficiency levels. The turbine runs most efficiently when it turns exactly fast enough to consume all the energy of the water. Hill diagrams, or performance curves, are developed to show efficiency at different operating percentages of design flow and head. Hill diagrams for Pelton, Francis, and Kaplan turbines are used in the analysis to evaluate turbine efficiency at different operating levels.

The following sections further describe the turbine types and efficiency levels used in the hydropower analysis.

500 kW Canyon Pelton Turbine for Colorado Springs Utility

Pelton Turbine

Pelton turbines are widely used in hydropower plants with high heads. Pelton turbines are impulse type turbines that use the kinetic energy in water. When water passes from a pressurized pen stock to the nozzle, it forms a jet stream which forces the turbine rotation, through impact on the turbine runner buckets. The runner is fixed on a shaft, and the rotational motion of the turbine is transmitted by the shaft to a generator. These turbines operate economically over a broad range of flows and heads.

Figure 3-5 depicts an example typical hill diagram for a Pelton turbine. The bounded region in the diagram shows the approximate limits of normal operation with head on the horizontal axis and power on the vertical axis. The curves shown on the diagram are corresponding efficiencies for given heads versus power output. The flow rate is not shown on the diagram and instead is calculated based on the net head, power output, and efficiency for any point of operation.

TURBINE SELECTION MATRIX

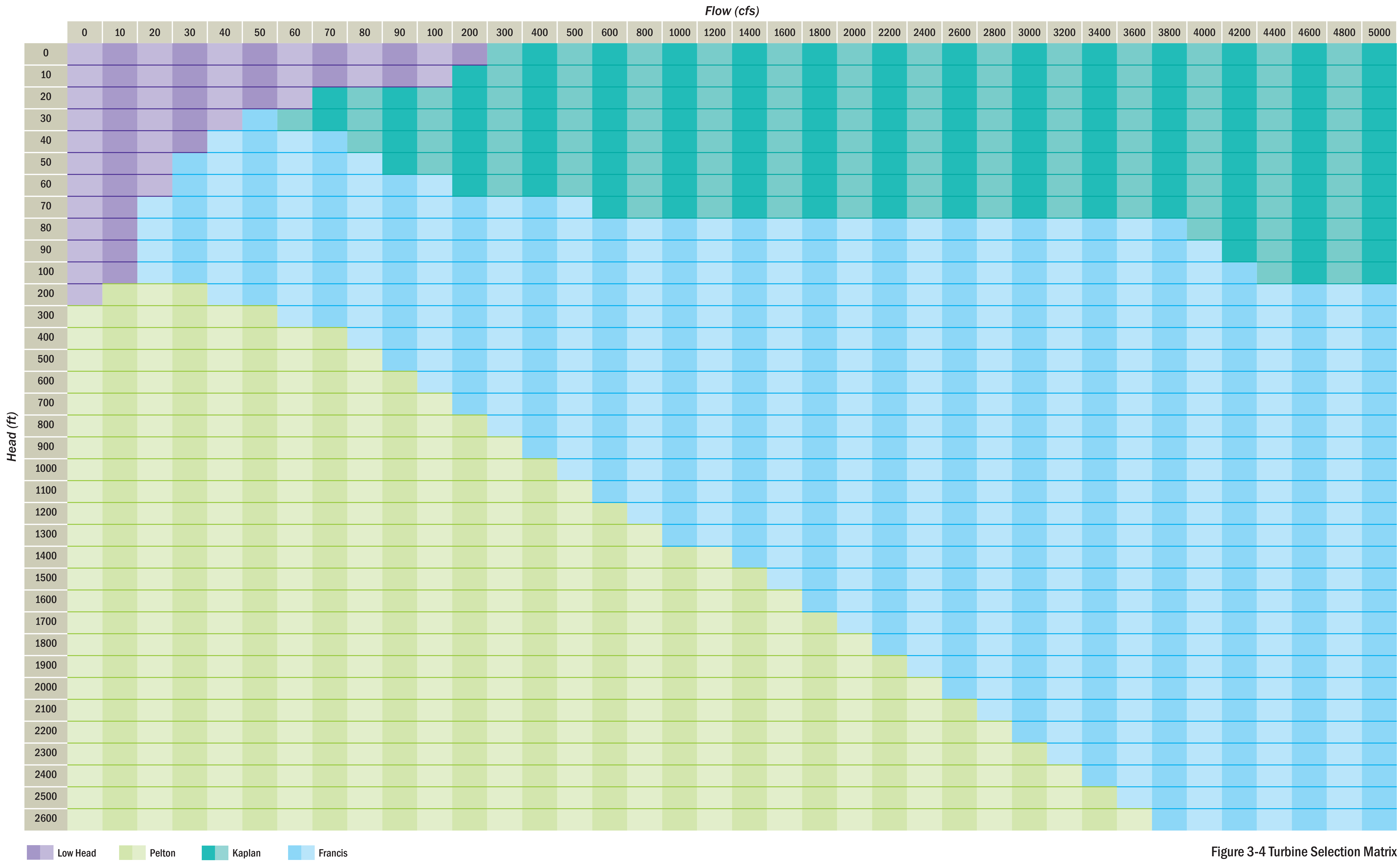

Figure 3-4 Turbine Selection Matrix

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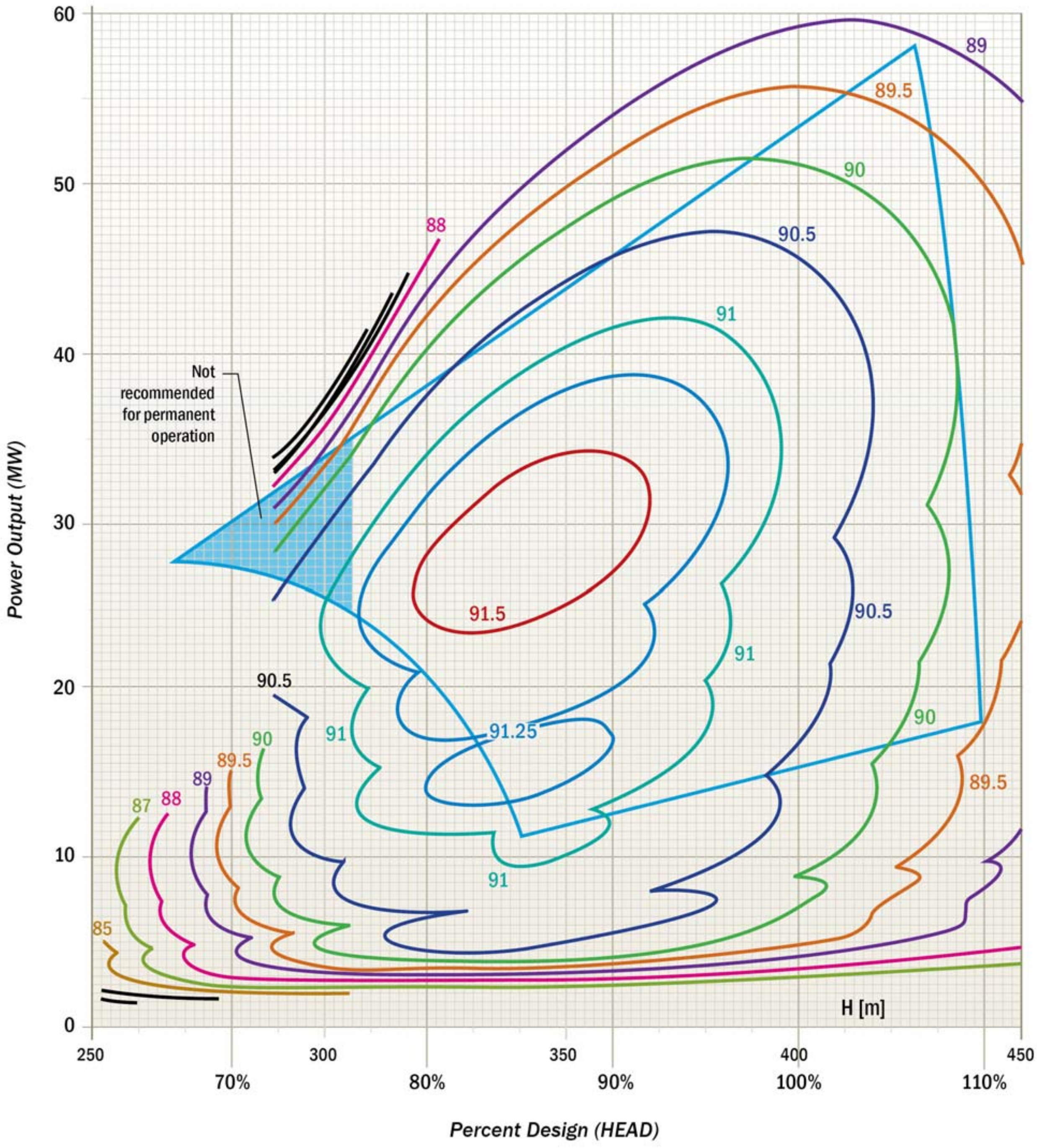

Figure 3-5 Pelton Turbine Hill Diagram

Kaplan Turbine

Kaplan turbines are primarily used in the low head range with large volumes of water. The turbine is made up of adjustable runner blades and adjustable wicket gates that control the flow. The adjustable runner blades enable high efficiency even in the range of partial load; and, there is little drop in efficiency due to head variation or load, but over a more narrow range than Pelton turbines.

Figure 3-6 shows a generalized hill diagram for a Kaplan turbine depicting efficiencies for a range of operating heads and flows. A typical Kaplan turbine can operate between 65 percent and 125 percent of the design head and down to roughly 20 percent of the design flow.

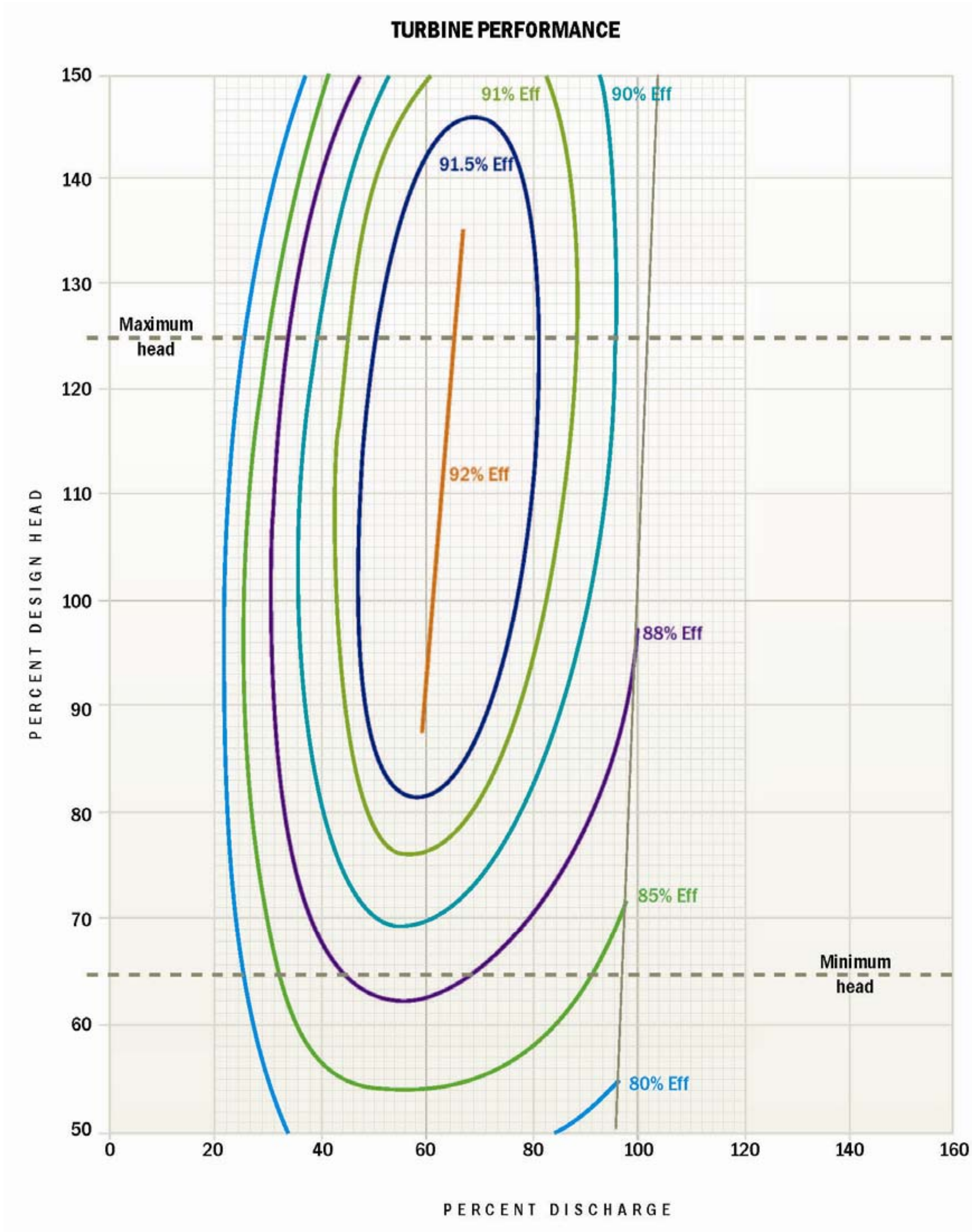

Figure 3-6 Kaplan Turbine Hill Diagram

Francis Turbine

Francis turbines are primarily used for medium to high head hydropower plants. The Francis runner is typically fitted directly to the generator shaft, which supports compact construction and low maintenance. Francis turbines are characterized by their optimal efficiency and high speed ranges. Francis turbine can adjust quickly to varying flows. The turbines typically have a worm-scroll case structure that directs water flow in easily and smoothly, and therefore, improves the overall turbine efficiency.

720 kW Canyon Francis for Swalley Irrigation District, Ponderosa Hydro

Figure 3-7 shows a generalized hill diagram for a Francis turbine. A typical Francis turbine has high efficiencies in a range of 65 percent to 125 percent of design head and can have relatively high efficiencies down to about 25 percent of the design flow. For example, the Boca Dam site turbine, with a design head of 91.5 feet and flow of 179 cfs, would operate most efficiently when head is between about 82 feet and 100 feet, and can operate efficiently when flow is about 150 cfs.

Low-Head Turbine

A number of the Reclamation sites that were analyzed had relatively low heads (less than 20 feet) and/or low flows (less than 10 cfs). These sites were generally sized at less than 100 kW. In these cases, a downsized Francis turbine with a set operating efficiency of 75 percent was used to estimate power production.

3.1.3 Power Production Calculations

Using available head and flow data, selected design head, flow, turbine type and efficiency, the analysis estimates average monthly and annual power generation at each site. Table 3-1 shows monthly average capacity and energy produced, and plant capacity factors, at a Boca Dam site. Average capacity indicates the average kW of capacity for each month. For example, the plant design capacity (also known as installed or nameplate capacity) is 1,184 kW (1.2 MW), but the machine only produces the equivalent power 43 percent (plant factor) of the time. Therefore, the average plant capacity is approximately 43 percent of the installed capacity. Average energy is the average energy production each month at the site. The average energy values are used to calculate power generation benefits, described in Section 3.2.1.

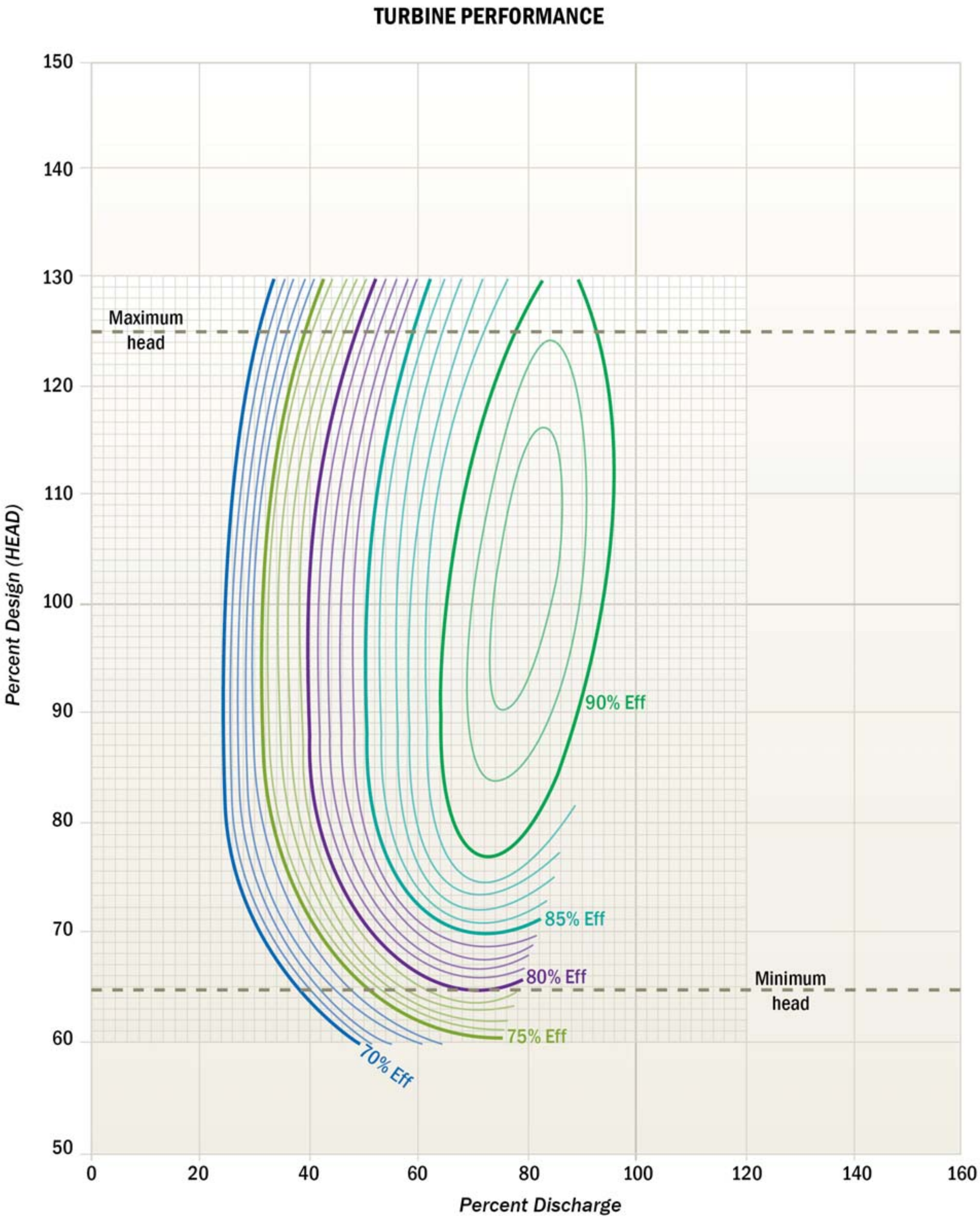

Figure 3-7 Francis Turbine Hill Diagram

Table 3-1 Generation Data for Boca Dam Site (for 30 year data set)

Months	Average Operating Capacity (kW)	Average Energy (MWh)
January	265	191
February	290	195
March	384	276
April	684	493
May	849	611
June	720	519
July	651	469
August	522	376
September	573	412
October	516	372
November	363	262
December	272	196
Annual		4,370
	Plant Design Capacity (kW)	1,184
	Average Plant Capacity (kW)	508
	Plant Peak Capacity (kW)	1,320
	Plant Factor	0.429

3.2 Benefits Evaluation

This analysis evaluates the economic benefits of potential hydropower development at the identified sites. The conceptual basis for the economic benefits of a new hydropower facility is society's willingness to pay for additional energy. The economic procedures for assessing willingness to pay values can be costly and time consuming, especially when considering the number, size, and geographic range of the sites included in this report. Therefore, an expedited method of estimating benefits was necessary.

Federal planning supports valuing the benefits of new hydroelectric power by use of wholesale market prices, which is the method used in this analysis. Because a focus of this report is identifying potential opportunities from a private hydropower development perspective, it is important to recognize other cost savings, or benefits, to a private developer. Given the current national emphasis on renewable energy development, green incentive programs are available that could reduce total development costs. This analysis quantifies potential green incentives available to support hydropower development based on the best available data.

The following sections further describe methods and data to quantify economic benefits from power generation and green incentives.

3.2.1 Power Generation

The Northwest Power and Conservation Council (Council) 6th Northwest Conservation and Electric Power Plan (February 2010) provided projections of regional wholesale power market prices, which were used to quantify economic benefits from new power generation. The Council used the AURORA$^{xmp®}$ Electric Market Model to forecast market prices. Prices are forecast each year through 2030 and were projected to increase in real terms at a rate above inflation. Hourly prices in the model are based on the variable cost of the most expensive generating plant or increment of load curtailment needed to meet load for each hour of the forecast period. With AURORA$^{xmp®}$, the Council simulated plant dispatch in 16 load-resource areas making up the Western Electricity Coordinating Council electric reliability area. The forecast prices vary across the load resource areas.

Because of the large geographic scope of this report, the hydropower assessment is performed on a state level. Thirteen of the 16 AURORA$^{xmp®}$ load resource areas are in the western United States. In some instances, the 13 areas did not correspond with a state boundary; in these cases, the prices were configured to best represent an entire state. In addition, the eastern tier of Reclamation states was not included in the 13 areas; for these states, the average prices across the 13 areas were utilized. Table 3-2 summarizes how the areas in AURORA$^{xmp®}$ were adjusted to a state basis for use in the hydropower assessment.

Table 3-2 Development of Prices Using Aurora$^{xmp®}$ Areas

Resource Assessment State	Corresponding AURORA$^{xmp®}$ Area(s)
Arizona	Arizona
California	Average of California North and California South
Colorado	Colorado
Idaho	Idaho South
Kansas	Average of 13 AURORA$^{xmp®}$ areas
Montana	Montana East
Nebraska	Average of 13 AURORA$^{xmp®}$ areas
Nevada	Average of Nevada North and Nevada South
New Mexico	New Mexico
North Dakota	Average of all 13 AURORA$^{xmp®}$ areas
Oklahoma	Average of all 13 AURORA$^{xmp®}$ areas
Oregon	Pacific Northwest West
South Dakota	Average of all 13 AURORA$^{xmp®}$ areas
Texas	Average of all 13 AURORA$^{xmp®}$ areas
Utah	Utah
Wyoming	Wyoming
Washington	Pacific Northwest

The analysis uses monthly "all hours" prices, which incorporate peak and off-peak prices. Prices were adjusted from 2006 to 2010 dollars to match construction and O&M costs using the AURORA$^{xmp®}$ general inflation index of 1.098. The analysis calculates benefits over a 50 year period of analysis; therefore, energy prices are required through 2060. The analysis assumes that the monthly 2030 forecast prices remain constant through 2060. Table 3-3 shows "all hours" energy price forecasts for January for five states in the hydropower assessment. There are similar price forecasts for each month for each state in the analysis. The prices for California are used to calculate power benefits for the Boca Dam site. The prices were multiplied by monthly energy generation to calculate the economic benefit. The Hydropower Assessment Tool contains the complete price forecast data.

Table 3-3 All-hours Price Forecasts for January from 2014 through 2060 ($/MWh)

Year	Arizona	California	Colorado	Idaho	Kansas
2014	$55.39	$60.99	$54.85	$54.53	$56.21
2015	$60.17	$65.97	$59.55	$59.33	$60.91
2016	$63.42	$69.52	$63.75	$63.19	$64.76
2017	$66.55	$72.27	$67.97	$66.81	$68.19
2018	$68.40	$73.97	$70.31	$68.70	$70.25
2019	$70.17	$75.96	$71.92	$70.96	$72.20
2020	$71.79	$77.53	$74.34	$72.60	$74.01
2021	$73.37	$79.47	$75.24	$74.37	$75.77
2022	$75.02	$81.35	$76.00	$75.75	$77.21
2023	$76.92	$84.03	$77.25	$77.74	$79.34
2024	$77.93	$85.39	$78.91	$78.87	$80.61
2025	$79.80	$87.46	$79.72	$80.52	$82.23
2026	$80.46	$88.67	$80.02	$81.43	$83.25
2027	$81.16	$89.63	$79.92	$82.21	$83.88
2028	$81.94	$90.86	$79.86	$83.34	$84.93
2029	$82.48	$91.57	$80.42	$84.29	$85.77
2030-2060	$83.23	$92.66	$81.20	$84.94	$86.66

3.2.2 Green Incentives

A wide variety of financial incentives for the implementation of renewable energy generation are available for new facilities within the United States; however, hydropower generation is not eligible in many programs. Therefore, even with the wide range of incentives available, incentives are limited for hydropower. This analysis incorporated financial incentives currently available for the generation of hydropower.

This analysis focuses on performance-, or generation-, based incentives, which generally include a utility providing cash payment to a renewable energy generator based on the amount of kilowatt hours (kWh) of renewable energy generated. Performance-based incentives are potentially available for hydropower generation for Arizona, California, and Washington states and at the Federal level.

Installation-based incentives, in the form of rebates, tax credits, or grants, are also available for new renewable energy generation. These incentives vary depending on location, ownership, generation capacity, and date of implementation and must be evaluated on a case by case basis. As a result, installation-based incentives are not included in the calculation of green benefits, but are described in further detail in Appendix B.

Federal Performance-based Incentives

The federal renewable electricity production tax credit is a per-kilowatt-hour tax credit for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person during the taxable year. Credits are generally given for 10 years following in service date. The tax credit is $0.011 per kWh for facilities in service by December 31, 2013. If sites are developed by Reclamation, they would not be eligible for the Federal incentive, but could qualify for state-sponsored incentives, described below.

State Performance-based Incentives

Performance-based incentives at the state level are only available for Arizona, California, and Washington. Arizona and Washington allow the state incentives to be stacked with the Federal incentive described above. Many of the remaining states have a wide range of financial incentives for renewable energy but those incentives do not include hydropower generation. Some states do not have any performance-based incentive programs available. Table 3-4 summarizes performance-based incentives for all states included in the analysis for hydropower. Appendix B provides further detail on implementation requirements for performance-based incentives.

Table 3-4 Available Hydropower Performance Based Incentives

State	Incentive Value	Notes
Arizona	\$0.054/kWh	20 year agreement, can be stacked with Federal incentive[1].
California	\$0.0984/kWh	Applicable to small hydropower facilities up to 3 MW, 20 year agreement, cannot be stacked with Federal incentive or participate in other state programs.
Colorado	Use Federal incentive rate	No state performance-based incentives available
Idaho	Use Federal incentive rate	No state performance-based incentives available
Kansas	Use Federal incentive rate	No state performance-based incentives available

Table 3-4 Available Hydropower Performance Based Incentives

State	Incentive Value	Notes
Montana	Use Federal incentive rate	Performance-based incentives do not apply to hydropower
Nebraska	Use Federal incentive rate	No state performance-based incentives available
Nevada	Use Federal incentive rate	Performance-based incentives available, but cannot be quantified at this time
New Mexico	Use Federal incentive rate	Performance-based incentives do not apply to hydropower
North Dakota	Use Federal incentive rate	Performance-based incentives do not apply to hydropower
Oklahoma	Use Federal incentive rate	No state performance-based incentives available
Oregon	Use Federal incentive rate	No state performance-based incentives available
South Dakota	Use Federal incentive rate	No state performance-based incentives available
Texas	Use Federal incentive rate	Performance-based incentives do not apply to hydropower
Utah	Use Federal incentive rate	Performance-based incentives do not apply to hydropower
Wyoming	Use Federal incentive rate	No state performance-based incentives available
Washington	$0.21/kWh	Available in first year of service, can be stacked with Federal incentive

Notes:
1 – Federal incentive rate is $0.011 per KWh for the first 10 years of service

If the site is in Arizona, California, or Washington, the state incentive was applied, with applicable rules indicated in Table 3-4. The Federal incentive was also included, if allowed, in total green incentive benefits. Note California renewable energy programs do not allow stacking with the Federal incentive program. Green energy benefits for all other states were calculated using the Federal incentive rate. For example, the Boca Dam site is in California; therefore, the State incentive rate of $0.0984 for the first 20 years was applied to calculate green energy benefits. The Federal incentive rate of $0.011 cannot be stacked on to the California state incentive rate.

3.3 Cost Estimates

This analysis incorporates cost estimating functions for construction costs, other non-construction development costs, and for the various annual expenses that would be expected for operations. Construction costs include those for the major equipment components, ancillary mechanical and electrical equipment, and the civil works. In estimating the total cost of development, various costs are added to the construction cost such as those required for licensing and a menu of potentially required mitigation costs, depending on the specifics of the project. The annual operation and maintenance expenses encompass water and hydraulic expenses, fees and taxes in addition to maintenance expenses, and funds for major component replacement or repair.

Cost estimates for the individual components were based on studies previously performed by INL in 2003 and from more recent experience data. The INL analysis was based on a survey of a wide range of cost components and a large number and sizes of projects and essentially involved a historical survey of costs associated with different existing facilities proved effective in estimating costs on a wide physical and geographic range of potential sites. These costs included licensing, construction, fish and wildlife mitigation, water quality monitoring, and O&M, as well as other categories of costs with the cost factors dependent on the size of the generating capacity of a proposed facility. INL acquired historical data on licensing, construction, and environmental mitigation from a number of sources including Federal Energy Regulatory Commission (FERC) environmental assessment and licensing documents, U.S. Energy Information Administration data, Electric Power Research Institute reports, and other reports on hydropower construction and environmental mitigation.

Cost estimating equations were then derived through generalized least squares regression techniques where the only statistically significant independent variable for each cost estimator was plant capacity. All data in the INL report were escalated to 2002 dollars. For purposes of the current study, the cost estimating equations were updated to 2010 by escalating the INL equations based on applicable Reclamation cost indices.

Appendix C provides a summary of the cost estimating equations.

3.3.1 Construction Costs

Total construction costs within the assessment tool include those for civil works, turbines, generators, balance of plant mechanical and electrical, transformers and transmission lines. Other additions include contingencies, sales taxes, and engineering and construction management. These construction costs reflect those that would be applicable to all projects but do not include potential mitigation measures which are subsequently included in the total development cost.

In estimating these costs, project information carried over from other worksheets within the model includes the plant capacity, turbine type, the design head, generator rotational speed, and transmission line length and voltage. Applicable cost equations are then applied to develop estimates for the specific cost categories. Applied to the summation of these costs is a contingency of 20 percent, state sales tax based on the project location, and an assumed engineering and construction management cost of 15 percent.

3.3.2 Total Development Costs

The total development cost includes the construction cost with the addition of a variety of other costs that are, or may be, required. Those additional costs, applicable to all projects include licensing and/or lease of power privilege costs and the transmission-line right-of-way.

Other costs that may apply, depending on the specific site, include fish passage requirements, historical and archaeological studies, water quality monitoring, and mitigation for fish and wildlife, and recreation. The magnitude of the above mitigation costs is dependent on the installed capacity of the project. In general, mitigation costs would increase the larger the project. The constraints analysis, described in Section 3.5, was used to determine if the above environmental and mitigation costs should be applied to the total development cost. If a site was in an area of a potential constraint, costs were assumed to apply to the site. Table 3-5 summarizes how regulatory constraints were interpreted as mitigation costs. For some sites, Reclamation's area offices had additional data on fish and wildlife, fish passage, and water quality issues at particular sites. Relevant mitigation costs were also added based on the local data provided. In the example for the Boca Dam site, the Reclamation area office indicated a Recreation and Historical & Archeological constraint could be present at the site; therefore, mitigation costs were added to the total development costs. In general, mitigation costs are very site-specific and should be reevaluated if a site is further analyzed. Mitigation costs could differ significantly than those presented in this analysis. Further, additional constraints may exist at the sites that are not identified in this analysis, which could also add to total development costs.

Table 3-5 Association Between Mitigation Costs and Constraints

Mitigation Cost Categories	Constraints Applicable to Mitigation Costs
Fish and Wildlife	Critical Habitat, National Wildlife Refuge
Recreation	National Forest, National Park, National Historic Area, National Monuments, Wild and Scenic Rivers, Wilderness Preservation Areas, National Wildlife Refuge
Historical and Archaeological	Indian Lands, National Historic Areas
Water Quality	Need more site specific information to apply water quality mitigation costs. Received data for some sites from Reclamation area offices. Some monitoring is included in annual O&M costs as water expenses
Fish Passage	Need more site specific information to apply fish passage costs. Received data for some sites from Reclamation area offices.

3.3.3 Operation and Maintenance Costs

The O&M costs reflect a variety of expenses and fees expected for most projects. These expenses include fixed and variable O&M expenses, federal fees or charges from FERC or other agencies, charges for transmission of power generated or interconnection fees, insurance, taxes, overhead, and the long-term funding of major repairs. The estimates for these expenses are based on either the installed capacity or the total construction cost, with several costs estimated as fixed lump sums. Similar to power prices and total development costs, O&M costs are expressed in 2010 dollars.

3.3.4 Cost Calculations

Table 3-6 summarizes the costs calculated for the Boca Dam site based on the above discussion of construction, development, and O&M costs. Appendix C includes cost equations. Cost calculations are similar for all sites. In general, turbine and generator costs are the highest components of total construction costs. Boca Dam site is 1.14 miles away from a transmission line, which is a relatively short distance, and results in lower transmission line construction costs. As noted above, distance to the transmission line does not necessarily indicate that an interconnection to the line is permissible. Further evaluation of the site may result in different transmission costs. The total development cost and annual O&M costs are used to calculate the present value of costs for the benefit cost analysis.

The cost per installed capacity ($/installed kW) is also calculated for each site to indicate development feasibility as related to costs. Potential hydropower sites that have unit costs in the range of less than $3,000-$6,000/installed kW are typically more feasible than sites with higher unit costs. The Boca Dam site has a calculated unit cost of $3,711/kW.

Table 3-6 Example Costs for Boca Dam Site

Cost Component	**Cost ($)**
Total Direct Construction Cost	**3,020,666**
Civil Works	413,583
Turbine(s)	651,112
Generator(s)	382,846
Balance of Plant Mechanical	130,222
Balance of Plant Electrical	133,996
Transformer	48,109
Transmission-Line	262,200
Contingency (20%)	404,414
Sales Taxes	200,185
Engineering and CM (15%)	394,000
Total Development Costs	**4,393,028**
Licensing Cost	0
Total Direct Construction Cost	877,844
T-Line Right-of-Way	3,020,666
Fish & Wildlife Mitigation	41,455

Table 3-6 Example Costs for Boca Dam Site

Cost Component	Cost ($)
Recreation Mitigation	0
Historical & Archeological	306,261
Water Quality Monitoring	146,802
Fish Passage	0
Annual O&M Expense	**144,379**
Fixed Annual O&M	29,509
Annual Variable O&M	29,760
FERC Charges	1,676
Transmission / Interconnection	10,000
Insurance	9,062
Taxes	36,248
Management / Office / Overhead	15,103
Major Repairs Fund	3,021
Reclamation / Federal Administration	10,000

3.4 Benefit Cost Ratio and Internal Rate of Return

The final step of the analysis is the calculation of the benefit cost ratio and IRR. Both are calculated over the 50-year period of analysis, 2011 to 2060. The construction period is assumed to be 3 years for all sites. Annual O&M costs begin after construction of the site is complete. Benefits, both power production and green energy benefits, also begin after construction is complete.

The benefit cost ratio compares the present value of benefits during the period of analysis to the present value of costs. The present value is calculated using the Fiscal Year 2010 Federal discount rate of 4.375 percent. A benefit cost ratio greater than 1.0 indicates the quantified benefits exceed costs for the project.

The IRR is an alternate measure of the worth of an investment. It is the discount rate that makes the present value of benefits equal to the present value of costs. Investments with higher IRRs are more economically favorable than investments with lower IRRs. IRR can be computed as a negative value, which clearly indicates that the project is uneconomic. In these cases, the results show a “negative” rather than a negative numeric estimate, due to limitations in Excel.

Table 3-7 summarizes the benefit cost ratio and IRR calculated for the Boca Dam site. The analysis presents the benefit cost ratio and IRR with and without green incentive benefits. The same calculations are made for all sites with available data. Boca Dam is a good example of a marginal project made economically feasible after the green incentive in California is taken into account.

Table 3-7 Boca Dam Site Benefit Cost Ratio and IRR Summary

Present Worth of Costs[1] (million)	$6.5
Present Worth of Benefits[1] (with Green Incentive) (million)	$11.0
Present Worth of Benefits[1] (w/o Green Incentive) (million)	$5.9
Benefit Cost Ratio (with Green)	1.68
IRR (with Green)	11.3%
Benefit Cost Ratio (w/o Green)	0.89
IRR (w/o Green)	3.4%

Note:

All costs in 2010 dollars

1- Total and Present Value Costs Calculated over 50-year Period of Analysis at 4.375% discount rate

3.5 Constraints Analysis

For this analysis, constraints are defined as land or water use regulations that could potentially affect development of hydropower sites. Constraints can either block development completely or add significant costs for mitigation, permitting, or further investigation of the site. Table 3-5 summarizes how constraints were incorporated into the development costs for a site. Some sites have existing development constraints, such as existing permits or rights to develop a site are already issued to a particular entity. Table 2-3 identifies development rights on sites that are known to Reclamation. The regulatory constraints analysis does not consider existing development rights.

3.5.1 Potential Regulatory Constraints

This study considers the following regulatory designations as potential constraints to hydropower development. Some constraints, such as National Parks, prohibit development within regulatory boundaries. For other constraints, management agencies would need to be consulted for potential development of a site. There may be other constraints applicable to each site. This is a broad overview of potential regulatory constraints; feasibility level analysis could identify additional constraints, some that may prohibit development at the site.

- **National Wildlife Refuges –** public lands and water set aside to protect and restore fish and wildlife habitat. Allows some recreational uses including fishing, hunting, observation, photography, education, and interpretation. United States Fish and Wildlife Service (USFWS) manages the National Wildlife Refuge System.

- **Wild and Scenic Rivers –** selected rivers classified as wild, scenic, or recreational to be preserved in free-flowing conditions. Designation neither prohibits development nor gives the federal government control over private property. The Bureau of Land Management (BLM), National Park Service (NPS), USFWS, and US Forest Service (USFS) can administer the National Wild and Scenic Rivers System.

- **National Parks –** lands reserved for natural, scenic, and historic properties for use by current and future generations. Established as an act of the United States Congress. National Park Service manages National Park System. Hydropower development is not allowed in National Parks.

- **National Monuments –** historic landmarks, historic and prehistoric structures, and other objects of historic or scientific interest. The President can declare a National Monument without the approval of Congress. BLM, NPS, USFWS, or USFS can administer National Monuments.

- **Wilderness Study Areas –** lands managed to preserve natural conditions, but are not included in the National Wilderness Preservation System until Congress passes wilderness legislation. Some WSAs permit motorized uses, such as off-road vehicles. Bureau of Land Management manages Wilderness Study Areas.

- **Critical Habitat –** lands designated as essential to the conservation of a species lists on the Federal Endangered Species Act. Designation does not set up a preserve or refuge and does not necessarily prohibit development. Applies when federal funding, permits, or projects are involved. USFWS and National Oceanic and Atmospheric Administration administer the Endangered Species Act.

- **Wilderness Preservation Area** - lands managed to preserve natural conditions under the National Wilderness Preservation System. Activities restricted to non-motorized uses. BLM, NPS, USFWS, or USFS own and administer Wilderness Preservation Areas.

- **National Forest** - forest and woodland areas managed by the USFS. Commercial uses, such as timber harvesting, livestock grazing are permitted, as well as recreation uses.

- **National Historic Areas** - protected areas of national historic significance including districts, sites, buildings, structures, or other historic objects. Listed on the National Register of Historic Places. NPS administers National Historic Areas.

- **Indian Lands** - lands with boundaries established by treaty, statute, or executive or court order, recognized by the Federal government as territory in which American Indian tribes have primary governmental authority. The Bureau of Indian Affairs administers land held in trust for American Indians, Indian tribes, and Alaska Natives.

3.5.2 Constraint Mapping

The above regulatory constraints have been mapped using Geographic Information System (GIS) data. Figure 3-8 shows the constraint boundaries mapped within Reclamation's regions. Appendix F discusses sources for GIS data. Using site coordinate data, the hydropower assessment sites were added to the constraints maps. If a site is close to or within a constraint area, it was assumed that the regulatory constraint is applicable to the site. As discussed in Section 3.3.2, the appropriate development costs were then applied to the site.

3.5.3 Local Information for Fish and Wildlife and Fish Passage Constraints

Reclamation's regional and area offices provided additional information on potential fish and wildlife and fish passage constraints. Fish and wildlife and fish passage issues could add significant development costs to a project site. Although this analysis cannot identify specific issues for each site, it has attempted to capture if potential issues may be present at the site. If Reclamation's offices identified that fish and wildlife and fish passage were a potential constraint at the site, mitigation costs were added to the total development costs of the site. As noted previously, depending on specific issues, costs could differ significantly from those used in the analysis. Because of the preliminary nature and geographic scope of the analysis, all sites could not be evaluated individually for fish and wildlife concerns.

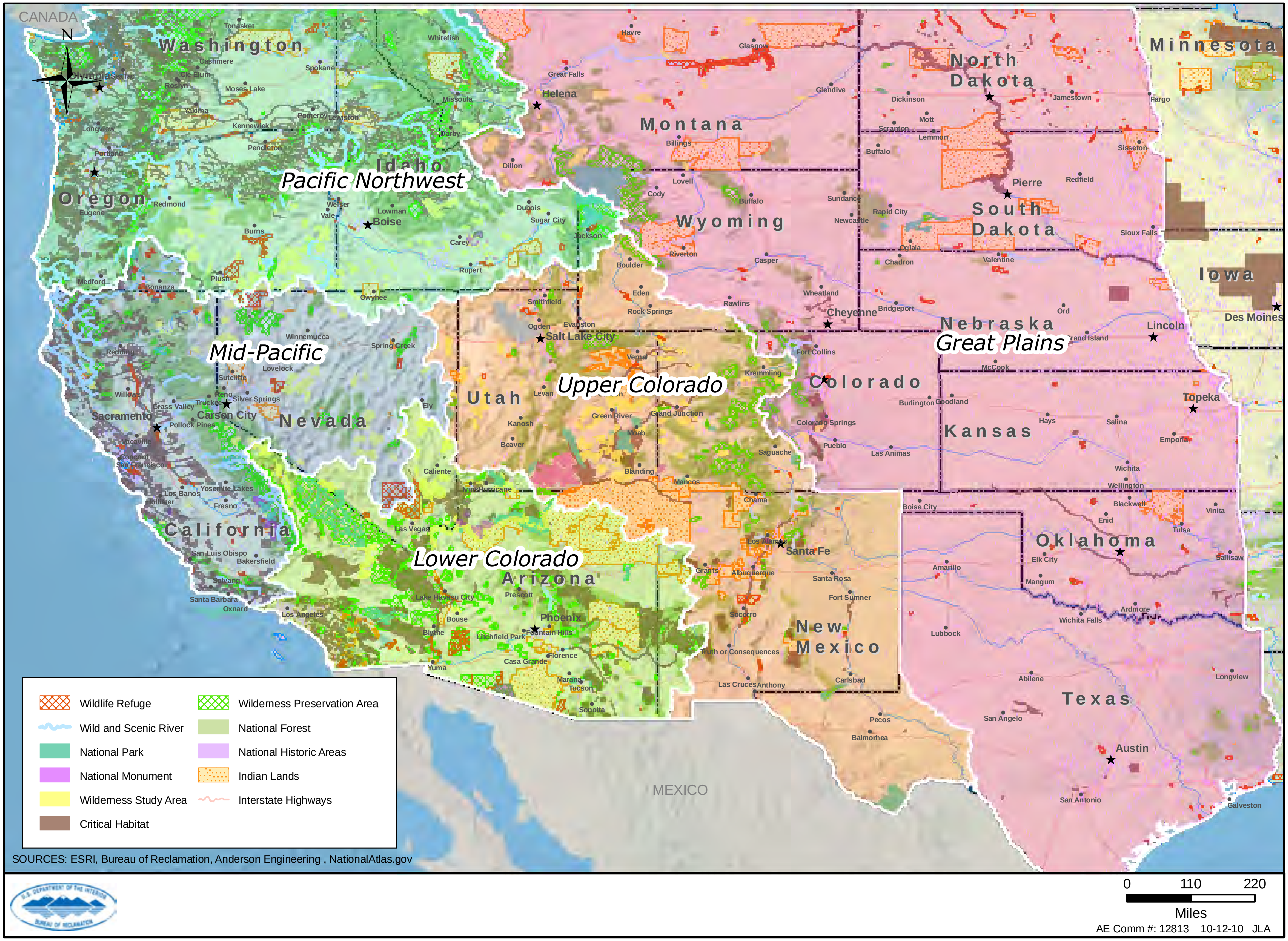

Figure 3-8 : Regulatory Constraints

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Chapter 4 Hydropower Assessment Tool

Reclamation developed the Hydropower Assessment Tool to estimate potential energy generation and economic benefits at the identified Reclamation facilities. The Hydropower Assessment Tool incorporates all the analysis components and assumptions described in Chapter 3. Data described in Chapter 2, including the state the site is located in, flow, head water and tail water elevation, and transmission line distance, is required for input into the model at a minimum. Appendix D includes a detailed user's manual for the Hydropower Assessment Tool. This chapter describes the model software, components, uses, and limitations.

4.1 Model Software

The Hydropower Assessment Tool is an Excel spreadsheet model with embedded macro functions programmed in Visual Basic. Microsoft Excel 2007 was used to develop the model.

4.2 Model Components

The Hydropower Assessment Tool spreadsheet includes 15 separate tabs or worksheets, including several input data sheets, worksheets that contain information used as databases within the model, and worksheets that perform calculations. The calculations are based on the data input for a specific site and from the internal databases. The worksheets are set up in user friendly and logical sequence with only two worksheets requiring input from the user, if sites are in the assessment study area. This section summarizes the worksheets in the model; the bold headers below are the actual names of the worksheets in the model. Appendix D is a user's manual for the model.

- **USBR** - includes the Disclaimer Statement and a link to the Start worksheet.

- **Start** – includes instructions for use of the model and cells where non-hydrologic inputs (state, transmission line voltage and distance, and constraints) are made. This worksheet also includes the buttons to run the model. There are three steps to running the model, which should be run in sequence from top to bottom. The model run is complete when the Results worksheet is displayed.

- **Input Data** – where the daily flow data, head water and tail water elevation is input. A minimum of 1 year of data is required and there can be no blanks in the sequence.

- **Flow Exceedance** – develops and displays the flow duration curve based on input flow data.

- **Net Head Exceedance** - develops and displays the net head duration curve based on input head water and tail water elevation data.

- **Turbine Type –** includes the turbine selection matrix (Figure 3-4) and selects a turbine based on 30 percent flow and net head exceedance. Also includes Pelton, Francis, and Kaplan turbine efficiencies tables based on Hill diagram performance curves and a generator speed matrix used in the cost calculations.

- **Generation –** performs the power and energy generation calculations.

- **Power Exceedance –** shows the power exceedance curve calculated based on generation calculations in the previous worksheet.

- **Plant Cost –** calculates cost estimates for construction, total development cost, and estimated annual costs.

- **BC Ratio and IRR –** presents the stream of benefits and costs over the 50-year period of analysis and calculates the benefit cost ratio and IRR.

- **Results** – presents a comprehensive summary of results of energy generation calculation and the economic analysis.

- **Other State** – allows the user to input the green incentives and price projection values for states outside of the 17 western states in Reclamation’s regions. If the user selects “Other” in the Project Location drop down menu in the Start worksheet, these values must be entered.

- **Price Projections –** includes the monthly price forecasts through 2060 for each state included in the analysis to calculate power generation benefits.

- **Green Incentives** – includes the performance-based green incentive values used for each state to calculate green incentive benefits.

- **Templates –** shows the input data required in the model, in the appropriate format to run the model.

4.3 Model Usage

The Hydropower Assessment Tool can be used in the evaluation of any potential hydropower site that has a continuous period of daily flow records, defined head water and tail water elevations, and the distance to the nearest transmission line. The model can use this minimum amount of data to perform the complete evaluation. For those sites that would likely be required to implement mitigation measures, a menu of options is provided that when selected, estimated additional costs for the selected mitigation measure is added to total development costs.

The Hydropower Assessment Tool is intended for use as a preliminary evaluation of potential hydropower sites and is valuable for informational purposes to support further evaluation of a potential site. It includes general, industry accepted assumptions for site development, including installed capacity and turbine selection and efficiency. The tool also considers appropriate project costs and economic benefits to indicate potential economic viability of a site. The model uses a "base-load" operation with no hour to hour shaping of releases to match load. Under a base-load operation, it is assumed that a power plant would not affect water deliveries from the facility.

The Hydropower Assessment Tool does not indicate feasibility of a site. Reclamation has made the Hydropower Assessment Tool available for public use with the following disclaimer statement:

> "This is an "open source" software tool developed by the Bureau of Reclamation (Reclamation) and the contractor Anderson Engineering for the Hydropower Resource Assessment at Existing Reclamation Facilities Report, and it has been made available for public use. It is important to recognize that the tool has been developed using broad power and economic criteria, and it is only intended for preliminary assessments of potential hydropower sites. This tool cannot take the place of a detailed hydropower feasibility study. There are no warranties, express or implied, for the accuracy or completeness of or any resulting products from the utilization of the tool."

4.4 Application and Limitations

The model is generally applicable to sites that are undeveloped from a hydroelectric perspective but do have some infrastructure in place that would assist in development, such as a small dam or water conveyance feature. Although it can be used to analyze other sites, the cost estimating portion of the model would likely contain increased error in the results as it does not account for substantial features such as new dams. In these cases, additional cost estimates for such features would need to be made and put into the cost estimating portion of the model (in the Plant Cost worksheet) manually.

Limitations of the model are related to its intended use as a planning level tool for preliminary evaluations of potential hydroelectric sites. Assumptions in the model were simplified to apply to 530 sites that had varying infrastructure (reservoirs, diversion dams, canals, etc.), broad range of flow and net head values, and were spread across 17 states. The model can analyze sites with flows up to 5,000 cfs, which is adequate for sites analyzed in the Resource Assessment. Most sites have flows well below 5,000 cfs. The model was constructed to analyze sites in the western 17 states. Selecting the appropriate state is important for benefits calculations. The tool has an option for other states, but the user must input energy prices and green incentives manually into the Other State worksheet.

Hydropower plants can be designed to meet specific site characteristics. For example, a penstock can be installed to control flow, multiple turbines can be installed to maximize power production, or turbines can be specified to meet various operating conditions. Design features can significantly affect the power production and costs of a hydropower plant. The Hydropower Assessment Tool does not evaluate cost or energy production at this level of detail. The tool does allow for the user to input site-specific data if it is available. The tool does allow the user to change the selected design flow and design head of a plant, which are set at a default 30 percent exceedance level.

FERC permitting and environmental mitigation costs can vary significantly based on the site. The Hydropower Assessment Tool includes cost functions for FERC licensing and mitigation, in which costs increase with installed capacity. Various types of licensing could occur, such as lease of power privilege from Reclamation or a FERC license application that depend on the specific site features and are not necessarily based on installed capacity. In addition, environmental conditions could be present that require significant mitigation actions. The cost equations for mitigation costs do not consider site specific conditions. The Hydropower Assessment Tool's cost estimates identify and are representative of general costs, but the user must recognize that specific site features could significantly affect licensing and mitigation costs.

Other model limitations include those cases with unusual duration curves, such as an irrigation canal with extended no flow periods, or extremely low flows generally that result in an unreasonable selection of turbine capacity based on the flow duration curve. Similarly, sites with extremely low heads tend to result in very high cost estimates. In either of these cases, or combined, the resulting installed cost per kW can be unreasonable.

The benefit cost ratio and IRR calculations are sensitive not only to the power generation and cost estimating assumptions, but also to the power price assumptions. The price data included in the Hydropower Assessment Tool reflects prices which are forecast to increase greater than the general level of inflation in the next two decades. If current prices had been used, the computed benefit cost ratios and IRRs would have been less. In addition, the Hydropower

Assessment Tool allows the user to input the relevant discount rate (in the BC Ratio and IRR worksheet) to compute the present worth of benefits and costs for the benefit cost ratio. In order to compare the economic performance of the sites on a consistent basis, results in this report reflect use of the Fiscal Year 2010 federal discount rate of 4.375 percent. The appropriate discount rate for a private developer may be higher or lower. Section 5.6 presents a sensitivity analysis on varying discount rates for selected potential hydropower sites.

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Chapter 5 Site Evaluation Results

After data collection and model development tasks were completed, sites were analyzed using the Hydropower Assessment Tool to determine potential power production and costs and benefits of hydropower development. This analysis evaluates all sites for hydropower potential; however, as described in Chapter 3, some sites may have prohibitive regulatory constraints or existing rights to development. Table 2-3 summarizes sites with known development rights.

As described in previous sections, there are some key indicators to assess if a site has hydropower production potential and if it would be economic to develop. These indicators are valuable in deciding if a site should be further analyzed. To summarize, these indicators include the following:

- Installed Capacity – measures power potential at a site based on design flow and net head.
- Annual Production – estimates potential energy production of a hydropower plant at a site.
- Plant Factor – indicates how often the hydropower plant operates at the installed capacity. Typically a higher plant factor indicates a more feasible site.
- Cost per Installed Capacity - indicates development feasibility as related only to costs. Potential hydropower sites that have a $/installed kW in the range of less than $3,000-$6,000/installed kW are typically more feasible than sites with higher $/installed kW.
- Benefit Cost Ratio – compares benefits and costs of potential hydropower development at the site. A benefit cost ratio greater than 1.0 indicates benefits are greater than costs.
- Internal Rate of Return – measures the worth of an investment. It is the discount rate that makes the present value of benefits equal to the present value of costs. Investments with higher IRRs are more economically favorable than investments with lower IRRs.

The following sections present power production and economic results of the site evaluations by Reclamation region. It is important to note the data confidence levels associated with the sites when reviewing the results. If the data has a low confidence, it should be considered in interpreting the results. Appendix E includes detailed results of all sites run through the Hydropower Assessment Tool. Appendix F includes detailed tables and figures of potential regulatory constraints relative to each site.

5.1 Great Plains Region

This section first provides an overview of the Resource Assessment results for sites in the Great Plains region, including an inventory of sites analyzed, number of sites within specified benefit cost ratio ranges, and a ranking of the sites with benefit cost ratios greater than 0.75. The overview then discusses some features of the top ranked sites with high or medium confidence, as determined by the hydropower production, economic, and constraints analyses. This discussion provides a general snapshot of the analysis conducted for each site ran through the Hydropower Assessment Tool. Because of the amount of total sites analyzed, individual discussion of each site is not possible within the scope the Resource Assessment. Sections 5.1.2, 5.1.3, and 5.1.4 summarize power production, economic results, and constraints for the remainder of sites.

5.1.1 Overview

Reclamation identified 146 sites at existing facilities in the Great Plains region to analyze hydropower development potential. Table 5-1 summarizes the sites relative hydropower potential. Reclamation's area offices provided much of the local knowledge for sites that do not have hydropower potential. In total, 73 sites could have hydropower potential and 64 sites would not have hydropower potential based on the available data sources and assumptions built into the analysis.

Table 5-1 Site Inventory in Great Plains Region

	No. of Sites
Total Sites Identified	146
Sites with No Hydropower Potential	64
Canal or Tunnel Sites (Separate Analysis In Progress)	0
Total Sites with Hydropower Potential	73
Sites Removed from Analysis (see Table 2-3)	9

The Hydropower Assessment Tool calculates a benefit cost ratio for each site analyzed with hydropower potential. The benefit cost ratio is a good indicator if the site should be further analyzed. Benefits cost ratios were calculated with and without green incentive benefits incorporated. The average difference between benefit cost ratio with and without green incentives for the sites analyzed in the Great Plains region was 0.04. In other words, on average, green incentives increased the benefit cost ratio by about 0.04. Table 5-2 summarizes the number of sites within different ranges of benefit cost ratios, with green incentives. The Great Plains region has 13 sites with benefit cost ratios (with green incentives) greater than 1.0.

Table 5-2 Benefit Cost Ratio (with Green Incentives) Summary of Sites Analyzed in Great Plains Region

	No. of Sites	Total Installed Capacity (MW)	Total Annual Production (MWh)
Benefit Cost Ratio (with Green Incentives) from:			
0 to 0.25	21	3.2	8,036
0.25 to 0.5	19	6.6	24,673
0.5 to 0.75	11	9.1	39,124
0.75 to 1.0	9	10.5	44,756
1.0 to 2.0	10	22.6	107,632
Greater than or equal to 2.0	3	45.4	221,338
Total	73	97.5	445,559

Table 5-3 identifies and ranks the sites in the Great Plains region with benefit cost ratios (with green incentives) above 0.75. Although the standard for economic viability is a benefit cost ratio of greater than 1.0, sites with benefit cost ratios of 0.75 and higher were ranked given the preliminary nature of the analysis.

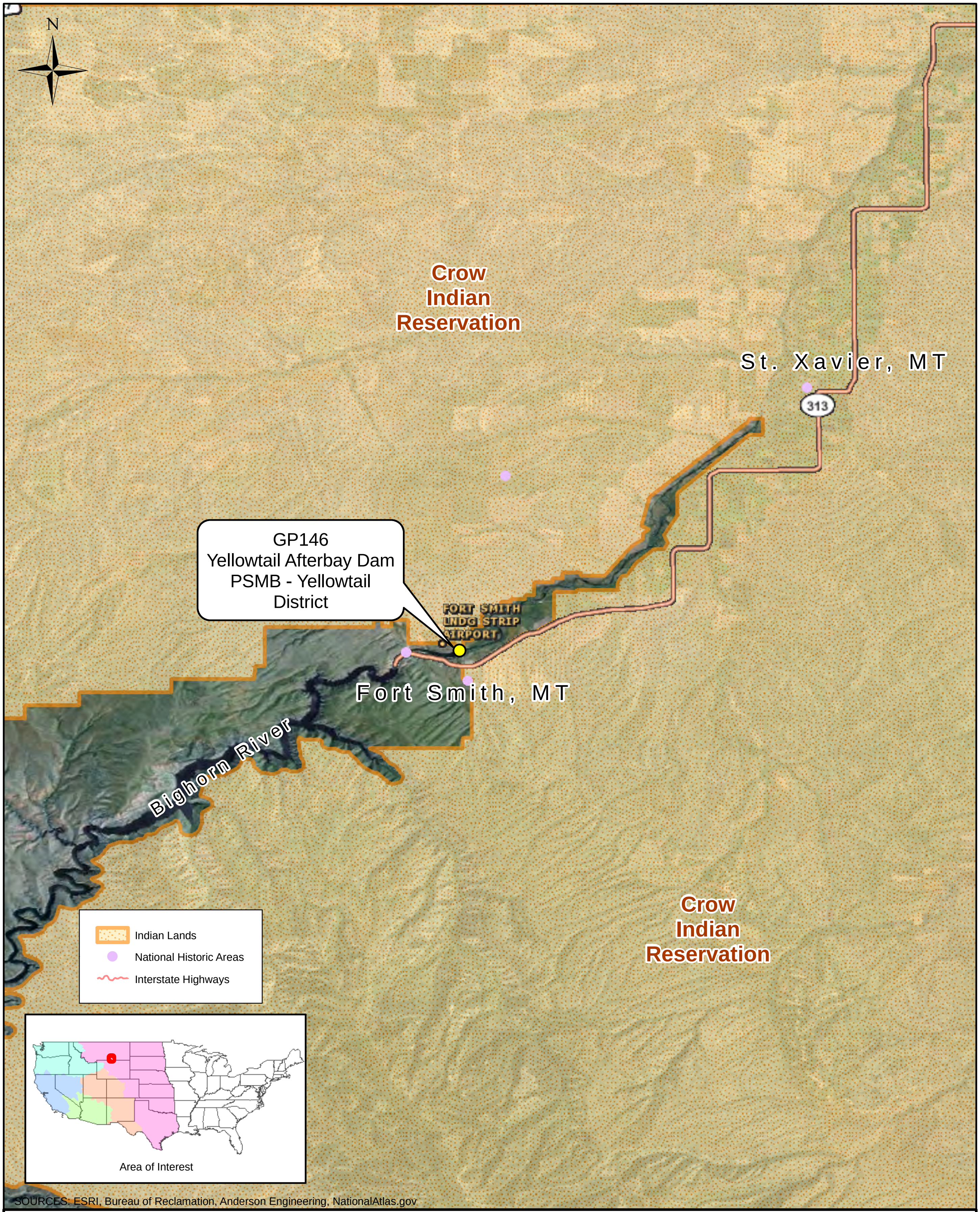
The Yellowtail Afterbay Dam ranked the highest in the region with a benefit cost ratio of 3.05 and an IRR of 18.2 percent. Yellowtail Afterbay Dam is part of the Pick-Sloan Missouri Basin Program (PSMBP) in Montana. The model selected a Kaplan turbine for the Yellowtail Afterbay Dam site, which has an installed capacity of about 9 MW and annual energy production of about 68,000 MWh. Figure 5-1 shows the Yellowtail Afterbay Dam site. The Federal green incentive rate was applied to calculate economic benefits; Montana does not have available state performance based incentives for hydropower. This site is near the Crow Indian Reservation. The Crow Tribe has exclusive rights to develop power at this site as part of the "Claims Resolution Act of 2010" (P.L. 111-291) that was signed into law by President Obama on December 8, 2010.

Twin Buttes Dam ranked the second highest in the region with a benefit cost ratio of 2.61 and an IRR of 16.0 percent. Even though Twin Buttes Dam ranks the highest in the Great Plains region, it has low confidence data associated with it that reduces the reliability of the results.

The Pueblo Dam site ranked third in the region with a benefit cost ratio of 2.34 and an IRR of 14.0 percent. Pueblo Dam is part of Reclamation's Fryingpan-Arkansas Project in Colorado. The model selected a Francis turbine for the Pueblo Dam site, with an installed capacity of 13 MW and annual energy production of about 55,600 MWh. The Federal green incentive rate was applied to calculate economic benefits. Figure 5-2 shows the Pueblo Dam site and associated constraints. Local area office staff identified potential fish constraints at the site.

Table 5-3 Sites with Benefit Cost Ratio (With Green Incentives) Greater than 0.75 in Great Plains Region

Site ID	Site Name	Data Confidence	Installed Capacity (kW)	Annual Production (MWh)	Plant Factor	Cost per Installed Capacity ($/kW)	Benefit Cost Ratio With Green	IRR With Green
GP-146	Yellowtail Afterbay Dam	Medium	9,203	68,261	0.86	$2,157	3.05	18.2%
GP-125	Twin Buttes Dam	Low	23,124	97,457	0.49	$1,455	2.61	16.0%
GP-99	Pueblo Dam	High	13,027	55,620	0.50	$1,704	2.34	14.0%
GP-56	Huntley Diversion Dam	Medium	2,426	17,430	0.84	$3,446	1.86	10.9%
GP-46	Gray Reef Dam	High	2,067	13,059	0.74	$3,947	1.58	8.7%
GP-23	Clark Canyon Dam	High	3,078	13,689	0.52	$2,575	1.52	8.6%
GP-52	Helena Valley Pumping Plant	High	2,626	9,608	0.43	$2,120	1.38	7.8%
GP-41	Gibson Dam	High	8,521	30,774	0.42	$2,339	1.32	7.1%
GP-126	Twin Lakes Dam (USBR)	High	981	5,648	0.67	$4,274	1.24	6.5%
GP-95	Pathfinder Dam	High	743	5,508	0.86	$6,022	1.23	6.2%
GP-43	Granby Dam	High	484	2,854	0.69	$4,426	1.16	5.9%
GP-136	Willwood Diversion Dam	High	1,062	6,337	0.69	$5,407	1.10	5.2%
GP-93	Pactola Dam	High	596	2,725	0.53	$3,706	1.07	5.1%
GP-34	East Portal Diversion Dam	High	283	1,799	0.74	$5,495	0.96	3.9%
GP-5	Angostura Dam	Low	947	3,218	0.40	$3,358	0.90	3.3%
GP-39	Fresno Dam	High	1,661	6,268	0.44	$3,620	0.88	3.2%
GP-129	Virginia Smith Dam	Low	1,607	9,799	0.71	$7,137	0.88	3.3%
GP-128	Vandalia Diversion Dam	Medium	326	1,907	0.68	$5,461	0.87	3.0%
GP-92	Olympus Dam	High	284	1,549	0.64	$5,472	0.82	2.3%
GP-117	St. Mary Canal - Drop 4	High	2,569	8,919	0.40	$3,736	0.82	2.6%
GP-42	Glen Elder Dam	High	1,008	3,713	0.43	$4,229	0.81	2.4%
GP-118	St. Mary Canal - Drop 5	High	1,901	7,586	0.46	$4,817	0.75	1.8%



Bureau of Reclamation Assessment Site

5 2.5 0 5
Miles

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Figure 5-1 : Great Plains Region (Northwest) Yellowtail Afterbay Dam Site Map

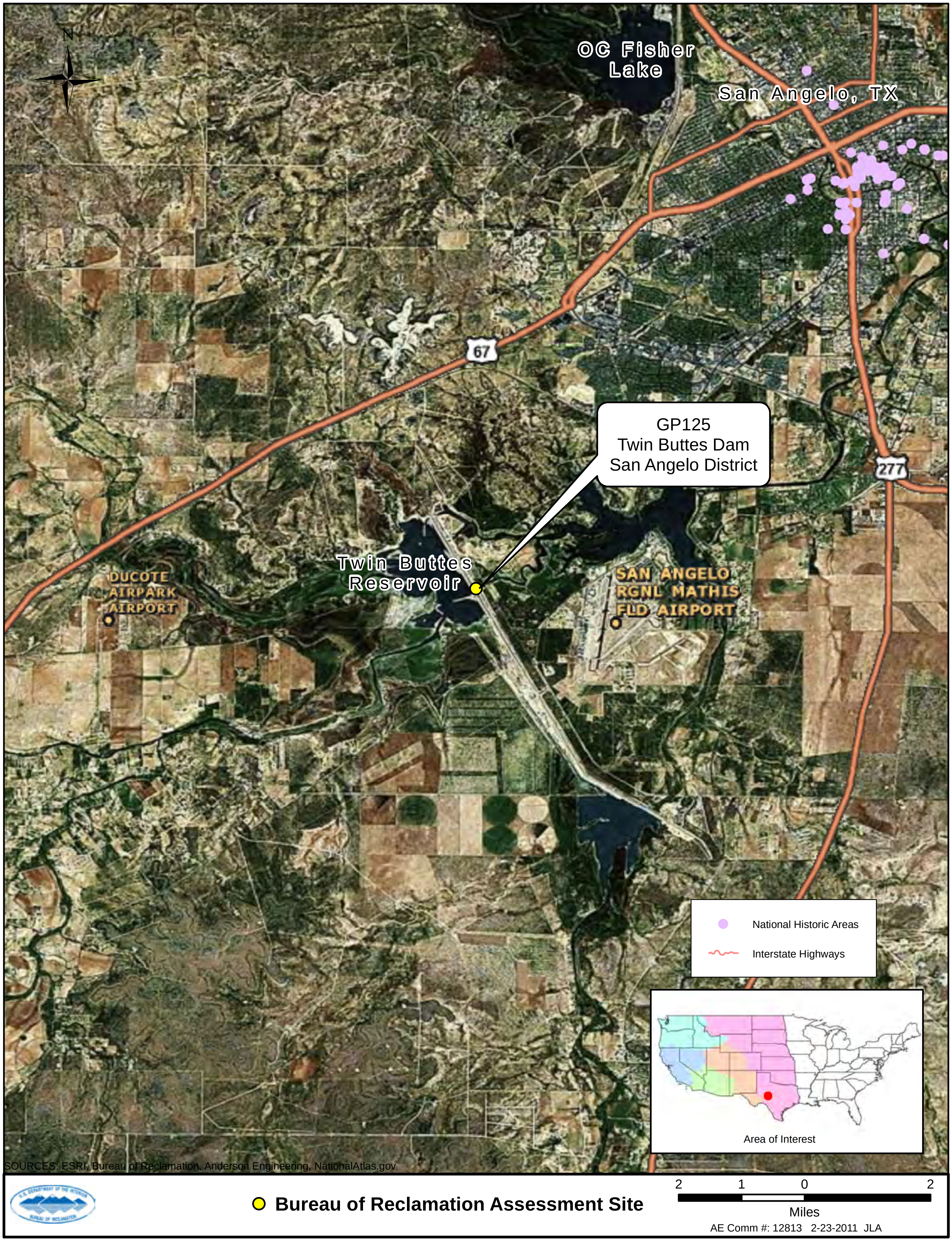


Figure 5-2 : Great Plains Region (South) Twin Buttes Dam Site Map

5.1.2 Power Production

Table 5-4 summarizes potential power production at sites in the Great Plains region. Sites are listed in sequential order by the site identification number. Sites with no hydropower potential are not included in the table. Based on available hydrologic data, the model estimated that the sites could have a total power capacity of about 98 MW and could produce about 446,000 MWh of energy annually. Economic costs and benefits are not considered in these results. Section 5.1.3 presents economic results of the Great Plains region sites. The table also shows the distance from the site to the nearest transmission line (T-line in table). Long distances to the transmission line can add significant costs to hydropower development, and affect the economic viability. There are 6 sites with transmission line distances greater than 10 miles.

For the Pathfinder Dam site (GP-95), Reclamation developed hydropower from Pathfinder Reservoir via a 3-mile tunnel to Fremont Canyon Power Plant. Most of the release from Pathfinder Reservoir goes through Reclamation's existing Fremont Canyon Power Plant, and the only consistent flow available at Pathfinder Dam for future power development would be about 75 cfs.

Table 5-4 Hydropower Production Summary for Sites in Great Plains Region

Site ID	Site Name	Design Head (feet)	Design Flow (cfs)	Installed Capacity (kW)	Annual Production (MWh)	Plant Factor	T- Line Distance (miles)
GP-4	Anchor Dam	60	17	62	126	0.23	15.95
GP-5	Angostura Dam	119	110	947	3,218	0.40	1.01
GP-8	Barretts Diversion Dam	15	106	102	546	0.62	1.44
GP-10	Belle Fourche Dam	50	160	497	1,319	0.31	0.35
GP-12	Bonny Dam	70	8	36	238	0.77	3.58
GP-14	Bretch Diversion Canal	8	51	24	111	0.54	1.34
GP-15	Bull Lake Dam	50	299	933	2,302	0.29	4.68
GP-18	Carter Lake Dam No. 1	142	82	842	2,266	0.31	3.17
GP-22	Choke Canyon Dam	71	38	194	1,199	0.72	1.44
GP-23	Clark Canyon Dam	88	484	3,078	13,689	0.52	0.33
GP-24	Corbett Diversion Dam	12	850	638	2,846	0.52	2.80
GP-28	Deerfield Dam	107	18	138	694	0.59	1.70
GP-29	Dickinson Dam	27	4	7	31	0.51	0.26
GP-31	Dodson Diversion Dam	26	86	140	566	0.47	0.42
GP-34	East Portal Diversion Dam	10	452	283	1,799	0.74	0.01
GP-35	Enders Dam	62	60	267	762	0.33	6.73
GP-37	Fort Shaw Diversion Dam	9	325	183	1,111	0.71	8.21
GP-38	Foss Dam	35	23	49	242	0.58	3.76
GP-39	Fresno Dam	47	560	1,661	6,268	0.44	1.69
GP-41	Gibson Dam	140	845	8,521	30,774	0.42	19.11
GP-42	Glen Elder Dam	69	201	1,008	3,713	0.43	3.35
GP-43	Granby Dam	202	33	484	2,854	0.69	1.23
GP-46	Gray Reef Dam	22	1,504	2,067	13,059	0.74	0.01
GP-47	Greenfield Project, Greenfield Main Canal Drop	38	100	238	830	0.41	1.49
GP-50	Heart Butte Dam	58	70	294	1,178	0.47	0.50
GP-51	Helena Valley Dam	10	197	126	152	0.14	0.56
GP-52	Helena Valley Pumping Plant	140	260	2,626	9,608	0.43	0.56
GP-54	Horsetooth Dam	119	41	350	847	0.28	2.47

Table 5-4 Hydropower Production Summary for Sites in Great Plains Region

Site ID	Site Name	Design Head (feet)	Design Flow (cfs)	Installed Capacity (kW)	Annual Production (MWh)	Plant Factor	T- Line Distance (miles)
GP-56	Huntley Diversion Dam	8	4,850	2,426	17,430	0.84	5.00
GP-58	James Diversion Dam	5	583	193	825	0.50	5.87
GP-59	Jamestown Dam	31	50	113	338	0.35	1.05
GP-60	Johnson Project, Greenfield Main Canal Drop	46	61	203	525	0.30	2.80
GP-63	Kirwin Dam	69	36	179	466	0.30	7.98
GP-67	Lake Alice No. 2 Dam	3	101	18	50	0.32	3.11
GP-68	Lake Sherburne Dam	45	317	898	1,502	0.19	6.91
GP-75	Medicine Creek Dam	66	58	276	1,001	0.42	2.42
GP-76	Merritt Dam	113	200	1,631	8,438	0.60	25.87
GP-85	Nelson Dikes DA	17	46	48	116	0.28	3.01
GP-91	Norton Dam	49	2	6	24	0.47	0.36
GP-92	Olympus Dam	42	107	284	1,549	0.64	0.09
GP-93	Pactola Dam	154	53	596	2,725	0.53	0.26
GP-95	Pathfinder Dam	135	76	743	5,508	0.86	2.33
GP-98	Pishkun Dike - No. 4	22	447	610	1,399	0.27	8.51
GP-99	Pueblo Dam	183	987	13,027	55,620	0.50	0.84
GP-102	Red Willow Dam	68	5	21	148	0.83	1.71
GP-103	Saint Mary Diversion Dam	5	534	177	720	0.47	1.96
GP-107	Shadehill Dam	64	70	322	1,536	0.55	7.32
GP-108	Shadow Mountain Dam	37	45	119	777	0.76	1.96
GP-114	St. Mary Canal - Drop 1	36	537	1,212	4,838	0.46	10.33
GP-115	St. Mary Canal - Drop 2	29	537	974	3,887	0.46	9.83
GP-116	St. Mary Canal - Drop 3	26	537	887	3,538	0.46	9.60
GP-117	St. Mary Canal - Drop 4	66	537	2,569	8,919	0.40	8.58
GP-118	St. Mary Canal - Drop 5	57	537	1,901	7,586	0.46	8.58
GP-120	Sun River Diversion Dam	45	716	2,015	8,645	0.50	16.61
GP-122	Trenton Dam	55	52	208	570	0.32	3.00
GP-125	Twin Buttes Dam	100	3,199	23,124	97,457	0.49	2.57
GP-126	Twin Lakes Dam (USBR)	46	344	981	5,648	0.67	0.68
GP-128	Vandalia Diversion Dam	32	161	326	1,907	0.68	0.37
GP-129	Virginia Smith Dam	72	310	1,607	9,799	0.71	21.69
GP-130	Webster Dam	72	15	66	164	0.29	6.72
GP-131	Whalen Diversion Dam	11	23	15	53	0.40	0.94
GP-132	Willow Creek Dam	90	42	272	863	0.37	1.89
GP-135	Willwood Canal	37	297	687	3,134	0.53	1.52
GP-136	Willwood Diversion Dam	41	414	1,062	6,337	0.69	1.52
GP-137	Wind River Diversion Dam	19	335	398	1,595	0.47	2.13
GP-138	Woods Project, Greenfield Main Canal Drop	53	225	746	2,680	0.42	3.52
GP-140	Wyoming Canal - Station 1016	13	270	220	939	0.50	1.98
GP-141	Wyoming Canal - Station 1490	40	215	538	2,305	0.50	2.34
GP-142	Wyoming Canal - Station 1520	13	215	175	749	0.50	2.31
GP-143	Wyoming Canal - Station 1626	4	215	52	195	0.43	2.39
GP-144	Wyoming Canal - Station 1972	24	190	285	1,218	0.50	7.31
GP-145	Wyoming Canal - Station 997	17	270	287	1,228	0.50	1.78
GP-146	Yellowtail Afterbay Dam	49	2,979	9,203	68,261	0.86	0.09

5.1.3 Economic Evaluation

Table 5-5 summarizes the economic evaluation of hydropower development at sites in the Great Plains region. The benefit cost ratio and IRR are presented both with and without green incentive benefits. As discussed in Chapter 3, the benefit cost ratio and IRR are calculated using present value of benefits and costs over a 50 year period of analysis with a discount rate of 4.375 percent. All states in the Great Plains region can receive the Federal green incentive for hydropower development; at this time, there are not performance based state incentives available for hydropower. The region has many sites that would not be economical for hydropower production, indicated by high cost per installed capacity, low benefit cost ratios, and low IRRs.

Table 5-5 Economic Evaluation Summary for Sites in Great Plains Region

Site ID	Site Name	Total Construction Cost (1,000 $)	Annual O&M Cost (1,000 $)	Cost per Installed Capacity ($/kW)	Benefit Cost Ratio	IRR	Benefit Cost Ratio	IRR
					With Green		Without Green	
GP-4	Anchor Dam	$5,656.5	$130.0	$90,738	0.02	< 0	0.02	< 0
GP-5	Angostura Dam	$3,179.2	$121.4	$3,358	0.90	3.3%	0.84	2.8%
GP-8	Barretts Diversion Dam	$1,391.4	$49.9	$13,596	0.35	< 0	0.33	< 0
GP-10	Belle Fourche Dam	$2,376.3	$90.5	$4,786	0.49	< 0	0.46	< 0
GP-12	Bonny Dam	$1,476.8	$50.7	$40,837	0.15	< 0	0.14	< 0
GP-14	Bretch Diversion Canal	$712.3	$35.7	$29,778	0.12	< 0	0.11	< 0
GP-15	Bull Lake Dam	$5,327.8	$160.6	$5,709	0.41	< 0	0.39	< 0
GP-18	Carter Lake Dam No. 1	$3,642.7	$126.2	$4,328	0.56	< 0	0.53	< 0
GP-22	Choke Canyon Dam	$1,506.0	$60.3	$7,755	0.69	0.7%	0.65	0.3%
GP-23	Clark Canyon Dam	$7,923.7	$261.2	$2,575	1.52	8.6%	1.42	7.6%
GP-24	Corbett Diversion Dam	$4,782.3	$122.8	$7,500	0.59	0.1%	0.56	< 0
GP-28	Deerfield Dam	$1,392.4	$55.3	$10,109	0.43	< 0	0.40	< 0
GP-29	Dickinson Dam	$229.3	$25.2	$32,329	0.07	< 0	0.06	< 0
GP-31	Dodson Diversion Dam	$1,106.9	$49.7	$7,895	0.40	< 0	0.37	< 0
GP-34	East Portal Diversion Dam	$1,553.3	$65.9	$5,495	0.96	3.9%	0.90	3.3%
GP-35	Enders Dam	$3,492.3	$100.7	$13,082	0.22	< 0	0.20	< 0
GP-37	Fort Shaw Diversion Dam	$4,029.4	$107.6	$22,014	0.26	< 0	0.25	< 0
GP-38	Foss Dam	$1,646.7	$54.8	$33,582	0.14	< 0	0.13	< 0
GP-39	Fresno Dam	$6,013.9	$201.1	$3,620	0.88	3.2%	0.82	2.7%
GP-41	Gibson Dam	$19,928.0	$636.5	$2,339	1.32	7.1%	1.23	6.2%
GP-42	Glen Elder Dam	$4,260.6	$144.2	$4,229	0.81	2.4%	0.76	2.0%
GP-43	Granby Dam	$2,144.1	$80.6	$4,426	1.16	5.9%	1.09	5.2%
GP-46	Gray Reef Dam	$8,159.3	$218.0	$3,947	1.58	8.7%	1.49	7.8%
GP-47	Greenfield Project, Greenfield Main Canal Drop	$1,848.6	$69.1	$7,779	0.37	< 0	0.34	< 0
GP-50	Heart Butte Dam	$1,562.5	$66.0	$5,315	0.64	< 0	0.60	< 0
GP-51	Helena Valley Dam	$1,069.4	$48.8	$8,485	0.10	< 0	0.09	< 0

Table 5-5 Economic Evaluation Summary for Sites in Great Plains Region

Site ID	Site Name	Total Construction Cost (1,000 $)	Annual O&M Cost (1,000 $)	Cost per Installed Capacity ($/kW)	Benefit Cost Ratio	IRR	Benefit Cost Ratio	IRR
					With Green		Without Green	
GP-52	Helena Valley Pumping Plant	$5,568.1	$217.9	$2,120	1.38	7.8%	1.29	6.8%
GP-54	Horsetooth Dam	$2,202.8	$80.0	$6,288	0.34	< 0	0.32	< 0
GP-56	Huntley Diversion Dam	$8,361.0	$269.1	$3,446	1.86	10.9%	1.74	9.7%
GP-58	James Diversion Dam	$3,357.8	$95.7	$17,377	0.24	< 0	0.23	< 0
GP-59	Jamestown Dam	$1,166.5	$49.2	$10,338	0.25	< 0	0.23	< 0
GP-60	Johnson Project, Greenfield Main Canal Drop	$2,038.9	$70.7	$10,052	0.21	< 0	0.20	< 0
GP-63	Kirwin Dam	$3,578.9	$98.1	$20,036	0.13	< 0	0.12	< 0
GP-67	Lake Alice No. 2 Dam	$1,254.1	$45.3	$69,333	0.04	< 0	0.03	< 0
GP-68	Lake Sherburne Dam	$5,934.4	$163.2	$6,605	0.24	< 0	0.22	< 0
GP-75	Medicine Creek Dam	$2,103.6	$75.2	$7,631	0.43	< 0	0.41	< 0
GP-76	Merritt Dam	$12,641.1	$321.2	$7,752	0.68	1.2%	0.64	0.9%
GP-85	Nelson Dikes DA	$1,479.3	$51.8	$30,895	0.07	< 0	0.06	< 0
GP-91	Norton Dam	$232.0	$25.1	$39,495	0.05	< 0	0.05	< 0
GP-92	Olympus Dam	$1,552.4	$65.8	$5,472	0.82	2.3%	0.77	1.9%
GP-93	Pactola Dam	$2,207.5	$87.2	$3,706	1.07	5.1%	1.01	4.5%
GP-95	Pathfinder Dam	$4,476.4	$114.4	$6,022	1.23	6.2%	1.16	5.6%
GP-98	Pishkun Dike - No. 4	$5,574.0	$155.2	$9,141	0.23	< 0	0.22	< 0
GP-99	Pueblo Dam	$22,193.9	$690.6	$1,704	2.34	14.0%	2.20	12.5%
GP-102	Red Willow Dam	$780.7	$52.1	$37,427	0.12	< 0	0.12	< 0
GP-103	Saint Mary Diversion Dam	$1,833.7	$65.2	$10,340	0.33	< 0	0.30	< 0
GP-107	Shadehill Dam	$4,128.1	$115.8	$12,806	0.37	< 0	0.35	< 0
GP-108	Shadow Mountain Dam	$1,471.5	$55.9	$12,316	0.46	< 0	0.43	< 0
GP-114	St. Mary Canal - Drop 1	$7,901.8	$218.3	$6,518	0.56	< 0	0.52	< 0
GP-115	St. Mary Canal - Drop 2	$7,141.0	$196.0	$7,333	0.50	< 0	0.47	< 0
GP-116	St. Mary Canal - Drop 3	$6,832.5	$187.2	$7,707	0.47	< 0	0.44	< 0
GP-117	St. Mary Canal - Drop 4	$9,599.7	$289.6	$3,736	0.82	2.6%	0.77	2.2%
GP-118	St. Mary Canal - Drop 5	$9,154.5	$264.0	$4,817	0.75	1.8%	0.70	1.4%
GP-120	Sun River Diversion Dam	$12,611.4	$318.5	$6,259	0.65	0.8%	0.60	0.4%
GP-122	Trenton Dam	$2,180.7	$73.8	$10,461	0.24	< 0	0.23	< 0
GP-125	Twin Buttes Dam	$33,654.2	$1,206.2	$1,455	2.61	16.0%	2.46	14.2%
GP-126	Twin Lakes Dam (USBR)	$4,192.7	$136.2	$4,274	1.24	6.5%	1.17	5.8%
GP-128	Vandalia Diversion Dam	$1,779.4	$72.0	$5,461	0.87	3.0%	0.82	2.5%
GP-129	Virginia Smith Dam	$11,467.6	$299.2	$7,137	0.88	3.3%	0.82	2.8%
GP-130	Webster Dam	$2,694.5	$75.4	$40,704	0.06	< 0	0.06	< 0

Table 5-5 Economic Evaluation Summary for Sites in Great Plains Region

Site ID	Site Name	Total Construction Cost (1,000 $)	Annual O&M Cost (1,000 $)	Cost per Installed Capacity ($/kW)	Benefit Cost Ratio	IRR	Benefit Cost Ratio	IRR
					With Green		Without Green	
GP-131	Whalen Diversion Dam	$549.3	$32.0	$35,641	0.07	< 0	0.06	< 0
GP-132	Willow Creek Dam	$1,239.9	$49.4	$14,980	0.29	< 0	0.27	< 0
GP-135	Willwood Canal	$4,452.3	$117.5	$6,481	0.70	1.4%	0.66	1.0%
GP-136	Willwood Diversion Dam	$5,741.7	$150.4	$5,407	1.10	5.2%	1.03	4.6%
GP-137	Wind River Diversion Dam	$2,921.2	$93.5	$7,344	0.51	< 0	0.48	< 0
GP-138	Woods Project, Greenfield Main Canal Drop	$4,131.6	$133.2	$5,540	0.56	< 0	0.53	< 0
GP-140	Wyoming Canal - Station 1016	$2,036.0	$72.0	$9,275	0.41	< 0	0.39	< 0
GP-141	Wyoming Canal - Station 1490	$3,249.5	$108.8	$6,042	0.64	0.3%	0.61	< 0
GP-142	Wyoming Canal - Station 1520	$2,002.2	$68.4	$11,454	0.34	< 0	0.32	< 0
GP-143	Wyoming Canal - Station 1626	$1,337.4	$49.6	$25,531	0.13	< 0	0.12	< 0
GP-144	Wyoming Canal - Station 1972	$4,237.5	$116.7	$14,860	0.28	< 0	0.26	< 0
GP-145	Wyoming Canal - Station 997	$2,224.9	$78.7	$7,751	0.49	< 0	0.46	< 0
GP-146	Yellowtail Afterbay Dam	$19,852.4	$667.1	$2,157	3.05	18.2%	2.86	16.1%

5.1.4 Constraints Evaluation

Figures 5-3 through 5-5 show constraints associated with the sites analyzed in the Hydropower Assessment Tool. Because of the size of the Great Plains region, the figures divide the region into northwest, northeast, and southern areas. Table 5-6 summarizes the number of sites with potential regulatory constraints in the Great Plains region.

In addition to mapping regulatory constraints, Reclamation staff identified potential fish and wildlife and fish passage constraints for sites in the Great Plains region with benefit cost ratios above 0.75. These sites included Lower Yellowstone Diversion Dam, Twin Lakes Dam, Granby Dam and Pueblo Dam. Appropriate mitigation costs were added to sites with regulatory or fish constraints.

Table 5-6 Number of Sites in the Great Plains Region with Potential Regulatory Constraints

Regulatory Constraint	No. of Sites
Critical Habitat	0
Indian Lands	13
National Forest	11
National Historic Areas	3
National Park	0
Wild & Scenic River	1
Wilderness Preservation Area	9
Wilderness Study Area	0
Wildlife Refuge	3
National Monument	0

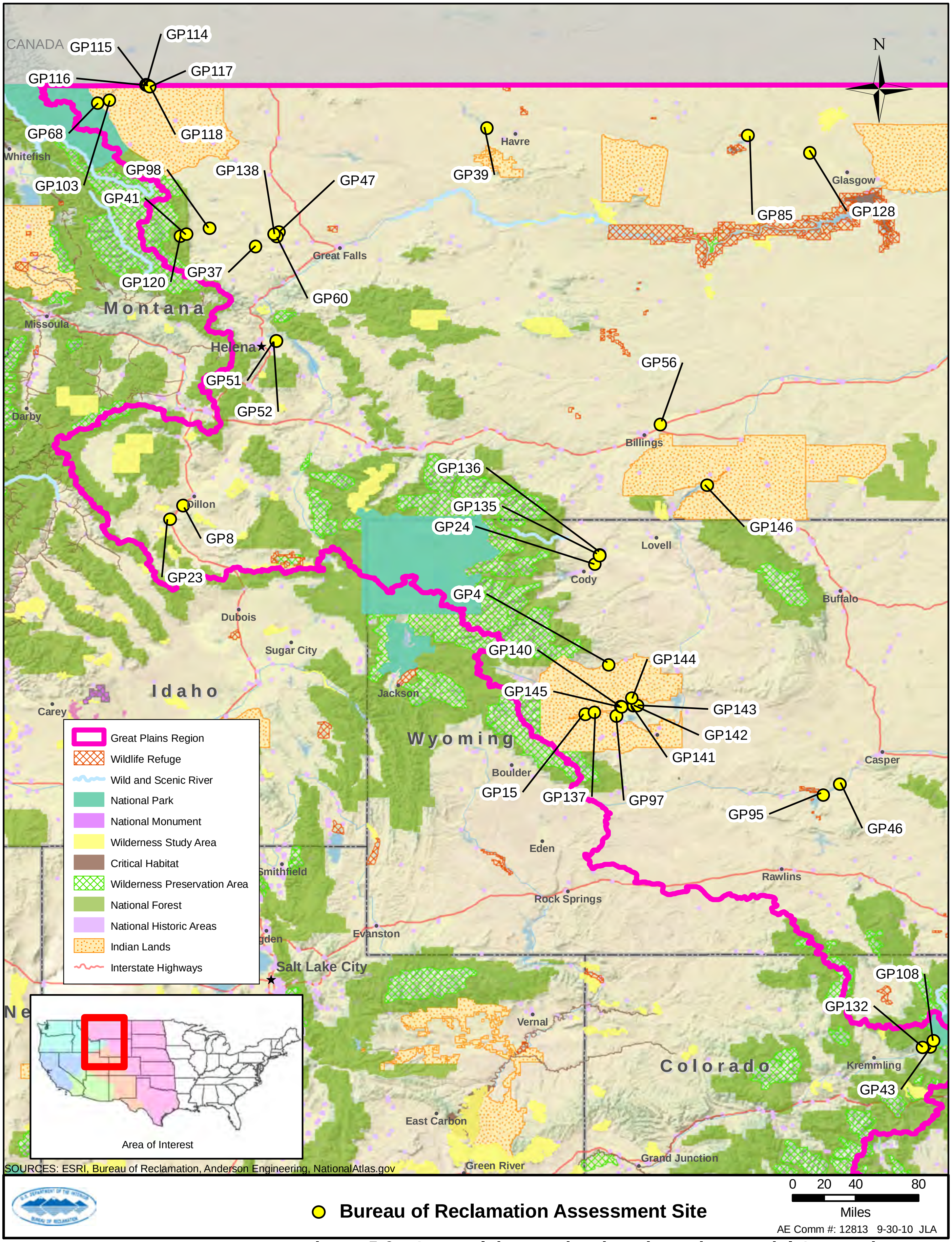


Figure 5-3 : Great Plains Region (Northwest) Potential Constraints Map

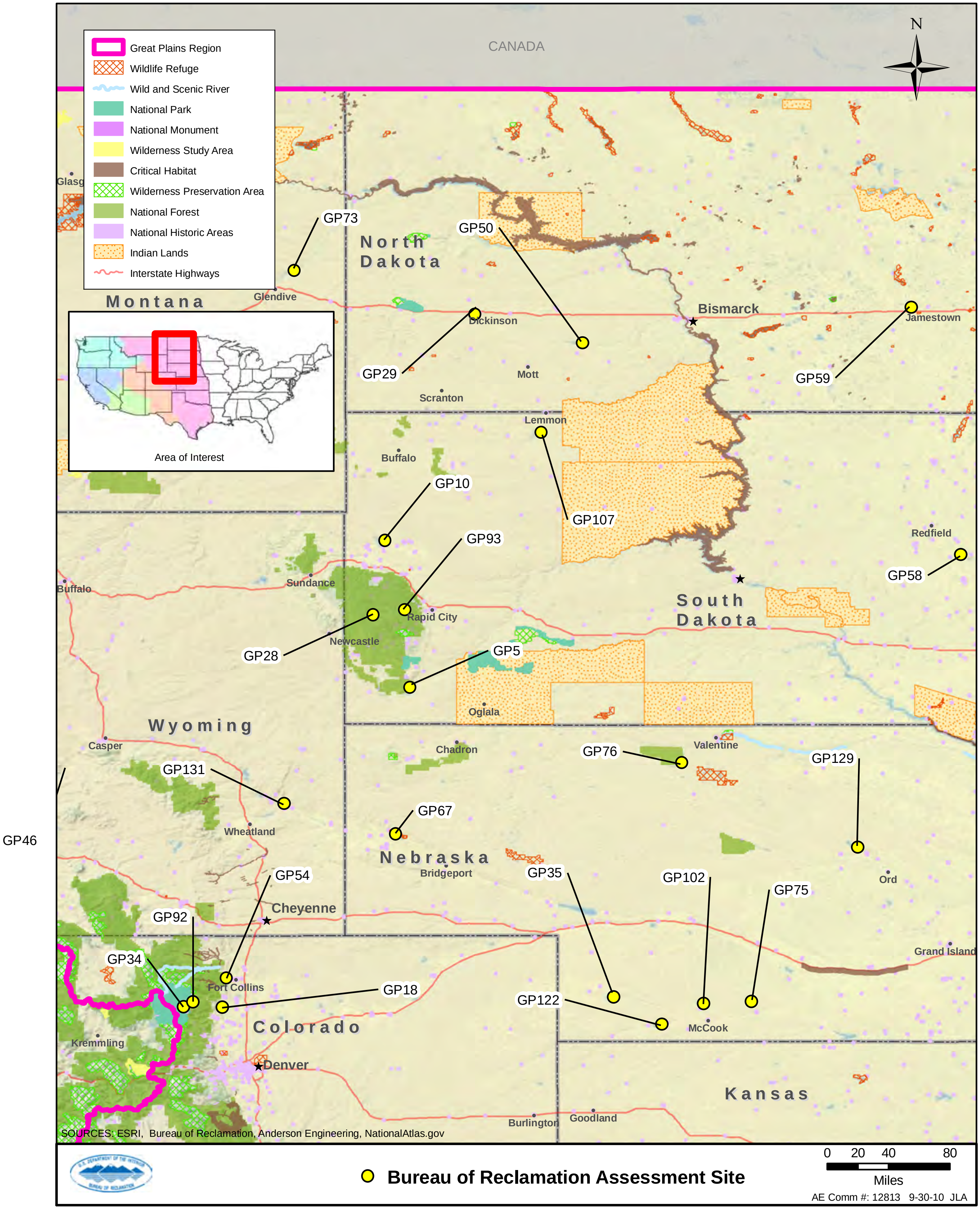


Figure 5-4 : Great Plains Region (Northeast) Potential Constraints Map

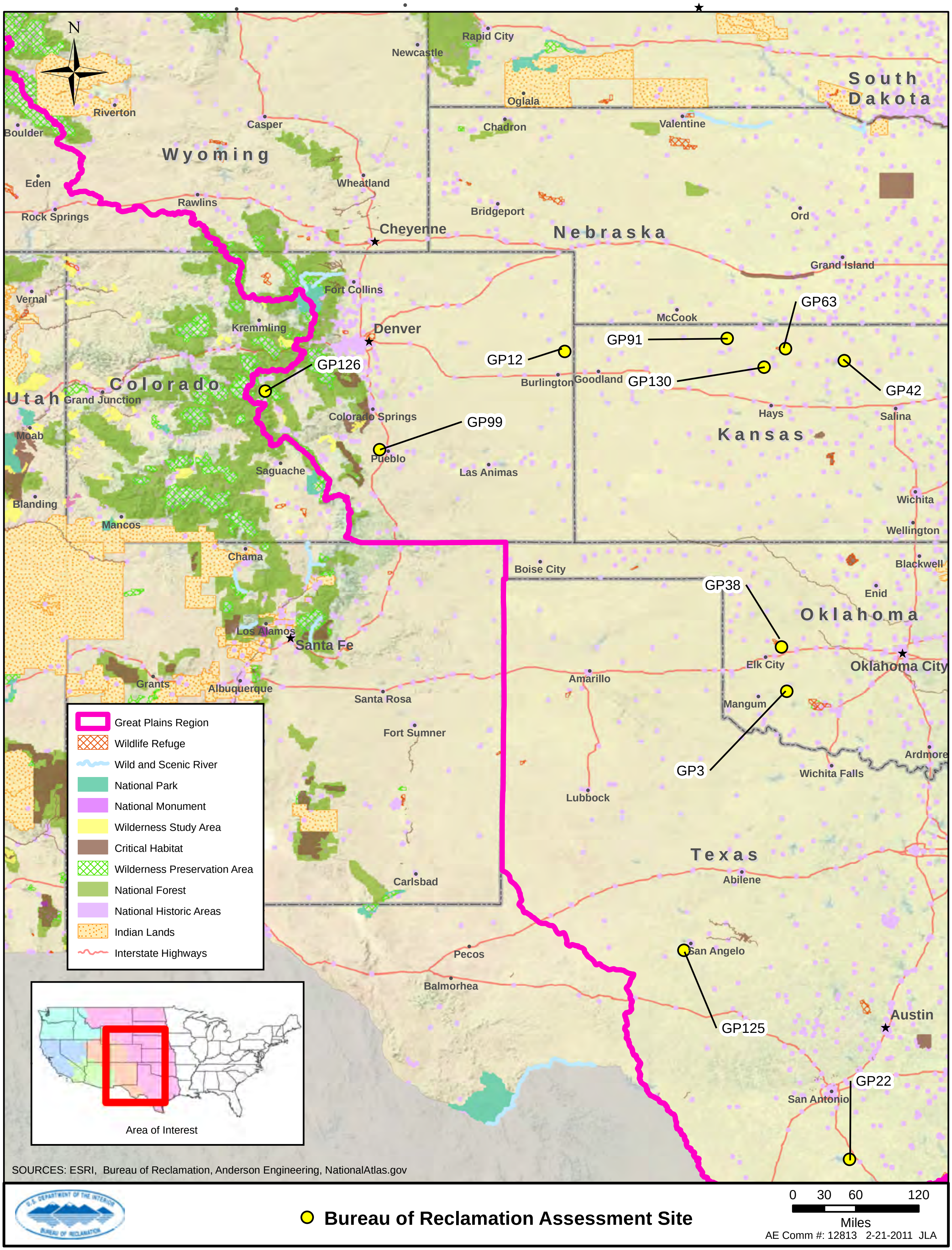


Figure 5-5 : Great Plains Region (South) Potential Constraints Map

5.2 Lower Colorado Region

Only 5 sites in the Lower Colorado region were analyzed with the Hydropower Assessment Tool. This section presents results of all 5 sites and does not include a ranking with benefit cost ratios greater than 0.75 in a separate table.

5.2.1 Overview

Reclamation identified 30 sites at existing facilities in the Lower Colorado region for analysis of hydropower development potential. Table 5-7 summarizes the number of sites relative to hydropower potential. Sites analyzed included Bartlett Dam and Gila Gravity Mesa with medium confidence data and Horseshoe Dam, Imperial Dam, and Laguna Dam with low confidence data.

Table 5-7 Site Inventory in Lower Colorado Region

	No. of Sites
Total Sites Identified	30
Sites with No Hydropower Potential	15
Canal or Tunnel Sites (Separate Analysis In Progress)	8
Total Sites with Hydropower Potential	5
Sites Removed from Analysis (see Table 2-3)	2

Table 5-8 summarizes the number of sites within different ranges of benefit cost ratios. Four of the 5 sites analyzed in the Lower Colorado region had benefit cost ratios greater than 1.0; Bartlett Dam in the Salt River Project in Arizona, Horseshoe and Imperial Dams in the Boulder Canyon Project at the Arizona and California border, and Gila Gravity Main Canal Headworks in the Central Arizona Project. Development rights for hydropower at Bartlett and Horseshoe Dams are under contract with the Salt River Project.

Table 5-8 Benefit Cost Ratio Summary of Sites Analyzed in Lower Colorado Region

	No. of Sites	Total Installed Capacity (MW)	Total Annual Production (MWh)
Benefit Cost Ratio (with Green Incentives) from:			
0 to 0.25	0	-	-
0.25 to 0.5	0	-	-
0.5 to 0.75	1	0.1	566
0.75 to 1.0	0	-	-
1.0 to 2.0	2	1.3	6,873
Greater than or equal to 2.0	2	21.4	96,734
Total	5	22.8	104,173

5.2.2 Power Production

Table 5-9 summarizes potential power production at sites in the Lower Colorado region. Based on available hydrologic data, the model estimated that the sites could have a total power capacity of about 23 MW and could produce about 104,000 MWh of energy annually. Horseshoe and Bartlett Dams could produce the most energy of the five sites. The table also shows the distance from the site to the nearest transmission line. All sites are within a mile to the nearest transmission line, except Horseshoe Dam, which is almost 7 miles away from a transmission line.

Table 5-9 Hydropower Production Summary for Sites in Lower Colorado Region

Site ID	Site Name	Design Head (feet)	Design Flow (cfs)	Installed Capacity (kW)	Annual Production (MWh)	Plant Factor	T- Line Distance (miles)
LC-6	Bartlett Dam	251	415	7,529	36,880	0.57	0.1
LC-15	Gila Gravity Main Canal Headworks	3	1,410	223	1,548	0.81	0.9
LC-20	Horseshoe Dam	142	1,350	13,857	59,854	0.50	6.8
LC-21	Imperial Dam	12	1,500	1,079	5,325	0.57	0.5
LC-24	Laguna Dam	10	200	125	566	0.53	0.5

5.2.3 Economic Evaluation

Table 5-10 summarizes the economic evaluation of hydropower development at sites in the Lower Colorado region. The benefit cost ratio and IRR are presented both with and without green incentive benefits. Bartlett Dam had the highest benefit cost ratio (with green incentives) of 3.50 relative to the other sites. It also had the lowest cost per installed capacity, $2,008 per kW. All sites analyzed are in Arizona, which assumes a state green incentive of $0.054 per kWh for 20 years in addition to the Federal incentive of $0.011 per kWh for 10 years. As a result, there is a larger difference in the benefit cost ratio with green incentives versus without green incentives relative to other states that are eligible for only the Federal incentive. On average, the benefit cost ratio with green incentives is 0.70 greater than the benefit cost ratio without green incentives.

Table 5-10 Economic Evaluation Summary for Sites in Lower Colorado Region

Site ID	Site Name	Total Construction Cost (1,000 $)	Annual O&M Cost (1,000 $)	Cost per Installed Capacity ($/kW)	Benefit Cost Ratio	IRR	Benefit Cost Ratio	IRR
					With Green Incentives		Without Green Incentives	
LC-6	Bartlett Dam	$15,120.0	$435.2	$2,008	3.50	23%	2.25	12%
LC-15	Gila Gravity Main Canal Headworks	$1,702.6	$66.0	$7,632	1.17	6%	0.75	2%
LC-20	Horseshoe Dam	$30,123.0	$792.5	$2,174	2.98	19%	1.93	11%
LC-21	Imperial Dam	$4,617.5	$147.3	$4,280	1.61	10%	1.05	5%
LC-24	Laguna Dam	$1,100.0	$48.9	$8,794	0.63	< 0	0.41	< 0

5.2.4 Constraints Evaluation

Figure 5-6 shows constraints associated with the sites analyzed in the Hydropower Assessment Tool. Table 5-11 summarizes the number of sites with potential regulatory constraints in the Lower Colorado region.

In addition to mapping regulatory constraints, Reclamation staff identified potential fish and wildlife and fish passage constraints for sites in the Lower Colorado region with benefit cost ratios above 0.75. These sites included Bartlett and Horseshoe Dams. Appropriate mitigation costs were added to sites with regulatory or fish constraints.

Table 5-11 Number of Sites in the Lower Colorado Region with Potential Regulatory Constraints

Regulatory Constraint	No. of Sites
Critical Habitat	3
Indian Lands	2
National Forest	2
National Historic Areas	0
National Park	0
Wild & Scenic River	0
Wilderness Preservation Area	0
Wilderness Study Area	0
Wildlife Refuge	0
National Monument	0

Figure 5-7 shows the Bartlett Dam site. Bartlett Dam is in the Tonto National Forest, which could require coordination with the USFS for potential development of the site. The hydropower analysis assumes recreation and fish and wildlife mitigation costs in the total development costs estimates for the site. Bartlett Dam has a FERC Preliminary Permit issued on the site; the docket number is 13819.

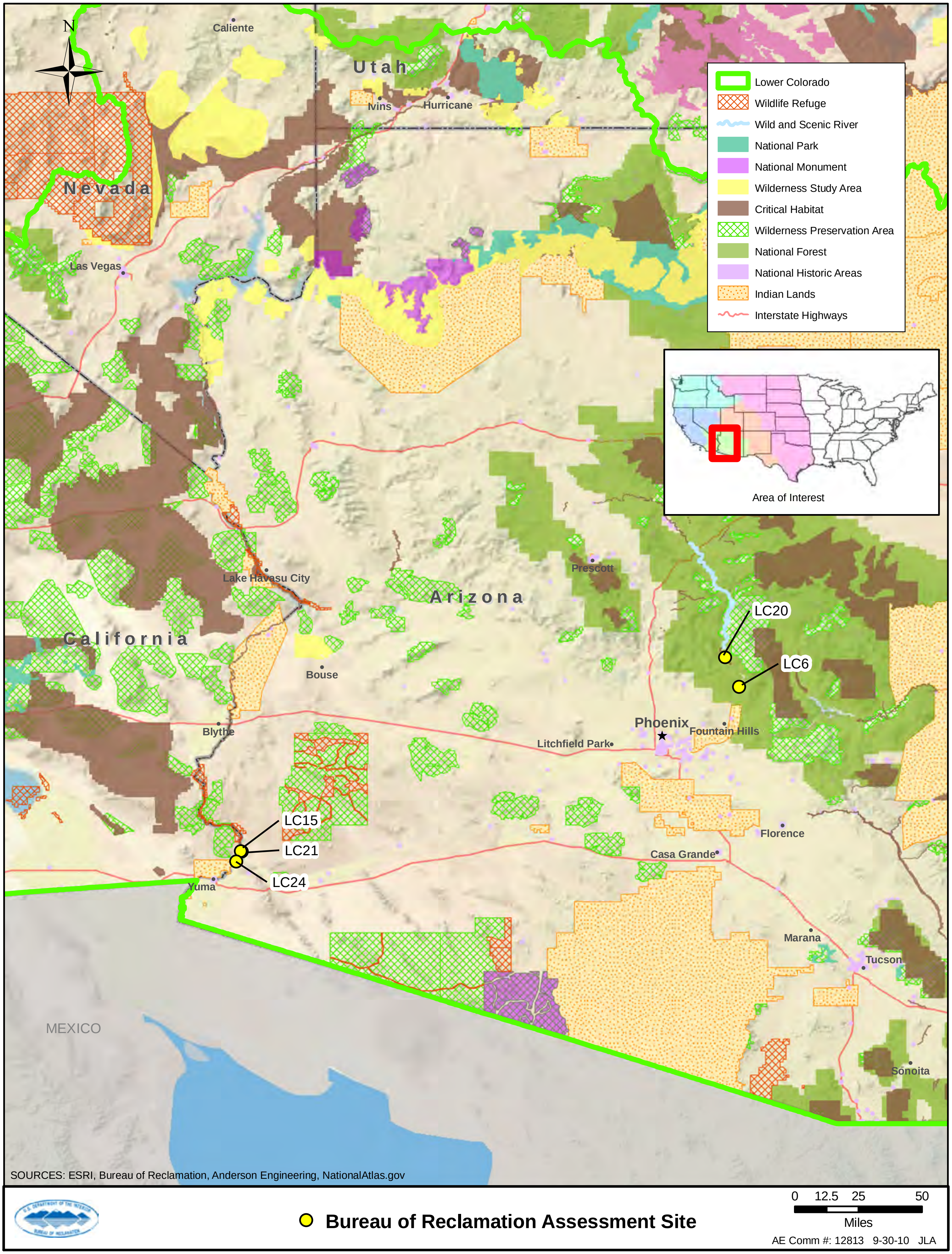


Figure 5-6: Lower Colorado Region Potential Constraints Map

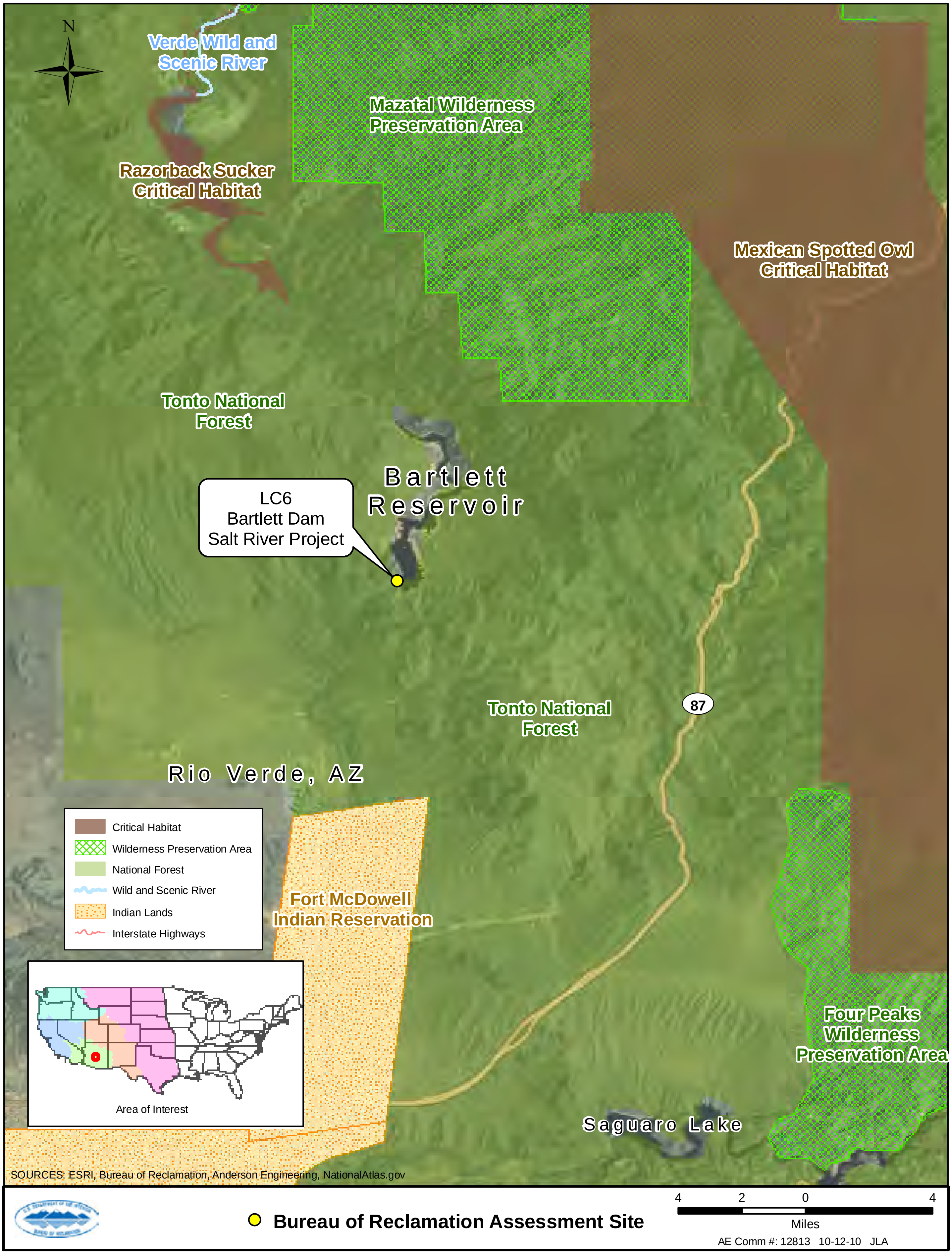


Figure 5-7: Lower Colorado Region Bartlett Dam Site Map

5.3 Mid-Pacific Region

This section is organized similar to the Great Plains region in Section 5.1.

5.3.1 Overview

Reclamation identified 44 sites at existing facilities in the Mid-Pacific region for analysis of hydropower development potential. Table 5-12 summarizes the number of sites relative to hydropower potential.

Table 5-12 Site Inventory in Mid-Pacific Region

	No. of Sites
Total Sites Identified	44
Sites with No Hydropower Potential	26
Canal or Tunnel Sites (Separate Analysis In Progress)	0
Total Sites with Hydropower Potential	14
Sites Removed from Analysis (see Table 2-3)	4

Table 5-13 summarizes the number of sites with hydropower potential within different ranges of benefit cost ratios. The Mid-Pacific region has 4 sites with benefit cost ratios greater than 1.0.

Table 5-13 Benefit Cost Ratio Summary of Sites Analyzed in Mid-Pacific Region

	No. of Sites	Total Installed Capacity (MW)	Total Annual Production (MWh)
Benefit Cost Ratio (with Green Incentives) from:			
0 to 0.25	5	0.5	1,919
0.25 to 0.5	2	0.3	1,518
0.5 to 0.75	1	0.3	893
0.75 to 1.0	2	1.6	7,487
1.0 to 2.0	4	3.5	13,393
Greater than or equal to 2.0	0	-	-
Total	14	6.2	25,210

Table 5-14 identifies and ranks the sites in the Mid-Pacific region with benefit cost ratios (with green incentives) above 0.75. The Prosser Creek Dam site ranked the highest in the region with a benefit cost ratio of 1.98 and an IRR of 14.2 percent. Prosser Creek Dam is part of Reclamation's Washoe Project and is in California. The state green incentive rate was applied to calculate economic benefits, which is $0.0984 per kWh for the 20 years. The model selected a Francis turbine for the Prosser Creek Dam site, with an installed capacity of 872 kW and annual energy production of about 3,800 MWh. Figure

5-8 shows the Prosser Creek Dam site, which is in the Tahoe National Forest. Recreation mitigation costs are added to the total development costs for the site.

The Boca Dam site is ranked the second highest in the region with a benefit cost ratio of 1.68 and an IRR of 11.3 percent, with green incentives. Similar to Prosser Creek Dam, Boca Dam is part of the Washoe Project and is in California. The state incentive was also used to calculate green incentive benefits. The model selected a Francis turbine for the Boca Dam site, which has an installed capacity of about 1 MW and annual energy production of about 4,400 MWh. Figure 5-8 also shows the Boca Dam site and associated constraints. Boca Dam is in the Tahoe National Forest and is included on the National Register of Historic Places. Recreation and archaeological and historical mitigation cost are added to the total development costs for the site.

Table 5-14 Sites with Benefit Cost Ratio (With Green Incentives) Greater than 0.75 in Mid-Pacific Region

Site ID	Site Name	Data Confidence	Installed Capacity (kW)	Annual Production (MWh)	Plant Factor	Cost per Installed Capacity ($/kW)	Benefit Cost Ratio With Green	IRR With Green
MP-30	Prosser Creek Dam	High	872	3,819	0.51	$ 3,576	1.98	14.2%
MP-2	Boca Dam	High	1,184	4,370	0.43	$ 3,711	1.68	11.3%
MP-8	Casitas Dam	High	1,042	3,280	0.37	$ 3,165	1.57	10.7%
MP-32	Putah Diversion Dam	Medium	363	1,924	0.62	$ 7,745	1.16	6.3%
MP-17	John Franchi Dam	Low	469	1,863	0.46	$ 7,728	0.90	3.0%
MP-24	Marble Bluff Dam	High	1,153	5,624	0.57	$ 5,943	0.83	2.8%

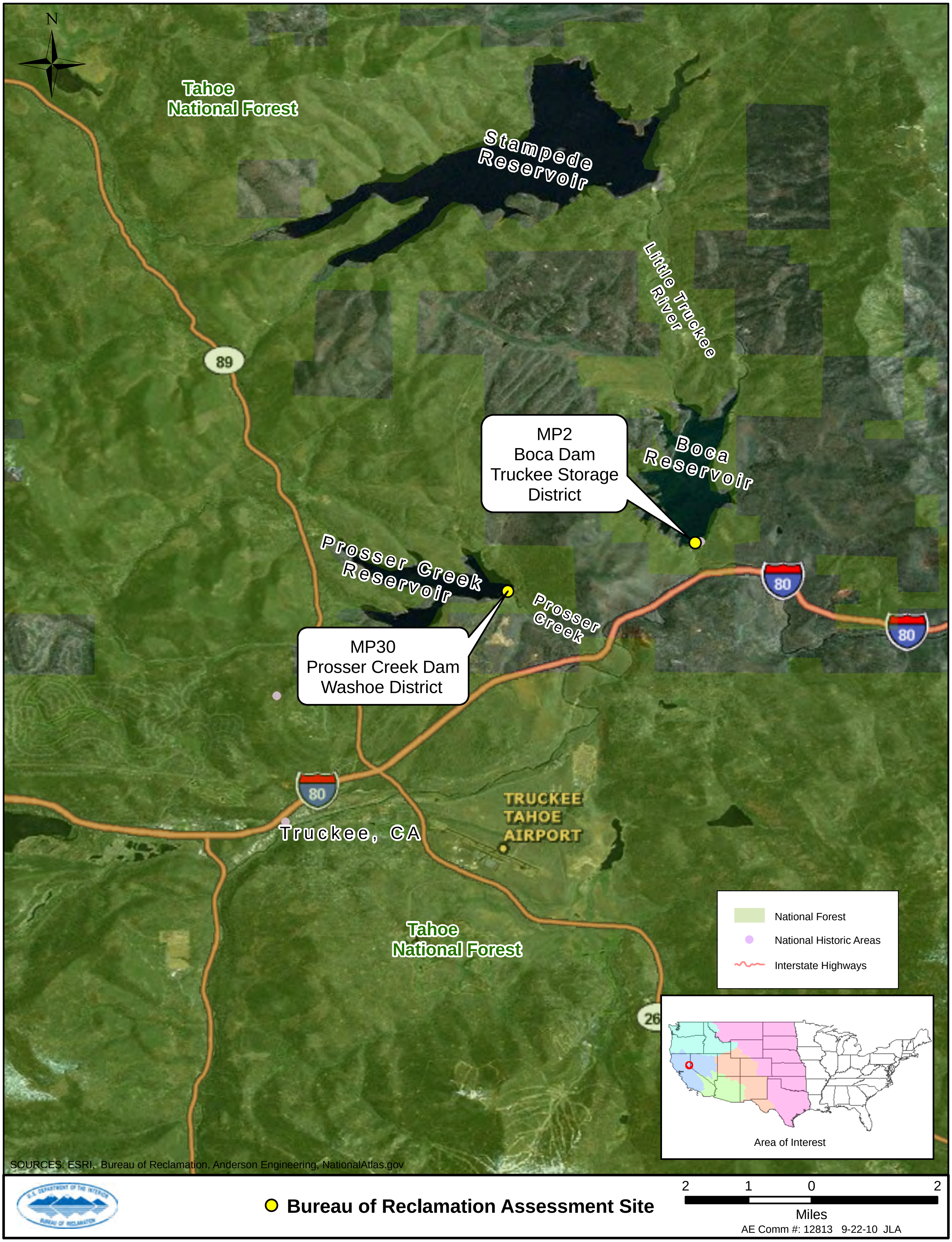


Figure 5-8 : Mid-Pacific Region (North) Prosser Creek/Boca Dam Site Map

5.3.2 Power Production

Table 5-15 summarizes potential power production at sites in the Mid-Pacific region. The Mid-Pacific region sites combined have a total capacity of about 6.2 MW and could produce up to about 25,000 MWh of energy annually. Three sites have the installed capacity of about 1 MW each. The table also shows the distance from the site to the nearest transmission line. The Gerber Dam and Rainbow Dam sites are over 10 miles to the nearest transmission lines.

Table 5-15 Hydropower Production Summary for Sites in Mid-Pacific Region

Site ID	Site Name	Design Head (feet)	Design Flow (cfs)	Installed Capacity (kW)	Annual Production (MWh)	Plant Factor	T- Line Distance (miles)
MP-1	Anderson-Rose Dam	12	40	29	126	0.5	0.24
MP-2	Boca Dam	92	179	1,184	4,370	0.43	1.14
MP-3	Bradbury Dam	190	10	142	521	0.43	7.18
MP-8	Casitas Dam	96	151	1,042	3,280	0.37	0.27
MP-15	Gerber Dam	35	112	248	760	0.36	11.3
MP-17	John Franchi Dam	15	500	469	1,863	0.46	3.03
MP-18	Lake Tahoe Dam	6	729	287	893	0.36	0.05
MP-23	Malone Diversion Dam	8	95	44	147	0.39	4.6
MP-24	Marble Bluff Dam	38	479	1,153	5,624	0.57	7.22
MP-30	Prosser Creek Dam	127	95	872	3,819	0.51	0.5
MP-31	Putah Creek Dam	11	43	28	166	0.7	1.94
MP-32	Putah Diversion Dam	11	553	363	1,924	0.62	2.23
MP-33	Rainbow Dam	29	105	190	998	0.63	13.88
MP-44	Upper Slaven Dam	8	316	158	720	0.53	7.25

5.3.3 Economic Evaluation

Table 5-16 summarizes the economic evaluation of hydropower development at sites in the Mid-Pacific region. Sites in California could receive the state green incentive. Oregon and Nevada could receive the Federal green incentive for hydropower development; at this time, there are not performance based state incentives available for hydropower. On average, for the sites analyzed, the green incentives resulted in an increase of the benefit cost ratio of about 0.3 than if green incentives were not included. Sites in California gained the most benefits from green incentives from the state program. Some sites in the Mid-Pacific region had very high cost per installed capacity, low benefit cost ratios, and low to negative IRRs, indicating they would not be economical to develop.

Table 5-16 Economic Evaluation Summary for Sites in Mid-Pacific Region

Site ID	Site Name	Total Construction Cost (1,000 $)	Annual O&M Cost (1,000 $)	Cost per Installed Capacity ($/kW)	Benefit Cost Ratio	IRR	Benefit Cost Ratio	IRR
					With Green Incentives		Without Green Incentives	
MP-1	Anderson-Rose Dam	$377.7	$29.8	$12,916	0.21	< 0	0.2	< 0
MP-2	Boca Dam	$4,393.0	$144.4	$3,711	1.68	11.3%	0.89	3.4%
MP-3	Bradbury Dam	$3,093.8	$87.0	$21,749	0.3	< 0	0.16	< 0
MP-8	Casitas Dam	$3,298.9	$127.3	$3,165	1.57	10.7%	0.84	2.8%
MP-15	Gerber Dam	$5,358.0	$135.7	$21,621	0.14	< 0	0.13	< 0
MP-17	John Franchi Dam	$3,624.5	$109.8	$7,728	0.9	3.0%	0.48	< 0
MP-18	Lake Tahoe Dam	$2,494.8	$68.0	$8,686	0.65	< 0	0.34	< 0
MP-23	Malone Diversion Dam	$1,835.6	$57.9	$41,464	0.07	< 0	0.07	< 0
MP-24	Marble Bluff Dam	$6,854.2	$193.9	$5,943	0.83	2.8%	0.78	2.4%
MP-30	Prosser Creek Dam	$3,119.0	$113.5	$3,576	1.98	14.2%	1.06	4.9%
MP-31	Putah Creek Dam	$1,047.7	$42.5	$38,062	0.25	< 0	0.13	< 0
MP-32	Putah Diversion Dam	$2,815.3	$90.6	$7,745	1.16	6.3%	0.62	0.2%
MP-33	Rainbow Dam	$5,915.9	$142.1	$31,116	0.32	< 0	0.17	< 0
MP-44	Upper Slaven Dam	$3,474.0	$95.6	$21,974	0.21	< 0	0.2	< 0

5.3.4 Constraints Evaluation

Figures 5-9 and 5-10 show constraints associated with the sites analyzed in the Hydropower Assessment Tool. The region is separated into north and south. Table 5-17 summarizes the number of sites with potential regulatory constraints in the Mid-Pacific region.

In addition to mapping regulatory constraints, Reclamation staff identified potential fish and wildlife and fish passage constraints for sites in the Mid-Pacific region with benefit cost ratios above 0.75. These sites included Lake Tahoe Dam and Putah Diversion Dam. Appropriate mitigation costs were added to sites with regulatory or fish constraints.

Table 5-17 Number of Sites in the Mid-Pacific Region with Potential Regulatory Constraints

Regulatory Constraint	No. of Sites
Critical Habitat	2
Indian Lands	1
National Forest	6
National Historic Areas	3
National Park	0
Wild & Scenic River	0
Wilderness Preservation Area	0
Wilderness Study Area	0
Wildlife Refuge	1
National Monument	0

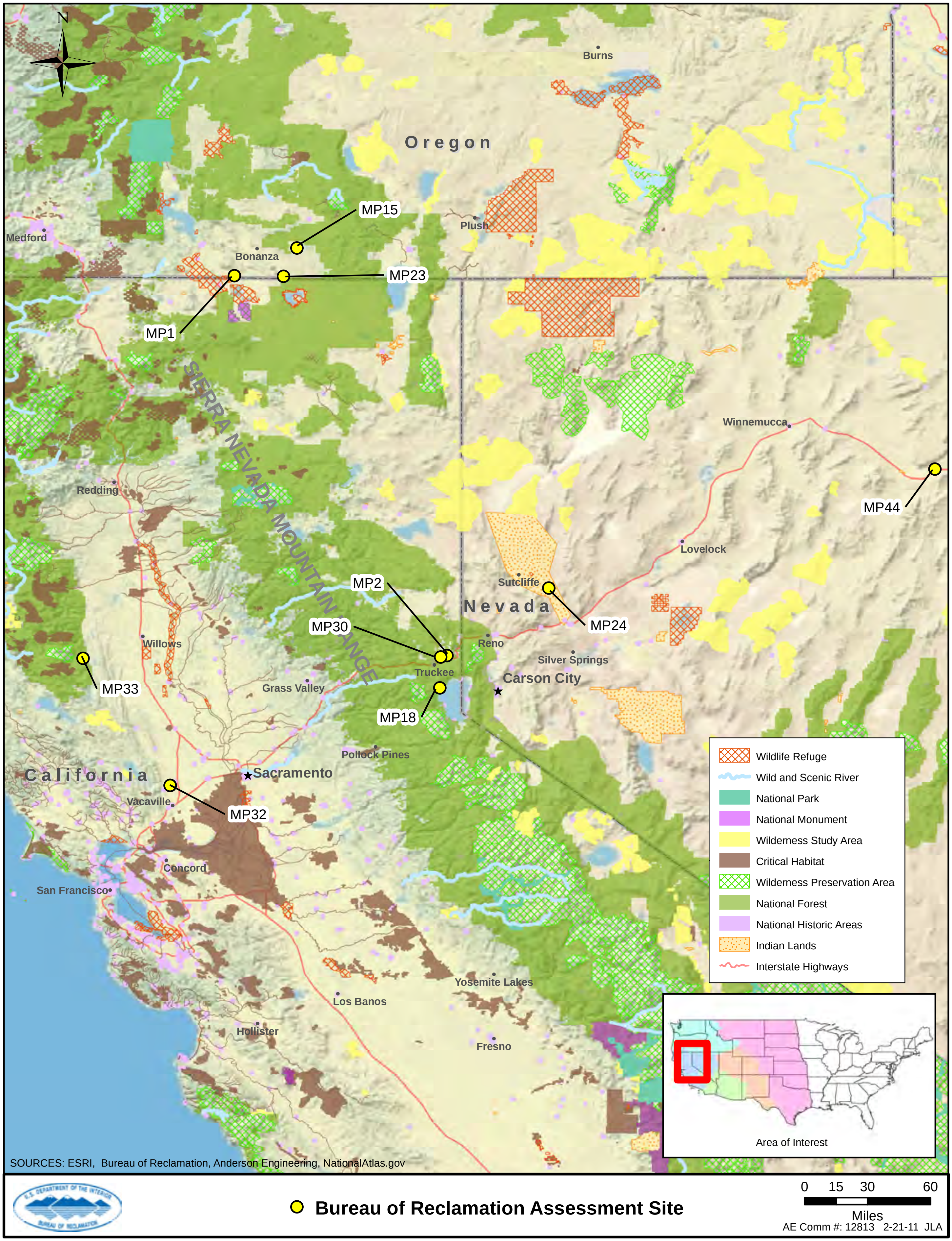


Figure 5-9 : Mid-Pacific Region (North) Potential Constraints Map

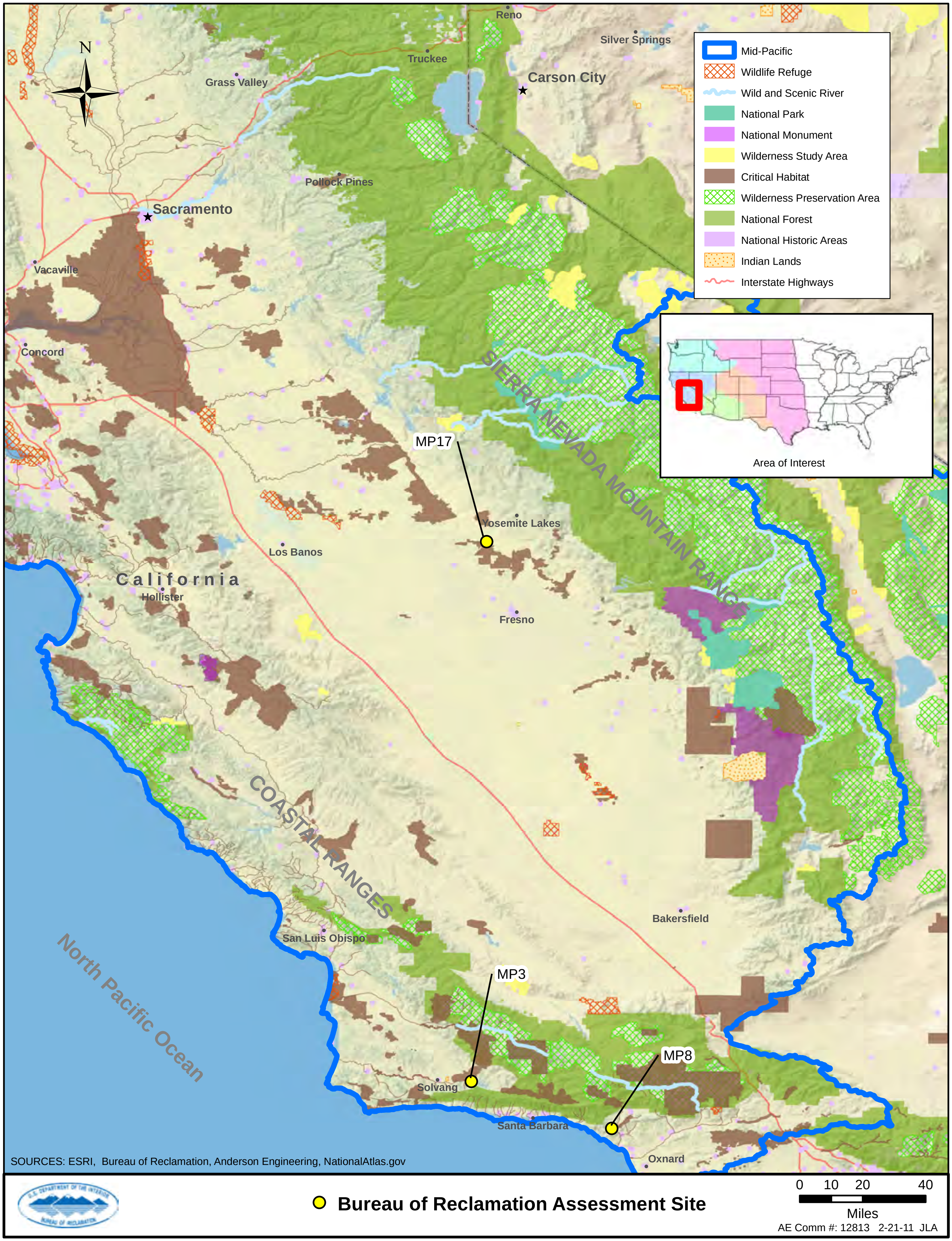


Figure 5-10 : Mid-Pacific Region (South) Potential Constraints Map

5.4 Pacific Northwest Region

This section is organized similar to the Great Plains region in Section 5.1.

5.4.1 Overview

Reclamation identified 105 sites at existing facilities in the Pacific Northwest region for analysis of hydropower development potential. Table 5-18 summarizes the number of sites analyzed in the Pacific Northwest region relative to hydropower potential.

Table 5-18 Site Inventory in Pacific Northwest Region

	No. of Sites
Total Sites Identified	105
Sites with No Hydropower Potential	40
Canal or Tunnel Sites (Separate Analysis In Progress)	9
Total Sites with Hydropower Potential	34
Sites Removed from Analysis (see Table 2-3)	22

Table 5-19 summarizes the number of sites within different ranges of benefit cost ratios. The Pacific Northwest region has 4 sites with benefit cost ratios greater than 1.0.

Table 5-19 Benefit Cost Ratio Summary of Sites Analyzed in Pacific Northwest Region

	No. of Sites	Total Installed Capacity (MW)	Total Annual Production (MWh)
Benefit Cost Ratio (with Green Incentives) from:			
0 to 0.25	11	2.7	11,363
0.25 to 0.5	5	3.5	12,201
0.5 to 0.75	5	4.3	15,252
0.75 to 1.0	9	19.7	59,347
1.0 to 2.0	4	7.9	47,102
Greater than or equal to 2.0	0	-	-
Total	34	38.1	145,265

Table 5-20 identifies and ranks the sites in the Pacific Northwest region with benefit cost ratios (with green incentives) above 0.75. The Arthur R. Bowman Dam site ranked the highest in the region with a benefit cost ratio of 1.90 and an IRR of 11.2 percent. Arthur R. Bowman Dam is part of Reclamation's Crooked River Project and is in Oregon. The Federal green incentive rate was applied to calculate economic benefits. The model selected a Francis turbine for the Arthur R. Bowman Dam site, with an installed capacity of about 3 MW and annual energy production of about 18,000 MWh. Figure 5-11 shows the Arthur R. Bowman Dam site, which near a portion of the Crooked River classified as a Wild and Scenic River. Recreation mitigation costs are added to the total development costs for the site.

The Easton Diversion Dam site is ranked the second highest in the region with a benefit cost ratio of 1.68 and an IRR of 9.9 percent, with green incentives. Easton Diversion Dam is part of the Yakima Project in Washington. The state incentive, stacked with the Federal green incentive rate, was used to calculate green incentive benefits. The model selected a Kaplan turbine for the Easton Diversion Dam site, which has an installed capacity of about 1 MW and annual energy production of 7,400 MWh. Figure 5-12 shows the Easton Diversion Dam site. There are no constraints directly associated with the site, but it is close to the Wenatchee National Forest and critical habitat designated for the Northern Spotted Owl.

Table 5-20 Sites with Benefit Cost Ratio (With Green Incentives) Greater than 0.75 in Pacific Northwest Region

Site ID	Site Name	Data Confidence	Installed Capacity (kW)	Annual Production (MWh)	Plant Factor	Cost per Installed Capacity ($/kW)	Benefit Cost Ratio With Green	IRR With Green
PN-6	Arthur R. Bowman Dam	High	3,293	18,282	0.65	$2,732	1.90	11.2%
PN-31	Easton Diversion Dam	High	1,057	7,400	0.82	$3,792	1.68	9.9%
PN-95	Sunnyside Dam	Medium	1,362	10,182	0.87	$5,075	1.43	7.8%
PN-88	Scootney Wasteway	Low	2,276	11,238	0.57	$3,521	1.26	6.6%
PN-34	Emigrant Dam	High	733	2,619	0.42	$3,013	0.99	4.3%
PN-104	Wickiup Dam	High	3,950	15,650	0.46	$3,843	0.98	4.2%
PN-12	Cle Elum Dam	High	7,249	14,911	0.24	$1,889	0.94	3.8%
PN-80	Ririe Dam	High	993	3,778	0.44	$3,661	0.94	3.8%
PN-87	Scoggins Dam	High	955	3,683	0.45	$3,838	0.92	3.6%
PN-59	McKay Dam	High	1,362	4,344	0.37	$3,138	0.88	3.2%
PN-49	Keechelus Dam	High	2,394	6,746	0.33	$2,830	0.87	3.0%
PN-44	Haystack	High	805	3,738	0.54	$4,866	0.85	2.9%
PN-48	Kachess Dam	Medium	1,227	3,877	0.37	$3,535	0.77	1.9%

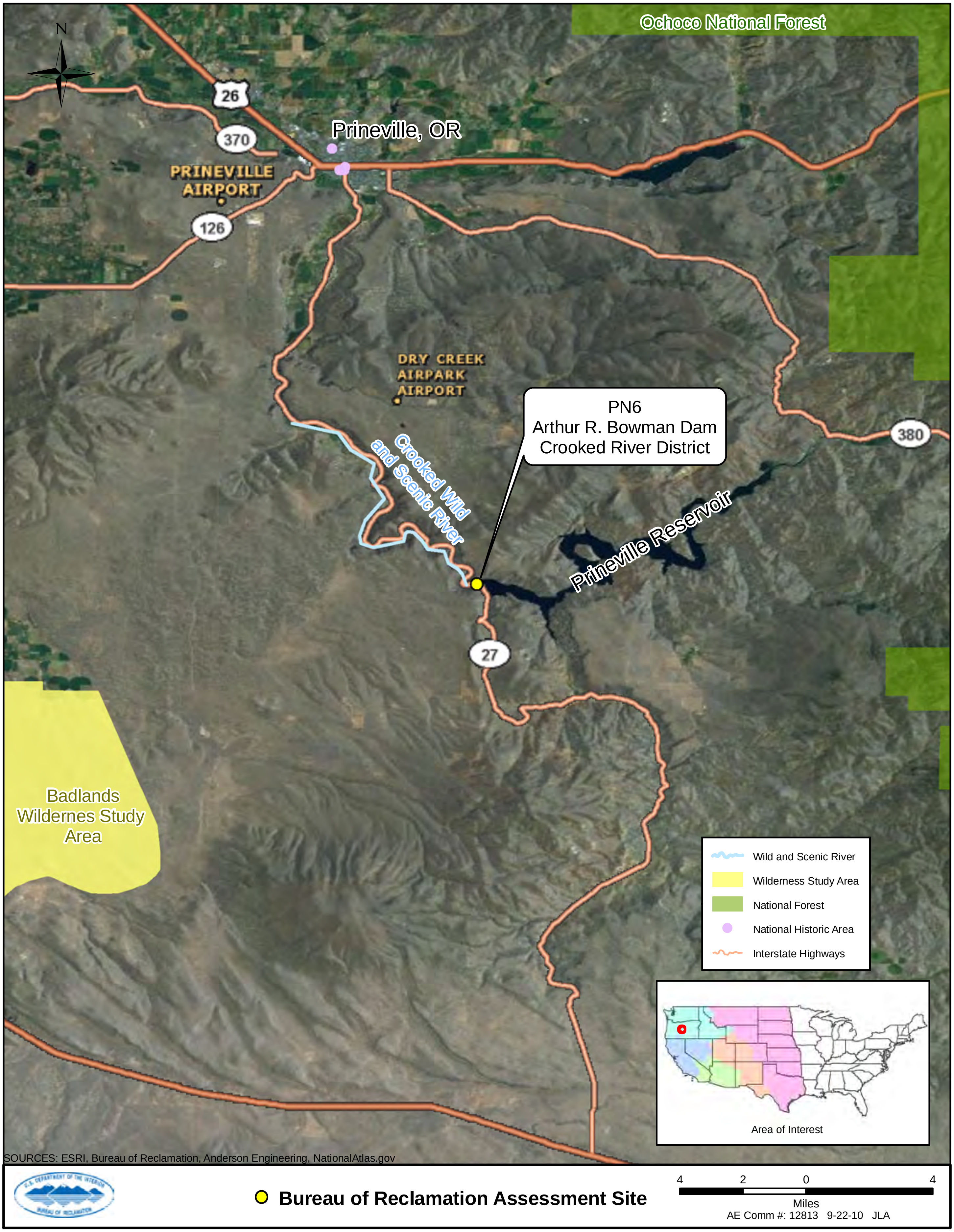


Figure 5-11: Pacific Northwest Region (West) Arthur R. Bowman Dam Site Map

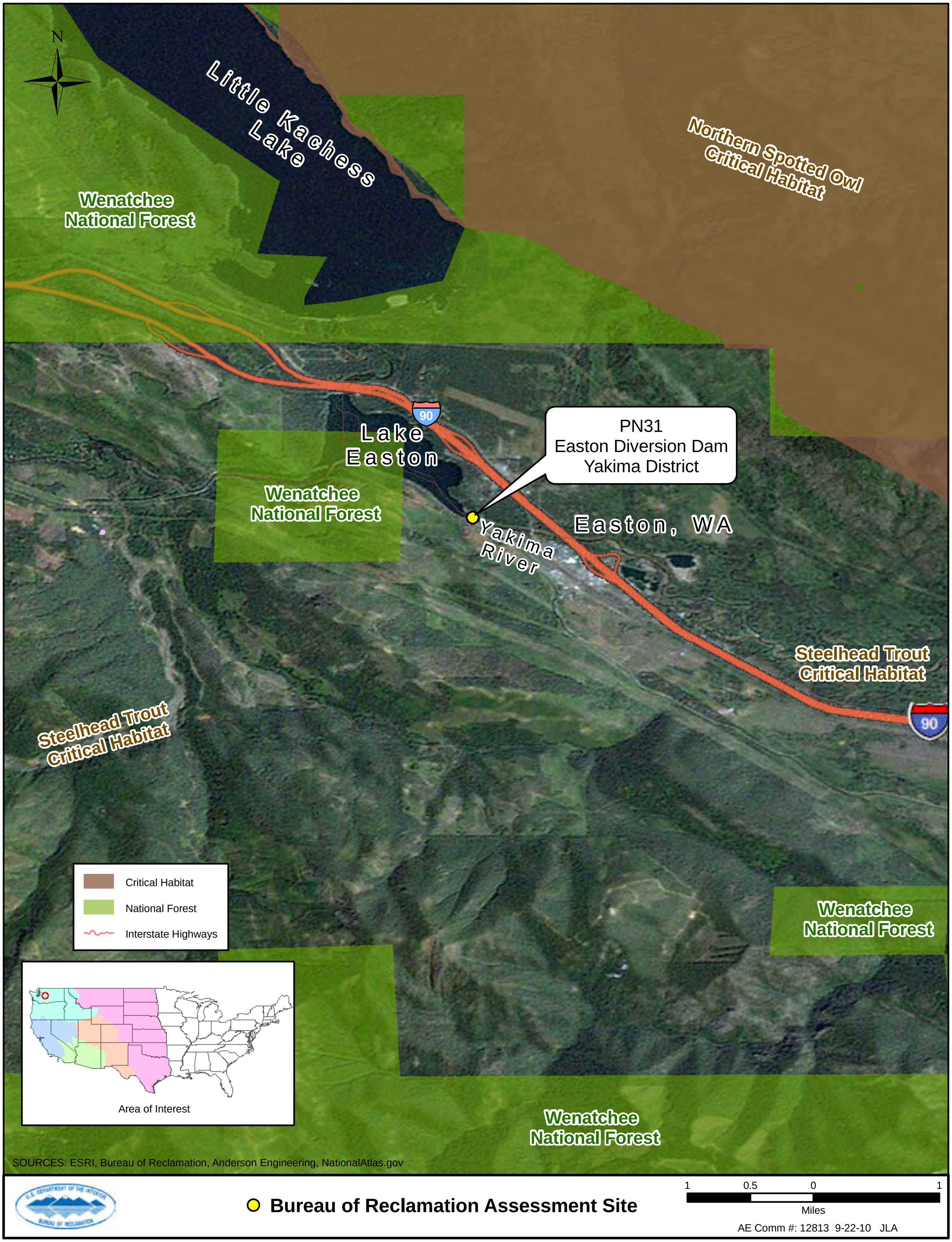


Figure 5-12 : Pacific Northwest Region (West) Easton Diversion Dam Site Map

5.4.2 Power Production

Table 5-21 summarizes potential power production at sites in the Pacific Northwest region. The Pacific Northwest region sites combined have a total capacity of about 38 MW and could produce up to about 145,000 MWh of energy annually. Cle Elum Dam has the highest installed capacity of the sites analyzed, about 7 MW. The table also shows the distance from the site to the nearest transmission line. Nine sites in the region are over 10 miles to the nearest transmission lines.

Table 5-21 Hydropower Production Summary for Sites in Pacific Northwest Region

Site ID	Site Name	Design Head (feet)	Design Flow (cfs)	Installed Capacity (kW)	Annual Production (MWh)	Plant Factor	T- Line Distance (miles)
PN-1	Agate Dam	63	23	89	264	0.35	0.75
PN-2	Agency Valley	67	244	1,179	3,941	0.39	22.46
PN-6	Arthur R. Bowman Dam	173	264	3,293	18,282	0.65	5.94
PN-9	Bully Creek	85	51	313	1,065	0.4	19.01
PN-10	Bumping Lake	30	279	521	2,200	0.49	22.78
PN-12	Cle Elum Dam	101	994	7,249	14,911	0.24	2.02
PN-15	Cold Springs Dam	38	28	66	131	0.23	2.51
PN-20	Crane Prairie	18	270	306	1,845	0.7	17.41
PN-24	Deadwood Dam	110	110	871	3,563	0.48	45.01
PN-31	Easton Diversion Dam	46	366	1,057	7,400	0.82	0.32
PN-34	Emigrant Dam	185	55	733	2,619	0.42	0.22
PN-37	Fish Lake	39	36	102	235	0.27	1.5
PN-41	Golden Gate Canal	43	191	514	2,293	0.52	5
PN-43	Harper Dam	80	75	434	1,874	0.5	13.5
PN-44	Haystack	57	225	805	3,738	0.54	2.49
PN-48	Kachess Dam	55	358	1,227	3,877	0.37	0.13
PN-49	Keechelus Dam	75	444	2,394	6,746	0.33	1.07
PN-52	Little Wood River Dam	103	200	1,493	4,951	0.39	37.37
PN-53	Lytle Creek	3	264	50	329	0.77	3.22
PN-56	Mann Creek	113	61	495	2,097	0.5	4.59
PN-57	Mason Dam	139	164	1,649	5,773	0.41	10.82
PN-58	Maxwell Dam	4	467	117	644	0.64	3.99
PN-59	McKay Dam	122	154	1,362	4,344	0.37	2.22
PN-65	Ochoco Dam	60	19	69	232	0.39	2.22
PN-78	Reservoir "A"	60	12	45	169	0.44	2.29
PN-80	Ririe Dam	132	104	993	3,778	0.44	2.27
PN-87	Scoggins Dam	96	138	955	3,683	0.45	2.66
PN-88	Scootney Wasteway	13	2,800	2,276	11,238	0.57	3.65
PN-95	Sunnyside Dam	6	3,630	1,362	10,182	0.87	5.98
PN-97	Thief Valley Dam	39	150	369	1,833	0.58	2.29
PN-100	Unity Dam	46	106	307	1,329	0.5	25.28
PN-101	Warm Springs Dam	57	346	1,234	3,256	0.31	0.67
PN-104	Wickiup Dam	55	1,157	3,950	15,650	0.46	12.43
PN-105	Wild Horse - BIA	70	53	267	791	0.35	4.22

5.4.3 Economic Evaluation

Table 5-22 summarizes the economic evaluation of hydropower development at sites in the Pacific Northwest region. Except for Washington, the other states in the Pacific Northwest region (sites are primarily in Oregon and Idaho) can receive the Federal green incentive for hydropower development. On average, for the sites analyzed, the green incentives only resulted in an increase in the benefit cost ratio of about 0.04. Some sites in the Pacific Northwest region had very high cost per installed capacity, low benefit cost ratios, and low IRRs, indicating they would not be economical to develop.

Table 5-22 Economic Evaluation Summary for Sites in Pacific Northwest Region

Site ID	Site Name	Total Construction Cost (1,000 $)	Annual O&M Cost (1,000 $)	Cost per Installed Capacity ($/kW)	Benefit Cost Ratio	IRR	Benefit Cost Ratio	IRR
					With Green Incentives		Without Green Incentives	
PN-1	Agate Dam	$821.5	$41.8	$9,267	0.24	< 0	0.22	< 0
PN-2	Agency Valley	$11,353.3	$283.6	$9,626	0.33	< 0	0.31	< 0
PN-6	Arthur R. Bowman Dam	$8,994.9	$285.6	$2,732	1.9	11.2%	1.79	10.0%
PN-9	Bully Creek	$8,062.9	$189.1	$25,773	0.13	< 0	0.12	< 0
PN-10	Bumping Lake	$11,275.7	$253.9	$21,650	0.2	< 0	0.19	< 0
PN-12	Cle Elum Dam	$13,692.3	$491.1	$1,889	0.94	3.8%	0.89	3.3%
PN-15	Cold Springs Dam	$1,308.8	$48.9	$19,942	0.09	< 0	0.08	< 0
PN-20	Crane Prairie	$7,751.3	$183.6	$25,317	0.25	< 0	0.23	< 0
PN-24	Deadwood Dam	$19,510.1	$428.5	$22,402	0.2	< 0	0.19	< 0
PN-31	Easton Diversion Dam	$4,006.9	$143.0	$3,792	1.68	9.9%	1.58	8.8%
PN-34	Emigrant Dam	$2,209.7	$95.0	$3,013	0.99	4.3%	0.93	3.7%
PN-37	Fish Lake	$1,176.0	$48.3	$11,555	0.18	< 0	0.17	< 0
PN-41	Golden Gate Canal	$3,991.6	$121.5	$7,771	0.56	< 0	0.53	< 0
PN-43	Harper Dam	$5,901.2	$152.4	$13,606	0.31	< 0	0.29	< 0
PN-44	Haystack	$3,916.4	$131.4	$4,866	0.85	2.9%	0.8	2.4%
PN-48	Kachess Dam	$4,335.9	$154.6	$3,535	0.77	1.9%	0.72	1.5%
PN-49	Keechelus Dam	$6,774.2	$224.0	$2,830	0.87	3.0%	0.81	2.5%
PN-52	Little Wood River Dam	$17,931.2	$419.3	$12,013	0.29	< 0	0.27	< 0
PN-53	Lytle Creek	$1,603.2	$54.4	$32,368	0.19	< 0	0.18	< 0
PN-56	Mann Creek	$3,554.4	$112.0	$7,174	0.56	< 0	0.52	< 0
PN-57	Mason Dam	$7,276.4	$220.2	$4,414	0.72	1.5%	0.68	1.1%
PN-58	Maxwell Dam	$2,075.4	$66.9	$17,766	0.3	< 0	0.28	< 0
PN-59	McKay Dam	$4,274.0	$155.7	$3,138	0.88	3.2%	0.83	2.7%
PN-65	Ochoco Dam	$1,286.3	$49.5	$18,532	0.16	< 0	0.15	< 0
PN-78	Reservoir "A"	$1,262.2	$47.4	$27,968	0.12	< 0	0.11	< 0
PN-80	Ririe Dam	$3,636.9	$131.5	$3,661	0.94	3.8%	0.89	3.3%
PN-87	Scoggins Dam	$3,665.4	$130.6	$3,838	0.92	3.6%	0.86	3.1%
PN-88	Scootney Wasteway	$8,014.4	$258.3	$3,521	1.26	6.6%	1.18	5.9%
PN-95	Sunnyside Dam	$6,912.0	$205.4	$5,075	1.43	7.8%	1.35	7.0%
PN-97	Thief Valley Dam	$2,601.0	$87.2	$7,050	0.64	0.1%	0.6	< 0
PN-100	Unity Dam	$9,462.0	$213.5	$30,808	0.14	< 0	0.13	< 0

Table 5-22 Economic Evaluation Summary for Sites in Pacific Northwest Region

Site ID	Site Name	Total Construction Cost (1,000 $)	Annual O&M Cost (1,000 $)	Cost per Installed Capacity ($/kW)	Benefit Cost Ratio	IRR	Benefit Cost Ratio	IRR
					With Green Incentives		Without Green Incentives	
PN-101	Warm Springs Dam	$4,326.6	$154.2	$3,507	0.66	0.40%	0.62	0.1%
PN-104	Wickiup Dam	$15,178.6	$422.3	$3,843	0.98	4.2%	0.92	3.7%
PN-105	Wild Horse - BIA	$2,873.0	$89.7	$10,764	0.27	< 0	0.26	< 0

5.4.4 Constraints Evaluation

Figures 5-13 and 5-14 show constraints associated with the sites analyzed in the Hydropower Assessment Tool. Because of the size of the region, the figures split the region into east and west. Table 5-23 summarizes the number of sites with potential regulatory constraints in the Pacific Northwest region. Reclamation staff did not identify additional fish and wildlife and fish passage constraints for sites in the Pacific Northwest region with benefit cost ratios above 0.75.

Table 5-23 Number of Sites in the Pacific Northwest Region with Potential Regulatory Constraints

Regulatory Constraint	No. of Sites
Critical Habitat	5
Indian Lands	3
National Forest	13
National Historic Areas	3
National Park	0
Wild & Scenic River	3
Wilderness Preservation Area	1
Wilderness Study Area	1
Wildlife Refuge	6
National Monument	0

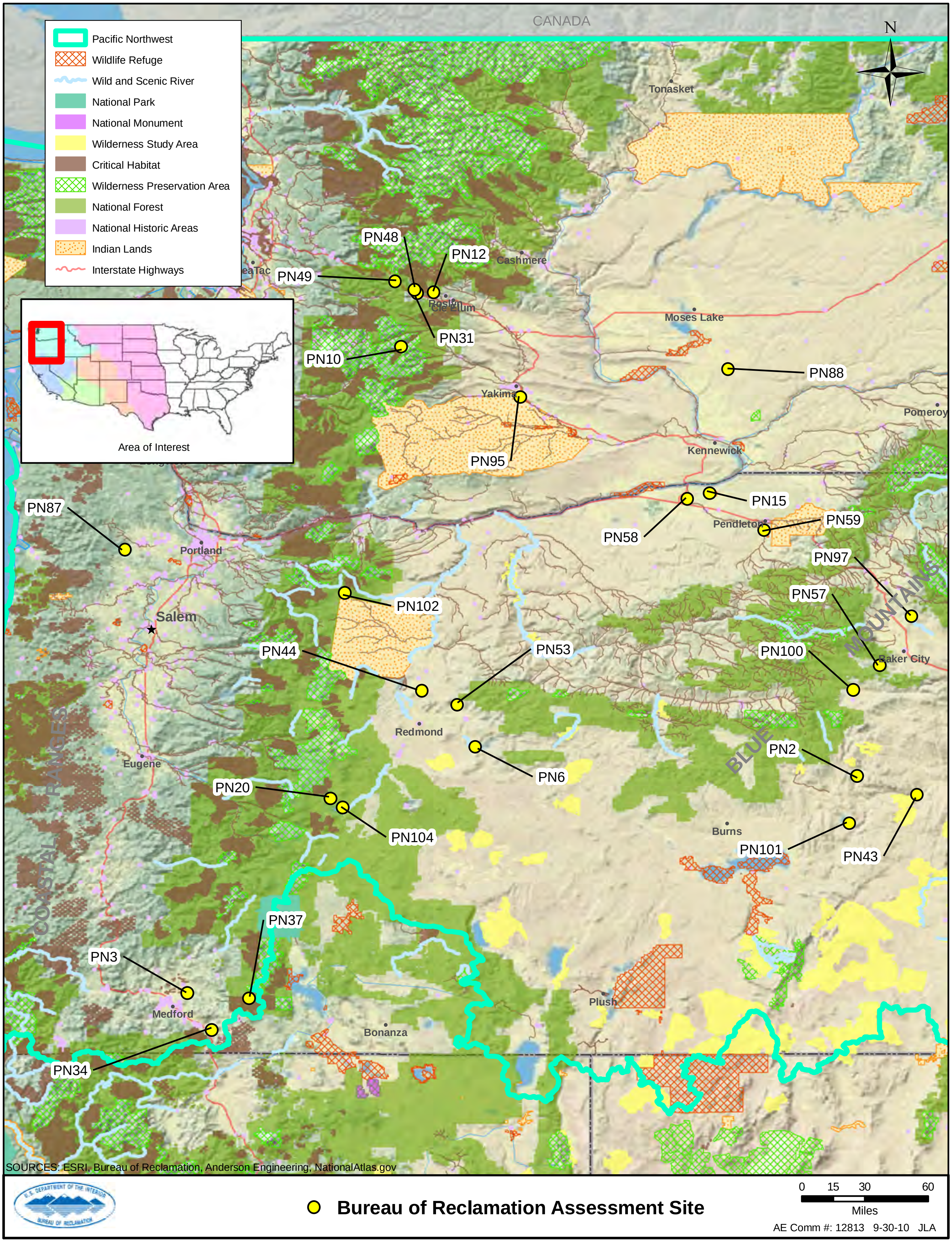


Figure 5-13: Pacific Northwest Region (West) Potential Constraints Map

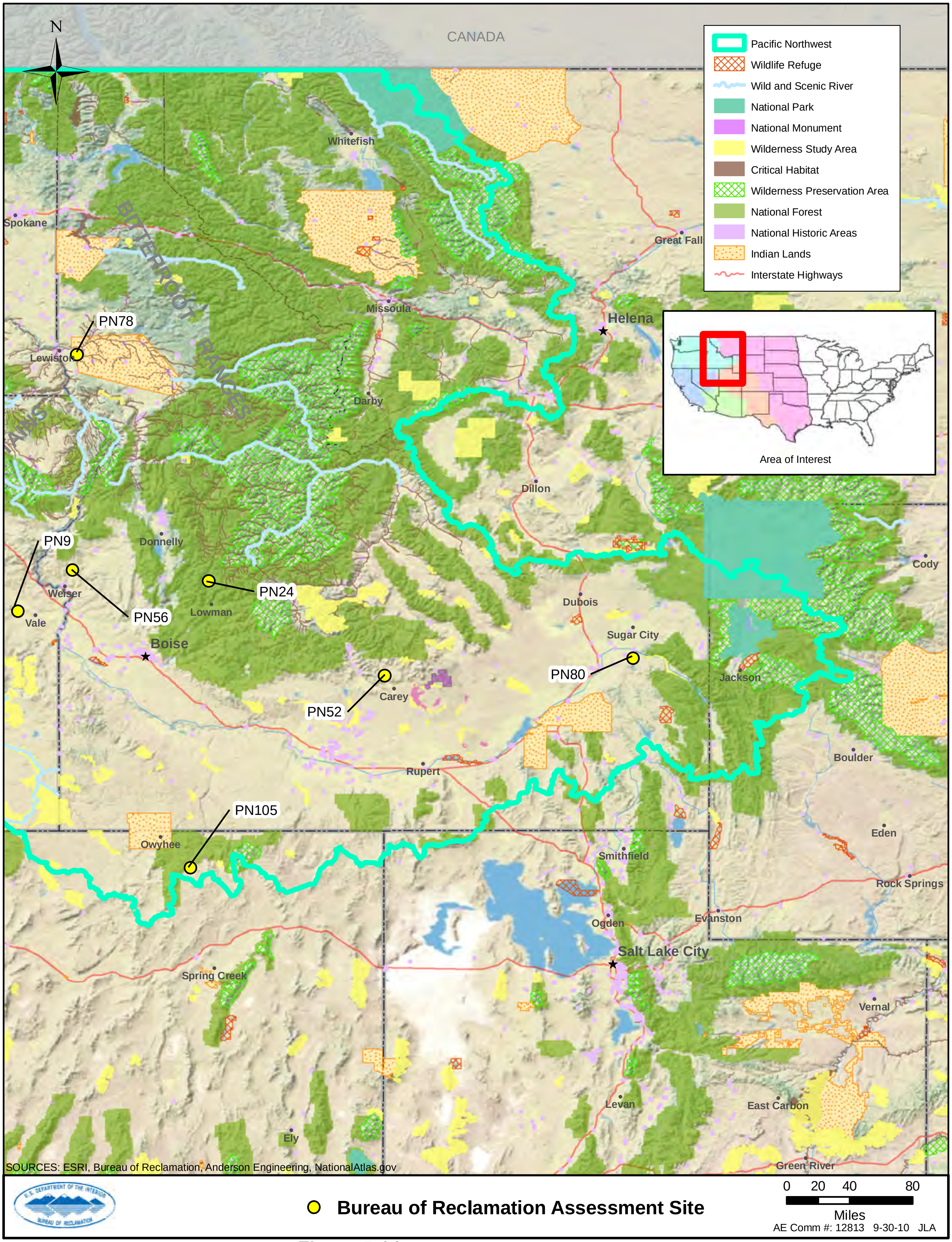


Figure 5-14: Pacific Northwest Region (East) Potential Constraints Map

5.5 Upper Colorado Region

This section is organized similar to the Great Plains region in Section 5.1.

5.5.1 Overview

Reclamation identified 205 sites at existing facilities in the Upper Colorado region for hydropower development potential. Table 5-24 summarizes the number of sites relative to hydropower potential.

Table 5-24 Site Inventory in Upper Colorado Region

	No. of Sites
Total Sites Identified	205
Sites with No Hydropower Potential	73
Canal or Tunnel Sites (Separate Analysis In Progress)	35
Total Sites with Hydropower Potential	65
Sites Removed from Analysis (see Table 2-3)	32

Table 5-25 summarizes the number of sites within different ranges of benefit cost ratios. The Upper Colorado region has 18 sites with benefit cost ratios greater than 1.0.

Table 5-25 Benefit Cost Ratio Summary of Sites Analyzed in Upper Colorado Region

	No. of Sites	Total Installed Capacity (MW)	Total Annual Production (MWh)
Benefit Cost Ratio (with Green Incentives) from:			
0 to 0.25	25	4.0	13,723
0.25 to 0.5	9	5.3	19,563
0.5 to 0.75	6	3.2	11,540
0.75 to 1.0	7	8.7	36,281
1.0 to 2.0	16	44.7	200,353
Greater than or equal to 2.0	2	38.0	166,581
Total	65	103.9	448,041

Table 5-26 identifies and ranks the sites in the Upper Colorado region with benefit cost ratios (with green incentives) above 0.75. The Sixth Water Flow Control Structure site is ranked the highest in the region with a benefit cost ratio of 3.02 and an IRR of 17.1 percent, with green incentives. The Sixth Water Flow Control Structure site is part of Reclamation's Central Utah Project Bonneville Unit in Utah. The model selected a Pelton turbine for the site, which has an installed capacity of about 26 MW and annual energy production of

114,000 MWh. Figure 5-15 also shows the Sixth Water Flow Control Structure site, which is in the Uinta National Forest. Recreation and fish and wildlife mitigation costs were added to the site's total development costs.

The Upper Diamond Fork Flow Control Structure is ranked second highest in the region with a benefit cost ratio of 2.36 and an IRR of 13.6 percent. The Upper Diamond Fork Site is part of Reclamation's Central Utah Project Bonneville Unit in Utah. The Federal green incentive rate was applied to calculate economic benefits. The model selected a Francis turbine for the Upper Diamond Fork site, with an installed capacity of about 12 MW and annual energy production of about 52,000 MWh. Figure 5-15 also shows the Upper Diamond Fork site, which is downstream of the Sixth Water Flow Control Structure. Recreation and fish and wildlife mitigation costs were added to the total development costs for the site.

Table 5-26 Sites with Benefit Cost Ratio (With Green Incentives) Greater than 0.75 in Upper Colorado Region

Site ID	Site Name	Data Confidence	Installed Capacity (kW)	Annual Production (MWh)	Plant Factor	Cost per Installed Capacity ($/kW)	Benefit Cost Ratio With Green	IRR With Green
UC-141	Sixth Water Flow Control	Medium	25,800	114,420	0.52	$1,482	3.02	17.1%
UC-185	Upper Diamond Fork Flow Control Structure	Medium	12,214	52,161	0.5	$1,806	2.36	13.6%
UC-89	M&D Canal-Shavano Falls	Low	2,862	15,419	0.62	$2,536	1.88	11.4%
UC-159	Spanish Fork Flow Control Structure	Medium	8,114	22,920	0.33	$1,620	1.66	9.6%
UC-49	Grand Valley Diversion Dam	Medium	1,979	14,246	0.84	$4,584	1.55	8.6%
UC-52	Gunnison Tunnel	Medium	3,830	19,057	0.58	$2,972	1.55	8.8%
UC-19	Caballo Dam	Low	3,260	15,095	0.52	$3,128	1.45	7.9%
UC-147	South Canal, Sta. 181+10, "Site #4"	Medium	3,046	15,536	0.59	$3,275	1.44	8.0%
UC-144	Soldier Creek Dam	High	444	2,909	0.76	$4,033	1.39	7.9%
UC-131	Ridgway Dam	High	3,366	14,040	0.49	$2,937	1.35	7.3%
UC-146	South Canal, Sta 19+ 10 "Site #1"	Medium	2,465	12,576	0.59	$3,603	1.32	7.1%
UC-51	Gunnison Diversion Dam	Medium	1,435	9,220	0.75	$4,832	1.28	6.7%
UC-150	South Canal, Sta.106+65, "Site #3"	Medium	2,224	11,343	0.59	$3,777	1.26	6.6%
UC-162	Starvation Dam	High	3,043	13,168	0.5	$3,461	1.23	6.2%
UC-179	Taylor Park Dam	High	2,543	12,488	0.57	$4,323	1.12	5.4%
UC-57	Heron Dam	Medium	2,701	8,874	0.38	$2,970	1.06	4.9%
UC-154	Southside Canal, Sta 171+ 90 thru 200+ 67 (2 canal drops)	Low	2,026	6,557	0.38	$2,762	1.05	4.8%
UC-148	South Canal, Sta. 472+00, "Site #5"	Medium	1,354	6,905	0.59	$4,548	1.05	4.8%
UC-177	Syar Tunnel	Medium	1,762	7,982	0.53	$4,680	0.99	4.3%
UC-174	Sumner Dam	Medium	822	4,300	0.61	$5,103	0.98	4.2%

Table 5-26 Sites with Benefit Cost Ratio (With Green Incentives) Greater than 0.75 in Upper Colorado Region

Site ID	Site Name	Data Confidence	Installed Capacity (kW)	Annual Production (MWh)	Plant Factor	Cost per Installed Capacity ($/kW)	Benefit Cost Ratio With Green	IRR With Green
UC-155	Southside Canal, Sta 349+ 05 thru 375+ 42 (3 canal drops)	Low	1,651	5,344	0.38	$3,131	0.93	3.7%
UC-132	Rifle Gap Dam	High	341	1,740	0.59	$4,621	0.92	3.5%
UC-72	Joes Valley Dam	High	1,624	6,596	0.47	$4,780	0.85	3.0%
UC-145	South Canal Tunnels	Medium	884	4,497	0.59	$5,665	0.84	2.8%
UC-117	Paonia Dam	Medium	1,582	5,821	0.43	$4,482	0.79	2.3%

5.5.2 Power Production

Table 5-27 summarizes potential power production at sites in the Upper Colorado region. The Upper Colorado region sites combined have a total installed capacity of about 104 MW and could produce up to about 448,000 MWh of energy annually. The Sixth Water Flow Control Structure has the highest installed capacity of the sites analyzed. The table also shows the distance from the site to the nearest transmission line. Fourteen sites in the region are over 10 miles to the nearest transmission lines.

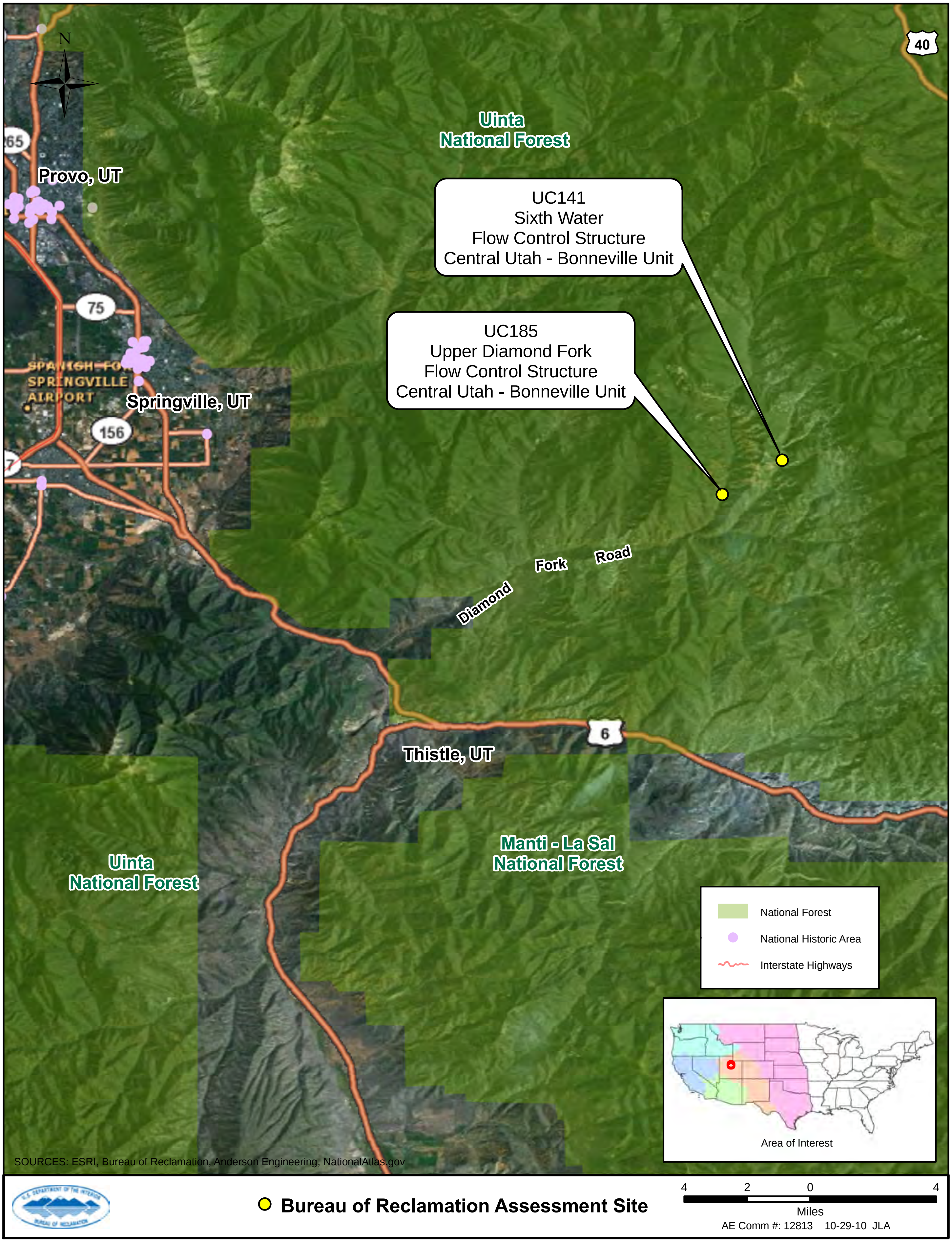


Figure 5-15 : Upper Colorado Region Sixth Water/Upper Diamond Fork Flow Control Structures Site Map

Table 5-27 Hydropower Production Summary for Sites in Upper Colorado Region

Site ID	Site Name	Design Head (feet)	Design Flow (cfs)	Installed Capacity (kW)	Annual Production (MWh)	Plant Factor	T- Line Distance (miles)
UC-4	Angostura Diversion	3	190	33	91	0.32	0.65
UC-5	Arthur V. Watkins Dam	25	20	31	122	0.46	1.99
UC-6	Avalon Dam	17	216	230	1,031	0.52	2.76
UC-7	Azeotea Creek and Willow Creek Conveyance Channel Station 1565+00	18	65	72	240	0.39	5
UC-8	Azeotea Creek and Willow Creek Conveyance Channel Station 1702+75	17	65	68	223	0.38	5
UC-9	Azeotea Creek and Willow Creek Conveyance Channel Station 1831+17	15	65	60	199	0.38	5
UC-11	Azotea Tunnel	22	65	86	222	0.3	5
UC-13	Big Sandy Dam	51	89	286	884	0.36	21.09
UC-14	Blanco Diversion Dam	22	35	47	146	0.36	12.93
UC-15	Blanco Tunnel	109	35	276	849	0.36	12.93
UC-16	Brantley Dam	15	219	210	697	0.39	2.18
UC-19	Caballo Dam	43	1,213	3,260	15,095	0.52	1.55
UC-22	Crawford Dam	135	31	303	1,217	0.47	0.94
UC-23	Currant Creek Dam	118	17	146	1,003	0.8	11.62
UC-28	Dolores Tunnel	84	17	103	515	0.58	5
UC-36	East Canyon Dam	170	76	929	3,549	0.44	15.32
UC-44	Fort Sumner Diversion Dam	14	90	75	378	0.59	5
UC-46	Fruitgrowers Dam	28	17	29	124	0.5	5.66
UC-49	Grand Valley Diversion Dam	14	2,260	1,979	14,246	0.84	5
UC-51	Gunnison Diversion Dam	17	1,350	1,435	9,220	0.75	5
UC-52	Gunnison Tunnel	70	875	3,830	19,057	0.58	5
UC-56	Hammond Diversion Dam	8	71	35	148	0.49	5
UC-57	Heron Dam	249	150	2,701	8,874	0.38	4.97
UC-59	Huntington North Dam	55	6	20	51	0.3	0.76
UC-62	Hyrum Dam	75	90	491	2,052	0.49	8.61
UC-67	Inlet Canal	159	22	252	966	0.45	5
UC-72	Joes Valley Dam	159	141	1,624	6,596	0.47	7.68
UC-84	Lost Creek Dam	164	34	410	1,295	0.37	15.99
UC-89	M&D Canal-Shavano Falls	165	240	2,862	15,419	0.62	5
UC-93	Meeks Cabin Dam	130	169	1,586	4,709	0.35	21
UC-98	Montrose and Delta Canal	3	511	96	478	0.58	5
UC-100	Moon Lake Dam	66	134	634	1,563	0.29	13.18
UC-102	Nambe Falls Dam	120	17	147	593	0.47	4.18
UC-116	Outlet Canal	252	32	586	1,839	0.37	5
UC-117	Paonia Dam	149	147	1,582	5,821	0.43	8.32
UC-124	Platoro Dam	131	89	845	3,747	0.52	23.64
UC-126	Red Fleet Dam	115	55	455	1,904	0.49	4.04
UC-131	Ridgway Dam	181	257	3,366	14,040	0.49	6.62
UC-132	Rifle Gap Dam	101	46	341	1,740	0.59	0.04
UC-135	San Acacia Diversion Dam	8	44	20	86	0.5	5
UC-136	Scofield Dam	39	110	266	906	0.4	0.82
UC-137	Selig Canal	2	186	23	98	0.5	5
UC-140	Silver Jack Dam	103	101	748	2,913	0.46	7.59
UC-141	Sixth Water Flow Control	1,149	309	25,800	114,420	0.52	6.14
UC-144	Soldier Creek Dam	233	26	444	2,909	0.76	0.56

Table 5-27 Hydropower Production Summary for Sites in Upper Colorado Region

Site ID	Site Name	Design Head (feet)	Design Flow (cfs)	Installed Capacity (kW)	Annual Production (MWh)	Plant Factor	T- Line Distance (miles)
UC-145	South Canal Tunnels	18	785	884	4,497	0.59	5
UC-146	South Canal, Sta 19+ 10 "Site #1"	51	773	2,465	12,576	0.59	5
UC-147	South Canal, Sta. 181+10, "Site #4"	63	773	3,046	15,536	0.59	5
UC-148	South Canal, Sta. 472+00, "Site #5"	28	773	1,354	6,905	0.59	5
UC-150	South Canal, Sta.106+65, "Site #3"	46	773	2,224	11,343	0.59	5
UC-154	Southside Canal, Sta 171+ 90 thru 200+ 67 (2 canal drops)	346	81	2,026	6,557	0.38	5
UC-155	Southside Canal, Sta 349+ 05 thru 375+ 42 (3 canal drops)	282	81	1,651	5,344	0.38	5
UC-159	Spanish Fork Flow Control Structure	900	124	8,114	22,920	0.33	3.5
UC-162	Starvation Dam	144	292	3,043	13,168	0.5	8.9
UC-164	Stateline Dam	89	44	282	720	0.3	19.35
UC-166	Steinaker Dam	120	70	603	1,965	0.38	0.99
UC-169	Stillwater Tunnel	65	88	413	1,334	0.38	12.24
UC-174	Sumner Dam	114	100	822	4,300	0.61	3.94
UC-177	Syar Tunnel	125	195	1,762	7,982	0.53	7.68
UC-179	Taylor Park Dam	141	250	2,543	12,488	0.57	14.62
UC-185	Upper Diamond Fork Flow Control Structure	547	309	12,214	52,161	0.5	4.34
UC-187	Upper Stillwater Dam	161	50	581	1,904	0.38	12.27
UC-190	Vega Dam	90	84	548	1,702	0.36	2.81
UC-196	Weber-Provo Canal	184	32	424	1,844	0.51	34.88
UC-197	Weber-Provo Diversion Canal	100	24	173	517	0.35	34.88

5.5.3 Economic Evaluation

Table 5-28 summarizes the economic evaluation of hydropower development at sites in the Upper Colorado region. All states in the Upper Colorado region can receive the Federal green incentive for hydropower development. On average, for the sites analyzed, the green incentives only resulted in an increase in the benefit cost ratio of about 0.03. Some sites in the Upper Colorado region had very high cost per installed capacity, low benefit cost ratios, and low IRRs, indicating they would not be economical to develop.

Table 5-28 Economic Evaluation Summary for Sites in Upper Colorado Region

Site ID	Site Name	Total Construction Cost (1,000 $)	Annual O&M Cost (1,000 $)	Cost per Installed Capacity ($/kW)	Benefit Cost Ratio	IRR	Benefit Cost Ratio	IRR
					With Green Incentives		Without Green Incentives	
UC-4	Angostura Diversion	$564.2	$33.4	$17,183	0.12	< 0	0.11	< 0
UC-5	Arthur V. Watkins Dam	$966.1	$40.9	$31,426	0.11	< 0	0.1	< 0
UC-6	Avalon Dam	$2,260.8	$76.5	$9,818	0.42	< 0	0.4	< 0
UC-7	Azeotea Creek and Willow Creek Conveyance Channel Station 1565+00	$2,215.3	$66.6	$30,674	0.1	< 0	0.1	< 0
UC-8	Azeotea Creek and Willow Creek Conveyance Channel Station 1702+75	$2,193.0	$65.9	$32,238	0.1	< 0	0.09	< 0
UC-9	Azeotea Creek and Willow Creek Conveyance Channel Station 1831+17	$2,149.4	$64.7	$35,760	0.09	< 0	0.08	< 0
UC-11	Azotea Tunnel	$2,284.4	$68.6	$26,649	0.09	< 0	0.09	< 0
UC-13	Big Sandy Dam	$9,260.7	$211.6	$32,416	0.1	< 0	0.09	< 0
UC-14	Blanco Diversion Dam	$4,656.2	$110.7	$98,200	0.03	< 0	0.03	< 0
UC-15	Blanco Tunnel	$5,526.7	$137.5	$20,041	0.16	< 0	0.15	< 0
UC-16	Brantley Dam	$1,991.3	$70.5	$9,481	0.32	< 0	0.3	< 0
UC-19	Caballo Dam	$10,197.9	$305.0	$3,128	1.45	7.9%	1.36	7.10 %
UC-22	Crawford Dam	$1,592.4	$66.7	$5,264	0.64	< 0	0.6	< 0
UC-23	Currant Creek Dam	$4,611.2	$114.8	$31,659	0.22	< 0	0.21	< 0
UC-28	Dolores Tunnel	$2,277.1	$69.2	$22,077	0.21	< 0	0.2	< 0
UC-36	East Canyon Dam	$8,271.6	$216.9	$8,907	0.44	< 0	0.41	< 0
UC-44	Fort Sumner Diversion Dam	$2,213.6	$67.1	$29,472	0.17	< 0	0.16	< 0
UC-46	Fruitgrowers Dam	$2,116.5	$62.2	$72,409	0.06	< 0	0.05	< 0
UC-49	Grand Valley Diversion Dam	$9,070.0	$241.3	$4,584	1.55	8.6%	1.45	7.7%
UC-51	Gunnison Diversion Dam	$6,934.9	$200.4	$4,832	1.28	6.7%	1.2	6.0%
UC-52	Gunnison Tunnel	$11,385.5	$366.6	$2,972	1.55	8.8%	1.45	7.9%
UC-56	Hammond Diversion Dam	$1,983.3	$60.2	$57,350	0.07	< 0	0.07	< 0
UC-57	Heron Dam	$8,020.4	$246.6	$2,970	1.06	4.9%	1	4.4%
UC-59	Huntington North Dam	$514.4	$31.7	$25,611	0.07	< 0	0.07	< 0
UC-62	Hyrum Dam	$5,081.3	$140.9	$10,346	0.4	< 0	0.37	< 0
UC-67	Inlet Canal	$2,596.6	$82.7	$10,320	0.34	< 0	0.32	< 0
UC-72	Joes Valley Dam	$7,764.3	$210.5	$4,780	0.85	3.0%	0.8	2.6%
UC-84	Lost Creek Dam	$6,599.2	$164.2	$16,082	0.2	< 0	0.19	< 0
UC-89	M&D Canal-Shavano Falls	$7,260.4	$256.6	$2,536	1.88	11.4%	1.77	10.1 %
UC-93	Meeks Cabin Dam	$11,641.2	$302.3	$7,341	0.4	< 0	0.38	< 0
UC-98	Montrose and Delta Canal	$2,343.8	$70.8	$24,452	0.19	< 0	0.18	< 0
UC-100	Moon Lake Dam	$7,328.5	$185.8	$11,564	0.22	< 0	0.2	< 0
UC-102	Nambe Falls Dam	$2,373.7	$73.7	$16,097	0.24	< 0	0.23	< 0
UC-116	Outlet Canal	$3,264.8	$108.6	$5,570	0.52	< 0	0.49	< 0
UC-117	Paonia Dam	$7,092.5	$203.7	$4,482	0.79	2.3%	0.74	1.9%
UC-124	Platoro Dam	$10,106.2	$246.5	$11,964	0.38	< 0	0.36	< 0

Table 5-28 Economic Evaluation Summary for Sites in Upper Colorado Region

Site ID	Site Name	Total Construction Cost (1,000 $)	Annual O&M Cost (1,000 $)	Cost per Installed Capacity ($/kW)	Benefit Cost Ratio	IRR	Benefit Cost Ratio	IRR
					With Green Incentives		Without Green Incentives	
UC-126	Red Fleet Dam	$3,031.9	$100.1	$6,666	0.59	< 0	0.55	< 0
UC-131	Ridgway Dam	$9,885.1	$296.2	$2,937	1.35	7.3%	1.27	6.5%
UC-132	Rifle Gap Dam	$1,574.9	$65.5	$4,621	0.92	3.5%	0.86	2.9%
UC-135	San Acacia Diversion Dam	$1,895.0	$57.2	$94,272	0.04	< 0	0.04	< 0
UC-136	Scofield Dam	$1,780.5	$69.3	$6,700	0.45	< 0	0.42	< 0
UC-137	Selig Canal	$1,868.6	$57.1	$82,287	0.05	< 0	0.05	< 0
UC-140	Silver Jack Dam	$4,863.9	$145.6	$6,504	0.57	< 0	0.54	< 0
UC-141	Sixth Water Flow Control	$38,227.9	$1,031.9	$1,482	3.02	17.1%	2.84	15.3 %
UC-144	Soldier Creek Dam	$1,790.2	$72.6	$4,033	1.39	7.9%	1.31	7.0%
UC-145	South Canal Tunnels	$5,005.8	$154.9	$5,665	0.84	2.8%	0.79	2.4%
UC-146	South Canal, Sta 19+ 10 "Site #1"	$8,883.4	$280.5	$3,603	1.32	7.1%	1.24	6.3%
UC-147	South Canal, Sta. 181+10, "Site #4"	$9,975.1	$318.0	$3,275	1.44	8.0%	1.35	7.2%
UC-148	South Canal, Sta. 472+00, "Site #5"	$6,155.4	$193.1	$4,548	1.05	4.8%	0.98	4.2%
UC-150	South Canal, Sta.106+65, "Site #3"	$8,399.7	$264.0	$3,777	1.26	6.6%	1.18	5.9%
UC-154	Southside Canal, Sta 171+ 90 thru 200+ 67 (2 canal drops)	$5,595.9	$199.5	$2,762	1.05	4.8%	0.99	4.2%
UC-155	Southside Canal, Sta 349+ 05 thru 375+ 42 (3 canal drops)	$5,169.8	$180.4	$3,131	0.93	3.7%	0.88	3.2%
UC-159	Spanish Fork Flow Control Structure	$13,147.5	$435.9	$1,620	1.66	9.6%	1.57	8.6%
UC-162	Starvation Dam	$10,530.6	$302.6	$3,461	1.23	6.2%	1.15	5.6%
UC-164	Stateline Dam	$8,492.4	$195.1	$30,145	0.09	< 0	0.08	< 0
UC-166	Steinaker Dam	$2,388.4	$93.9	$3,959	0.71	1.0%	0.67	0.7%
UC-169	Stillwater Tunnel	$6,342.4	$159.5	$15,340	0.21	< 0	0.2	< 0
UC-174	Sumner Dam	$4,193.5	$130.0	$5,103	0.98	4.2%	0.92	3.7%
UC-177	Syar Tunnel	$8,246.1	$222.7	$4,680	0.99	4.3%	0.93	3.8%
UC-179	Taylor Park Dam	$10,991.2	$299.3	$4,323	1.12	5.4%	1.05	4.8%
UC-185	Upper Diamond Fork Flow Control Structure	$22,058.5	$613.6	$1,806	2.36	13.6%	2.22	12.2 %
UC-187	Upper Stillwater Dam	$6,064.5	$158.5	$10,431	0.32	< 0	0.31	< 0
UC-190	Vega Dam	$3,012.5	$103.7	$5,499	0.51	< 0	0.48	< 0
UC-196	Weber-Provo Canal	$14,266.2	$311.3	$33,648	0.14	< 0	0.13	< 0
UC-197	Weber-Provo Diversion Canal	$13,771.4	$291.4	$79,382	0.04	< 0	0.04	< 0

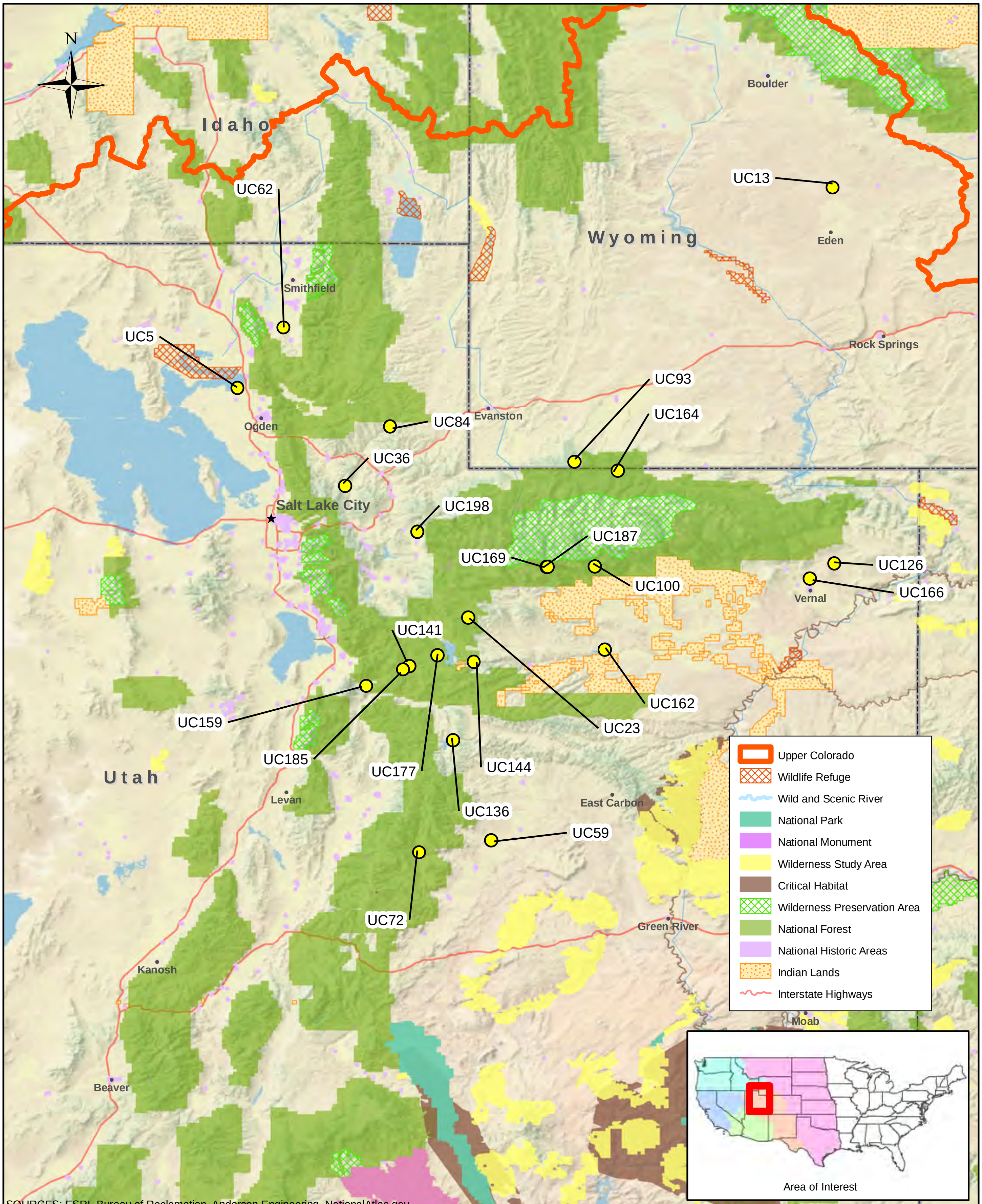
5.5.4 Constraints Evaluation

Figures 5-16 and 5-17 show constraints associated with the sites analyzed in the Hydropower Assessment Tool. Because of the size of the Upper Colorado region, the figures divide the region into east and west. Table 5-29 summarizes the number of sites with potential regulatory constraints in the Upper Colorado region. Sixty-nine sites are within National Forests.

In addition to mapping regulatory constraints, Reclamation staff identified potential fish and wildlife and fish passage constraints for sites in the Upper Colorado region with benefit cost ratios above 0.75. These sites included Caballo Dam, Grand Valley Diversion Dam, Gunnison Diversion Dam, Heron Dam, Joes Valley Dam, Paonia Dam, Ridgway Dam, Rifle Gap Dam, Sixth Water Flow Control Structure, Soldier Creek Dam, Spanish Fork Flow Control Structure, Starvation Dam, Sumner Dam, Syar Tunnel, Taylor Park Dam, and Upper Diamond Fork Flow Control Structure. Appropriate mitigation costs were added to sites with regulatory or fish constraints.

Table 5-29 Number of Sites in the Upper Colorado Region with Potential Regulatory Constraints

Regulatory Constraint	No. of Sites
Critical Habitat	2
Indian Lands	3
National Forest	69
National Historic Areas	5
National Park	0
Wild & Scenic River	0
Wilderness Preservation Area	1
Wilderness Study Area	2
Wildlife Refuge	1
National Monument	0



Bureau of Reclamation Assessment Site

0 10 20 40
Miles
AE Comm #: 12813 9-30-10 JLA

Figure 5-16: Upper Colorado Region (West) Potential Constraints Map

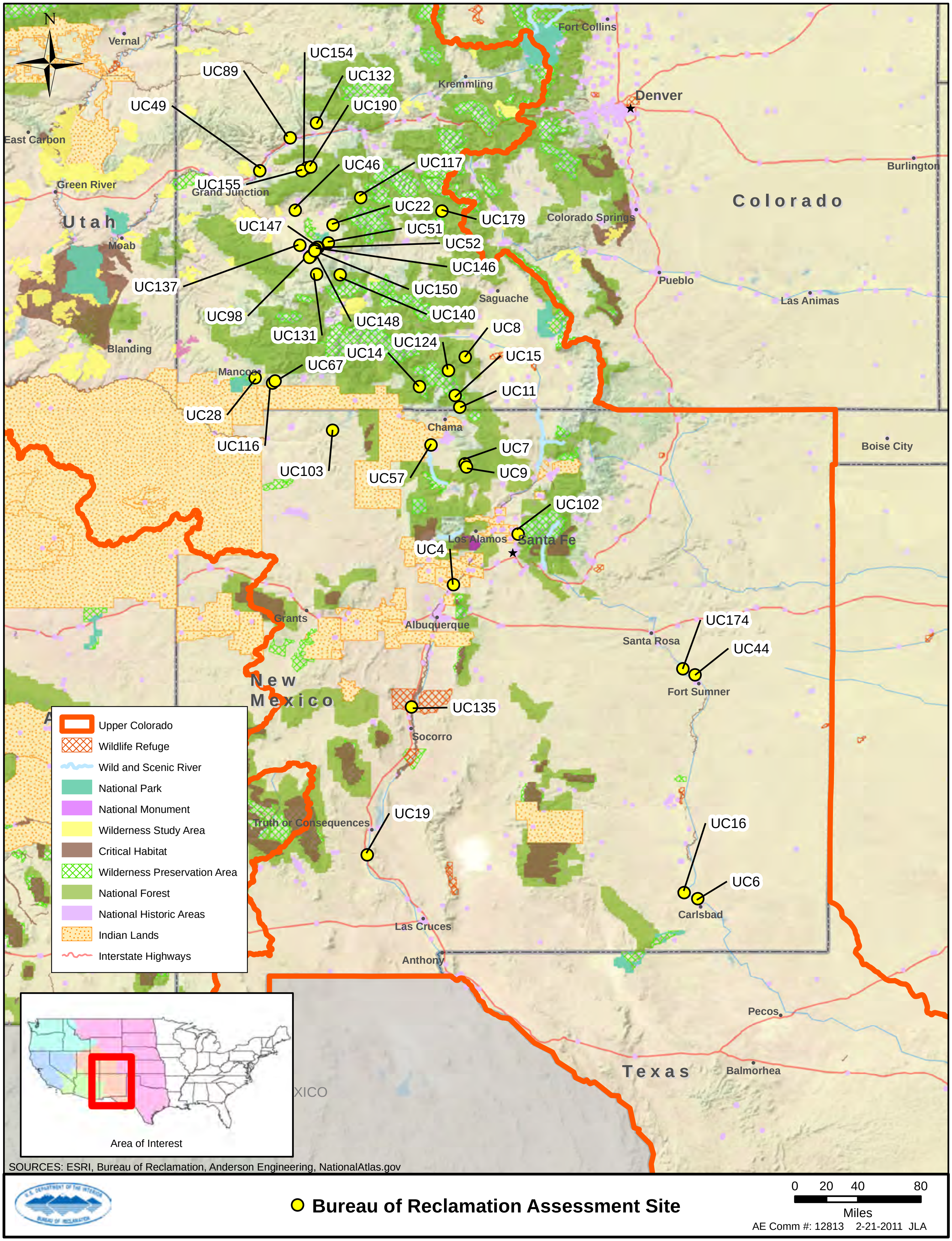


Figure 5-17 : Upper Colorado Region (East) Potential Constraints Map

5.6 Discount Rate Sensitivity Analysis

In order to compute net present value, it is necessary to discount future benefits and costs to reflect the time value of money. In general, benefits and costs are worth more if they are experienced sooner. The higher the discount rate, the lower is the present value of future cash flows. Federal planning studies require use of the Federal discount rate for economic analysis, which is published annually by the Office of Management and Budget. For this study, the Fiscal Year 2010 Federal Discount Rate of 4.375 percent was used to calculate present worth of benefits and costs of potential hydropower development.

If private developers or municipalities choose to pursue a Reclamation site for hydropower development, the Federal discount rate may not be applicable. They would likely face a higher discount rate, depending on ownership and the financing source. Discount rates could be higher or lower than the current rate and historically a high has been 12 percent. This section presents a sensitivity analysis to determine how the benefit cost ratio is affected by varying the discount rate. The sensitivity analysis was performed on three sites, Sixth Water Flow Control Structure in the Upper Colorado region, Helena Valley Pumping Plant in the Great Plains region, and Wikiup Dam in the Pacific Northwest region, using discount rates of 4.375 percent, 8 percent, and 12 percent.

Figure 5-18 shows the results of the sensitivity analysis of discount rates for the three sites. Benefit cost ratios are shown with green incentives. Under a 4.375 percent discount rate, the Sixth Water Flow Control Structure and Helena Valley Pumping Plant sites would be economical to develop because the benefit cost ratio is greater than 1.0. The Wikiup Dam site would also have potential with a benefit cost ratio just under 1.0.

With an 8 percent discount rate, the Sixth Water Flow Control Structure site would still be economical, the Helena Valley Pumping Plant site would have potential, but the Wikiup Dam site’s benefit cost ratio would fall to 0.67, which indicates it may not be economical to develop the site with some financing options.

With a 12 percent discount rate, the Sixth Water Flow Control Structure site’s benefit cost ratio was still well above 1.0, but the Helena Valley Pumping Plant site’s benefit cost ratio fell to 0.71, which may not be economical to develop at higher discount rates.

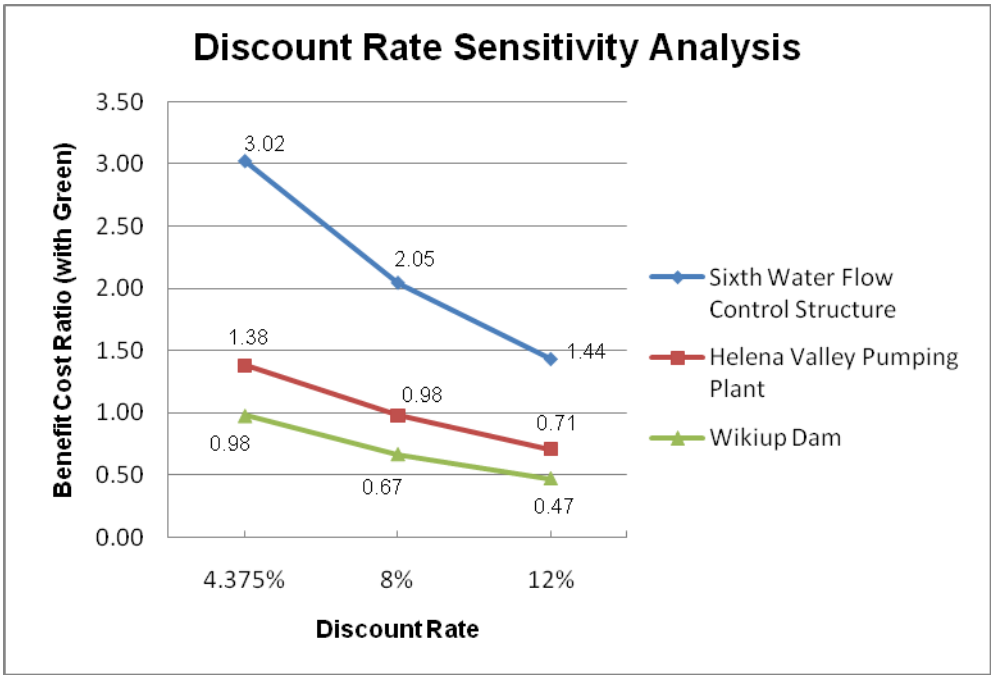


Figure 5-18 Discount Rate Sensitivity Analysis Results

Figure 5-18 shows that the benefit cost ratio is sensitive to changes in the discount rate. The benefit cost ratios decreased in the range of 30 percent when the discount rate was increased to 8 percent from 4.35 percent. The benefit cost ratios decreased in the range of 50 percent when the discount rate was increased to 12 percent relative to from 4.35 percent. If private developers or municipalities face a relative high discount rate, some sites indicated as economically feasible in this analysis may not be. Developers should consider this if a site is further pursued.

The sensitivity analysis also shows the contribution of green incentive benefits in California to the economic viability of a site. California has the most aggressive incentives of any state in the analysis for hydropower development. In many cases, state incentives effectively double the avoided cost or the prices typically received by developers. Figure 5-19 illustrates the difference green incentive makes for the Boca Dam in California under a 4.375 percent, 8 percent, and 12 percent discount rate. The benefit cost ratio with green incentives shows the site would be economical under the 4.375 percent and 8 percent discount rates and close to economic under the 12 percent discount rate. The benefit cost ratio without green incentives indicates the site could be close to economically feasible under the 4.375 percent discount rate, but the higher discount rates (8 and 12 percent) result in a much lower benefit cost ratio.

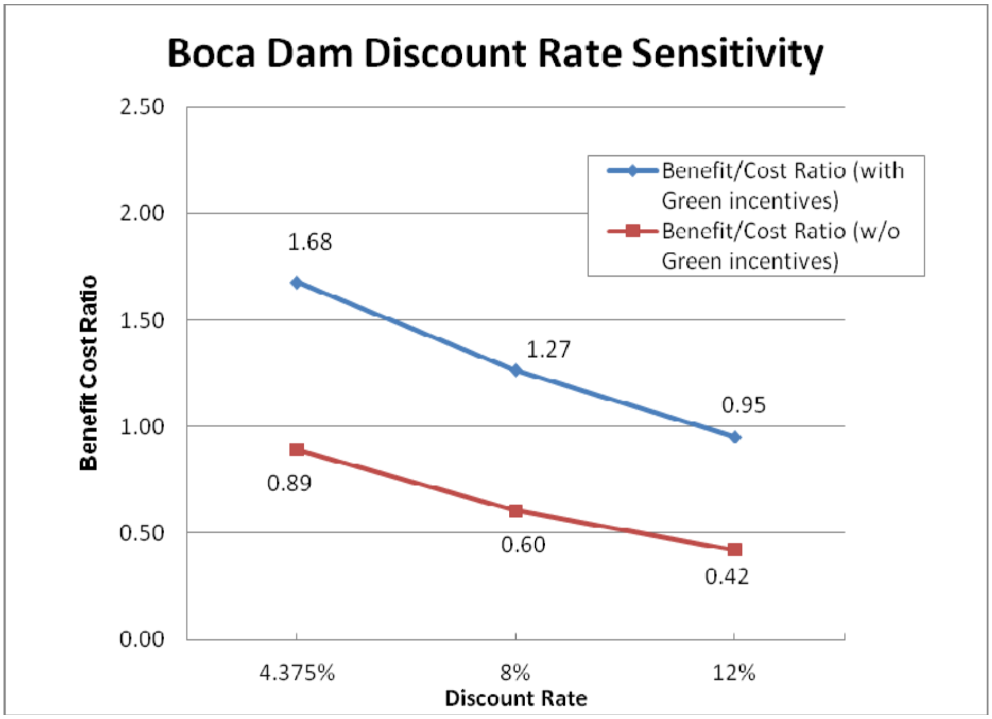


Figure 5-19 Boca Dam Site Discount Rate Sensitivity Analysis

5.7 Exceedance Level Sensitivity Analysis

As described in Chapter 3, this analysis sets the design flow and design head of the proposed hydropower plant at a 30 percent exceedance level, based on the flow and net head exceedance curves calculated with available hydrologic data. Different exceedance percentages can be selected for sizing the hydropower plant, which could increase or decrease the plant capacity. Changing the plant capacity would effectively change the amount of energy the plant can generate and the costs to develop, operate, and maintain the plant. During feasibility analysis of a potential site, the developer should analyze different plant sizes to evaluate the most economic plant size. This is usually accomplished by picking different exceedance percentages from the flow duration curve and calculating the benefit cost ratio for each alternate size. For example, exceedance levels for sizing the plant might be compared at the 15, 20, 25, 30 and 35 percent exceedance levels.

This sensitivity analysis compares the benefit cost ratios of selected sites based on 30 percent and 20 percent exceedance levels. In general, plants designed at a 20 percent exceedance level would have a larger plant capacity and can generate more energy when flows are available. Table 5-30 shows sensitivity results for annual generation and benefit cost ratios (with green incentives) of six sites with installed capacities set at 30 percent and 20 percent exceedance levels.

Table 5-30
20 and 30 Percent Exceedance Level Sensitivity Results

Site ID	Site Name	Installed Capacity (MW)		Annual Generation (MWh)		Benefit Cost Ratio	
		30%	20%	30%	20%	30%	20%
GP-52	Helena Valley Pumping Plant	2.6	3.3	9,608	10,879	1.38	1.35
PN-49	Keechelus Dam	2.4	3.9	6,746	8,220	0.87	0.71
PN-80	Ririe Dam	1.0	2.1	3,778	5,582	0.94	0.90
UC-51	Gunnison Diversion Dam	1.4	1.9	9,220	9,963	1.28	1.19
UC-57	Heron Dam	2.7	4.4	8,874	12,274	1.09	1.12
UC-141	Sixth Water Flow Control Structure	25.8	35.2	114,420	128,420	3.02	2.69

For the six sites analyzed, the capacity and annual production increased when the plant design was set at a 20 percent exceedance versus 30 percent exceedance. For the six sites, the sum of the installed capacities is 50.8 MW under a 20 percent exceedance relative to 35.9 MW under a 30 percent exceedance, a 42 percent increase. This is a relatively large increase in capacity; however, development and annual costs would also increase for larger plants. For five of the six sites, the benefit cost ratio fell when the 20 percent exceedance was used. This indicates that the costs of adding capacity were rising faster than the revenues (energy production) of the added capacity. For some sites, such as the Heron Dam, site characteristics could result in a higher benefit cost ratio under the 20 percent exceedance rate.

This study consistently used a 30 percent exceedance, which resulted in more sites having higher benefit cost ratios. Using a 20 percent exceedance could have resulted in higher installed capacities and more energy generation, but the number of economically feasible projects, based on the benefit cost ratios, would decrease. The results of this sensitivity analysis indicate the necessity of evaluating various exceedance rates during feasibility-level analysis to determine the most economic plant size.

5.8 Sites with Seasonal Flows

The exceedance level sensitivity analysis in Section 5.7 focuses on sites that have benefit cost ratios close to or above 1.0, meaning the sites could be economical to develop for hydropower. The analysis above shows that, for most sites, designing plant capacity at a 20 percent exceedance level reduces the benefit cost ratio, meaning that incremental costs of adding capacity are rising faster than incremental benefits of energy production. For some sites with unusual duration curves, the benefit cost ratio could increase at lower exceedance levels; sites with seasonal flows fall into this category.

Much of Reclamation’s infrastructure delivers water for agricultural irrigation purposes. The irrigation season varies by region, but generally spans from April through October. In some areas, the season is shorter, spanning from May through September. Some sites analyzed in the Resource Assessment only have flows during the irrigation season and have zero or very low flows during the remainder of the year. Under the 30 percent exceedance analysis, sites with seasonal flow had benefit cost ratios mostly under 0.75, indicating hydropower development would be uneconomical. In general, setting the design flow at a 20 percent exceedance for sites with seasonal flow would increase capacity to capture more flow and increase energy generated; however, development costs would also increase. This section performs a sensitivity analysis on exceedance levels for sites GP-1 A-Drop Project, Greenfield Main Canal Drop and GP-54 Horsetooth Dam to determine how much more seasonal flow could be captured and energy generated at lower exceedance levels and the associated economic implications. This section also identifies additional sites in the Resource Assessment study area with seasonal flows and what the 20 percent flow exceedance level would be.

The Hydropower Assessment Tool selects design flow for the power plant based on 30 percent exceedance calculated on year round flows. Because of months with low to no flows, the design flow would be set at a level which may be much lower than the seasonal flows; therefore, much of the seasonal flow may not be captured by the power plant. Sizing the plant larger would capture more of the seasonal flow and produce more energy at increased cost. Sites with seasonal flows tend to have a steeper sloped flow duration curve than sites with more constant flows. Figure 5-20 shows a flow duration curve for site GP-1 A-Drop Project, Greenfield Main Canal Drop, which has flows May through August, sometimes into September, and no flows during the other months.

For the A-Drop Project, the 30 percent exceedance level for flows is zero, causing the model to determine no hydropower potential at this site. At a 20 percent exceedance, the design flow would be set at 1,090 cfs and the model sizes the plant at 2.3 MW, which would have an annual generation of 5,974 MWh at the site. However, the benefit cost ratio would only be 0.69 at 20 percent exceedance, which, similar to the 30 percent exceedance results, indicates it is still uneconomical to develop.

Table 5-31 shows production and economic results for the A-Drop Project at varying flow exceedance levels. As discussed above, the installed capacity and annual generation will increase at lower exceedance levels. The benefit cost ratio is highest at a 20 percent exceedance and then begins to decrease again at the 15 and 10 percent exceedance levels. The economic analysis shows that costs are greater than benefits at each exceedance level; and, each unit of energy produced costs more than the revenue it generates. None of the exceedance level sensitivity runs for the A-Drop Project indicate that the site would be economic to develop.

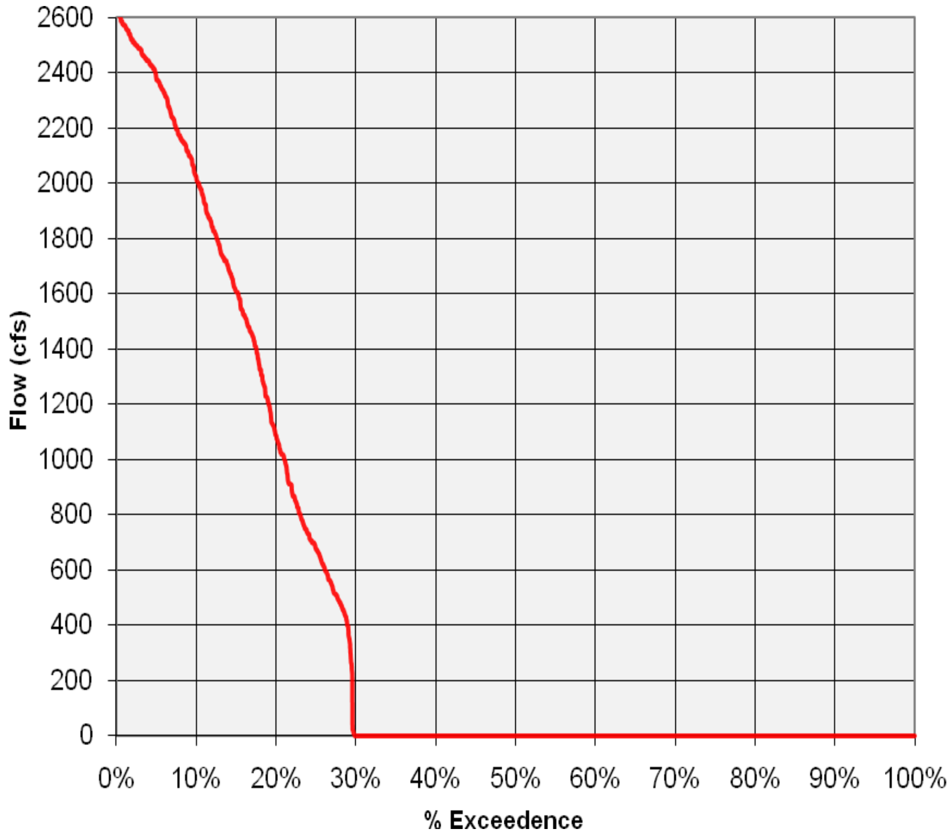


Figure 5-20 A-Drop Project Flow Exceedance Curve

Table 5-31 GP-1 A-Drop Project, Greenfield Main Canal Drop Seasonal Flow Analysis						
	Flow Exceedance Level					
	10%	**15%**	**20%**	**25%**	**30%**	**35%**
Selected Turbine Type	Low Head	Low Head	Kaplan	Kaplan	30% exceedance for flows is 0; therefore, model determined no hydropower potential at this flow exceedance level	35% exceedance for flows is 0; therefore, model determined no hydropower potential at this flow exceedance level
Selected Design Head	34	34	34	34		
Selected Design Flow	2,030	1,613	1,090	680		
Installed Capacity	4,204	3,341	2,318	1,446		
Production (MWh)						
January	0	0	0	0		
February*	0	0	0	0		
March	0	0	0	0		
April	0	0	0	0		
May	1,225	1,093	1,003	690		
June	2,336	2,035	1,742	1,155		
July	2,838	2,361	1,892	1,182		

Table 5-31
GP-1 A-Drop Project, Greenfield Main Canal Drop Seasonal Flow Analysis

	Flow Exceedance Level					
	10%	**15%**	**20%**	**25%**	**30%**	**35%**
August	1,035	1,038	1,132	821	30% exceedance for flows is 0; therefore, model determined no hydropower potential at this flow exceedance level	35% exceedance for flows is 0; therefore, model determined no hydropower potential at this flow exceedance level
September	145	161	205	201		
October	0	0	0	0		
November	0	0	0	0		
December	0	0	0	0		
Annual production*	7,579	6,688	5,974	4,049		
Benefit/Cost Ratio (with Green incentives)	0.65	0.67	0.69	0.62		
Internal Rate of Return (with Green incentives)	0.23%	0.50%	0.87%	Negative		

Table 5-32 shows similar results for the Horsetooth Dam site. The benefit cost ratio is highest under the 15 percent exceedance level; however, none of the exceedance level sensitivity runs show that the site would be economic to develop. Sizing sites with seasonal flows at a lower exceedance level would increase potential generation, but, in general, development of the sites would not be economically viable. The developer would have higher development costs for a larger capacity facility, and the power plant can remain idle for up to six, sometimes more, months a year. It would take a much longer time period to recover costs, as indicated by the low benefit cost ratios.

Table 5-32
GP-54 Horsetooth Dam Seasonal Flow Analysis

	Flow Exceedance Level					
	10%	**15%**	**20%**	**25%**	**30%**	**35%**
Selected Turbine Type	Francis	Francis	Francis	Francis	Francis	Francis
Selected Design Head	127	125	123	121	119	117
Selected Design Flow	362	268	188	107	40.8	17
Installed Capacity	3,318	2,425	1,670	934	350	144
Production (MWh)						
January	0	0	0	0	0	0
February*	0	0	0	0	0	0
March	0	0	0	0	0	0
April	113	97	77	49	32	22
May	557	491	399	261	125	63
June	268	251	221	170	104	62
July	1,328	1,080	809	486	196	86
August	1,141	949	731	448	182	79

Table 5-32
GP-54 Horsetooth Dam Seasonal Flow Analysis

	Flow Exceedance Level					
	10%	**15%**	**20%**	**25%**	**30%**	**35%**
September	470	421	347	241	125	63
October	290	263	221	161	82	43
November	0	0	0	1	2	2
December	0	0	0	0	0	0
Annual production*	4,168	3,551	2,805	1,817	847	419
Benefit/Cost Ratio (with Green incentives)	0.51	0.53	0.52	0.46	0.34	0.23
Internal Rate of Return (with Green incentives)	Negative	Negative	Negative	Negative	Negative	Negative

Table 5-33 lists other sites with seasonal flows. At a 30 percent exceedance level, these sites had benefit cost ratios less than 1.0. Because of seasonal flows, all but two sites (Fresno Dam and Joes Valley Dam) have the same or slightly higher benefit cost ratios at a 20 percent exceedance level relative to 30 percent exceedance; however, they would still not be economical to develop. The benefit cost ratio at even lower exceedance levels would likely change similar to the analysis above for A-Drop Project and Horsetooth Dam – increased capacity and generation at lower exceedance levels, but the site remains uneconomical to develop.

If sites with seasonal flows are further analyzed, developers should investigate alternative design capacities than 30 percent flow exceedance. Design flows can be easily changed in the Hydropower Assessment Tool (see Appendix D). There may be some additional sites in the Resource Assessment not listed in Table 5-33 with seasonal flows that have very low head available for hydropower production. Sites with seasonal flows can generally be identified by a steeply sloped flow duration curve. Table 2-3 further identifies some seasonal flow characteristics for sites.

Table 5-33
20 Percent Exceedance Analysis of Sites with Seasonal Flows and Benefit Cost Ratios Less Than 1.0 at 30 Percent Exceedance

Site Number	Site Name	Seasonal Flow Description	30% Design Head (ft)	30% Design Flow (cfs)	BC Ratio with Green (at 30%)	20% Design Head (ft)	20% Design Flow (cfs)	BC Ratio with Green (at 20%)
GP-1	A-Drop Project, Greenfield Main Canal Drop	Flows only May-August, up to about 2,500 cfs	34	0	N/A	34	1,090	0.69
GP-10	Belle Fourche Dam	Flows only May- September, 500-600 cfs for 2-3 months	50	160	0.49	52	400	0.55
GP-15	Bull Lake Dam	Year-round flows, higher June-September	50	299	0.41	55	606	0.63
GP-18	Carter Lake Dam No.1	Flows April-October, higher (300-400 cfs) July-August	142	82	0.56	147	156	0.58
GP-24	Corbett Diversion Dam	Flows April-September, peak at 1,000-1,100 cfs	12	850	0.59	12	938	0.60
GP-35	Enders Dam	Higher flows June-August, mostly <200 cfs	62	60	0.22	65	129	0.29
GP-39	Fresno Dam	Year-round flows, higher April-October, up to about 1,200 cfs mostly	47	560	0.88	50	778	0.84
GP-54	Horsetooth Dam	Flows only May-October, flows vary by year	119	41	0.34	122	188	0.52
GP-60	Johnson Project, Greenfield Main Canal Drop	Flows only May through August, about 100-250 cfs	46	61	0.21	46	133	0.31
GP-64	Knights Project, Greenfield Main Canal Drop	Flows only May through August, mostly <50 cfs	60	0	N/A	60	35	0.25
GP-68	Lake Sherburne	Flows mostly April-September, flow vary by year	45	317	0.24	51	488	0.34
GP-71	Lovewell Dam	Flows mostly April/May-September, some winter flows, inconsistent flows	47.4	0	N/A	49	83	0.12
GP-74	Mary Taylor Drop Structure	Flows May-August/September, up to about 300 cfs mostly	43.7	2.3	N/A	44	123	0.26
GP-80	Minatare Dam	Flows July-September, vary 200-400 cfs	35	2	0.01	38	160	0.22
GP-94	Paradise Diversion Dam	Flows June-September, mostly <150 cfs	11.8	0	N/A	12	89	0.10
GP-98	Pishkun Dike – No. 4	Flows May-September, vary, mostly	22	447	0.23	25	712	0.39

Table 5-33 20 Percent Exceedance Analysis of Sites with Seasonal Flows and Benefit Cost Ratios Less Than 1.0 at 30 Percent Exceedance								
Site Number	Site Name	Seasonal Flow Description	30% Design Head (ft)	30% Design Flow (cfs)	BC Ratio with Green (at 30%)	20% Design Head (ft)	20% Design Flow (cfs)	BC Ratio with Green (at 20%)
		>500 cfs						
GP-114	Saint Mary Canal Drop No. 1	Flows April-September, vary but most from 400-600 cfs	36	537	0.56	36	594	0.57
GP-115	Saint Mary Canal Drop No. 2	Flows April-September, vary but most from 400-600 cfs	29	537	0.50	29	594	0.51
GP-116	Saint Mary Canal Drop No. 3	Flows April-September, vary but most from 400-600 cfs	26	537	0.47	26	594	0.49
GP-117	Saint Mary Canal Drop No. 4	Flows April-September, vary but most from 400-600 cfs	66	537	0.82	66	594	0.83
GP-118	Saint Mary Canal Drop No. 5	Flows April-September, vary but most from 400-600 cfs	57	537	0.75	57	594	0.76
GP-120	Sun River Diversion Dam	Year round flows, highest April-September, vary but can be 3,000-5,000 cfs in some years	45	716	0.65	45	1,423	0.68
GP-135	Willwood Canal	Flows only mid-April-mid-October, vary 150-400 cfs	37	297	0.70	37	336	0.70
GP-137	Wind River Diversion Dam	Flows only May-September, only 3 years data	19	335	0.51	19	435	0.52
LC-24	Laguna Dam	Flows only April- September, constant at 200 cfs	10	200	0.63	10	200	0.63
MP-15	Gerber Dam	Flows only May- September, generally <140 cfs	35	112	0.14	37	126	0.15
MP-17	John Franchi Dam	Flows only April-September, 700-900 cfs for 3 months	15	500	0.90	15	700	0.96
PN-41	Golden Gate Canal	Flows only May-October, generally <250 cfs, only 2 years data	43	191	0.56	43	240	0.59
PN-43	Harper Dam	Flows only April- September, constant at 75 cfs	80	75	0.31	80	75	0.31
PN-44	Haystack Canal	Flows April-mid-October, generally 200-320 cfs	57	225	0.85	57	257	0.85
PN-57	Mason Dam	Higher flows April- September, vary by year, 100-400 cfs	139	164	0.72	143	220	0.76
PN-105	Wild Horse – BIA	Flows mid-May- September, vary by year	70	53	0.27	72	95	0.34
UC-7	Azeotea Creek and Willow Creek Conveyance Channel Station 1565+00	Flows only April-September, >500 cfs April-June in most years	18	65	0.10	19	208	0.21

Table 5-33
20 Percent Exceedance Analysis of Sites with Seasonal Flows and Benefit Cost Ratios Less Than 1.0 at 30 Percent Exceedance

Site Number	Site Name	Seasonal Flow Description	30% Design Head (ft)	30% Design Flow (cfs)	BC Ratio with Green (at 30%)	20% Design Head (ft)	20% Design Flow (cfs)	BC Ratio with Green (at 20%)
UC-8	Azeotea Creek and Willow Creek Conveyance Channel Station 1702+75	Flows only April-September, >500 cfs April-June in most years	17	65	0.10	18	208	0.20
UC-9	Azeotea Creek and Willow Creek Conveyance Channel Station 1831+17	Flows only April-September, >500 cfs April-June in most years	15	65	0.10	16	208	0.18
UC-11	Azotea Tunnel	Flows only April-September, >500 cfs April-June in most years	22	65	0.09	23	208	0.20
UC-14	Blanco Diversion Dam	Flows April-July/August, vary 100-300 cfs mostly	22	35	0.03	22	96	0.07
UC-15	Blanco Tunnel	Flows April-July/August, vary 100-300 cfs mostly	109	35	0.16	109	96	0.25
UC-72	Joes Valley Dam	Flows mostly year round, but higher in May-August	159	141	0.85	162	172	0.83
UC-93	Meeks Cabin Dam	Flows mostly year round, but higher in May-September	130	169	0.40	140	260	0.47
UC-100	Moon Lake	Flows only April/May-September, vary 100-300 cfs, up to 500 cfs in some months	66	134	0.22	72	240	0.29
UC-116	Outlet Canal	Flows only May- October, mostly 40-60 cfs	252	32	0.52	252	44	0.58
UC-124	Platoro Dam	Flows mostly year round, but higher in May-August	131	89	0.38	131	210	0.46
UC-136	Scofield Dam	Flows mostly year round, but higher in May-August	39	110	0.45	40	150	0.49
UC-166	Steinaker Dam	Flows vary, only May- September in most years, mostly <150 cfs	120	70	0.71	125	102	0.71
UC-190	Vega Dam	Flows May-September, mostly 100-200 cfs	90	84	0.51	90	122	0.56

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Chapter 6 Conclusions

This chapter summarizes results of all sites, not separated by region, and presents conclusions and potential future uses for study results.

6.1 Results Summary

Reclamation initially identified 530 sites, including reservoir dams, diversion dams, canals, tunnels, dikes and siphons, as potential for adding hydropower. Table 6-1 summarizes the number of sites analyzed in the Resource Assessment relative to hydropower potential, no hydropower potential, requiring further analysis, and removed from analysis. Significant efforts were made to collect hydrologic data for all 530 sites, including obtaining data from existing stream gages, facility designs, Reclamation area offices', field offices', and irrigation districts' records, and field staff knowledge. Based on available hydrologic data, information from Reclamation and irrigation district staff, assumptions and calculations from the Hydropower Assessment Tool, it was determined that 191 sites have hydropower potential and 218 of the 530 sites would not have hydropower potential.

Reclamation has identified 52 canals and tunnels sites for further analysis. Data available for these sites was not sufficient to estimate potential hydropower production. Reclamation has begun a separate study to confirm existing data and collect additional flow distribution and net head data for canal and tunnel sites. After data is collected, hydropower potential and economic viability of the sites can be estimated using the Hydropower Assessment Tool.

Table 6-1 Site Inventory Summary

	No. of Sites
Total Sites Identified	530
Sites with No Hydropower Potential	218
Total Sites with Hydropower Potential	191
Canal or Tunnel Sites (Separate Analysis In Progress)	52
Sites Removed from Analysis[1]	69

1 – Sites were removed from the analysis for various reasons, including duplicate to another site identified, no longer a Reclamation-owned site, hydropower already developed or being developed at the site.

The Hydropower Assessment Tool calculated a benefit cost ratio for each site with available hydrologic data as an indicator of the economic viability of developing hydropower. Table 6-2 summarizes the number of sites within different ranges of benefit cost ratios, with green incentives. There were 191 sites with power potential; however, the economic results varied widely and clearly showed some sites to be uneconomical to develop.

Table 6-2 Benefit Cost Ratio (with Green Incentives) Summary of Sites With Hydropower Potential

	No. of Sites	Total Installed Capacity (MW)	Total Annual Production (MWh)
Sites with Hydropower Potential	191	268.3	1,168,248
Benefit Cost Ratio (with Green Incentives) from:			
0 to 0.25	62	10.4	35,041
0.25 to 0.5	35	15.7	57,955
0.5 to 0.75	24	17	67,375
0.75 to 1.0	27	40.5	147,871
1.0 to 2.0	36	79.9	375,353
Greater than or equal to 2.0	7	104.8	484,653

Table 6-3 presents sites with a benefit cost ratio, with green incentives, greater than 0.75. Although the standard for economic viability is a benefit cost ratio of greater than 1.0, sites with benefit cost ratios of 0.75 and higher were ranked given the preliminary nature of the analysis. The table shows a potential of approximately 225 MW of installed capacity and 1,000,000 MWh of energy could be produced annually at existing Reclamation facilities if all sites with a benefit cost ratio greater than 0.75 are summed. It is important to note that results for sites with low confidence data may not be as reliable as sites with higher confidence data. There are 10 sites with low confidence data, including the third and fourth ranked sites. The IRR for sites listed in Table 6-3 varies from a high of 23 percent to 1.8 percent.

Table 6-3 Sites Analyzed with Benefit Cost Ratio (with Green Incentives) Greater than 0.75

Site ID	Site Name/Facility	Data Confidence Level	Installed Capacity (kW)	Annual Production (MWh)	Benefit Cost Ratio (with Green)	IRR (with Green)
LC-6	Bartlett Dam	Medium	7,529	36,880	3.5	23.0%
GP-146	Yellowtail Afterbay Dam	Medium	9,203	68,261	3.05	18.2%
UC-141	Sixth Water Flow Control	Medium	25,800	114,420	3.02	17.1%
LC-20	Horseshoe Dam	Low	13,857	59,854	2.98	19.0%
GP-125	Twin Buttes Dam	Low	23,124	97,457	2.61	16.0%
UC-185	Upper Diamond Fork Flow Control Structure	Medium	12,214	52,161	2.36	13.6%
GP-99	Pueblo Dam	High	13,027	55,620	2.34	14.0%

Table 6-3 Sites Analyzed with Benefit Cost Ratio (with Green Incentives) Greater than 0.75

Site ID	Site Name/Facility	Data Confidence Level	Installed Capacity (kW)	Annual Production (MWh)	Benefit Cost Ratio (with Green)	IRR (with Green)
MP-30	Prosser Creek Dam	High	872	3,819	1.98	14.2%
PN-6	Arthur R. Bowman Dam	High	3,293	18,282	1.9	11.2%
UC-89	M&D Canal-Shavano Falls	Low	2,862	15,419	1.88	11.4%
GP-56	Huntley Diversion Dam	Medium	2,426	17,430	1.86	10.9%
MP-2	Boca Dam	High	1,184	4,370	1.68	11.3%
PN-31	Easton Diversion Dam	High	1,057	7,400	1.68	9.9%
UC-159	Spanish Fork Flow Control Structure	Medium	8,114	22,920	1.66	9.6%
LC-21	Imperial Dam	Low	1,079	5,325	1.61	10.0%
GP-46	Gray Reef Dam	High	2,067	13,059	1.58	8.7%
MP-8	Casitas Dam	High	1,042	3,280	1.57	10.7%
UC-49	Grand Valley Diversion Dam	Medium	1,979	14,246	1.55	8.6%
UC-52	Gunnison Tunnel	Medium	3,830	19,057	1.55	8.8%
GP-23	Clark Canyon Dam	High	3,078	13,689	1.52	8.6%
UC-19	Caballo Dam	Low	3,260	15,095	1.45	7.9%
UC-147	South Canal, Sta. 181+10, "Site #4"	Medium	3,046	15,536	1.44	8.0%
PN-95	Sunnyside Dam	Medium	1,362	10,182	1.43	7.8%
UC-144	Soldier Creek Dam	High	444	2,909	1.39	7.9%
GP-52	Helena Valley Pumping Plant	High	2,626	9,608	1.38	7.8%
UC-131	Ridgway Dam	High	3,366	14,040	1.35	7.3%
GP-41	Gibson Dam	High	8,521	30,774	1.32	7.1%
UC-146	South Canal, Sta 19+ 10 "Site #1"	Medium	2,465	12,576	1.32	7.1%
UC-51	Gunnison Diversion Dam	Medium	1,435	9,220	1.28	6.7%
PN-88	Scootney Wasteway	Low	2,276	11,238	1.26	6.6%
UC-150	South Canal, Sta.106+65, "Site #3"	Medium	2,224	11,343	1.26	6.6%
GP-126	Twin Lakes Dam (USBR)	High	981	5,648	1.24	6.5%
GP-95	Pathfinder Dam	High	743	5,508	1.23	6.2%
UC-162	Starvation Dam	High	3,043	13,168	1.23	6.2%
LC-15	Gila Gravity Main Canal Headworks	Medium	223	1,548	1.17	6.0%
GP-43	Granby Dam	High	484	2,854	1.16	5.9%
MP-32	Putah Diversion Dam	Medium	363	1,924	1.16	6.3%
UC-179	Taylor Park Dam	High	2,543	12,488	1.12	5.4%
GP-136	Willwood Diversion Dam	High	1,062	6,337	1.1	5.2%
GP-93	Pactola Dam	High	596	2,725	1.07	5.1%
UC-57	Heron Dam	Medium	2,701	8,874	1.06	4.9%
UC-154	Southside Canal, Sta 171+ 90 thru 200+ 67 (2 canal drops)	Low	2,026	6,557	1.05	4.8%
UC-148	South Canal, Sta. 472+00, "Site #5"	Medium	1,354	6,905	1.05	4.8%
PN-34	Emigrant Dam	High	733	2,619	0.99	4.3%

Table 6-3 Sites Analyzed with Benefit Cost Ratio (with Green Incentives) Greater than 0.75

Site ID	Site Name/Facility	Data Confidence Level	Installed Capacity (kW)	Annual Production (MWh)	Benefit Cost Ratio (with Green)	IRR (with Green)
UC-177	Syar Tunnel	Medium	1,762	7,982	0.99	4.3%
PN-104	Wickiup Dam	High	3,950	15,650	0.98	4.2%
UC-174	Sumner Dam	Medium	822	4,300	0.98	4.2%
GP-34	East Portal Diversion Dam	High	283	1,799	0.96	3.9%
PN-12	Cle Elum Dam	High	7,249	14,911	0.94	3.8%
PN-80	Ririe Dam	High	993	3,778	0.94	3.8%
UC-155	Southside Canal, Sta 349+ 05 thru 375+ 42 (3 canal drops)	Low	1,651	5,344	0.93	3.7%
PN-87	Scoggins Dam	High	955	3,683	0.92	3.6%
UC-132	Rifle Gap Dam	High	341	1,740	0.92	3.5%
GP-5	Angostura Dam	Low	947	3,218	0.9	3.3%
MP-17	John Franchi Dam	Low	469	1,863	0.9	3.0%
GP-39	Fresno Dam	High	1,661	6,268	0.88	3.2%
GP-129	Virginia Smith Dam	Low	1,607	9,799	0.88	3.3%
PN-59	McKay Dam	High	1,362	4,344	0.88	3.2%
GP-128	Vandalia Diversion Dam	Medium	326	1,907	0.87	3.0%
PN-49	Keechelus Dam	High	2,394	6,746	0.87	3.0%
PN-44	Haystack	High	805	3,738	0.85	2.9%
UC-72	Joes Valley Dam	High	1,624	6,596	0.85	3.0%
UC-145	South Canal Tunnels	Medium	884	4,497	0.84	2.8%
MP-24	Marble Bluff Dam	High	1,153	5,624	0.83	2.8%
GP-92	Olympus Dam	High	284	1,549	0.82	2.3%
GP-117	St. Mary Canal - Drop 4	High	2,569	8,919	0.82	2.6%
GP-42	Glen Elder Dam	High	1,008	3,713	0.81	2.4%
UC-117	Paonia Dam	Medium	1,582	5,821	0.79	2.3%
PN-48	Kachess Dam	Medium	1,227	3,877	0.77	1.9%
GP-118	St. Mary Canal - Drop 5	High	1,901	7,586	0.75	1.8%

The site evaluation results are based on design flow and design head set at 30 percent exceedance level. Sections 5.7 and 5.8 include sensitivity analyses on varying the exceedance level for sites with benefit cost ratios close to or greater than 1 and sites with seasonal flows, which typically had a benefit cost ratio much lower than 1. For most sites that would be economical for hydropower development at the 30 percent exceedance level, the benefit cost ratio decreased at the 20 percent exceedance level, indicating that the costs of adding capacity were rising faster than the revenues (energy production) of the added capacity. For sites with seasonal flows, designing the plant at a lower exceedance level would slightly increase the benefit cost ratio relative to the 30 percent exceedance design because of increased revenues from more energy production, but the plant would continue to be uneconomical to develop (the benefit cost ratio remains less than 1).

The Resource Assessment consistently used a 30 percent exceedance, which resulted in more sites having higher benefit cost ratios. Using a 20 percent exceedance could have resulted in higher installed capacities and more energy generation, but the number of economically feasible projects, based on the benefit cost ratios, would decrease. During feasibility analysis of a potential site, the developer should analyze different plant sizes to evaluate the most economic plant size.

6.2 Conclusions

Recent national policies have focused on increasing domestic renewable energy development. Hydropower can be a relatively low cost clean energy source. The purposes of the Resource Assessment were to evaluate hydropower potential at existing Reclamation facilities and provide information on which sites may be the most economical for development purposes.

The Resource Assessment concludes that hydropower potential exists at select Reclamation facilities. Some site analyses are based on over 20 years of hydrologic data that indicate a high likelihood of generation capability. Table 6-3 presents 70 sites that could be economically feasible to develop, based on available data and study assumptions. Reclamation may not pursue or fund site development; however, opportunities may be available to private developers.

Power generation benefits, calculated using current and forecasted energy prices, indicate economic benefits from hydropower development could outweigh costs at many sites. The analysis also shows that Federal and few state green incentive programs are available to private developers financing a project. For Arizona, California, and Washington, state-sponsored green incentives can be a contributing factor in the economic viability of a project. For the remaining western states in Reclamation's regions, hydropower is not eligible for state renewable energy incentives; however, Federal incentives can be applicable for public municipalities or private developers. The sensitivity analysis on varying discount rates shows that project feasibility will be sensitive to changes in discount rates.

Constraints such as water supply, fish and wildlife considerations, and effects on Native Americans, water quality, and recreation have precluded development of additional hydropower in the past. Many of these constraints still exist. Sites with obvious constraints to development, such as a site location in a National Park, should not be further investigated, but some constraints may be accommodated by implementing mitigation. Although mitigation activities can be costly, power prices and financing options may make these sites worth further investigation.

Site-specific analysis is necessary if a site will be further pursued for hydropower potential. Because of the large geographic scope and extensive number of sites analyzed, the Resource Assessment could not go into great detail on physical and environmental features that may affect construction feasibility and development costs for each site. Some sites have particular physical features that may make construction difficult or more costly. For example, the Gunnison Tunnel is an open channel flow conduit, which may not be conducive to being converted to a pressurized penstock to serve a power plant. Some sites may also have additional environmental constraints related to fish habitat and passage not identified in this analysis. The Resource Assessment does not evaluate sites at this site-specific level of detail, which could affect the economic results presented in the analysis.

Despite its preliminary level of analysis, the Resource Assessment has provided valuable information on hydropower potential at existing Reclamation facilities to advance the objectives of the Federal MOU and help meet the nation's renewable energy development goals.

6.3 Potential Future Uses of Study Results

The results of the Resource Assessment will be of value to public municipalities and private developers seeking to add power to their load area or for investment purposes. It provides a valuable database in which potential sites can be viewed to help determine whether or not to proceed with a feasibility study. For many of these Reclamation sites, development would proceed under a Lease of Power Privilege Agreement as opposed to a FERC License. A lease of power privilege is a contractual right of up to 40 years given to a non-Federal entity to use a Reclamation facility for electric power generation. It is an alternative to federal power development where Reclamation has the authority to develop power on a federal project. The selection of a Lessee is done through a public process to ensure fair and open competition though preference is given through the Reclamation Project Act of 1939 to municipalities, other public corporations or agencies, and also to cooperatives and other nonprofit organizations financed through the Rural Electrification Act of 1936. In order to proceed under a lease, the project must have adequate design information, satisfactory environmental analysis/impacts, and cannot be detrimental to the existing project.

The results could also be used to support an incentive program for hydropower as a renewable energy source. A large number of projects fall in the gray area of being economically feasible. The Resource Assessment shows that green incentives for hydropower development are largely not available in individual states, but, when they are, can contribute substantially to the economic viability of a project. A Federal incentive program exists, but does not contribute significantly to economic benefits. Further, if sites are developed by Reclamation, they would not be eligible for the Federal incentive, but could qualify for state-sponsored incentives. This analysis could be useful in promoting hydropower at existing facilities as a low cost renewable energy source and determining incentives that would be necessary to stimulate investment.

The Hydropower Assessment Tool is a valuable tool for further analysis of these sites and new sites. The tool is user-friendly and allows simple adjustments if users have site specific information. Users can input new hydrologic data, change the exceedance level, turbine selected, and update costs, energy prices, constraints, green incentives, and/or the discount rate. The tool provides a valuable first step for understanding potential hydropower production at a site and if its benefits and costs warrant further investigation.

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Chapter 7 References

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Appendix A Site Identification

The Resource Assessment reevaluates potential hydropower development at the 530 Reclamation-owned facilities inventoried in the 1834 Study. Table A-1 summarizes the number of sites in each Reclamation region. Sites were initially identified in the 1834 Study; no new sites were added for this analysis. For analysis purposes, each site is labeled with the region initials and a number, based on alphabetical order of the sites in the region. Table A-2 lists the sites, state, Reclamation project, and assigned site identification numbers. These site identification numbers are carried through the entire report.

Table A-1 Number of Sites in Each Reclamation Region

Reclamation Region	Number of Sites	Site Identification Numbering
Great Plains (GP)	146	GP-1 to GP-146
Lower Colorado (LC)	30	LC-1 to LC-30
Mid-Pacific (MP)	44	MP-1 to MP-44
Pacific Northwest (PN)	105	PN-1 to PN-105
Upper Colorado (UC)	205	UC-1 to UC-205

Table A-2 Site Identification Inventory

Site ID	Site Name	State	Project
GP-1	A-Drop Project, Greenfield Main Canal Drop	Montana	Sun River
GP-2	Almena Diversion Dam	Kansas	PSMBP - Almena
GP-3	Altus Dam	Oklahoma	W.C. Austin
GP-4	Anchor Dam	Wyoming	PSMBP - Owl Creek
GP-5	Angostura Dam	South Dakota	PSMBP - Cheyenne Diversion
GP-6	Anita Dam	Montana	Huntley
GP-7	Arbuckle Dam	Oklahoma	Arbuckle
GP-8	Barretts Diversion Dam	Montana	PSMBP - East Bench
GP-9	Bartley Diversion Dam	Nebraska	PSMBP - Frenchman-Cambridge
GP-10	Belle Fourche Dam	South Dakota	Belle Fourche
GP-11	Belle Fourche Diversion Dam	South Dakota	Belle Fourche
GP-12	Bonny Dam	Colorado	PSMBP - Armel
GP-13	Box Butte Dam	Nebraska	Mirage Flats
GP-14	Bretch Diversion Canal	Oklahoma	Mountain Park
GP-15	Bull Lake Dam	Wyoming	PSMBP - Riverton
GP-16	Cambridge Diversion Dam	Nebraska	PSMBP - Frenchman-Cambridge
GP-17	Carter Creek Diversion Dam	Colorado	Fryingpan-Arkansas
GP-18	Carter Lake Dam No. 1	Colorado	Colorado-Big Thompson

Table A-2 Site Identification Inventory

Site ID	Site Name	State	Project
GP-19	Cedar Bluff Dam	Kansas	PSMBP - Cedar Bluff
GP-20	Chapman Diversion Dam	Colorado	Fryingpan-Arkansas
GP-21	Cheney Dam	Kansas	Wichita
GP-22	Choke Canyon Dam	Texas	Nueces River
GP-23	Clark Canyon Dam	Montana	PSMBP - East Bench
GP-24	Corbett Diversion Dam	Wyoming	Shoshone
GP-25	Culbertson Diversion Dam	Nebraska	PSMBP - Frenchman-Cambridge
GP-26	Davis Creek Dam	Nebraska	PSMBP - North Loup
GP-27	Deaver Dam	Wyoming	Shoshone
GP-28	Deerfield Dam	South Dakota	Rapid Valley
GP-29	Dickinson Dam	North Dakota	PSMBP - Dickinson
GP-30	Dixon Canyon Dam	Colorado	Colorado-Big Thompson
GP-31	Dodson Diversion Dam	Montana	Milk River
GP-32	Dry Spotted Tail Diversion Dam	Nebraska	North Platte
GP-33	Dunlap Diversion Dam	Nebraska	Mirage Flats
GP-34	East Portal Diversion Dam	Colorado	Colorado-Big Thompson
GP-35	Enders Dam	Nebraska	PSMBP - Frenchman-Cambridge
GP-36	Fort Cobb Dam	Oklahoma	Washita Basin
GP-37	Fort Shaw Diversion Dam	Montana	Sun River
GP-38	Foss Dam	Oklahoma	Washita Basin
GP-39	Fresno Dam	Montana	Milk River
GP-40	Fryingpan Diversion Dam	Colorado	Fryingpan-Arkansas
GP-41	Gibson Dam	Montana	Sun River
GP-42	Glen Elder Dam	Kansas	PSMBP Glen Elder Unit
GP-43	Granby Dam	Colorado	Colorado-Big Thompson
GP-44	Granby Dikes 1-4	Colorado	Colorado-Big Thompson
GP-45	Granite Creek Diversion Dam	Colorado	Fryingpan-Arkansas
GP-46	Gray Reef Dam	Wyoming	PSMBP - Glendo
GP-47	Greenfield Project, Greenfield Main Canal Drop	Montana	Sun River
GP-48	Halfmoon Creek Diversion Dam	Colorado	Fryingpan-Arkansas
GP-49	Hanover Diversion Dam	Wyoming	PSMBP - Hanover-Bluff
GP-50	Heart Butte Dam	North Dakota	PSMBP - Heart Butte
GP-51	Helena Valley Dam	Montana	PSMBP - Helena Valley
GP-52	Helena Valley Pumping Plant	Montana	PSMBP - Helena Valley
GP-53	Horse Creek Diversion Dam	Wyoming	North Platte
GP-54	Horsetooth Dam	Colorado	Colorado-Big Thompson
GP-55	Hunter Creek Diversion Dam	Colorado	Fryingpan-Arkansas
GP-56	Huntley Diversion Dam	Montana	Huntley
GP-57	Ivanhoe Diversion Dam	Colorado	Fryingpan-Arkansas
GP-58	James Diversion Dam	South Dakota	PSMBP - James Diversion
GP-59	Jamestown Dam	North Dakota	PSMBP - Jamestown Dam
GP-60	Johnson Project, Greenfield Main Canal Drop	Montana	Sun River
GP-61	Kent Diversion Dam	Nebraska	PSMBP - North Loup

Table A-2 Site Identification Inventory

Site ID	Site Name	State	Project
GP-62	Keyhole Dam	Wyoming	PSMBP - Cheyenne Diversion
GP-63	Kirwin Dam	Kansas	PSMBP - Kirwin
GP-64	Knights Project, Greenfield Main Canal Drop	Montana	Sun River
GP-65	Lake Alice Lower 1-1/2 Dam	Nebraska	North Platte
GP-66	Lake Alice No. 1 Dam	Nebraska	North Platte
GP-67	Lake Alice No. 2 Dam	Nebraska	North Platte
GP-68	Lake Sherburne Dam	Montana	Milk River
GP-69	Lily Pad Diversion Dam	Colorado	Fryingpan-Arkansas
GP-70	Little Hell Creek Diversion Dam	Colorado	Colorado-Big Thompson
GP-71	Lovewell Dam	Kansas	PSMBP - Bostwick
GP-72	Lower Turnbull Drop Structure	Montana	Sun River
GP-73	Lower Yellowstone Diversion Dam	Montana	Lower Yellowstone
GP-74	Mary Taylor Drop Structure	Montana	Sun River
GP-75	Medicine Creek Dam	Nebraska	PSMBP - Frenchman-Cambridge
GP-76	Merritt Dam	Nebraska	PSMBP Ainsworth Unit
GP-77	Merritt Dam	Nebraska	PSMBP Ainsworth Unit
GP-78	Middle Cunningham Creek Diversion Dam	Colorado	Fryingpan-Arkansas
GP-79	Midway Creek Diversion Dam	Colorado	Fryingpan-Arkansas
GP-80	Mill Coulee Canal Drop, Upper and Lower Drops Combined	Montana	Sun River
GP-81	Minatare Dam	Nebraska	North Platte
GP-82	Mormon Creek Diversion Dam	Colorado	Fryingpan-Arkansas
GP-83	Mountain Park Dam	Oklahoma	Mountain Park
GP-84	Nelson Dikes C	Montana	Milk River
GP-85	Nelson Dikes DA	Montana	Milk River
GP-86	No Name Creek Diversion Dam	Colorado	Fryingpan-Arkansas
GP-87	Norman Dam	Oklahoma	Norman
GP-88	North Cunningham Creek Diversion Dam	Colorado	Fryingpan-Arkansas
GP-89	North Fork Diversion Dam	Colorado	Fryingpan-Arkansas
GP-90	North Poudre Diversion Dam	Colorado	Colorado-Big Thompson
GP-91	Norton Dam	Kansas	PSMBP - Almena
GP-92	Olympus Dam	Colorado	Colorado-Big Thompson
GP-93	Pactola Dam	South Dakota	PSMBP - Rapid Valley
GP-94	Paradise Diversion Dam	Montana	Milk River
GP-95	Pathfinder Dam	Wyoming	North Platte
GP-96	Pathfinder Dike	Wyoming	North Platte
GP-97	Pilot Butte Dam	Wyoming	PSMBP - Riverton
GP-98	Pishkun Dike - No. 4	Montana	Sun River
GP-99	Pueblo Dam	Colorado	Fryingpan-Arkansas
GP-100	Ralston Dam	Wyoming	Shoshone
GP-101	Rattlesnake Dam	Colorado	Colorado-Big Thompson
GP-102	Red Willow Dam	Nebraska	PSMBP - Frenchman-Cambridge

Table A-2 Site Identification Inventory

Site ID	Site Name	State	Project
GP-103	Saint Mary Diversion Dam	Montana	Milk River
GP-104	Sanford Dam	Texas	Canadian River
GP-105	Satanka Dike	Colorado	Colorado-Big Thompson
GP-106	Sawyer Creek Diversion Dam	Colorado	Fryingpan-Arkansas
GP-107	Shadehill Dam	South Dakota	PSMBP - Shadehill
GP-108	Shadow Mountain Dam	Colorado	Colorado-Big Thompson
GP-109	Soldier Canyon Dam	Colorado	Colorado-Big Thompson
GP-110	South Cunningham Creek Diversion Dam	Colorado	Fryingpan-Arkansas
GP-111	South Fork Diversion Dam	Colorado	Fryingpan-Arkansas
GP-112	South Platte Supply Canal Diversion Dam	Colorado	Colorado-Big Thompson
GP-113	Spring Canyon Dam	Colorado	Colorado-Big Thompson
GP-114	St. Mary Canal - Drop 1	Montana	Milk River
GP-115	St. Mary Canal - Drop 2	Montana	Milk River
GP-116	St. Mary Canal - Drop 3	Montana	Milk River
GP-117	St. Mary Canal - Drop 4	Montana	Milk River
GP-118	St. Mary Canal - Drop 5	Montana	Milk River
GP-119	St. Vrain Canal	Colorado	Colorado-Big Thompson
GP-120	Sun River Diversion Dam	Montana	Sun River
GP-121	Superior-Courtland Diversion Dam	Nebraska	PSMBP - Bostwick
GP-122	Trenton Dam	Nebraska	PSMBP Cambridge Unit
GP-123	Trenton Dam	Nebraska	PSMBP Cambridge Unit
GP-124	Tub Springs Creek Diversion Dam	Nebraska	North Platte
GP-125	Twin Buttes Dam	Texas	San Angelo
GP-126	Twin Lakes Dam (USBR)	Colorado	Fryingpan-Arkansas
GP-127	Upper Turnbull Drop Structure	Montana	Sun River
GP-128	Vandalia Diversion Dam	Montana	Milk River
GP-129	Virginia Smith Dam	Nebraska	PSMBP - North Loup
GP-130	Webster Dam	Kansas	PSMBP - Webster
GP-131	Whalen Diversion Dam	Wyoming	North Platte
GP-132	Willow Creek Dam	Colorado	Colorado-Big Thompson
GP-133	Willow Creek Dam (MT)	Montana	Sun River
GP-134	Willow Creek Forebay Diversion Dam	Colorado	Colorado-Big Thompson
GP-135	Willwood Canal	Wyoming	Shoshone
GP-136	Willwood Diversion Dam	Wyoming	Shoshone
GP-137	Wind River Diversion Dam	Wyoming	PSMBP - Riverton
GP-138	Woods Project, Greenfield Main Canal Drop	Montana	Sun River
GP-139	Woodston Diversion Dam	Kansas	PSMBP - Webster
GP-140	Wyoming Canal - Sta 1016	Wyoming	PSMBP - Riverton
GP-141	Wyoming Canal - Sta 1490	Wyoming	PSMBP - Riverton
GP-142	Wyoming Canal - Sta 1520	Wyoming	PSMBP - Riverton
GP-143	Wyoming Canal - Sta 1626	Wyoming	PSMBP - Riverton
GP-144	Wyoming Canal - Sta 1972	Wyoming	PSMBP - Riverton
GP-145	Wyoming Canal - Sta 997	Wyoming	PSMBP - Riverton

Table A-2 Site Identification Inventory

Site ID	Site Name	State	Project
GP-146	Yellowtail Afterbay Dam	Montana	PSMBP - Yellowtail
LC-1	Agua Fria River Siphon	Arizona	Central Arizona Project
LC-2	Agua Fria Tunnel	Arizona	Central Arizona Project
LC-3	All American Canal	California	Boulder Canyon Project
LC-4	All American Canal Headworks	California	Boulder Canyon Project
LC-5	Arizona Canal	Arizona	Salt River Project
LC-6	Bartlett Dam	Arizona	Salt River Project
LC-7	Buckskin Mountain Tunnel	Arizona	Central Arizona Project
LC-8	Burnt Mountain Tunnel	Arizona	Central Arizona Project
LC-9	Centennial Wash Siphon	Arizona	Central Arizona Project
LC-10	Coachella Canal	California	Boulder Canyon Project
LC-11	Consolidated Canal	Arizona	Salt River Project
LC-12	Cross Cut Canal	Arizona	Salt River Project
LC-13	Cunningham Wash Siphon	Arizona	Central Arizona Project
LC-14	Eastern Canal	Arizona	Salt River Project
LC-15	Gila Gravity Main Canal Headworks	Arizona	Central Arizona Project
LC-16	Gila River Siphon	Arizona	Central Arizona Project
LC-17	Grand Canal	Arizona	Salt River Project
LC-18	Granite Reef Diversion Dam	Arizona-California	Boulder Canyon Project
LC-19	Hassayampa River Siphon	Arizona	Central Arizona Project
LC-20	Horseshoe Dam	Arizona	Salt River Project
LC-21	Imperial Dam	Arizona-California	Boulder Canyon Project
LC-22	Interstate Highway Siphon	Arizona	Central Arizona Project
LC-23	Jackrabbit Wash Siphon	Arizona	Central Arizona Project
LC-24	Laguna Dam	Arizona-California	Yuma Project
LC-25	New River Siphon	Arizona	Central Arizona Project
LC-26	Palo Verde Diversion Dam	Arizona-California	Palo Verde Diversion Project
LC-27	Reach 11 Dike	Arizona	Central Arizona Project
LC-28	Salt River Siphon Blowoff	Arizona	Central Arizona Project
LC-29	Tempe Canal	Arizona	Salt River Project
LC-30	Western Canal	Arizona	Salt River Project
MP-1	Anderson-Rose Dam	Oregon	Klamath
MP-2	Boca Dam	California	Truckee Storage
MP-3	Bradbury Dam	California	Cachuma
MP-4	Buckhorn Dam (Reclamation)	California	Central Valley
MP-5	Camp Creek Dam	California	Central Valley
MP-6	Carpenteria	California	Cachuma
MP-7	Carson River Dam	Nevada	Newlands
MP-8	Casitas Dam	California	Ventura River
MP-9	Clear Lake Dam	California	Klamath
MP-10	Contra Loma Dam	California	Central Valley
MP-11	Derby Dam	Nevada	Newlands
MP-12	Dressler Dam	Nevada	Washoe
MP-13	East Park Dam	California	Orland
MP-14	Funks Dam	California	Central Valley
MP-15	Gerber Dam	Oregon	Klamath

Table A-2 Site Identification Inventory

Site ID	Site Name	State	Project
MP-16	Glen Anne Dam	California	Cachuma
MP-17	John Franchi Dam	California	Central Valley
MP-18	Lake Tahoe Dam	California	Newlands
MP-19	Lauro Dam	California	Cachuma
MP-20	Little Panoche Detention Dam	California	Central Valley
MP-21	Los Banos Creek Detention Dam	California	Central Valley
MP-22	Lost River Diversion Dam	Oregon	Klamath
MP-23	Malone Diversion Dam	Oregon	Klamath
MP-24	Marble Bluff Dam	Nevada	Washoe
MP-25	Martinez Dam	California	Central Valley
MP-26	Miller Dam	Oregon	Klamath
MP-27	Mormon Island Auxiliary Dike	California	Central Valley
MP-28	Northside	California	Orland
MP-29	Ortega	California	Cachuma
MP-30	Prosser Creek Dam	California	Washoe
MP-31	Putah Creek Dam	California	Solano
MP-32	Putah Diversion Dam	California	Solano
MP-33	Rainbow Dam	California	Orland
MP-34	Red Bluff Dam	California	Central Valley
MP-35	Robles Dam	California	Ventura River
MP-36	Rye Patch Dam	Nevada	Humboldt
MP-37	San Justo Dam	California	Central Valley
MP-38	Sheckler Dam	Nevada	Newlands
MP-39	Sly Park Dam	California	Central Valley
MP-40	Spring Creek Debris Dam	California	Central Valley
MP-41	Sugar Pine	California	Central Valley
MP-42	Terminal Dam	California	Solano
MP-43	Twitchell Dam	California	Santa Maria
MP-44	Upper Slaven Dam	Nevada	Humboldt
PN-1	Agate	Oregon	Rogue River Basin
PN-2	Agency Valley	Oregon	Vale
PN-3	Antelope Creek	Oregon	Rogue River Basin
PN-4	Arnold	Oregon	Deschutes
PN-5	Arrowrock	Idaho	Boise
PN-6	Arthur R. Bowman Dam	Oregon	Crooked River
PN-7	Ashland Lateral	Oregon	Rogue River Basin
PN-8	Beaver Dam Creek	Oregon	Rogue River Basin
PN-9	Bully Creek	Oregon	Vale
PN-10	Bumping Lake	Washington	Yakima
PN-11	Cascade Creek	Idaho	Minidoka
PN-12	Cle Elum Dam	Washington	Yakima
PN-13	Clear Creek	Washington	Yakima
PN-14	Col W.W. No 4	Washington	Columbia Basin
PN-15	Cold Springs	Oregon	Umatilla
PN-16	Conconully	Washington	Okanogan
PN-17	Conde Creek	Oregon	Rogue River Basin

Table A-2 Site Identification Inventory

Site ID	Site Name	State	Project
PN-18	Cowiche	Washington	Yakima
PN-19	Crab Creek Lateral #4	Washington	Columbia Basin
PN-20	Crane Prairie	Oregon	Deschutes
PN-21	Cross Cut	Idaho	Minidoka
PN-22	Daley Creek	Oregon	Rogue River Basin
PN-23	Dead Indian	Oregon	Rogue River Basin
PN-24	Deadwood Dam	Idaho	Boise
PN-25	Deer Flat East Dike	Idaho	Boise
PN-26	Deer Flat Middle	Idaho	Boise
PN-27	Deer Flat North Lower	Idaho	Boise
PN-28	Deer Flat Upper	Idaho	Boise
PN-29	Diversion Canal Headworks	Oregon	Crooked River
PN-30	Dry Falls - Main Canal Headworks	Washington	Columbia Basin
PN-31	Easton Diversion Dam	Washington	Yakima
PN-32	Eltopia Branch Canal	Washington	Columbia Basin
PN-33	Eltopia Branch Canal 4.6	Washington	Columbia Basin
PN-34	Emigrant	Oregon	Rogue River Basin
PN-35	Esquatzel Canal	Washington	Columbia Basin
PN-36	Feed Canal	Oregon	Umatilla
PN-37	Fish Lake	Oregon	Rogue River Basin
PN-38	Fourmile Lake	Oregon	Rogue River Basin
PN-39	French Canyon	Washington	Yakima
PN-40	Frenchtown	Montana	Frenchtown
PN-41	Golden Gate Canal	Idaho	Boise
PN-42	Grassy Lake	Wyoming	Minidoka
PN-43	Harper Dam	Oregon	Vale
PN-44	Haystack Canal	Oregon	Deschutes
PN-45	Howard Prairie	Oregon	Rogue River Basin
PN-46	Hubbard Dam	Idaho	Boise
PN-47	Hyatt Dam	Oregon	Rogue River Basin
PN-48	Kachess Dam	Washington	Yakima
PN-49	Keechelus Dam	Washington	Yakima
PN-50	Keene Creek	Oregon	Rogue River Basin
PN-51	Little Beaver Creek	Oregon	Rogue River Basin
PN-52	Little Wood River Dam	Idaho	Little Wood River
PN-53	Lytle Creek	Oregon	Crooked River
PN-54	Main Canal No. 10	Idaho	Boise
PN-55	Main Canal No. 6	Idaho	Boise
PN-56	Mann Creek	Idaho	Mann Creek
PN-57	Mason Dam	Oregon	Baker
PN-58	Maxwell Dam	Oregon	Umatilla
PN-59	McKay Dan	Oregon	Umatilla
PN-60	Mile 28 - on Milner Gooding Canal	Idaho	Minidoka
PN-61	Mora Canal Drop	Idaho	Boise
PN-62	North Canal Diversion Dam	Oregon	Deschutes
PN-63	North Unit Main Canal	Oregon	Deschutes

Table A-2 Site Identification Inventory

Site ID	Site Name	State	Project
PN-64	Oak Street	Oregon	Rogue River Basin
PN-65	Ochoco Dam	Oregon	Crooked River
PN-66	Orchard Avenue	Washington	Yakima
PN-67	Owyhee Tunnel No. 1	Oregon	Owyhee
PN-68	PEC Mile 26.3	Washington	Columbia Basin
PN-69	Phoenix Canal	Oregon	Rogue River Basin
PN-70	Pilot Butte Canal	Oregon	Deschutes
PN-71	Pinto Dam	Washington	Columbia Basin
PN-72	Potholes Canal Headworks	Washington	Columbia Basin
PN-73	Potholes East Canal - PEC 66.0	Washington	Columbia Basin
PN-74	Potholes East Canal 66.0	Washington	Columbia Basin
PN-75	Prosser Dam	Washington	Yakima
PN-76	Quincy Chute Hydroelectric	Washington	Columbia Basin
PN-77	RB4C W. W. Hwy26 Culvert	Washington	Columbia Basin
PN-78	Reservoir "A"	Idaho	Lewiston Orchards
PN-79	Ringold W. W.	Washington	Columbia Basin
PN-80	Ririe Dam	Idaho	Ririe River
PN-81	Rock Creek	Montana	Bitter Root
PN-82	Roza Diversion Dam	Washington	Yakima
PN-83	Russel D Smith	Washington	Columbia Basin
PN-84	Saddle Mountain W. W.	Washington	Columbia Basin
PN-85	Salmon Creek	Washington	Okanogan
PN-86	Salmon Lake	Washington	Okanogan
PN-87	Scoggins	Oregon	Tualatin
PN-88	Scootney Wasteway	Washington	Columbia Basin
PN-89	Soda Creek	Oregon	Rogue River Basin
PN-90	Soda Lake Dike	Washington	Columbia Basin
PN-91	Soldier´s Meadow	Idaho	Lewiston Orchards
PN-92	South Fork Little Butte Creek	Oregon	Rogue River Basin
PN-93	Spectacle Lake Dike	Washington	Chief Joseph Dam
PN-94	Summer Falls on Main Canal	Washington	Columbia Basin
PN-95	Sunnyside Diversion Dam	Washington	Yakima
PN-96	Sweetwater Canal	Idaho	Lewiston Orchards
PN-97	Thief Valley Dam	Oregon	Baker
PN-98	Three Mile Falls	Oregon	Umatilla
PN-99	Tieton Diversion	Washington	Yakima
PN-100	Unity Dam	Oregon	Burnt River
PN-101	Warm Springs Dam	Oregon	Vale
PN-102	Wasco Dam	Oregon	Wapinitia
PN-103	Webb Creek	Idaho	Lewiston Orchards
PN-104	Wickiup Dam	Oregon	Deschutes
PN-105	Wild Horse - BIA	Nevada	Duck Valley Irrigation District - BIA
UC-1	Alpine Tunnel	Utah	Central Utah Project - Bonneville Unit
UC-2	Alpine-Draper Tunnel	Utah	Provo River
UC-3	American Diversion Dam	New Mexico	Rio Grande

Table A-2 Site Identification Inventory

Site ID	Site Name	State	Project
UC-4	Angostura Diversion	New Mexico	Middle Rio Grande
UC-5	Arthur V. Watkins Dam	Utah	Weber Basin
UC-6	Avalon Dam	New Mexico	Carlsbad
UC-7	Azeotea Creek and Willow Creek Conveyance Channel Station 1565+00	New Mexico	San Juan-Chama
UC-8	Azeotea Creek and Willow Creek Conveyance Channel Station 1702+75	New Mexico	San Juan-Chama
UC-9	Azeotea Creek and Willow Creek Conveyance Channel Station 1831+17	New Mexico	San Juan-Chama
UC-10	Azotea Creek and Willow Creek Conveyance Channel Outlet	New Mexico	San Juan-Chama
UC-11	Azotea Tunnel	New Mexico	San Juan-Chama
UC-12	Beck's Feeder Canal	Utah	Sanpete
UC-13	Big Sandy Dam	Wyoming	Eden
UC-14	Blanco diversion Dam	New Mexico	San Juan-Chama
UC-15	Blanco Tunnel	New Mexico	San Juan-Chama
UC-16	Brantley Dam	New Mexico	Brantley
UC-17	Broadhead Diversion Dam	Utah	Provo River
UC-18	Brough's Fork Feeder Canal	Utah	Sanpete
UC-19	Caballo Dam	New Mexico	Rio Grande
UC-20	Cedar Creek Feeder Canal	Utah	Sanpete
UC-21	Cottonwood Creek/Huntington Canal	Utah	Emery County
UC-22	Crawford Dam	Colorado	Smith Fork
UC-23	Currant Creek Dam	Utah	Central Utah Project - Bonneville Unit
UC-24	Currant Tunnel	Utah	Central Utah Project - Bonneville Unit
UC-25	Dam No. 13	New Mexico	Vermejo
UC-26	Dam No. 2	New Mexico	Vermejo
UC-27	Davis Aqueduct	Utah	Weber Basin
UC-28	Dolores Tunnel	Colorado	Dolores
UC-29	Docs Diversion Dam	Utah	Central Utah Project - Bonneville Unit
UC-30	Duchesne Diversion Dam	Utah	Provo River
UC-31	Duchesne Tunnel	Utah	Provo River
UC-32	Duchesne Feeder Canal	Utah	Moon Lake
UC-33	East Canal	Utah	Newton
UC-34	East Canal	Colorado	Uncompahgre
UC-35	East Canal Diversion Dam	Colorado	Uncompahgre
UC-36	East Canyon Dam	Utah	Weber Basin
UC-37	East Fork Diversion Dam	Colorado	Collbran
UC-38	Eden Canal	Wyoming	Eden
UC-39	Eden Dam	Wyoming	Eden
UC-40	Ephraim Tunnel	Utah	Sanpete
UC-41	Farmington Creek Stream Inlet	Utah	Weber Basin

Table A-2 Site Identification Inventory

Site ID	Site Name	State	Project
UC-42	Fire Mountain Diversion Dam	Colorado	Paonia
UC-43	Florida Farmers Diversion Dam	Colorado	Florida
UC-44	Fort Sumner Diversion Dam	New Mexico	Fort Sumner
UC-45	Fort Thornburgh Diversion Dam	Utah	Central Utah Project - Vernal Unit
UC-46	Fruitgrowers Dam	Colorado	Fruitgrowers Dam
UC-47	Garnet Diversion Dam	Colorado	Uncompahgre
UC-48	Gateway Tunnel	Utah	Weber Basin
UC-49	Grand Valley Diversion Dam	Colorado	Grand Valley
UC-50	Great Cut Dike	Colorado	Dolores
UC-51	Gunnison Diversion Dam	Colorado	Uncompahgre
UC-52	Gunnison Tunnel	Colorado	Uncompahgre
UC-53	Hades Creek Diversion Dam	Utah	Central Utah Project - Bonneville Unit
UC-54	Hades Tunnel	Utah	Central Utah Project - Bonneville Unit
UC-55	Haights Creek Stream Inlet	Utah	Weber Basin
UC-56	Hammond Diversion Dam	New Mexico	Hammond
UC-57	Heron Dam	New Mexico	San Juan-Chama
UC-58	Highline Canal	Utah	Newton
UC-59	Huntington North Dam	Utah	Emery County
UC-60	Huntington North Feeder Canal	Utah	Emery County
UC-61	Huntington North Service Canal	Utah	Emery County
UC-62	Hyrum Dam	Utah	Hyrum
UC-63	Hyrum Feeder Canal	Utah	Hyrum
UC-64	Hyrum-Mendon Canal	Utah	Hyrum
UC-65	Indian Creek Crossing Div. Dam	Utah	Strawberry Valley
UC-66	Indian Creek Dike	Utah	Strawberry Valley
UC-67	Inlet Canal	Colorado	Mancos
UC-68	Ironstone Canal	Colorado	Uncompahgre
UC-69	Ironstone Diversion Dam	Colorado	Uncompahgre
UC-70	Isleta Diversion Dam	New Mexico	Middle Rio Grande
UC-71	Jackson Gulch Dam	Colorado	Mancos
UC-72	Joes Valley Dam	Utah	Emery County
UC-73	Jordanelle Dam	Utah	Central Utah Project - Bonneville Unit
UC-74	Knight Diversion Dam	Utah	Central Utah Project - Bonneville Unit
UC-75	Layout Creek Diversion Dam	Utah	Central Utah Project - Bonneville Unit
UC-76	Layout Creek Tunnel	Utah	Central Utah Project - Bonneville Unit
UC-77	Layton Canal	Utah	Weber Basin
UC-78	Leasburg Diversion Dam	New Mexico	Rio Grande
UC-79	Leon Creek Diversion Dam	Colorado	Collbran
UC-80	Little Navajo River Siphon	New Mexico	San Juan-Chama
UC-81	Little Oso Diversion Dam	Colorado	San Juan-Chama
UC-82	Little Sandy Diversion Dam	Wyoming	Eden

Table A-2 Site Identification Inventory

Site ID	Site Name	State	Project
UC-83	Little Sandy Feeder Canal	Wyoming	Eden
UC-84	Lost Creek Dam	Utah	Weber Basin
UC-85	Lost Lake Dam	Utah	Central Utah Project - Bonneville Unit
UC-86	Loutzenheizer Canal	Colorado	Uncompahgre
UC-87	Loutzenheizer Diversion Dam	Colorado	Uncompahgre
UC-88	Lucero Dike	New Mexico	Rio Grande
UC-89	M&D Canal-Shavano Falls	Colorado	Uncompahgre
UC-90	Madera Diversion Dam	Texas	Balmorhea
UC-91	Main Canal	Utah	Newton
UC-92	Means Canal	Wyoming	Eden
UC-93	Meeks Cabin Dam	Wyoming	Lyman
UC-94	Mesilla Diversion Dam	New Mexico	Rio Grande
UC-95	Middle Fork Kays Creek Stream Inlet	Utah	Weber Basin
UC-96	Midview Dam	Utah	Moon Lake
UC-97	Mink Creek Canal	Idaho	Preston Bench
UC-98	Montrose and Delta Canal	Colorado	Uncompahgre
UC-99	Montrose and Delta Div. Dam	Colorado	Uncompahgre
UC-100	Moon Lake Dam	Utah	Moon Lake
UC-101	Murdock Diversion Dam	Utah	Provo River
UC-102	Nambe Falls Dam	New Mexico	San Juan-Chama
UC-103	Navajo Dam Diversion Works	New Mexico	Navajo Indian Irrigation
UC-104	Newton Dam	Utah	Newton
UC-105	Ogden Brigham Canal	Utah	Ogden River
UC-106	Ogden Valley Canal	Utah	Weber Basin
UC-107	Ogden Valley Diversion Dam	Utah	Weber Basin
UC-108	Ogden-Brigham Canal	Utah	Ogden River
UC-109	Olmstead Diversion Dam	Utah	Central Utah Project - Bonneville Unit
UC-110	Olmsted Tunnel	Utah	Provo River
UC-111	Open Channel #1	Utah	Central Utah Project - Bonneville Unit
UC-112	Open Channel #2	Utah	Central Utah Project - Bonneville Unit
UC-113	Oso Diversion Dam	Colorado	San Juan-Chama
UC-114	Oso Feeder Conduit	New Mexico	San Juan-Chama
UC-115	Oso Tunnel	New Mexico	San Juan-Chama
UC-116	Outlet Canal	Colorado	Mancos
UC-117	Paonia Dam	Colorado	Paonia
UC-118	Park Creek Diversion Dam	Colorado	Collbran
UC-119	Percha Arroyo Diversion Dam	New Mexico	Rio Grande
UC-120	Percha Diversion Dam	New Mexico	Rio Grande
UC-121	Picacho North Dam	New Mexico	Rio Grande
UC-122	Picacho South Dam	New Mexico	Rio Grande
UC-123	Pineview Dam	Utah	Ogden River
UC-124	Platoro Dam	Colorado	San Luis Valley

Table A-2 Site Identification Inventory

Site ID	Site Name	State	Project
UC-125	Provo Reservoir Canal	Utah	Provo River
UC-126	Red Fleet Dam	Utah	Central Utah Project - Jensen Unit
UC-127	Rhodes Diversion Dam	Utah	Central Utah Project - Bonneville Unit
UC-128	Rhodes Flow Control Structure	Utah	Central Utah Project - Bonneville Unit
UC-129	Rhodes Tunnel	Utah	Central Utah Project - Bonneville Unit
UC-130	Ricks Creek Stream Inlet	Utah	Weber Basin
UC-131	Ridgway Dam	Colorado	Dallas Creek
UC-132	Rifle Gap Dam	Colorado	Silt
UC-133	Riverside Diversion Dam	Texas	Rio Grande
UC-134	S.Ogden Highline Canal Div. Dam	Utah	Ogden River
UC-135	San Acacia Diversion Dam	New Mexico	Middle Rio Grande
UC-136	Scofield Dam	Utah	Scofield
UC-137	Selig Canal	Colorado	Uncompahgre
UC-138	Selig Diversion Dam	Colorado	Uncompahgre
UC-139	Sheppard Creek Stream Inlet	Utah	Weber Basin
UC-140	Silver Jack Dam	Colorado	Bostwick Park
UC-141	Sixth Water Flow Control	Utah	Central Utah Project - Bonneville Unit
UC-142	Slaterville Diversion Dam	Utah	Weber Basin
UC-143	Smith Fork Diversion Dam	Colorado	Smith Fork
UC-144	Soldier Creek Dam	Utah	Central Utah Project - Bonneville Unit
UC-145	South Canal Tunnels	Colorado	Uncompahgre
UC-146	South Canal, Sta 19+ 10 "Site #1"	Colorado	Uncompahgre
UC-147	South Canal, Sta. 181+10, "Site #4"	Colorado	Uncompahgre
UC-148	South Canal, Sta. 472+00, "Site #5"	Colorado	Uncompahgre
UC-149	South Canal, Sta. 72+50, Site #2"	Colorado	Uncompahgre
UC-150	South Canal, Sta.106+65, "Site #3"	Colorado	Uncompahgre
UC-151	South Feeder Canal	Utah	Sanpete
UC-152	South Fork Kays Creek Stream Inlet	Utah	Weber Basin
UC-153	Southside Canal	Colorado	Collbran
UC-154	Southside Canal, Sta 171+ 90 thru 200+ 67 (2 canal drops)	Colorado	Collbran
UC-155	Southside Canal, Sta 349+ 05 thru 375+ 42 (3 canal drops)	Colorado	Collbran
UC-156	Southside Canal, Station 1245 + 56	Colorado	Collbran
UC-157	Southside Canal, Station 902 + 28	Colorado	Collbran
UC-158	Spanish Fork Diversion Dam	Utah	Strawberry Valley
UC-159	Spanish Fork Flow Control Structure	Utah	Central Utah Project - Bonneville Unit
UC-160	Spring City Tunnel	Utah	Sanpete

Table A-2 Site Identification Inventory

Site ID	Site Name	State	Project
UC-161	Staight Creek Stream Inlet	Utah	Weber Basin
UC-162	Starvation Dam	Utah	Central Utah Project - Bonneville Unit
UC-163	Starvation Feeder Conduit Tunnel	Utah	Central Utah Project - Bonneville Unit
UC-164	Stateline Dam	Utah	Lyman
UC-165	Station Creek Tunnel	Utah	Preston Bench
UC-166	Steinaker Dam	Utah	Central Utah Project - Vernal Unit
UC-167	Steinaker Feeder Canal	Utah	Central Utah Project - Vernal Unit
UC-168	Steinaker Service Canal	Utah	Central Utah Project - Vernal Unit
UC-169	Stillwater Tunnel	Utah	Central Utah Project - Bonneville Unit
UC-170	Stoddard Diversion Dam	Utah	Weber Basin
UC-171	Stone Creek Stream Inlet	Utah	Weber Basin
UC-172	Strawberry Tunnel Turnout	Utah	Central Utah Project - Bonneville Unit
UC-173	Stubblefield Dam	New Mexico	Vermejo
UC-174	Sumner Dam	New Mexico	Carlsbad
UC-175	Swasey Diversion Dam	Utah	Emery County
UC-176	Syar Inlet	Utah	Central Utah Project - Bonneville Unit
UC-177	Syar Tunnel	Utah	Central Utah Project - Bonneville Unit
UC-178	Tanner Ridge Tunnel	Utah	Central Utah Project - Bonneville Unit
UC-179	Taylor Park Dam	Colorado	Uncompahgre
UC-180	Towaoc Canal	Colorado	Dolores
UC-181	Trial Lake Dam	Utah	Central Utah Project - Bonneville Unit
UC-182	Tunnel #1	Colorado	Grand Valley
UC-183	Tunnel #2	Colorado	Grand Valley
UC-184	Tunnel #3	Colorado	Grand Valley
UC-185	Upper Diamond Fork Flow Control Structure	Utah	Central Utah Project - Bonneville Unit
UC-186	Upper Diamond Fork Tunnel	Utah	Central Utah Project - Bonneville Unit
UC-187	Upper Stillwater Dam	Utah	Central Utah Project - Bonneville Unit
UC-188	Vat Diversion Dam	Utah	Central Utah Project - Bonneville Unit
UC-189	Vat Tunnel	Utah	Central Utah Project - Bonneville Unit
UC-190	Vega Dam	Colorado	Collbran
UC-191	Vermejo Diversion Dam	New Mexico	Vermejo
UC-192	Washington Lake Dam	Utah	Central Utah Project - Bonneville Unit
UC-193	Water Hollow Diversion Dam	Utah	Central Utah Project -

Table A-2 Site Identification Inventory

Site ID	Site Name	State	Project
			Bonneville Unit
UC-194	Water Hollow Tunnel	Utah	Central Utah Project - Bonneville Unit
UC-195	Weber Aqueduct	Utah	Weber Basin
UC-196	Weber-Provo Canal	Utah	Provo River
UC-197	Weber-Provo Diversion Canal	Utah	Provo River
UC-198	Weber-Provo Diversion Dam	Utah	Provo River
UC-199	Wellsville Canal	Utah	Hyrum
UC-200	West Canal	Colorado	Uncompahgre
UC-201	West Canal Tunnel	Colorado	Uncompahgre
UC-202	Willard Canal	Utah	Weber Basin
UC-203	Win Diversion Dam	Utah	Central Utah Project - Bonneville Unit
UC-204	Win Flow Control Structure	Utah	Central Utah Project - Bonneville Unit
UC-205	Yellowstone Feeder Canal	Utah	Moon Lake

Appendix B Green Incentives Programs

A wide variety of financial incentives for the implementation of renewable energy generation are available for new facilities within the United States, assuming they meet what can be very specific criteria. Often hydropower generation does not meet the criteria. Hydropower does qualify for Federal incentives, but most states offer no or limited incentives for hydropower. This appendix details financial incentives currently available for the installation and generation of hydropower within specific states.

B.1 Types of Incentives and Policies Renewable Energy

The Hydropower Assessment Tool considers financial incentives from performance-, or generation-, based incentives; however, several types of incentives are potentially available for the implementation of hydropower electricity generation at both the state and Federal levels. These incentives need to be assessed on a case by case basis as they can vary depending on location, ownership, generation capacity, and date of implementation.

Corporate or Property Tax Credits

Generally administered by states, these incentives provide corporations with tax credits, deductions, and/or exemptions typically associated with the implementation of renewable energy facilities. In a few cases, these tax incentives are based on the amount of energy produced at a facility. Individual state tax incentives generally have a maximum amount of credit or deduction allowed and in some cases cannot be stacked with or taken if federal tax incentives are also available.

For most states, there are limitations in types of renewable energy that are eligible and the amounts that can be claimed.

PACE Financing

Property-Assessed Clean Energy (PACE) financing is generally a type of loan, administered by local government who are authorized by the state, which is repaid typically via a special assessment on the owner's property over time.

Utility Rebate Programs

These are programs offered by utilities to encourage development of renewable energy and energy efficiency measures. These programs typically target specific types of renewable energy systems (such as photovoltaic or hydropower) and can be used by utilities to help them meet renewable portfolio standards or other renewable power generation requirements.

Performance-Based Incentives

Also known as generation-based or production-based incentives, these types of incentives can include a wide range of financial mechanisms that generally include a utility providing case payment to a renewable energy generator based on the amount of kilowatt hours (kWh) of renewable energy generated. These incentives are commonly accompanied by strict limitations for types of renewable energies included and other incentives that can be used when also receiving the performance-based incentives.

B.2 Federal Incentives for Hydroelectric Power Generation

As shown in the tables at the end of this appendix, the primary incentives available for renewable energy on a federal basis are the Production Tax Credit (PTC) or Investment Tax Credit (ITC). While these are two separate programs, as of 2009, facilities that qualify for the PTC could opt instead for two other options (not in addition to):

- Take the Federal business energy ITC, which incentivizes the implementation of renewable energy; versus
- Receive an equivalent cash grant from the U.S. Treasury Department

Both options generally equal 30 percent of eligible costs. It should be noted that in 2009 and 2010 there have been several bills within both the U.S. House and Senate that address energy, including renewable energy generation, impacts on climate change, and renewable portfolio standards (RPS). While to date, none of the bills or initiatives have successfully navigated the legislative branches, discussions continue to particularly focus on a federal RPS which proponents feel would standardize renewable energy generation requirements and incentives nationwide.

B.3 State Incentives for Hydroelectric Power Generation

Generation-, or performance-, based and installation-based incentives also exist on a state by state basis. In many cases, state incentives can be utilized along with federal incentives, further enhancing financial opportunities; however navigating program details are very important as each program has different thresholds, allowed installation size, and renewable generation type.

It was generally noted, for the states included in this assessment, that many states have a wide range of financial incentives for renewable energy but those incentives do not include hydropower generation. State incentives are listed individually in the tables attached at the end of this appendix. Additional details and insights specific to state programs (where necessary) are also provided below.

Arizona

Incentive programs within Arizona are primarily funded by utilities looking to comply with the state's RPS. These programs are administered by the individual utilities, require that the hydropower generation facility surrender their Renewable Energy Credits (RECs), and have limitation on the amount of incentives received from other sources.

Similar to most states, property tax exemptions are also available.

California

California's renewable energy program is both extensive and complex. Many of the energy initiatives in the state are driven by their existing RPS regulations, which require utilities to meet a 20 percent renewable generation requirement by 2010, and by the Global Warming Solutions Act of 2006 (AB 32), which includes a variety of complementary measures to reduce GHG emissions (such as adding a RPS of 33 percent by 2020 for utilities in state).

While a range of incentives exist, California's regulatory landscape can be difficult to navigate and may result in additional costs to project implementation, reducing the net benefit of renewable energy incentives. The incentives noted here do not take these potential direct and indirect financial costs into account, primarily because they must be evaluated on an individual project basis. Therefore, it is important for any project developer to consider both the location and regulatory requirements in each unique location in California.

Colorado

While there is a renewable portfolio goal in Colorado (30 percent by 2020), incentives for hydropower are primarily in the form of utility rebates focused on installations (versus generation). In addition to the utilities, grant programs and rebates are available for installation of hydropower in several communities throughout the state

Idaho

The state currently has no RPS regulation or goal. Available incentives are in the form of tax refunds and bonds.

Kansas

While there is a RPS in Kansas (20 percent by 2020), incentives for hydropower are primarily in the form of tax credits focused on installations (versus generation).

Montana

While there is a RPS in Montana (15 percent by 2015), incentives associated with this program and purchases of RECs are for solar, wind, and geothermal explicitly. (No listings for hydropower).

Incentives for hydropower are primarily in the form of tax credits and exemptions, focused on installations (versus generation).

Nebraska

The state currently has no RPS regulation or goal. Only limited tax incentives are available and focused on wind power generation specifically.

Nevada

Nevada does have an active REC market which utilities participate in to meet the 25 percent by 2025 standard. As with all markets, in the absence of a Federal RPS and uncertainty of what will happen if a Federal program is, or is not, implemented, this market is in a state of flux. Also, similar to other REC state and regional markets, RECs associated with solar energy are typically sold for much higher than any other renewable energy, including hydropower. As with all RECs, it is highly recommended that a producer consult a respected REC broker specific to their property location and generation capacity as prices can vary widely based on utility, number of RECs generated, and length of contract.

In addition to the REC potential incentives, other implementation-based incentives, such as tax credits and PACE funding, are available in the state, based on location.

New Mexico

While there is a RPS in New Mexico (20 percent by 2020), incentives associated with this program and purchases of RECs are for solar explicitly. (No listings for hydropower).

North Dakota

While there is a RPS in North Dakota (10 percent by 2015), this RPS is considered a very low/easily achievable standard in comparison to other states. In addition, available incentives, including tax credits are focused on solar and wind energy explicitly. (No listings for hydropower).

Oklahoma

While there is a RPS in Oklahoma (15 percent by 2015), only minimal incentives are available explicitly for hydropower, in particular PACE funding for implementation.

Oregon

Oregon has a 25 percent by 2025 RPS that does include hydropower in its listing of eligible RECs, though limited information is available on RECs specifically traded for hydropower generation. All available utility rebates, generally driven by compliance with the state RPS, are focused on solar power generation and/or energy efficiency at commercial, industrial, and residential locations.

Oregon does have a wide range of loan, tax, and grant incentives available for the implementation of hydropower within the state.

South Dakota

South Dakota has a 10 percent by 2025 RPS goal that does include hydropower in its listing of eligible RECs; however, the goal is for renewable, recycled, and conserved energy. All available utility rebates, generally driven by compliance with the state RPS, are focused on energy efficiency at commercial and residential locations. Property tax exemptions for hydropower generation facilities are available.

Texas

Texas' renewable power generation market has been largely focused on wind and some solar generation. There are numerous implementation-based incentives, though those also are focused on solar and wind technologies explicitly.

Utah

Utah has a renewable portfolio goal which utilities participate in to meet the 20 percent by 2025 standard. Different from other states RPS, Utah's program requires utilities to pursue renewable energy options only if it cost effective to do so.

As with all markets, in the absence of a Federal RPS and uncertainty of what will happen if a Federal program is, or is not, implemented, this market is in a state of flux. Also similar to other REC state and regional markets, RECs associated with solar energy are typically sold for much higher than any other renewable energy, including hydropower. As with all RECs, it is highly recommended that a producer consult a respected REC broker specific to their property location and generation capacity as prices can vary widely based on utility, number of RECs generated and length of contract.

There are numerous implementation-based incentives, though they are also focused on solar and wind technologies explicitly.

Washington

Incentive programs within Washington are primarily funded by utilities looking to comply with the state's RPS. These programs are administered by the individual utilities, require that the hydropower generation facility surrender their RECs, and have limitation on the amount of incentives received from other sources.

Wyoming

The state currently has no RPS regulation or goal. Available incentives are in the form of sales tax exemptions.

B.4 Summary Tables

The table below summarizes the green incentives rates used in the analysis for each state. On the following pages, Summary Tables B-1 through B-18 identify some incentive programs available from Federal and State programs. Due to the complexity and variability of the implementation-based incentives, only generation-based incentives have been included in the Hydropower Assessment Tool.

Performance Based Incentives ($/kWh)

State	Incentive Value	Notes
Arizona	$0.054	20 year agreement, can be stacked with Federal incentive[1].
California	$0.0984	Applicable to small hydropower facilities up to 3 MW, 20 year agreement, cannot be stacked with Federal incentive or participate in other state programs.
Colorado	Use Federal incentive rate	No state performance-based incentives available
Idaho	Use Federal incentive rate	No state performance-based incentives available
Kansas	Use Federal incentive rate	No state performance-based incentives available
Montana	Use Federal incentive rate	Performance-based incentives do not apply to hydropower
Nebraska	Use Federal incentive rate	No state performance-based incentives available
Nevada	Use Federal incentive rate	Performance-based incentives available, but cannot be quantified at this time
New Mexico	Use Federal incentive rate	Performance-based incentives do not apply to hydropower
North Dakota	Use Federal incentive rate	Performance-based incentives do not apply to hydropower
Oklahoma	Use Federal incentive rate	No state performance-based incentives available
Oregon	Use Federal incentive rate	No state performance-based incentives available
South Dakota	Use Federal incentive rate	No state performance-based incentives available
Texas	Use Federal incentive rate	Performance-based incentives do not apply to hydropower
Utah	Use Federal incentive rate	Performance-based incentives do not apply to hydropower
Wyoming	Use Federal incentive rate	No state performance-based incentives available
Washington	$0.21	Available in first year of service, can be stacked with Federal incentive

Notes:
1 – Federal incentive rate is $0.011 per KWh for the first 10 years of service

Table B-1 Federal Incentives

Program		**Renewable Electricity Production Tax Credit (PTC)**		**Business Energy Investment Tax Credit (ITC)**	**USDA - Rural Energy for America Program (REAP) Grants**
Incentive Type		Corporate Tax Credit		Corporate Tax Credit or Federal Grant	Federal Grant Program
Description		The federal renewable electricity production tax credit (PTC) is a per-kilowatt-hour tax credit for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person during the taxable year. Credits generally given for 10 years following in service date.		The American Recovery and Reinvestment Act of 2009 allows taxpayers, eligible for the federal PTC, to take the federal business energy investment tax credit (ITC) or to receive a grant from the U.S. Treasury Department instead of taking the PTC for new installations.	REAP promotes energy efficiency and renewable energy for agricultural producers and rural small businesses.
Applicability		Qualified hydroelectric generation in service by Dec. 31, 2013.	**Non-Generation based Incentives**	PTC qualified facility	"USDA will also make competitive grants to eligible entities to provide assistance to agricultural producers and rural small businesses "to become more energy efficient" and "to use renewable energy technologies and resources." These grants are generally available to state government entities, local governments, tribal governments, land-grant colleges and universities, rural electric cooperatives and public power entities, and other entities, as determined by the USDA."
Amount of Incentive	Program units	0.75¢/kWh in 1993 dollars		30% of eligible cost for implementation	Competitive grants of up to 25% project cost; loan up to $25M. Grants and Loans may combine for up to 75% of project costs.
	$/kWh	**$0.011 (2010 to 2013)**			
Can this be used with other incentives?		a) The tax credit is reduced for projects that receive other federal tax credits, grants, tax-exempt financing, or subsidized energy financing. b) PTC eligible facilities can opt for ITC or equiv. cash grant approximately equal to 30% of eligible costs		This would be instead of the PTC: cannot be combined with other federal tax credit incentives.	
Additional info		2009 tax form 8835 (http://www.irs.gov/pub/irs-pdf/f8835.pdf) and 2009 tax form 3800 (http://www.irs.gov/pub/irs-pdf/f3800.pdf)			Amounts available: $60 million for FY 2010, $70 million for FY 2011, and $70 million for FY 2012.
Source		Internal revenue services: 26 USC section 45; American recovery and reinvestment act of 2009: http://thomas.loc.gov/home/h1/Recovery_Bill_Div_B.pdf		American recovery and reinvestment act of 2009: http://thomas.loc.gov/home/h1/Recovery_Bill_Div_B.pdf	

Table B-2 Arizona State Incentives

Program		**APS - Renewable Energy Incentive Program**	**TEP - Renewable Energy Credit Purchase Program**	**UES - Renewable Energy Credit Purchase Program**	**Non-Generation based Incentives**	**Energy Equipment Property Tax Exemption**
Incentive Type		Utility Rebate Program	Utility Rebate Program	Utility Rebate Program		Property Tax Incentive
Description		Renewable Incentive Program, Arizona Public Service (APS) offers customers who install various renewable energy sources the opportunity to sell the credits associated with the energy generated to APS.	Tucson Electric Power (TEP) created the SunShare Program. TEP offers these incentives in exchange for the renewable energy certificates they generate.	Through the Renewable Incentive Program, UniSource Energy Services (UES) offers customers who install various renewable energy sources the opportunity to sell the credits associated with the energy generated to UES.		For property tax assessment purposes, these devices [renewable energy including low-impact hydropower] are considered to add no value to the property.
Applicability		PS Incentives are available for a variety of renewable energy technologies installed in the APS service area. Amounts vary based on the type of technology used and the scope of your project.	The technologies now eligible for funding through the RECPP all qualify under Arizona's renewable energy standard (RES) including commercial small hydro. Hydro must be installed in TEP's service area.	All technologies eligible for Arizona's Renewable Energy Standard (RES).		Any property installing renewable energy equipment in AZ.
Amount of Incentive	Program units	APS requires you to call with specific project information to discuss the production based incentives. No upfront (implementation) incentives are available under this program (though other incentive values mirror TEP's program).	Performance-based incentives (PBIs)	Performance-based incentives (PBIs)		Dependant on Property: tax exemption associated with installation cost.
	$/kWh		$0.060 (10yr agreement), $0.056 (15yr agreement), $0.054 (20yr agreement) signed in 2010-2014 (tenative for 2011-2014 and dependant on ACC incentive approval). PBI can't exceed 60% of real project cost.	$0.060 (10yr agreement), $0.056 (15yr agreement), $0.054 (20yr agreement) signed in 2010-2014 (tenative for 2011-2014 and dependant on ACC incentive approval). PBI can't exceed 60% of real project cost.		
Can this be used with other incentives?		Yes with restrictions (must pay for 15% of project cost after all state and federal incentives).	Yes with restrictions (must pay for 15% of project cost after all state and federal incentives). Exception: may not receive incentives if other utility incentives are applied. Note RECs are sold.	Yes with restrictions (must pay for 15% of project cost after all state and federal incentives). Exception: may not receive incentives if other utility incentives are applied. Note RECs are sold.		Implication is yes though not explicitly stated.
Additional info			The PBI are awarded via a bid process, so lower bids have a higher potential for aceptance. http://www.tep.com/Green/Home/hydro.asp	The PBI are awarded via a bid process, so lower bids have a higher potential for aceptance. http://uesaz.com/Green/Home/hydro.asp		Documentation on installtion and cost must be submitted to County Assessor no less then 6 months before "the notice of full cash value is issued for the initial valuation year."
Source		APS: Solar and Renewable Energy: http://www.aps.com/main/green/choice/solar/default.html	TEP: Green Energy - http://www.tep.com/Green/	UES: Green Energy - http://uesaz.com/Green/		

Table B-3 California State Incentives

Program		California Feed-In Tariff		Local Option - Municipal Energy Districts
Incentive Type		Performance-Based Incentive	Non-Generation based Incentives	PACE Financing
Description		The California feed-in tariff allows eligible customer-generators to enter into 10-, 15- or 20-year standard contracts with their utilities to sell the electricity produced by small renewable energy systems at time-differentiated market-based prices.		Property-Assessed Clean Energy (PACE) financing effectively allows property owners to borrow money to pay for energy improvements. The amount borrowed is typically repaid via a special assessment on the property over a period of years. Only certain communties included.
Applicability		Small hydro electric (up to 3 MW).		All this is determined on a case by case/community by community basis. Recommend reviewing for specific implementation only. Local options also available for property and sales tax incentives which should be reviewed for specific installations. Note that in CA PACE loans require the owner agree to contractual assessments on their property tax bill for up to 20 yrs.
Amount of Incentive	Program units	MPR vary by year and contract size (10, 15, or 20-year agreements)		
	$/kWh	(2010): 10-yr $0.09357/kWh, 15-yr $0.09591/kWh, 20-yr $0.09840/kWh,		
Can this be used with other incentives?		No: cannot participate in other state programs		
Additional info		REC are surrendered for life of contract to one of the three publicly-owned utilities (SCE, PG&E, SDG&E). CPUC: Energy Division Resolution E-4137		
Source		CPUC, Feed-in Tariff program page: http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/feedintariffs.htm		
Note: SMUD also has a feed in tariff program, however as of July 2010 it is over subscribed and only accepting applications as a "waiting list".				
Also note: REC program is being revised to include tRECs in the next year. This could change performance incentives in CA.				

Table B-4 Colorado State Incentives

Program		Non-Generation based Incentives	**Roaring Fork Valley - Sun Power Pioneers Rebate Program**	**Holy Cross Energy - WE CARE Rebates**	**La Plata Electric Association - Renewable Generation Rebate Program**	**New Energy Economic Development Grant**	**Improvement Districts for Energy Efficiency and Renewable Energy Improvements**
Incentive Type			Local Rebate Program	Utility Rebate Program	Utility Rebate Program		PACE Financing
Description			The Community Office for Resource Efficiency (CORE), a nonprofit organization promoting renewable energy and energy efficiency in western Colorado, offers residential and commercial rebates within the Roaring Fork Valley for the installation of photovoltaic, solar hot water, and micro hydro systems.	Holy Cross Energy's WE CARE (With Efficiency, Conservation And Renewable Energy) Program offers a $1.50-per-watt DC incentive for renewable energy generation using wind, hydroelectric, photovoltaic, biomass or geothermal technology.	To support and encourage the use of renewable generation, by offering customers payments for Renewable Energy Credits (RECs) as environmental attributes on approved installations.		Property-Assessed Clean Energy (PACE) financing effectively allows property owners to borrow money to pay for energy improvements. The amount borrowed is typically repaid via a special assessment on the property over a period of years. Only certain communties included.
Applicability			Commercial small hydro systems installed within specific Colorado zip codes.	Systems must be within Holy Cross's service territory and connected to Holy Cross Energy's electric system to qualify for renewable energy incentives.	Small hydro up to 10,000 watts (10 kW).	$2M in funding approved in 2009. Additional funding may be available in the future, but nothing currently.	All this is determined on a case by case/community by community basis. Recommend reviewing for specific implementation only. Local options also available for property and sales tax incentives which should be reviewed for specific installations.
Amount of Incentive	Program units		$0.50/Watt installed	$1.50/Watt installed ($1 rebate, $0.50 REC purchase for 10 years)	Need to contact LPEA for specific project pricingREC purchased for 10 year		
	$/kWh						
Can this be used with other incentives?			Yes	Yes, though note REC are sold here (can only sell	Yes, though note REC are sold here (can only sell once)		
Additional info			For up to 2 kW systems ($1000 maximum rebate). Additional information: http://www.aspencore.org/file/CORE_Rebates_files/2010-04-16%20Microhydro%20Guidelines%20%26%20Pre-Application.pdf	Up to 50% of installed costs, maximum of $9,000. systems larger than 6 kW are eligible (but capped at $9,000).	Policy was updated mid June 2010. Estimated cap is at $7,000 per facility.		

Table B-5 Idaho State Incentives

		Non-Generation based Incentives		
Program			**Renewable Energy Equipment Sales Tax Refund**	**Renewable Energy Project Bond Program**
Incentive Type			Sales Tax Incentive	State Bond Program
Description			Idaho offers a sales-and-use tax rebate for qualifying equipment and machinery used to generate electricity from fuel cells, low-impact hydro, wind, geothermal resources, biomass, cogeneration, solar and landfill gas.	Allows independent (non-utility) developers of renewable energy projects in the state to request financing from the Idaho Energy Resources Authority.
Applicability			Any renewable system generating at least 25 kW.	All renewables
Amount of Incentive	Program units		100% of sales tax (6% of equipment sales price assuming tax was paid).	
	$/kWh			
Can this be used with other incentives?			Yes.	
Additional info			Valid for purchases through July 1, 2011.	

Table B-6 Kansas State Incentives

		Non-Generation based Incentives		
Program			**Renewable Electricity Facility Tax Credit (Corporate)**	**Renewable Energy Property Tax Exemption**
Incentive Type			Corporate Tax Credit	Property Tax Incentive
Description			Kansas provides an investment tax credit for certain renewable energy facilities constructed between January 1, 2007 and December 31, 2011.	Exempts renewable energy equipment from property taxes.
Applicability			Facility must be owned by and located on the property of a commercial, industrial or ag business; project must run for 10 years	Renewable sources implemented after Jan 1, 1999.
Amount of Incentive	Program units		10% of first $50,000,000; 5% of costs above $50M.	Property tax exemption from power generation equipment.
	$/kWh			
Can this be used with other incentives?			Not explicit, but implied yes.	Not explicit, but implied yes.
Additional info			Tax credit claimed in equal amounts over ten years. This is also known as the "Renewable Electric Cogeneration Facility Tax Credit", Reference KS Statue 79-201.	

Table B-7 Montana State Incentives

Program		**Renewable Portfolio Standard**	**Non-Generation based Incentives**	**Corporate Property Tax Reduction for New/Expanded Generating Facilities**	**Renewable Energy Systems Exemption**
Incentive Type		While MT has a 15% by 2015 RPS , all incentives and REC purchases are focused on solar, wind and geothermal, no hydropower.		Property Tax Incentive	Property Tax Incentive
Description				This incentive reduces the local mill levy during the first nine years of operation, subject to approval by the local government.	Montana's property tax exemption for recognized non-fossil forms of energy generation to be claimed for 10 years after installation of the property.
Applicability				Generating plants producing one megawatt (MW) or more with an alternative renewable energy source are eligible for the new or expanded industry property tax reduction.	Small hydropower facilitiest at commercial, industrial, ag, or residential locations.
Amount of Incentive	Program units			Each year thereafter, the taxable value percentage is increased in equal increments until the full taxable value is attained in the tenth year. Only on local taxes.	Property tax incentive for up to $100,000 for non-residential structures.
	$/kWh				
Can this be used with other incentives?				Not explicit, but implied yes.	Not explicit, but implied yes.
Additional info					
Source		PSR Authority: http://www.mtrules.org/gateway/ruleno.asp?RN=38.5.8301			

Table B-8 Nebraska State Incentives

Program		None found for NE: focus is on energy efficency within the state with one tax incentive available for renewables (wind projects only).
Incentive Type		
Description		
Applicability		
Amount of Incentive	Program units	
	$/kWh	
Can this be used with other incentives?		

Table B-9 Nevada State Incentives

<table>
<tr><th colspan="2">Program</th><th>Portfolio Energy Credits</th><th rowspan="9">Non-Generation based Incentives</th><th>NV Energy - RenewableGenerations Rebate Program</th><th>Local Option - Special Improvement Districts</th><th>Renewable Energy Systems Property Tax Exemption</th></tr>
<tr><td colspan="2">Incentive Type</td><td>Performance-Based Incentive</td><td>State Rebate Program</td><td>PACE Financing</td><td>Property Tax Incentive</td></tr>
<tr><td colspan="2">Description</td><td>Nevada's Energy Portfolio Standard</td><td>Rebates made available to NV Energy customers to encourage implemenation of renewable energies in line with NV's RPS.</td><td>Property-Assessed Clean Energy (PACE) financing effectively allows property owners to borrow money to pay for energy improvements. The amount borrowed is typically repaid via a special assessment on the property over a period of years. Only certain communties included.</td><td>Value added from renewable energy generation is exempt from property taxes.</td></tr>
<tr><td colspan="2">Applicability</td><td>Customer-maintained distributed renewable energy systems receive a 0.05 adder for each kilowatt-hour generated.</td><td>Small hydroelectric 1 MW and smaller.</td><td rowspan="5">All this is determined on a case by case/community by community basis. Recommend reviewing for specific implementation only. Local options also available for property and sales tax incentives which should be reviewed for specific installations.</td><td>All hydroelectric.</td></tr>
<tr><td rowspan="2">Amount of Incentive</td><td>Program units</td><td>Between $0.50 and $3 per kWh estimated.</td><td rowspan="2">Non-net metered system $2.80/W, net metered system $2.50/W (under 2010/2011 program).</td><td rowspan="2">100% of value added to property exempt.</td></tr>
<tr><td>$/kWh</td><td>Must see a broker, note that higher values for solar are typical</td></tr>
<tr><td colspan="2">Can this be used with other incentives?</td><td>Yes, however systems installed via NV Energy rebate program have already surrendered their PEC and therefore have nothing to sell into this system</td><td>Yes, BUT: selling PEC here - cannot participate/resell PEC as it's gone.</td><td>Yes.</td></tr>
<tr><td colspan="2">Additional info</td><td>PEC prices are in a state of flux and it is currently not advised to include a price for PEC (or any form of REC) on a generic basis for those systems in an open market situation.

Note PECs are typically issued for 4 years.</td><td>Maximum incentive is $560,00 for net metered system, $500,000.</td><td></td></tr>
<tr><td colspan="2">Source</td><td>PUCN: http://pucweb1.state.nv.us/PUCN/RenewableEnergy.aspx?AspxAutoDetectCookieSupport=1</td><td></td><td></td><td></td></tr>
</table>

Table B-10 New Mexico State Incentives

Program		None found for NM: All performance based incentives are focusd on Photovoltaics (only one incentive for wind energy generation).
Incentive Type		
Description		
Applicability		
Amount of Incentive	Program units	
	$/kWh	
Can this be used with other incentives?		
Additional info		

Table B-11 North Dakota State Incentives

Program		None found for ND: Focus is on solar and win energy generation (hydropower is not even listed for the corporate tax credit incentives).
Incentive Type		
Description		
Applicability		
Amount of Incentive	Program units	
	$/kWh	
Can this be used with other incentives?		
Additional info		

Table B-12 Oklahoma State Incentives

Program		**Non-Generation based Incentives**	**Local Option - County Energy District Authority**
Incentive Type			PACE Financing
Description			Property-Assessed Clean Energy (PACE) financing effectively allows property owners to borrow money to pay for energy improvements. The amount borrowed is typically repaid via a special assessment on the property over a period of years. Only certain communties included.
Applicability			All this is determined on a case by case/community by community basis. Recommend reviewing for specific implementation only. Local options also available for property and sales tax incentives which should be reviewed for specific installations.
Amount of Incentive	Program units		
	$/kWh		
Can this be used with other incentives?			
Additional info			

Table B-13 Oregon State Incentives

Program			**Business Energy Tax Credit**	**Local Option - Local Improvement Districts**	**Renewable Energy Systems Exemption**	**Community Renewable Energy Feasibility Fund Program**
Incentive Type		**Non-Generation based Incentives**	Corporate Tax Credit	PACE Financing	Property Tax Incentive	State Grant Program (competitive)
Description			Oregon's Business Energy Tax Credit (BETC) is for investments in energy conservation, recycling, renewable energy resources, sustainable buildings, and less-polluting transportation fuels.	Property-Assessed Clean Energy (PACE) financing effectively allows property owners to borrow money to pay for energy improvements. The amount borrowed is typically repaid via a special assessment on the property over a period of years. Only certain communties included.	Value added from renewable energy generation is exempt from property taxes.	The Oregon Department of Energy (ODOE) provides grants for feasibility studies for renewable energy, heat, and fuel projects under the Community Renewable Energy Feasibility Fund (CREFF). Funding for the program comes from a settlement between the Oregon Department of Justice and Reliant Energy.
Applicability			Any Oregon business may qualify. Hydroelectric energy is eligible.	All this is determined on a case by case/community by community basis. Recommend reviewing for specific implementation only. Local options also available for property and sales tax incentives which should be reviewed for specific installations.	All hydroelectric.	Commercial hydroelectric 25 kw to 10 MW sized projects.
Amount of Incentive	Program units		Tax credit equal to 50% certified project costs, over 5 years (10% per year); up to $10 million.		100% of value added to property exempt.	Up to $50,000 grant, though this is a competitive bid process with awards ranging from $100,000 to $500,000.
	$/kWh					
Can this be used with other incentives?			Yes.		Yes.	Yes.
Additional info					Program expires 7/1/2012 currently.	Approximately $200,000 availabe in 2010.

Table B-14 South Dakota State Incentives

		Non-Generation based Incentives	
Program			**Renewable Energy Systems Exemption**
Incentive Type			Property Tax Incentive
Description			Value added from renewable energy generation is exempt from property taxes.
Applicability			All hydroelectric generation facilities, less than 5 MW.
Amount of Incentive	Program units		$50,000 or 70% of the assessed value of eligible property, whichever is greater.
	$/kWh		
Can this be used with other incentives?			Yes.
Additional info			Program effective as of 7/1/10. Credit available the first three years in service.

Table B-15 Texas State Incentives

Program		Numerous production and implementation based incentives, however they are all focused on PV, solar, and wind generation technologies specifically.
Incentive Type		
Description		
Applicability		
Amount of Incentive	Program units	
	$/kWh	
Can this be used with other incentives?		
Additional info		

Table B-16 Utah State Incentives

Program			Numerous production and implementation based incentives, however they are all focused on PV, solar, and wind generation technologies specifically. Hydropower is listed as an accepted REC in UT (small hydropower owners can net meter) and an active market for REC's exists. However the rate is project specific and varies based on market conditions.
Incentive Type			
Description			
Applicability			
Amount of Incentive	Program units		
	$/kWh		
Can this be used with other incentives?			
Additional info			

Table B-17 Wyoming State Incentives

Program		Non-Generation based Incentives	**Renewable Energy Equipment Sales Tax Refund**
Incentive Type			Sales Tax Incentive
Description			Idaho offers a sales-and-use tax rebate for qualifying equipment and machinery used to generate electricity from renewables including hydroelectric.
Applicability			Any renewable system generating at least 25 kW.
Amount of Incentive	Program units		100% of sales tax (4% of equipment sales price assuming tax was paid).
	$/kWh		
Can this be used with other incentives?			Yes.
Additional info			Valid for purchases through June 30, 2012.

Table B- 18 Washington State Incentives

Program		Chelan County PUD - Sustainable Natural Alternative Power Producers Program	Orcas Power & Light - Production Incentive
Incentive Type		Performance-Based Incentive	Performance-Based Incentive
Description		Sustainable Natural Alternative Power (SNAP) program encourages customers to install alternative power generators and connect them to the District's electrical distribution system by offering an incentive payment based on the system's production.	Orcas Power and Light (OPALCO), an electric cooperative serving Washington's San Juan Islands, provides a production-based incentive for residential and commercial members who generate energy from wind and micro-hydroelectric sources.
Applicability		Hydroelectric systems up to 25kW, Chelan County PUD customers.	Small hydroelectric systems (up to 100kW) in OPALCO area.
Amount of Incentive	Program units	Dependant on total sellers in program, varies by year.	$1.50kWh (first year production only), up to $4,500 max
	$/kWh	$0.21/kWh (2010)	$1.50/kWh
Can this be used with other incentives?		Yes.	Yes but note that RECs are being surrendered here.
Additional info		Program currently includes 5 kw of small hydropower. Additional benefits associated with net metering, but no additional payments.	To receive an incentive, members must sign an Agreement for Interconnection granting OPALCO rights to the system's Green Tags (renewable energy certificates).
Source		PUD SNAP producer program: http://www.chelanpud.org/become-a-snap-producer.html	OPALCO: http://www.opalco.com/energy-services/renewable-generation/

Appendix C Cost Estimating Method

The Hydropower Assessment Tool incorporates cost estimating functions for construction costs, other non-construction development costs, and for the various annual expenses that would be expected for operations. Construction costs include those for the major equipment components, ancillary mechanical and electrical equipment, and the civil works. In estimating the total cost of development, various costs are added to the construction cost such as those required for licensing and a menu of potentially required mitigation costs, depending on the specifics of the project. The annual operation and maintenance expenses encompass fees and taxes in addition to maintenance expenses and funds for major component replacement or repair.

Cost estimates for the individual components were based on studies previously performed by the Idaho National Engineering and Environmental Laboratory (INL) in 2003 and from more recent experience data. The INL analysis, as contained in “Estimation of Economic Parameters of U.S. Hydropower Resources”, INL, 2003, was based on a survey of a wide range of cost components and a large number and sizes of projects and essentially involved a historical survey of costs associated with different existing facilities. These costs included licensing, construction, fish and wildlife mitigation, water quality monitoring, and operations and maintenance (O&M), as well as other categories of costs with the cost factors dependent on the size of the generating capacity of a proposed facility. INL acquired historical data on licensing, construction, and environmental mitigation from a number of sources including Federal Energy Regulatory Commission (FERC) environmental assessment and licensing documents, U.S. Energy Information Administration data, Electric Power Research Institute reports, and other reports on hydropower construction and environmental mitigation

Cost estimating equations were then derived through generalized least squares regression techniques where the only statistically significant independent variable for each cost estimator was plant capacity. All data in the INL report were escalated to 2002 dollars. For purposes of the current study, the cost estimating equations were updated to 2010 based on escalating the INL equations based on applicable USBR cost indices. For construction years beyond 2010, the assessment tool assumes an escalation of 2.5% and is applied to the total development cost.

C.1 Construction Costs

Total construction costs within the assessment tool include those for civil works, turbines, generators, balance of plant mechanical and electrical, transformers and transmission lines. Other additions include contingences, sales taxes, and engineering and construction management. These construction costs reflect those that would be applicable to all projects but do not include potential mitigation measures which are subsequently included in the total development cost.

In estimating these costs, project information carried over from other worksheets within the model includes the plant capacity, turbine type, the design head, generator rotational speed, and transmission line length and voltage. Applicable cost equations are then applied to develop estimates for the specific cost categories. Applied to the summation of these costs is a contingency of 20%, a state sales tax based on the project location, and an assumed engineering and construction management cost of 15%. The associated equations developed are shown in Table C-1.

C.2 Total Development Costs

The total development cost includes the construction cost with the addition of a variety of other costs that are, or may be, required. Those additional costs applicable to all projects include any escalation to the 2010 time-frame, licensing costs, and the transmission-line right-of-way. Other costs that may apply, depending on the specific site, include fish passage requirements, historical and archaeological studies, water quality monitoring, and mitigation for fish and wildlife, and recreation. The requirements for specific sites are carried over to the cost estimating worksheet from previously input site specific information in the Start worksheet of the tool. Costs are all estimated based on the installed capacity of the project. The associated equations developed are shown in Table C-1.

C.3 Operation and Maintenance Costs

The operation and maintenance costs reflect a variety of expenses and fees expected for most projects. These expenses include fixed and variable O&M expenses, federal fees or charges from FERC or other agencies, charges for transmission of power generated or interconnection fees, insurance, taxes, overhead, and the long-term funding of major repairs. Fixed and variable O&M costs include water quality monitoring, other water expenses, hydraulic expenses, electric expenses, and rent. The estimates for these expenses are based on either the installed capacity or the total construction cost, with several costs estimated as fixed lump sums. The associated cost equations developed are shown in Table C-1.

Table C-1
Summary of Cost Estimating Equations

Cost Item	Cost Equation	Comment
Direct Construction Cost:	**Sum of the following costs:**	
Civil Works	Cost ($) = (0.40) x (Turbine Cost + Generator Cost)	Applied cost factor based on experience and judgment for relatively small scale hydroelectric developments.
Turbine	Kaplan at less than or equal to 100-foot head: Cost ($) = $(\text{Capacity, MW})^{0.72}$ x 909,000 x $2.71826^{(-0.0013 \text{ x design head})}$ Kaplan at greater than 100-foot head: Cost ($) = 5,240,000x$(\text{Capacity, MW})^{0.72}$ x Design Head $^{-0.38}$ Francis at less than or equal to 100-foot head: Cost ($) = $(\text{Capacity, MW})^{0.71}$ x 760,000 x $2.71828^{(-0.003 \text{ x Design Head})}$ Francis at greater than 100-foot head: Cost ($) = 3,930,000 x $(\text{Capacity, MW})^{0.71}$ x $(\text{Design Head})^{-0.42}$ Pelton: Cost ($) = 0.8 x 3,930,000 x $(\text{Capacity, MW})^{0.71}$ x Design Head$^{-0.42}$ Low Head: Cost ($) = $(\text{Capacity, MW})^{0.71}$ x 760,000 x $2.71828^{(-0.003 \text{ x Design Head})}$	Kaplan and Francis turbine cost regression equations for heads greater than 100-feet escalated from 2002 dollars, in generalized turbine cost equations in 2003 INL report by 31% based on USBR cost indices. Modified regression equations developed for heads less than 100-feet. Pelton turbine costs estimated at 80% of Francis turbine with Low Head Turbine estimated at Francis turbine cost. The turbine equation is multiplied by the number of units. The hydropower generation calculations in the model all assume 1 unit.
Generator	Cost ($) = 3,900,000 x $(\text{Capacity, MW})^{0.65}$ x $(\text{Generator Speed, RPM})^{-0.38}$	Escalated from 2002 dollars, as developed in 2003 INL report for generalized generator cost, by 31% based on USBR cost indices. The generator equation is multiplied by the number of units. The hydropower generation calculations in the model all assume 1 unit.
Balance of Plant Mechanical	Cost ($) = (0.20) x (Turbine Cost)	Applied cost factor based on experience and judgment for relatively small scale hydroelectric developments.

Table C-1
Summary of Cost Estimating Equations

Cost Item	Cost Equation	Comment
Balance of Plant Electrical	Cost ($) = (0.35) x (Generator Cost)	Applied cost factor based on experience and judgment for relatively small scale hydroelectric developments.
Transformer	Cost ($) = 14,866 – (0.0001 x (Capacity, kW/.9)^2) + (25.403 x (Capacity, kW/.9))	Cost regression equation developed based on recent experience, published recent bids, and kVA. Assumes 0.9 power factor.
Transmission Line	Cost ($) = (Length, miles) x (100,000/mile if less then 69 kV) Cost ($) = (Length, miles) x (200,000/mile if less then or equal to 115 kV) Cost ($) = (Length, miles) x (230,000/mile if greater then 115 kV)	Estimated costs per mile based on current generic costs based on line capacity.
Contingency	Cost ($) = (0.20) x (Sum of above Direct Construction Costs)	Assumed 20% of the total of the other direct construction costs not including the sales tax and E&CM.
Sales Tax	Cost ($) = (State Rate %) x (Sum of Other Direct Construction Costs)	Tax rate applied to previous sum of construction costs based on project location.
Engineering and Construction Management	Cost ($) = (0.15) x (Sum of Other Direct Construction Costs)	Assumed 15% of the total of the other direct construction costs.
Total Development Cost:	**Direct Construction Cost + the following costs:**	
Licensing Cost	Cost ($) = (780,000) x (Capacity, MW)$^{0.7}$	Escalated from 2002 dollars, as developed in 2003 INL report for undeveloped sites, by 30% based on USBR cost indices.
Transmission Line Right-of-Way	Cost ($) = (Length, miles) x (5,280x150/43,560)x(2,000)	Assumed 150-foot right-of-way with land cost of $2,000 per acre.
Fish and Wildlife Mitigation	Cost ($) = 390,000 x (Capacity, MW)$^{0.96}$	Escalated from 2002 dollars, as developed in 2003 INL report for undeveloped sites, by 30% based on USBR cost indices.
Recreation Mitigation	Cost ($) = 260,000 x (Capacity, MW)$^{0.97}$	Escalated from 2002 dollars, as developed in 2003 INL report for

Table C-1
Summary of Cost Estimating Equations

Cost Item	Cost Equation	Comment
		undeveloped sites, by 30% based on USBR cost indices.
Historical & Archeological	Cost ($) = 130,000 x (Capacity, MW)$^{0.72}$	Escalated from 2002 dollars, as developed in 2003 INL report for undeveloped sites, by 30% based on USBR cost indices.
Water Quality Monitoring	Cost ($) = 520,000 x (Capacity, MW)$^{0.44}$	Escalated from 2002 dollars, as developed in 2003 INL report for undeveloped sites, by 30% based on USBR cost indices.
Fish Passage	Cost ($) = 1,300,000 x (Capacity, MW)$^{0.56}$	Escalated from 2002 dollars, as developed in 2003 INL report for undeveloped sites, by 30% based on USBR cost indices.
Operation and Maintenance Costs:	**Sum of the following costs:**	
Fixed Annual Operation & Maintenance	Cost ($) = (26,000) x (Capacity, MW)$^{0.75}$	Escalated from 2002 dollars, as developed in 2003 INL report for undeveloped sites, by 30% based on USBR cost indices.
Variable Operation and Maintenance	Cost ($) = (26,000) x (Capacity, MW)$^{0.80}$	Escalated from 2002 dollars, as developed in 2003 INL report for undeveloped sites, by 30% based on USBR cost indices.
FERC Charges	Cost ($) = Installed Capacity (kW) + 112.5 x Annual Generation (GWh [gigawatt hours])	FERC Charges for 2010 as calculated under the Federal Power Act
Transmission / Interconnection	Cost ($) = 10,000	Same as used in Plant Cost Estimator Model V1.0, USBR, 2007.
Insurance	Cost ($) = (Total Direct Construction Cost) x (0.003)	Same as used in Plant Cost Estimator Model V1.0, USBR, 2007.
Taxes	Cost ($) = (Total Direct Construction Cost) x (0.012)	Same as used in Plant Cost Estimator Model V1.0, USBR, 2007.
Management	Cost ($) = (Total Direct Construction Cost) x (0.005)	Same as used in Plant Cost Estimator Model V1.0, USBR, 2007.

Table C-1
Summary of Cost Estimating Equations

Cost Item	Cost Equation	Comment
Major Repairs Fund	Cost ($) = (Total Direct Construction Cost) x (0.001)	Same as used in Plant Cost Estimator Model V1.0, USBR, 2007.
Reclamation / Federal Administration	Cost ($) = 10,000	Same as used in Plant Cost Estimator Model V1.0, USBR, 2007.

Appendix D Using the Hydropower Assessment Tool

Reclamation in conjunction with the contractors Anderson Engineering, CDM, and URS, developed the Hydropower Assessment Tool to estimate potential energy generation and economic benefits at the identified 530 Reclamation facilities. It is important to recognize that the tool has been developed using broad power and economic criteria, and it is only intended for preliminary assessments of potential hydropower sites. This tool cannot take the place of a detailed hydropower feasibility study.

Reclamation has made the Hydropower Assessment Tool available for public use with the following disclaimer statement:

"This is an "open source" software tool developed by the Bureau of Reclamation (Reclamation) and the contractor Anderson Engineering for the Hydropower Resource Assessment at Existing Reclamation Facilities Report, and it has been made available for public use. It is important to recognize that the tool has been developed using broad power and economic criteria, and it is only intended for preliminary assessments of potential hydropower sites. This tool cannot take the place of a detailed hydropower feasibility study. There are no warranties, express or implied, for the accuracy or completeness of or any resulting products from the utilization of the tool."

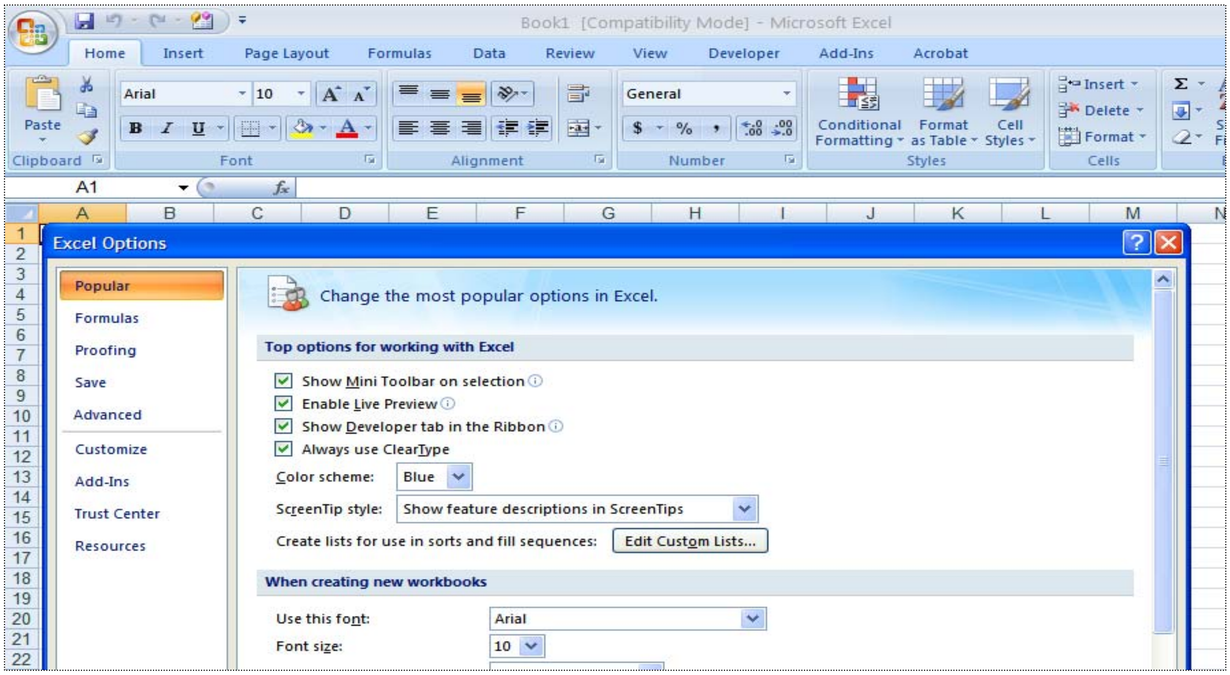
The Hydropower Assessment Tool is an Excel spreadsheet model with embedded macro functions programmed in Visual Basic. Microsoft Excel 2007 was used to develop the model. *To run the model successfully you must have a moderate working knowledge of Microsoft Excel.*

Chapter 3 of the report describes the assumptions built into the model; this appendix serves more as a user's manual for the Hydropower Assessment Tool.

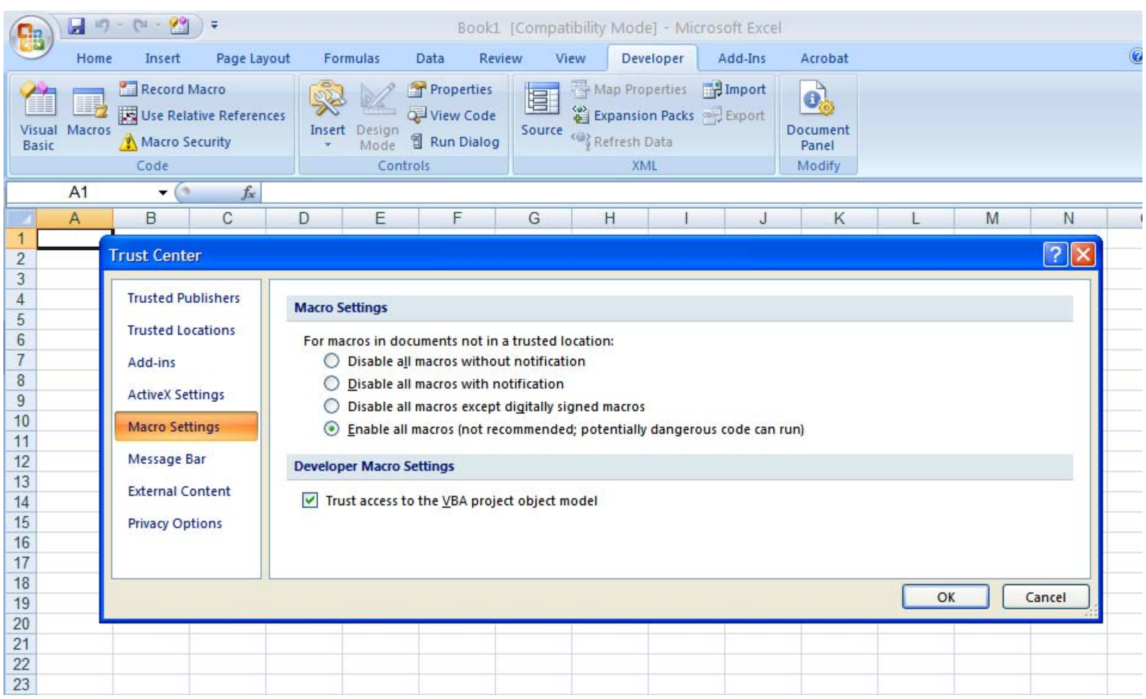
D.1 Before You Begin

Enabling Macros: If you use Excel 2007, the program will not run until macros are enabled. To enable macros:

1. Go to Office Button at the upper left corner of the excel spreadsheet when you start Excel and click on Excel Options.
2. Under the Popular tab check the Show Developer Tab as shown in the screen shot below.



3. After the Show developer tab is checked the Developer tab will show up in the Office Ribbon. Go to the Developer tab click Macro security and then go to the Macro Settings tab. In the Macro Settings tab check the Enable all macros as shown in the screen shot.



Data required to run the tool: The following information will need to be entered into the model for the analysis:

1. Daily upstream dam or headwater water elevation and flow through the potential site. This information must be on a daily basis and must be for at least one full year (minimum 365 day). The user should preferably enter only even full year increments of data in order to have a non-biased representation of annual records. The recommended data period is either on a water year or calendar year basis. Although some “missing” and “bad data” checking capabilities are included in the model, the user should ensure the data entered are correct. An example set of data of select years for A.R. Bowman Dam are included in the model.
2. Daily headwater and tail water elevations entered should be referenced to the same period. Alternatively, if the tail water elevation is constant it can be entered as a constant/single value.
3. Transmission voltage and the estimated transmission line length also need to be entered to estimate the development cost of the project. The model will pick a default of 115 kV, but this value can be over ridden if site specific information exists. This must be done after the second model step has been completed.
4. Site location i.e. the State the facility is located in needs to be entered for estimating the power values and the green incentives revenue.
5. The user can select if various mitigation cost should be added to the total development cost of the site.

D.2 Tool Components

Available Worksheets

The Hydropower Assessment Tool spreadsheet includes 15 separate tabs or worksheets, including several input data sheets, worksheets that contain information used as databases within the model, and worksheets that perform calculations. The calculations are based on the data input for a specific site and from the internal databases. The worksheets are set up in user friendly and logical sequence with only 2 worksheets requiring input from the user. This section summarizes the worksheets in the model; the bold headers below are the actual names of the worksheets in the model.

- **USBR** - includes the Disclaimer Statement and a link to the Start worksheet.

- **Start –** includes instructions for use of the model and cells where non-hydrologic inputs (state, transmission line voltage and distance, and constraints) are made. This worksheet also includes the command buttons to run the model. There are three steps to running the model, which should be run in sequence from top to bottom. The model run is complete when the Results worksheet is displayed.

- **Input Data –** where the daily flow data, head water and tail water elevation is input. A minimum of 1 year of data is required and there can be no blanks in the sequence.

- **Flow Exceedance –** develops and displays the flow duration curve based on input flow data.

- **Net Head Exceedance -** develops and displays the net head duration curve based on input head water and tail water elevation data.

- **Turbine Type –** includes the turbine selection matrix (Figure 3-4) and selects a turbine based on 30 percent flow and net head exceedance. Also includes Pelton, Francis, and Kaplan turbine efficiencies tables based on Hill diagram performance curves and a generator speed matrix used in the cost calculations.

- **Generation –** performs the power and energy generation calculations.

- **Power Exceedance –** shows the power exceedance curve calculated based on generation calculations in the previous worksheet.

- **Plant Cost –** calculates cost estimates for construction, total development cost, and estimated annual costs.

- **BC Ratio and IRR –** presents the stream of benefits and costs over the 50-year period of analysis and calculates the benefit cost ratio and IRR.

- **Results –** presents a comprehensive summary of results of energy generation calculation and the economic analysis.

- **Other State -** allows the user to input the green incentives and price projection values for states outside of the 17 western states in Reclamation's regions.

- **Price Projections –** includes the monthly price forecasts through 2060 for each state included in the analysis to calculate power generation benefits.

- **Green Incentives** – includes the performance-based green incentive values used for each state to calculate green incentive benefits.

- **Templates –** show the input data required in the model, in the appropriate format to run the model.

Start and Input Tab

The Start tab is where the program execution occurs. Most of the user interaction will occur in the start tab. The worksheet contains the instructions for the model. There are three buttons to be clicked in the order described below to complete the three steps of the analysis. A new user should follow the instructions provided in the Start tab and shown in Figure D-1.

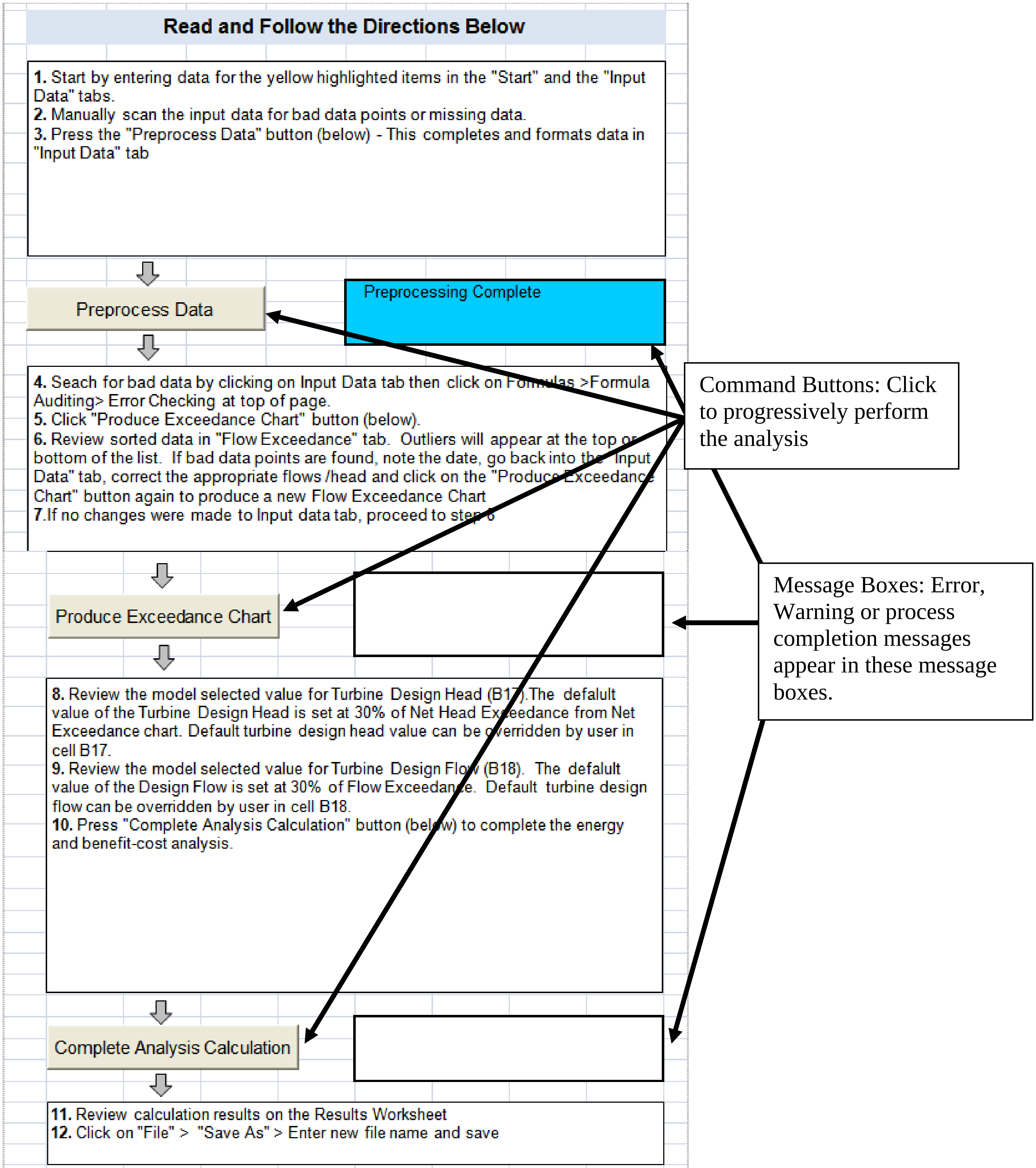
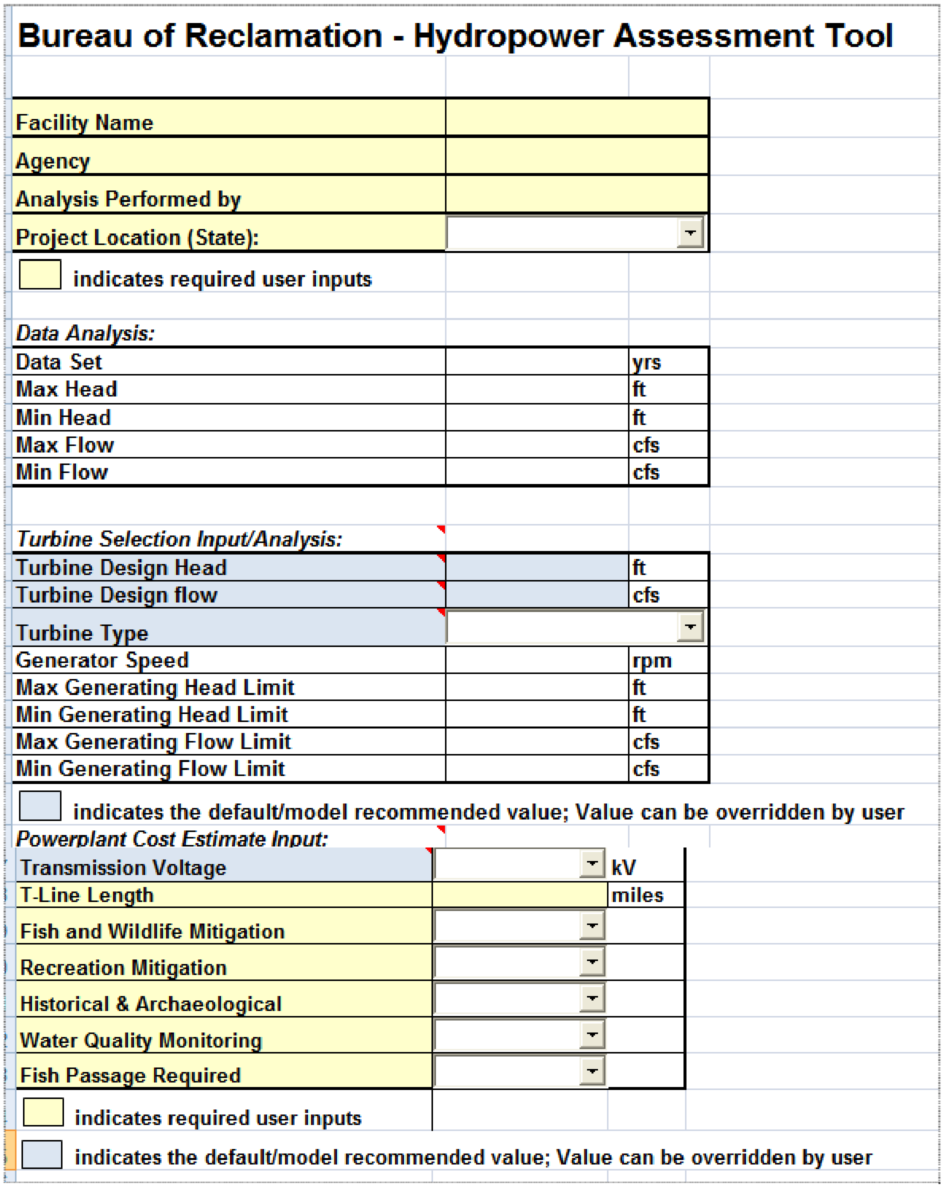


Figure D-1 Screen Shot of Start Tab-Program Execution Flow Chart



Bureau of Reclamation - Hydropower Assessment Tool

Facility Name		
Agency		
Analysis Performed by		
Project Location (State):		

indicates required user inputs

Data Analysis:

Data Set		yrs
Max Head		ft
Min Head		ft
Max Flow		cfs
Min Flow		cfs

Turbine Selection Input/Analysis:

Turbine Design Head		ft
Turbine Design flow		cfs
Turbine Type		
Generator Speed		rpm
Max Generating Head Limit		ft
Min Generating Head Limit		ft
Max Generating Flow Limit		cfs
Min Generating Flow Limit		cfs

indicates the default/model recommended value; Value can be overridden by user

Powerplant Cost Estimate Input:

Transmission Voltage		kV
T-Line Length		miles
Fish and Wildlife Mitigation		
Recreation Mitigation		
Historical & Archaeological		
Water Quality Monitoring		
Fish Passage Required		

indicates required user inputs

indicates the default/model recommended value; Value can be overridden by user

Figure D-2 Screen Shot of Start Tab-Data Input Windows

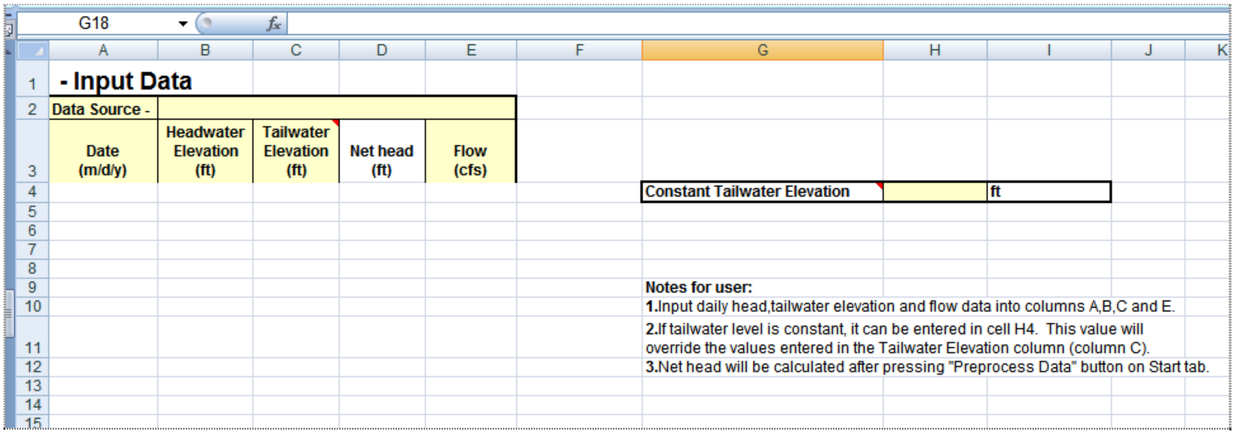


Figure D-3 Screen Shot of Input Data Worksheet

D.3 Using the Tool

1. Start by Saving the Workbook to a Different Name

Save the “Generic” workbook under a different name that preferably helps to identify the project. To save the workbook under s different name go to **File** > **Save As,** enter the desired name for the file and then click the **Save** button.

2. Entering Data

Enter data into the required fields highlighted in yellow in the Start tab (See Figure D-2). Cells highlighted in blue are optional entries, the model will use the default value unless the user overrides the default value. If the site being analyzed lies outside of Reclamation’s regions (i.e. it is not one of 17 western states in the drop down menu), then the user can use the “Other” state from the drop down menu. If the Other State option is selected then the user needs to provide the green incentive and power prices for the site in the “Other State” tab.

Daily headwater water elevation and flow through the potential site should be entered in the Input data tab (See Figure D-3). Tail water elevation can be entered as daily values or a constant elevation can be entered in the input data tab (See Figure D-3).

Input data (Date, Head, Flow, and Location) must be entered or transferred into the proper input columns/cells for the program to produce accurate results. The model will not run if there are blank cells or bad data in the input data columns.

3. Running the Analysis

The analysis runs in three steps, described below.

Step 1: Preprocess Data

After entering all the required user input data into the model, the user needs to follow the instructions provided in the Start tab to progressively execute the analysis. The model has an example data built in to provide initial understanding of how the tool functions.

To use the demonstration data, click on the Use Demonstration Data A.R. Bowman Dam button in the Start tab. The required user input information for Arthur R. Bowman Dam in Oregon will be transferred into the respective input fields. The user can now run the model with the example site data. To input new data, the user will need to Clear Charts – Start Over, and input new data in the process described above.

To start the analysis, the user should click on the Preprocess Data button. The model at this point will check if all the required data entries have been made and calculate net head using the headwater and tail water input data. The model has some intrinsic data checking capabilities. If the data entry is not complete an error message will show up in the message box next to the command button. Any missing data is considered an error and the model cannot run without filling out the missing information. For example, if the daily head and flow data entered is less than a year i.e. less than 365 data points, the following message Error - Insufficient data (< 365 data points in all) will show up in the message box adjacent to the Preprocess Data button.

A minimum of 1 year of data is required to run the model but the confidence in the results of the model increases with more data points. If the data set has less than 3 years of data a warning message will show up Warning - Insufficient data (< 3 years), Low Confidence indicating low confidence. The user can continue to run the model with existing data or try to get more data to increase the confidence in the results.

When more than 3 years of complete data is entered and the preprocessing step is complete the following message will show up in the message box Preprocessing Complete to indicate the completion of the preprocessing step in the analysis.

Step 2: Produce Exceedance Chart

Click on the Produce Exceedance Chart button in the Start tab to complete the second step of the analysis. At this step, the tool will create exceedance charts using the flow and net head data. Turbines will be sized using the flow exceedance and net head exceedance curves. Turbine design head and flow is defaulted to 30% exceedance level. These values can be overridden by the user in the Start tab (See Figure D-2) after the completion of the preprocess step. The tool will use the new overridden values in the final step of the analysis. If the design flow is less than 0.5 cfs the following error message will show up Error - Flow too low for hydropower Development indicating the analysis cannot be completed as the site does not have any hydropower potential at the 30 percent exceedance level. At this time the user can change the design head and flow on the Start tab. The Flow Exceedance and Net Head Exceedance worksheets have the flow and head exceedance curves in which the user can find design capacities at alternate percentages (i.e., 10, 15, 20, 25, etc., percent exceedance).

After the design flow and head are calculated for each site, a specific turbine type is selected for the site using the design head and design flow. The turbine type chosen by the model is based on the turbine selection matrix shown in the Turbine Type worksheet assuming a single turbine unit for the project**.** The user can change the selected turbine type in the Start tab. The change should be completed before the last step of the analysis. Again, any changes to the design head and design flow (i.e., if the user wants to run a different exceedance level than 30 percent) should be done at this time, before the last step of the analysis. If changing design head and design flow, the user should also note the turbine type selected at consider if a change in turbine type is appropriate. The transmission line voltage should also be selected after this step is complete.

Note: if the user chooses to run alternate design heads and design flows on a single site, the "Clear Charts – Start Over" button on the Start tab should be pressed after each model run is complete.

Step 3: Complete Analysis Calculations

Click on the Complete Analysis Calculation button to complete the analysis. If the user picked the "Other" state option and failed to provide the green incentive and power prices in the "Other State" tab the following error message will show up Error-Missing Power Price indicating the missing information and the analysis cannot be completed.

Note that this step in the analysis includes many calculations which might slow down the computer. It is suggested not to have multiple Excel file or large files open while this step runs.

The calculations include:

- **Power and Energy Calculations:** The calculations occur in the Generation worksheet. Using available head and flow data, selected design head, flow, turbine type and efficiency, the model estimates average monthly and annual power generation at each site. The available head and flow data is converted to generating head and flow data if the available flow and head meets the design limitations i.e. if the available flow is greater than the maximum allowable design flow capacity, the flow is constrained to the upper (Qmax) . Relevant information is noted in the Notes column in the Generation tab (See Figure D-4). This tab also has two summary tables with information regarding the plant generation capacity and the monthly/annual production rates (See Figure D-4). The model assumes that the plant generation and development costs are calculated based on a single turbine plant.

- Cost Calculations: Cost calculations occur in the Plant Cost worksheet (See Figure D-5). The cost analysis incorporated construction cost, other non-construction development costs (i.e., licensing/permitting costs) and O&M costs. Information in the Site Information table (Rows 6 to 23 in Figure D-5) shows the site specific information that is used in the cost analysis. Most of this information is imported from the Start or Input data tab or is based on the calculations using the information provided in the Start or Input Data worksheets.

  The total construction cost, development costs and annual O&M expense tables have the breakdown of the cost items included to calculate the total development/construction cost and Annual O&M expenses. Cells highlighted in light green in the Plant Cost worksheet can be updated or changed by the user.

A.R. Bowman Dam - Generation

Date (m/d/y)	Water Elevation (ft)	Tailwater Elevation (ft)	Net head (ft)	Flow (cfs)	Notes	Generating Head (ft)	Generating Flow (cfs)	Power (kW)	Day Energy (kWH)
1/1/2005	3234.64	3052.60	182.04	271	Q>Qmax,	182.04	264.00	3,474	83,373
1/2/2005	3234.72	3052.60	182.12	275	Q>Qmax,	182.12	264.00	3,475	83,410
1/3/2005	3234.83	3052.60	182.23	287	Q>Qmax,	182.23	264.00	3,478	83,460
1/4/2005	3234.90	3052.60	182.30	288	Q>Qmax,	182.30	264.00	3,479	83,492
1/5/2005	3234.93	3052.60	182.33	287	Q>Qmax,	182.33	264.00	3,479	83,506
1/6/2005	3234.96	3052.60	182.36	290	Q>Qmax,	182.36	264.00	3,480	83,520
1/7/2005	3234.95	3052.60	182.35	345	Q>Qmax,	182.35	264.00	3,480	83,515
1/8/2005	3186.98	3052.60	134.38	52	Q<Qmin,	134.38	0.00	0	0
1/9/2005	3186.97	3052.60	134.37	52	Q<Qmin,	134.37	0.00	0	0
1/10/2005	3186.87	3052.60	134.27	52	Q<Qmin,	134.27	0.00	0	0
1/11/2005	3186.86	3052.60	134.26	52	Q<Qmin,	134.26	0.00	0	0
1/12/2005	3186.86	3052.60	134.26	52	Q<Qmin,	134.26	0.00	0	0
1/13/2005	3186.86	3052.60	134.26	52	Q<Qmin,	134.26	0.00	0	0
1/14/2005	3164.75	3052.60	112.15	33	H<Hmin, Q<Qmin,	0.00	0.00	0	0
1/15/2005	3164.66	3052.60	112.06	33	H<Hmin, Q<Qmin,	0.00	0.00	0	0
1/16/2005	3164.61	3052.60	112.01	33	H<Hmin, Q<Qmin,	0.00	0.00	0	0
1/17/2005	3162.46	3052.60	109.86	86	H<Hmin,	0.00	86.12	0	0
1/18/2005	3162.61	3052.60	110.01	107	H<Hmin,	0.00	107.34	0	0
1/19/2005	3162.77	3052.60	110.17	107	H<Hmin,	0.00	107.34	0	0
1/20/2005	3163.00	3052.60	110.40	108	H<Hmin,	0.00	107.57	0	0
1/21/2005	3217.92	3052.60	165.32	224		165.32	224.26	2,770	66,486
1/22/2005	3218.14	3052.60	165.54	224		165.54	224.26	2,774	66,574
1/23/2005	3218.41	3052.60	165.81	224		165.81	224.26	2,778	66,683
1/24/2005	3218.59	3052.60	165.99	224		165.99	224.26	2,781	66,755
1/25/2005	3218.80	3052.60	166.20	224		166.20	224.26	2,785	66,840
1/26/2005	3218.98	3052.60	166.38	224		166.38	224.26	2,788	66,912
1/27/2005	3219.18	3052.60	166.58	224		166.58	224.26	2,791	66,993
1/28/2005	3219.39	3052.60	166.79	224		166.79	224.26	2,795	67,077
1/29/2005	3219.61	3052.60	167.01	224		167.01	224.26	2,799	67,166
1/30/2005	3219.83	3052.60	167.23	224		167.23	224.26	2,802	67,254
1/31/2005	3220.03	3052.60	167.43	224		167.43	224.26	2,806	67,335
2/1/2005	3220.22	3052.60	167.62	224		167.62	224.26	2,809	67,411
2/2/2005	3220.38	3052.60	167.78	224		167.78	224.26	2,811	67,475
2/3/2005	3220.64	3052.60	168.04	224		168.04	224.26	2,816	67,580
2/4/2005	3220.83	3052.60	168.23	224		168.23	224.26	2,819	67,656
2/5/2005	3221.04	3052.60	168.44	224		168.44	224.26	2,838	68,109

Plant Generation Summary:

Plant Design Capacity (kW)	3,293
Number of Data	10,592
Data Years	29.00
Total Data Period Energy (kWH)	540,722,417
Average Plant Capacity (kW)	2127
Plant Peak Capacity (kW)	3,628
Plant Factor	0.646

Plant Monthly Generation:

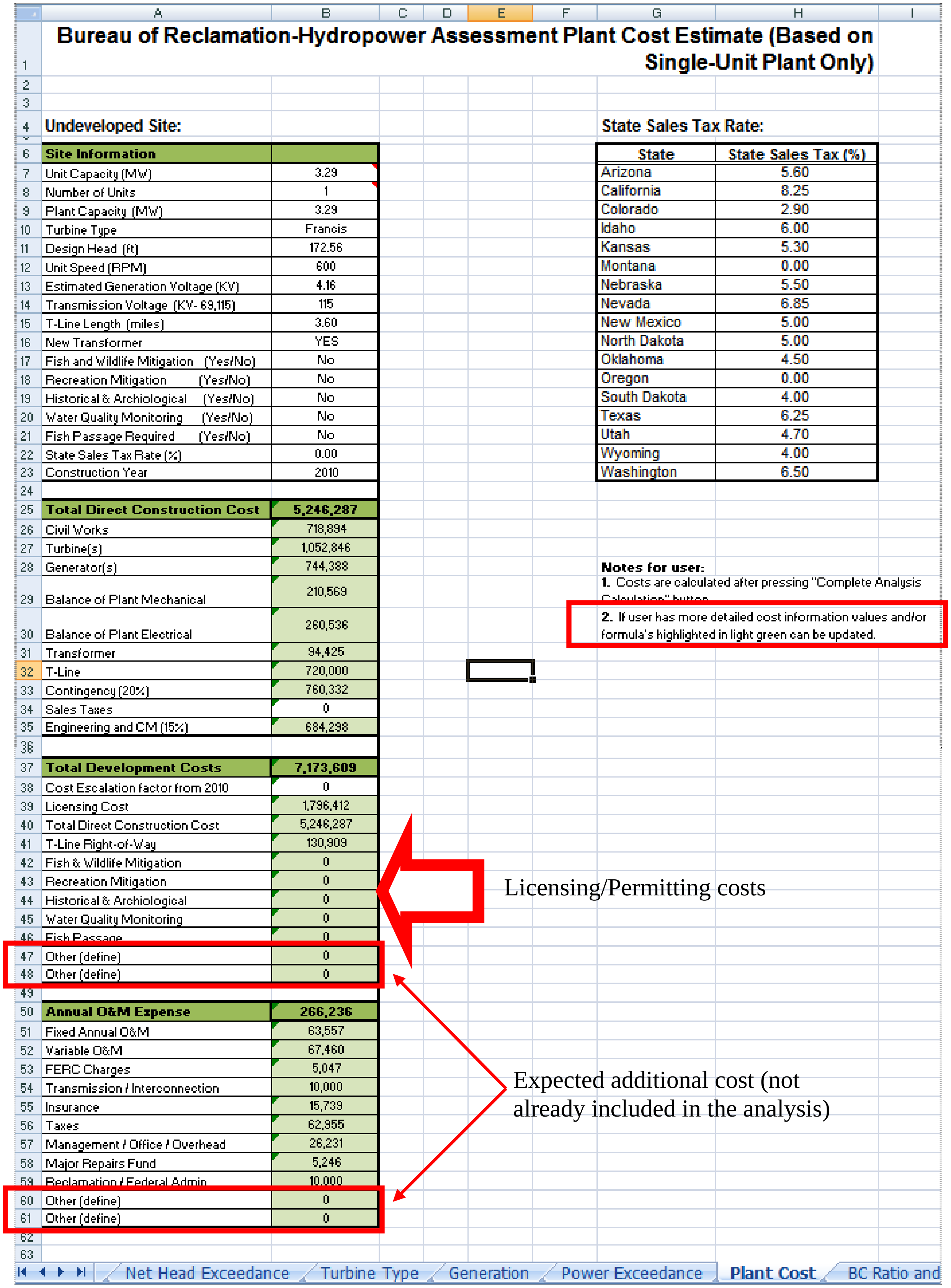
Months	Days with Data	Average Capacity (kW)	Average Energy (MWH)
January	899	1,215	875
February*	819	1,625	1,092
March	899	1,935	1,393
April	870	2,763	1,989
May	899	3,126	2,250
June	870	3,102	2,233
July	899	2,986	2,150
August	899	2,843	2,047
September	870	2,387	1,718
October	899	1,564	1,126
November	870	848	611
December	899	1,106	796
Annual*			18,282

* For non-leap year

Notes for user:

USBR | Start | Input Data | Flow Exceedance | Net Head Exceedance | Turbine Type | Generation | Powe

Figure D-4 Screen Shot of Generation Worksheet



Bureau of Reclamation-Hydropower Assessment Plant Cost Estimate (Based on Single-Unit Plant Only)

Undeveloped Site:

Site Information	
Unit Capacity (MW)	3.29
Number of Units	1
Plant Capacity (MW)	3.29
Turbine Type	Francis
Design Head (ft)	172.56
Unit Speed (RPM)	600
Estimated Generation Voltage (KV)	4.16
Transmission Voltage (KV- 69,115)	115
T-Line Length (miles)	3.60
New Transformer	YES
Fish and Wildlife Mitigation (Yes/No)	No
Recreation Mitigation (Yes/No)	No
Historical & Archiological (Yes/No)	No
Water Quality Monitoring (Yes/No)	No
Fish Passage Required (Yes/No)	No
State Sales Tax Rate (%)	0.00
Construction Year	2010

Total Direct Construction Cost	5,246,287
Civil Works	718,894
Turbine(s)	1,052,846
Generator(s)	744,388
Balance of Plant Mechanical	210,569
Balance of Plant Electrical	260,536
Transformer	94,425
T-Line	720,000
Contingency (20%)	760,332
Sales Taxes	0
Engineering and CM (15%)	684,298

Total Development Costs	7,173,609
Cost Escalation factor from 2010	0
Licensing Cost	1,796,412
Total Direct Construction Cost	5,246,287
T-Line Right-of-Way	130,909
Fish & Wildlife Mitigation	0
Recreation Mitigation	0
Historical & Archiological	0
Water Quality Monitoring	0
Fish Passage	0
Other (define)	0
Other (define)	0

Annual O&M Expense	266,236
Fixed Annual O&M	63,557
Variable O&M	67,460
FERC Charges	5,047
Transmission / Interconnection	10,000
Insurance	15,739
Taxes	62,955
Management / Office / Overhead	26,231
Major Repairs Fund	5,246
Reclamation / Federal Admin	10,000
Other (define)	0
Other (define)	0

State Sales Tax Rate:

State	State Sales Tax (%)
Arizona	5.60
California	8.25
Colorado	2.90
Idaho	6.00
Kansas	5.30
Montana	0.00
Nebraska	5.50
Nevada	6.85
New Mexico	5.00
North Dakota	5.00
Oklahoma	4.50
Oregon	0.00
South Dakota	4.00
Texas	6.25
Utah	4.70
Wyoming	4.00
Washington	6.50

Notes for user:
1. Costs are calculated after pressing "Complete Analysis Calculation" button
2. If user has more detailed cost information values and/or formula's highlighted in light green can be updated.

Figure D-5 Screen Shot of Plant Cost Worksheet

- Benefit-Cost (BC) Ratio and Internal Rate of Return (IRR) Calculation: The calculations occur in the BC Ratio and IRR worksheet (See Figure D-6). The benefits analysis quantifies the green incentives and the power market price based on the project location (state). The power generation income and green energy income is calculated in column F and G in the BC Ratio and IRR worksheet (See Figure D-6). The construction cost is distributed equally within the first 3 years of project implementation i.e. from 2011-2014 for all sites. Income from power generation and green incentives and annual O&M expenses are calculated over the consecutive 47 year period after construction of project. The benefit cost ratio compares the present value of benefits during the period of analysis to the present value of costs (using a discount rate of 4.375%). The user can choose to enter a different interest rate if applicable. Figure D-6 highlights where the discount rate can be changed in the worksheet.
- The IRR is an alternate measure of the worth of an investment. Due to limitations in Excel, highly negative IRR results cannot be computed. Since a negative IRR indicates that a project is clearly uneconomic, the results (cells K 14 and K 17) show a “negative” rather than a negative numeric estimate.

    - Power Generation Income: Price forecasts from the AURORAxmp® Electric Market Model had to be adjusted to a state basis for use in model (see Chapter 3 for further discussion). The resulting price projections in $/MWhr were compiled in the Price Projects worksheet (see Figure D-7). The Price Projections worksheet works as a lookup table for the model’s power generation income calculations. Thus if the user has additional information regarding the power market and chooses to update or change any of the prices, the change should be made in the Price Projections worksheet. The user assumes responsibility for changes to the Price Projection worksheet and associated results.

    - Green Incentives: The green incentives values were also compiled in a manner and format similar to the energy prices. This information has been made available to the user in the Green Incentives worksheet (see Figure D-8). The Green Incentives tab also works as a lookup table for the green incentives calculations. Since the renewable energy generation (green energy) market is still evolving and the information provided in the green incentives need to be updated regularly for better accuracy of results, the model allows the user to make changes to the values provided in the Green Incentives worksheet. The user assumes responsibility for changes to the Green Incentives worksheet and associated results.

Benefit-Cost (BC) Ratio and Internal Rate of Return (IRR)

Notes for user:

1. BC ratio calculation uses FY 2010 Federal Discount Rate of 4.375% to compute present value of benefits and costs (discount rate is calculation input)
2. IRR is the computed discount rate which equates the present value of benefits to the present value of costs (discount rate is calculation output)
3. Costs and benefits are discounted to Year 2010 (current year)
4. Nominal construction costs, O&M costs, and benefits are expressed at 2010 price level
5. 3-year construction period is 2011-2013, and 1/3 of costs are expended each year
6. Annual O&M expenditures and power generation benefits begin in 2014, the first year after construction is complete
7. Costs and benefits are evaluated over a 50-year period of analysis, 2011-2060
8. Benefits computed from average monthly generation (worksheet "Generation") and Aurora model prices (worksheet "Price Projections")
9. Due to limitations in excel,highly negative IRR results can not be computed.Since a negative IRR indicates that a project is clearly uneconomic,no numeric estimates are provided for any negative IRR results and the result is simply identified .

Input Variables from "Plant Cost" Worksheet

Construction Cost	$7,173,609
O&M Cost	$266,236

Assumptions

Discount Rate	4.375%

With Green Incentive:

Benefit-Cost Ratio:	2.25
IRR:	13.8%

Without Green Incentive:

Benefit-Cost Ratio:	2.11
IRR:	12.3%

Calendar Year	Construction Cost (2010 Dollars)	Annual OM&R Cost (2010 Dollars)	Total Costs	Present Worth of Costs	Generation Income (2010 Dollars)	Green Energy Price (2010 Dollars)	Total Benefits	Worth of Benefits (with Green Incentive)	Present Worth of Benefits (w/o Green Incentive)	Net Benefits or Net Costs (with Green Incentive)	Net Benefits or Net Costs (w/o Green Incentive)
2010			$0	$0				$0	$0	$0	$0
2011	$2,391,203		$2,391,203	$2,290,973				$0	$0	-$2,391,203	-$2,391,203
2012	$2,391,203		$2,391,203	$2,194,944				$0	$0	-$2,391,203	-$2,391,203
2013	$2,391,203		$2,391,203	$2,102,940				$0	$0	-$2,391,203	-$2,391,203
2014		$266,236	$266,236	$224,327	$1,005,348	$201,098	$1,206,446	$1,016,534	$847,092	$940,210	$739,112
2015		$266,236	$266,236	$214,924	$1,078,565	$201,098	$1,279,663	$1,033,030	$870,691	$1,013,426	$812,329
2016		$266,236	$266,236	$205,915	$1,146,176	$201,098	$1,347,274	$1,042,022	$886,487	$1,081,038	$879,940
2050		$266,236	$266,236	$48,018	$1,479,856	$0	$1,479,856	$266,907	$266,907	$1,213,620	$1,213,620
2051		$266,236	$266,236	$46,006	$1,479,856	$0	$1,479,856	$255,719	$255,719	$1,213,620	$1,213,620
2052		$266,236	$266,236	$44,077	$1,479,856	$0	$1,479,856	$245,000	$245,000	$1,213,620	$1,213,620
2053		$266,236	$266,236	$42,230	$1,483,354	$0	$1,483,354	$235,286	$235,286	$1,217,118	$1,217,118
2054		$266,236	$266,236	$40,460	$1,479,856	$0	$1,479,856	$224,892	$224,892	$1,213,620	$1,213,620
2055		$266,236	$266,236	$38,764	$1,479,856	$0	$1,479,856	$215,465	$215,465	$1,213,620	$1,213,620
2056		$266,236	$266,236	$37,139	$1,479,856	$0	$1,479,856	$206,434	$206,434	$1,213,620	$1,213,620
2057		$266,236	$266,236	$35,582	$1,483,354	$0	$1,483,354	$198,248	$198,248	$1,217,118	$1,217,118
2058		$266,236	$266,236	$34,091	$1,479,856	$0	$1,479,856	$189,491	$189,491	$1,213,620	$1,213,620
2059		$266,236	$266,236	$32,662	$1,479,856	$0	$1,479,856	$181,548	$181,548	$1,213,620	$1,213,620
2060		$266,236	$266,236	$31,293	$1,479,856	$0	$1,479,856	$173,938	$173,938	$1,213,620	$1,213,620
Total	$7,173,609	$12,513,096	$19,686,705	$11,225,391	$66,632,205	$2,212,931	$68,845,136	$25,203,046	$23,683,994	$49,158,430	$46,945,499
Average		$266,236			$1,417,706	$47,084					

Turbine Type | Generation | Power Exceedance | Plant Cost | **BC Ratio and IRR** | Results | Price Projecti

Table D-6 Screen Shot of BC Ratio and IRR Worksheet

MONTHLY ENERGY PRICE PROJECTIONS

Prices in $/MWH

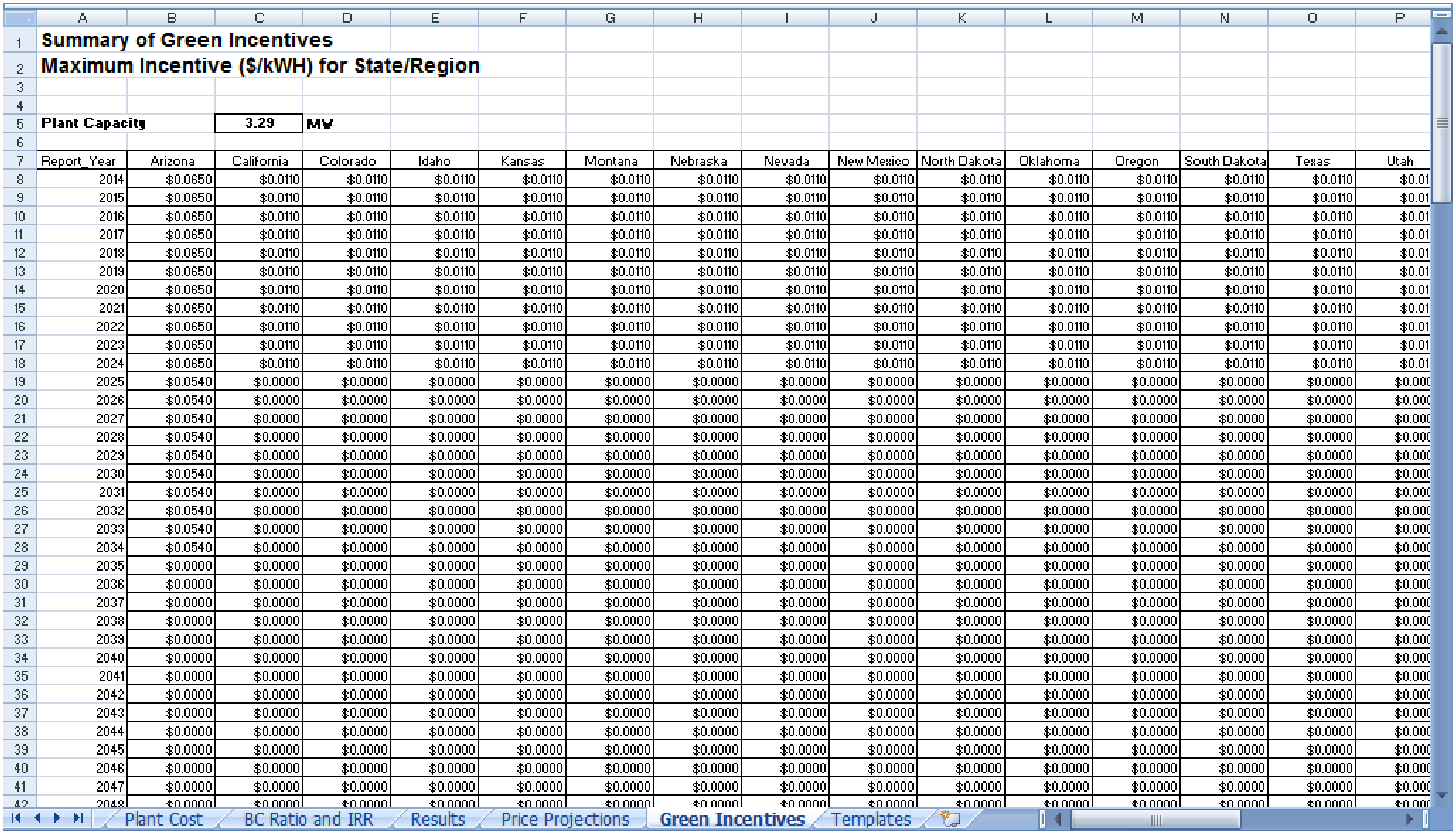
Notes for user:

1. Base data source: Aurora model run, provided by Northwest Power Planning Council for 6th Power Plan
2. Aurora 2006 nominal prices were indexed to 2010 price level to match project costs, using Aurora "GenInfl" worksheet
3. Prices were disaggregated from Aurora regional basis to a state basis; prices for eastern tier of Reclamation states set equal to average of all other Reclamation states
4. It is assumed that power generation begins in 2014, the first year after construction is complete, and prices are evaluated over a 47 year period, 2014-2060
5. Aurora price projections were used for years 2014-2030; after that the 2030 Aurora projection is used for the period 2031-2060

Sum of 2010 Price		State Name													
Report_Month	Report_Year	Arizona	California	Colorado	Idaho	Kansas	Montana	Nebraska	Nevada	New Mexico	North Dakota	Oklahoma	Oregon	South Dakota	Te
1	2014	$55.39	$60.99	$54.85	$54.53	$56.21	$52.66	$56.21	$57.82	$53.59	$56.21	$56.21	$58.58	$56.21	
	2015	$60.17	$65.97	$59.55	$59.33	$60.91	$57.53	$60.91	$62.14	$58.34	$60.91	$60.91	$63.65	$60.91	
	2016	$63.42	$69.52	$63.75	$63.19	$64.76	$61.38	$64.76	$65.61	$62.88	$64.76	$64.76	$67.57	$64.76	
	2017	$66.55	$72.27	$67.97	$66.81	$68.19	$64.43	$68.19	$68.86	$67.22	$68.19	$68.19	$70.74	$68.19	
	2018	$68.40	$73.97	$70.31	$68.70	$70.25	$66.76	$70.25	$70.83	$69.86	$70.25	$70.25	$72.67	$70.25	
	2019	$70.17	$75.96	$71.92	$70.96	$72.20	$68.73	$72.20	$72.77	$71.61	$72.20	$72.20	$74.89	$72.20	
	2020	$71.79	$77.53	$74.34	$72.60	$74.01	$70.73	$74.01	$74.48	$73.42	$74.01	$74.01	$76.29	$74.01	
	2021	$73.37	$79.47	$75.24	$74.37	$75.77	$72.68	$75.77	$76.43	$75.55	$75.77	$75.77	$77.99	$75.77	
	2022	$75.02	$81.35	$76.00	$75.75	$77.21	$73.68	$77.21	$78.10	$76.96	$77.21	$77.21	$79.04	$77.21	
	2023	$76.92	$84.03	$77.25	$77.74	$79.34	$75.75	$79.34	$80.31	$78.77	$79.34	$79.34	$81.54	$79.34	
	2024	$77.93	$85.39	$78.91	$78.87	$80.61	$76.81	$80.61	$81.72	$79.76	$80.61	$80.61	$82.67	$80.61	
	2025	$79.80	$87.46	$79.72	$80.52	$82.23	$78.01	$82.23	$83.63	$81.19	$82.23	$82.23	$84.28	$82.23	
	2026	$80.46	$88.67	$80.02	$81.43	$83.25	$79.21	$83.25	$84.79	$82.35	$83.25	$83.25	$85.52	$83.25	
	2027	$81.16	$89.63	$79.92	$82.21	$83.88	$79.47	$83.88	$85.76	$82.74	$83.88	$83.88	$86.20	$83.88	
	2028	$81.94	$90.86	$79.86	$83.34	$84.93	$80.88	$84.93	$86.91	$83.69	$84.93	$84.93	$87.69	$84.93	
	2029	$82.48	$91.57	$80.42	$84.29	$85.77	$81.65	$85.77	$87.96	$84.35	$85.77	$85.77	$88.58	$85.77	
	2030	$83.23	$92.66	$81.20	$84.94	$86.66	$82.52	$86.66	$89.16	$85.32	$86.66	$86.66	$89.71	$86.66	
	2031	$83.23	$92.66	$81.20	$84.94	$86.66	$82.52	$86.66	$89.16	$85.32	$86.66	$86.66	$89.71	$86.66	
	2032	$83.23	$92.66	$81.20	$84.94	$86.66	$82.52	$86.66	$89.16	$85.32	$86.66	$86.66	$89.71	$86.66	
	2033	$83.23	$92.66	$81.20	$84.94	$86.66	$82.52	$86.66	$89.16	$85.32	$86.66	$86.66	$89.71	$86.66	
	2034	$83.23	$92.66	$81.20	$84.94	$86.66	$82.52	$86.66	$89.16	$85.32	$86.66	$86.66	$89.71	$86.66	
	2035	$83.23	$92.66	$81.20	$84.94	$86.66	$82.52	$86.66	$89.16	$85.32	$86.66	$86.66	$89.71	$86.66	
	2036	$83.23	$92.66	$81.20	$84.94	$86.66	$82.52	$86.66	$89.16	$85.32	$86.66	$86.66	$89.71	$86.66	
	2037	$83.23	$92.66	$81.20	$84.94	$86.66	$82.52	$86.66	$89.16	$85.32	$86.66	$86.66	$89.71	$86.66	
	2038	$83.23	$92.66	$81.20	$84.94	$86.66	$82.52	$86.66	$89.16	$85.32	$86.66	$86.66	$89.71	$86.66	
	2039	$83.23	$92.66	$81.20	$84.94	$86.66	$82.52	$86.66	$89.16	$85.32	$86.66	$86.66	$89.71	$86.66	
	2040	$83.23	$92.66	$81.20	$84.94	$86.66	$82.52	$86.66	$89.16	$85.32	$86.66	$86.66	$89.71	$86.66	
	2041	$83.23	$92.66	$81.20	$84.94	$86.66	$82.52	$86.66	$89.16	$85.32	$86.66	$86.66	$89.71	$86.66	

Generation | Power Exceedance | Plant Cost | BC Ratio and IRR | Results | Price Projections | Green Ind

Figure D-7 Screen Shot of the Price Projections Worksheet



Summary of Green Incentives

Maximum Incentive ($/kWH) for State/Region

Plant Capacity 3.29 **MW**

Report_Year	Arizona	California	Colorado	Idaho	Kansas	Montana	Nebraska	Nevada	New Mexico	North Dakota	Oklahoma	Oregon	South Dakota	Texas	Utah
2014	$0.0650	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.01
2015	$0.0650	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.01
2016	$0.0650	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.01
2017	$0.0650	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.01
2018	$0.0650	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.01
2019	$0.0650	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.01
2020	$0.0650	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.01
2021	$0.0650	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.01
2022	$0.0650	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.01
2023	$0.0650	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.01
2024	$0.0650	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.0110	$0.01
2025	$0.0540	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.000
2026	$0.0540	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.000
2027	$0.0540	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.000
2028	$0.0540	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.000
2029	$0.0540	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.000
2030	$0.0540	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.000
2031	$0.0540	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.000
2032	$0.0540	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.000
2033	$0.0540	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.000
2034	$0.0540	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.000
2035	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.000
2036	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.000
2037	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.000
2038	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.000
2039	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.000
2040	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.000
2041	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.000
2042	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.000
2043	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.000
2044	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.000
2045	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.000
2046	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.000
2047	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.000
2048	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.000

Figure D-8 Screen Shot of Green Incentives Worksheet

D.4 Analysis Results

The Results worksheet (see Figure D-9) summarizes key results from the analysis about the site characteristics and relative economics of implementing the project. The user should review the flow exceedance and net head exceedance worksheets for a better understanding of the hydrological aspects of the site.

The value of the Hydropower Assessment Tool is that it allows a very quick assessment of a site's potential. The model is reliable in making preliminary analysis as it calculates the key factors that can influence the project's economical potential. It also displays some key design factors, such as installation capacity and plant factor to assist in decision making.

	A	B	C
1	**Bureau of Reclamation - Hydropower Assessment Tool**		
2			
3	Facility Name	A.R. Bowman Dam	
4	Agency	Bureau of Reclamation	
5	Analysis Performed by		
6	Project Location (State)	Oregon	
7			
8	**Results**		
9	***Input Data Analysis***		
10	Data Set	29	years
11	Max Head	190.1	ft
12	Min Head	109.7	ft
13	Max Flow	3,280	cfs
14	Min Flow	7	cfs
15			
16	***Turbine Selection Analysis***		
17	Selected Turbine Type	Francis	
18	Selected Design Head	173	ft
19	Selected Design flow	264	cfs
20	Generator Speed	600	rpm
21	Max Head Limit	215.7	ft
22	Min Head Limit	112.2	ft
23	Max Flow Limit	264	cfs
24	Min Flow Limit	53	cfs
25			
26	***Power Generation Analysis***		
27	Installed Capacity	3,293	kW
28	Plant Factor	0.65	
29	Projected Monthly Production:		
30	January	875	MWH
31	February*	1,092	MWH
32	March	1,393	MWH
33	April	1,989	MWH
34	May	2,250	MWH
35	June	2,233	MWH
36	July	2,150	MWH
37	August	2,047	MWH
38	September	1,718	MWH
39	October	1,126	MWH
40	November	611	MWH
41	December	796	MWH
42	Annual production*	18,282	MWH
43	* For non-leap year		
44			

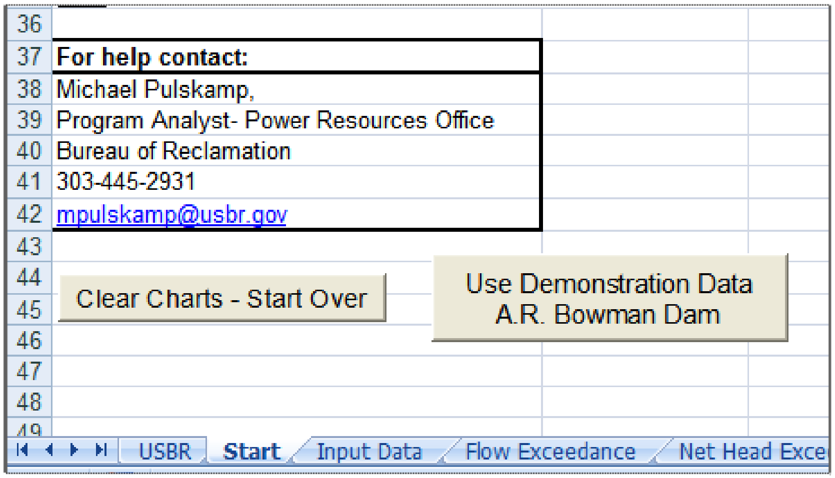
Benefit/Cost Analysis		
Projected expenditure to implement project		
[1] Total Construction Cost	$	7,173,609
[1] Annual O&M Cost	$	266,236
[2] Projected Total Cost over 50 year period	$	11,225,391
Projected revenue after implementation of project		
[1] Power generation income for 2014 to 2060	$	66,632,205
[1] Green Energy Sellback income for 2014 to 2060	$	2,212,931
[2] Projected Total Revenue over 50 year period (with Green Incentives)	$	25,203,046
[2] Projected Total Revenue over 50 year period (w/o Green Incentives)	$	23,683,994
Benefit/Cost Ratio (with Green incentives)		2.25
Benefit/Cost Ratio (w/o Green incentives)		2.11
Internal Rate of Return (with Green incentives)		13.8%
Internal Rate of Return (w/o Green incentives)		12.3%
Installed Cost $ per kW	$	2,178

Note:
[1] expressed in nominal 2010 dollars
[2] expressed in present worth

Figure D-9 Screen Shot of Results Worksheet

D.5 Contact Information

Reclamation has provided contact information for further information on the Hydropower Assessment Tool, as shown in the Start worksheet and below.



Please note:

- **Modifying the cell locations, inserting columns or rows into the spreadsheet may cause inaccurate or unexpected results.**
- **Project data (Date, Head & Flow) must be entered or transferred into the proper input columns for the program to produce accurate results. There must be no blank or empty cells in the data record.**
- **Command buttons must be pressed in sequence from 1 to 3. The analysis is not complete until buttons have in sequence with the same data set.**
- **This tool has been developed using broad power and economic criteria, and is only intended for preliminary assessments of potential hydropower sites.**
- **There are no warranties, express or implied, for the accuracy or completeness of or any resulting products from the utilization of the Hydropower Assessment Tool. See Reclamation's Disclaimer Statement on the USBR worksheet.**

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Appendix E Site Evaluation Results

This appendix presents the detailed results reported by the Hydropower Assessment Tool for all sites run through the model.

E.1 Site Ranking

Tables E-1 and E-2 rank all sites run through the Hydropower Assessment Tool from highest benefit cost ratio to lowest benefit cost ratio, incorporating green incentives and without green incentives. The table does not include canal and tunnel sites identified for further analysis. Chapter 5 of the report discusses results by Reclamation region and ranks sites by region according to the benefit cost ratio with green incentives.

E.2 Detailed Results Tables

Tables E-3 through E-7 include detailed site evaluation results for power generation and the economic analysis. The results format is taken directly from the Results worksheet in the Hydropower Assessment Tool. The tables show results for all sites run through the model, even those that were determined not to have hydropower potential. For some sites that did not have hydropower potential, the model could not complete calculations and the column is mostly blank. For other sites without hydropower potential, the model could complete calculations, but the design head and design flow are zero or close to zero, indicating no potential for hydropower development.

Table E-1 Ranked Site Specific Results from Highest Benefit Cost Ratio to Lowest Benefit Cost Ratio With Green Incentives

Site ID	Site Name/Facility	Data Confidence Level	Installed Capacity (kW)	Annual Production (MWh)	Total Development Cost ($)	$/Installed Capacity	BC Ratio with Green	IRR with Green
LC-6	Bartlett Dam	Medium	7529	36880	$15,120.0	$2,008	3.5	23.0%
GP-146	Yellowtail Afterbay Dam	Medium	9203	68261	$19,852.4	$2,157	3.05	18.2%
UC-141	Sixth Water Flow Control	Medium	25800	114420	$38,227.9	$1,482	3.02	17.1%
LC-20	Horseshoe Dam	Low	13857	59854	$30,123.0	$2,174	2.98	19.0%
GP-125	Twin Buttes Dam	Low	23124	97457	$33,654.2	$1,455	2.61	16.0%
UC-185	Upper Diamond Fork Flow Control Structure	Medium	12214	52161	$22,058.5	$1,806	2.36	13.6%
GP-99	Pueblo Dam	High	13027	55620	$22,193.9	$1,704	2.34	14.0%
MP-30	Prosser Creek Dam	High	872	3819	$3,119.0	$3,576	1.98	14.2%
PN-6	Arthur R. Bowman Dam	High	3293	18282	$8,994.9	$2,732	1.9	11.2%
UC-89	M&D Canal-Shavano Falls	Low	2862	15419	$7,260.4	$2,536	1.88	11.4%
GP-56	Huntley Diversion Dam	Medium	2426	17430	$8,361.0	$3,446	1.86	10.9%
MP-2	Boca Dam	High	1184	4370	$4,393.0	$3,711	1.68	11.3%
PN-31	Easton Diversion Dam	High	1057	7400	$4,006.9	$3,792	1.68	9.9%
UC-159	Spanish Fork Flow Control Structure	Medium	8114	22920	$13,147.5	$1,620	1.66	9.6%
LC-21	Imperial Dam	Low	1079	5325	$4,617.5	$4,280	1.61	10.0%
GP-46	Gray Reef Dam	High	2067	13059	$8,159.3	$3,947	1.58	8.7%
MP-8	Casitas Dam	High	1042	3280	$3,298.9	$3,165	1.57	10.7%
UC-49	Grand Valley Diversion Dam	Medium	1979	14246	$9,070.0	$4,584	1.55	8.6%
UC-52	Gunnison Tunnel	Medium	3830	19057	$11,385.5	$2,972	1.55	8.8%
GP-23	Clark Canyon Dam	High	3078	13689	$7,923.7	$2,575	1.52	8.6%
UC-19	Caballo Dam	Low	3260	15095	$10,197.9	$3,128	1.45	7.9%
UC-147	South Canal, Sta. 181+10, "Site #4"	Medium	3046	15536	$9,975.1	$3,275	1.44	8.0%
PN-95	Sunnyside Dam	Medium	1362	10182	$6,912.0	$5,075	1.43	7.8%
UC-144	Soldier Creek Dam	High	444	2909	$1,790.2	$4,033	1.39	7.9%
GP-52	Helena Valley Pumping Plant	High	2626	9608	$5,568.1	$2,120	1.38	7.8%
UC-131	Ridgway Dam	High	3366	14040	$9,885.1	$2,937	1.35	7.3%
GP-41	Gibson Dam	High	8521	30774	$19,928.0	$2,339	1.32	7.1%
UC-146	South Canal, Sta 19+ 10 "Site #1"	Medium	2465	12576	$8,883.4	$3,603	1.32	7.1%
UC-51	Gunnison Diversion Dam	Medium	1435	9220	$6,934.9	$4,832	1.28	6.7%
PN-88	Scootney Wasteway	Low	2276	11238	$8,014.4	$3,521	1.26	6.6%
UC-150	South Canal, Sta.106+65, "Site	Medium	2224	11343	$8,399.7	$3,777	1.26	6.6%

Table E-1 Ranked Site Specific Results from Highest Benefit Cost Ratio to Lowest Benefit Cost Ratio With Green Incentives

Site ID	Site Name/Facility	Data Confidence Level	Installed Capacity (kW)	Annual Production (MWh)	Total Development Cost ($)	$/Installed Capacity	BC Ratio with Green	IRR with Green
	#3"							
GP-126	Twin Lakes Dam (USBR)	High	981	5648	$4,192.7	$4,274	1.24	6.5%
GP-95	Pathfinder Dam	High	743	5508	$4,476.4	$6,022	1.23	6.2%
UC-162	Starvation Dam	High	3043	13168	$10,530.6	$3,461	1.23	6.2%
LC-15	Gila Gravity Main Canal Headworks	Medium	223	1548	$1,702.6	$7,632	1.17	6.0%
GP-43	Granby Dam	High	484	2854	$2,144.1	$4,426	1.16	5.9%
MP-32	Putah Diversion Dam	Medium	363	1924	$2,815.3	$7,745	1.16	6.3%
UC-179	Taylor Park Dam	High	2543	12488	$10,991.2	$4,323	1.12	5.4%
GP-136	Willwood Diversion Dam	High	1062	6337	$5,741.7	$5,407	1.1	5.2%
GP-93	Pactola Dam	High	596	2725	$2,207.5	$3,706	1.07	5.1%
UC-57	Heron Dam	Medium	2701	8874	$8,020.4	$2,970	1.06	4.9%
UC-148	South Canal, Sta. 472+00, "Site #5"	Medium	1354	6905	$6,155.4	$4,548	1.05	4.8%
UC-154	Southside Canal, Sta 171+ 90 thru 200+ 67 (2 canal drops)	Low	2026	6557	$5,595.9	$2,762	1.05	4.8%
PN-34	Emigrant Dam	High	733	2619	$2,209.7	$3,013	0.99	4.3%
UC-177	Syar Tunnel	Medium	1762	7982	$8,246.1	$4,680	0.99	4.3%
PN-104	Wickiup Dam	High	3950	15650	$15,178.6	$3,843	0.98	4.2%
UC-174	Sumner Dam	Medium	822	4300	$4,193.5	$5,103	0.98	4.2%
GP-34	East Portal Diversion Dam	High	283	1799	$1,553.3	$5,495	0.96	3.9%
PN-12	Cle Elum Dam	High	7249	14911	$13,692.3	$1,889	0.94	3.8%
PN-80	Ririe Dam	High	993	3778	$3,636.9	$3,661	0.94	3.8%
UC-155	Southside Canal, Sta 349+ 05 thru 375+ 42 (3 canal drops)	Low	1651	5344	$5,169.8	$3,131	0.93	3.7%
PN-87	Scoggins Dam	High	955	3683	$3,665.4	$3,838	0.92	3.6%
UC-132	Rifle Gap Dam	High	341	1740	$1,574.9	$4,621	0.92	3.5%
GP-5	Angostura Dam	Low	947	3218	$3,179.2	$3,358	0.9	3.3%
MP-17	John Franchi Dam	Low	469	1863	$3,624.5	$7,728	0.9	3.0%
GP-39	Fresno Dam	High	1661	6268	$6,013.9	$3,620	0.88	3.2%
GP-129	Virginia Smith Dam	Low	1607	9799	$11,467.6	$7,137	0.88	3.3%
PN-59	McKay Dam	High	1362	4344	$4,274.0	$3,138	0.88	3.2%
GP-128	Vandalia Diversion Dam	Medium	326	1907	$1,779.4	$5,461	0.87	3.0%
PN-49	Keechelus Dam	High	2394	6746	$6,774.2	$2,830	0.87	3.0%
PN-44	Haystack	High	805	3738	$3,916.4	$4,866	0.85	2.9%
UC-72	Joes Valley Dam	High	1624	6596	$7,764.3	$4,780	0.85	3.0%
UC-145	South Canal Tunnels	Medium	884	4497	$5,005.8	$5,665	0.84	2.8%

Table E-1 Ranked Site Specific Results from Highest Benefit Cost Ratio to Lowest Benefit Cost Ratio With Green Incentives

Site ID	Site Name/Facility	Data Confidence Level	Installed Capacity (kW)	Annual Production (MWh)	Total Development Cost ($)	$/Installed Capacity	BC Ratio with Green	IRR with Green
MP-24	Marble Bluff Dam	High	1153	5624	$6,854.2	$5,943	0.83	2.8%
GP-92	Olympus Dam	High	284	1549	$1,552.4	$5,472	0.82	2.3%
GP-117	St. Mary Canal - Drop 4	High	2569	8919	$9,599.7	$3,736	0.82	2.6%
GP-42	Glen Elder Dam	High	1008	3713	$4,260.6	$4,229	0.81	2.4%
UC-117	Paonia Dam	Medium	1582	5821	$7,092.5	$4,482	0.79	2.3%
PN-48	Kachess Dam	Medium	1227	3877	$4,335.9	$3,535	0.77	1.9%
GP-118	St. Mary Canal - Drop 5	High	1901	7586	$9,154.5	$4,817	0.75	1.8%
PN-57	Mason Dam	High	1649	5773	$7,276.4	$4,414	0.72	1.5%
UC-166	Steinaker Dam	High	603	1965	$2,388.4	$3,959	0.71	1.0%
GP-135	Willwood Canal	Medium	687	3134	$4,452.3	$6,481	0.7	1.4%
GP-22	Choke Canyon Dam	Low	194	1199	$1,506.0	$7,755	0.69	0.7%
GP-76	Merritt Dam	Low	1631	8438	$12,641.1	$7,752	0.68	1.2%
PN-101	Warm Springs Dam	High	1234	3256	$4,326.6	$3,507	0.66	0.4%
GP-120	Sun River Diversion Dam	High	2015	8645	$12,611.4	$6,259	0.65	0.8%
MP-18	Lake Tahoe Dam	High	287	893	$2,494.8	$8,686	0.65	Negative
GP-50	Heart Butte Dam	High	294	1178	$1,562.5	$5,315	0.64	Negative
GP-141	Wyoming Canal - Station 1490	Low	538	2305	$3,249.5	$6,042	0.64	0.3%
PN-97	Thief Valley Dam	Medium	369	1833	$2,601.0	$7,050	0.64	0.1%
UC-22	Crawford Dam	High	303	1217	$1,592.4	$5,264	0.64	Negative
LC-24	Laguna Dam	Low	125	566	$1,100.0	$8,794	0.63	Negative
GP-24	Corbett Diversion Dam	High	638	2846	$4,782.3	$7,500	0.59	0.1%
UC-126	Red Fleet Dam	High	455	1904	$3,031.9	$6,666	0.59	Negative
UC-140	Silver Jack Dam	High	748	2913	$4,863.9	$6,504	0.57	Negative
GP-18	Carter Lake Dam No. 1	High	842	2266	$3,642.7	$4,328	0.56	Negative
GP-114	St. Mary Canal - Drop 1	High	1212	4838	$7,901.8	$6,518	0.56	Negative
GP-138	Woods Project, Greenfield Main Canal Drop	Low	746	2680	$4,131.6	$5,540	0.56	Negative
PN-41	Golden Gate Canal	Low	514	2293	$3,991.6	$7,771	0.56	Negative
PN-56	Mann Creek	High	495	2097	$3,554.4	$7,174	0.56	Negative
UC-116	Outlet Canal	Medium	586	1839	$3,264.8	$5,570	0.52	Negative
GP-137	Wind River Diversion Dam	High	398	1595	$2,921.2	$7,344	0.51	Negative
UC-190	Vega Dam	Medium	548	1702	$3,012.5	$5,499	0.51	Negative
GP-115	St. Mary Canal - Drop 2	High	974	3887	$7,141.0	$7,333	0.5	Negative
GP-10	Belle Fourche Dam	High	497	1319	$2,376.3	$4,786	0.49	Negative
GP-145	Wyoming Canal - Station 997	Low	287	1228	$2,224.9	$7,751	0.49	Negative
GP-116	St. Mary Canal - Drop 3	High	887	3538	$6,832.5	$7,707	0.47	Negative
GP-108	Shadow Mountain Dam	High	119	777	$1,471.5	$12,316	0.46	Negative

Table E-1 Ranked Site Specific Results from Highest Benefit Cost Ratio to Lowest Benefit Cost Ratio With Green Incentives

Site ID	Site Name/Facility	Data Confidence Level	Installed Capacity (kW)	Annual Production (MWh)	Total Development Cost ($)	$/Installed Capacity	BC Ratio with Green	IRR with Green
UC-136	Scofield Dam	High	266	906	$1,780.5	$6,700	0.45	Negative
UC-36	East Canyon Dam	High	929	3549	$8,271.6	$8,907	0.44	Negative
GP-28	Deerfield Dam	High	138	694	$1,392.4	$10,109	0.43	Negative
GP-75	Medicine Creek Dam	High	276	1001	$2,103.6	$7,631	0.43	Negative
UC-6	Avalon Dam	High	230	1031	$2,260.8	$9,818	0.42	Negative
GP-15	Bull Lake Dam	High	933	2302	$5,327.8	$5,709	0.41	Negative
GP-140	Wyoming Canal - Station 1016	Low	220	939	$2,036.0	$9,275	0.41	Negative
GP-31	Dodson Diversion Dam	Low	140	566	$1,106.9	$7,895	0.4	Negative
UC-62	Hyrum Dam	High	491	2052	$5,081.3	$10,346	0.4	Negative
UC-93	Meeks Cabin Dam	High	1586	4709	$11,641.2	$7,341	0.4	Negative
UC-124	Platoro Dam	High	845	3747	$10,106.2	$11,964	0.38	Negative
GP-47	Greenfield Project, Greenfield Main Canal Drop	Low	238	830	$1,848.6	$7,779	0.37	Negative
GP-107	Shadehill Dam	High	322	1536	$4,128.1	$12,806	0.37	Negative
GP-8	Barretts Diversion Dam	Medium	102	546	$1,391.4	$13,596	0.35	Negative
GP-54	Horsetooth Dam	High	350	847	$2,202.8	$6,288	0.34	Negative
GP-142	Wyoming Canal - Station 1520	Low	175	749	$2,002.2	$11,454	0.34	Negative
UC-67	Inlet Canal	Medium	252	966	$2,596.6	$10,320	0.34	Negative
GP-103	Saint Mary Diversion Dam	High	177	720	$1,833.7	$10,340	0.33	Negative
PN-2	Agency Valley	High	1179	3941	$11,353.3	$9,626	0.33	Negative
MP-33	Rainbow Dam	Medium	190	998	$5,915.9	$31,116	0.32	Negative
UC-16	Brantley Dam	Medium	210	697	$1,991.3	$9,481	0.32	Negative
UC-187	Upper Stillwater Dam	Medium	581	1904	$6,064.5	$10,431	0.32	Negative
PN-43	Harper Dam	Low	434	1874	$5,901.2	$13,606	0.31	Negative
MP-3	Bradbury Dam	Medium	142	521	$3,093.8	$21,749	0.3	Negative
PN-58	Maxwell Dam	Medium	117	644	$2,075.4	$17,766	0.3	Negative
GP-132	Willow Creek Dam	High	272	863	$1,239.9	$14,980	0.29	Negative
PN-52	Little Wood River Dam	High	1493	4951	$17,931.2	$12,013	0.29	Negative
GP-144	Wyoming Canal - Station 1972	Low	285	1218	$4,237.5	$14,860	0.28	Negative
PN-105	Wild Horse - BIA	High	267	791	$2,873.0	$10,764	0.27	Negative
GP-37	Fort Shaw Diversion Dam	Medium	183	1111	$4,029.4	$22,014	0.26	Negative
GP-59	Jamestown Dam	High	113	338	$1,166.5	$10,338	0.25	Negative
MP-31	Putah Creek Dam	Medium	28	166	$1,047.7	$38,062	0.25	Negative
PN-20	Crane Prairie	High	306	1845	$7,751.3	$25,317	0.25	Negative
GP-58	James Diversion Dam	High	193	825	$3,357.8	$17,377	0.24	Negative
GP-68	Lake Sherburne Dam	Medium	898	1502	$5,934.4	$6,605	0.24	Negative
GP-122	Trenton Dam	High	208	570	$2,180.7	$10,461	0.24	Negative

Table E-1 Ranked Site Specific Results from Highest Benefit Cost Ratio to Lowest Benefit Cost Ratio With Green Incentives

Site ID	Site Name/Facility	Data Confidence Level	Installed Capacity (kW)	Annual Production (MWh)	Total Development Cost ($)	$/Installed Capacity	BC Ratio with Green	IRR with Green
PN-1	Agate Dam	High	89	264	$821.5	$9,267	0.24	Negative
UC-102	Nambe Falls Dam	Low	147	593	$2,373.7	$16,097	0.24	Negative
GP-98	Pishkun Dike - No. 4	High	610	1399	$5,574.0	$9,141	0.23	Negative
GP-35	Enders Dam	High	267	762	$3,492.3	$13,082	0.22	Negative
UC-23	Currant Creek Dam	High	146	1003	$4,611.2	$31,659	0.22	Negative
UC-100	Moon Lake Dam	High	634	1563	$7,328.5	$11,564	0.22	Negative
GP-60	Johnson Project, Greenfield Main Canal Drop	Medium	203	525	$2,038.9	$10,052	0.21	Negative
MP-1	Anderson-Rose Dam	Medium	29	126	$377.7	$12,916	0.21	Negative
MP-44	Upper Slaven Dam	Medium	158	720	$3,474.0	$21,974	0.21	Negative
UC-28	Dolores Tunnel	Medium	103	515	$2,277.1	$22,077	0.21	Negative
UC-169	Stillwater Tunnel	Medium	413	1334	$6,342.4	$15,340	0.21	Negative
PN-10	Bumping Lake	High	521	2200	$11,275.7	$21,650	0.2	Negative
PN-24	Deadwood Dam	High	871	3563	$19,510.1	$22,402	0.2	Negative
UC-84	Lost Creek Dam	High	410	1295	$6,599.2	$16,082	0.2	Negative
PN-53	Lytle Creek	Low	50	329	$1,603.2	$32,368	0.19	Negative
UC-98	Montrose and Delta Canal	Low	96	478	$2,343.8	$24,452	0.19	Negative
PN-37	Fish Lake	High	102	235	$1,176.0	$11,555	0.18	Negative
UC-44	Fort Sumner Diversion Dam	High	75	378	$2,213.6	$29,472	0.17	Negative
PN-65	Ochoco Dam	High	69	232	$1,286.3	$18,532	0.16	Negative
UC-15	Blanco Tunnel	Medium	276	849	$5,526.7	$20,041	0.16	Negative
GP-12	Bonny Dam	High	36	238	$1,476.8	$40,837	0.15	Negative
GP-38	Foss Dam	Low	49	242	$1,646.7	$33,582	0.14	Negative
MP-15	Gerber Dam	Medium	248	760	$5,358.0	$21,621	0.14	Negative
PN-100	Unity Dam	Medium	307	1329	$9,462.0	$30,808	0.14	Negative
UC-196	Weber-Provo Canal	Low	424	1844	$14,266.2	$33,648	0.14	Negative
GP-63	Kirwin Dam	High	179	466	$3,578.9	$20,036	0.13	Negative
GP-143	Wyoming Canal - Station 1626	Low	52	195	$1,337.4	$25,531	0.13	Negative
PN-9	Bully Creek	High	313	1065	$8,062.9	$25,773	0.13	Negative
GP-14	Bretch Diversion Canal	Low	24	111	$712.3	$29,778	0.12	Negative
GP-102	Red Willow Dam	High	21	148	$780.7	$37,427	0.12	Negative
PN-78	Reservoir "A"	High	45	169	$1,262.2	$27,968	0.12	Negative
UC-4	Angostura Diversion	High	33	91	$564.2	$17,183	0.12	Negative
UC-5	Arthur V. Watkins Dam	High	31	122	$966.1	$31,426	0.11	Negative
GP-51	Helena Valley Dam	High	126	152	$1,069.4	$8,485	0.1	Negative
UC-7	Azeotea Creek and Willow Creek Conveyance Channel	Low	72	240	$2,215.3	$30,674	0.1	Negative

Table E-1 Ranked Site Specific Results from Highest Benefit Cost Ratio to Lowest Benefit Cost Ratio With Green Incentives

Site ID	Site Name/Facility	Data Confidence Level	Installed Capacity (kW)	Annual Production (MWh)	Total Development Cost ($)	$/Installed Capacity	BC Ratio with Green	IRR with Green
	Station 1565+00							
UC-8	Azeotea Creek and Willow Creek Conveyance Channel Station 1702+75	Low	68	223	$2,193.0	$32,238	0.1	Negative
UC-13	Big Sandy Dam	Medium	286	884	$9,260.7	$32,416	0.1	Negative
PN-15	Cold Springs Dam	High	66	131	$1,308.8	$19,942	0.09	Negative
UC-9	Azeotea Creek and Willow Creek Conveyance Channel Station 1831+17	Low	60	199	$2,149.4	$35,760	0.09	Negative
UC-11	Azotea Tunnel	High	86	222	$2,284.4	$26,649	0.09	Negative
UC-164	Stateline Dam	High	282	720	$8,492.4	$30,145	0.09	Negative
GP-29	Dickinson Dam	High	7	31	$229.3	$32,329	0.07	Negative
GP-85	Nelson Dikes DA	High	48	116	$1,479.3	$30,895	0.07	Negative
GP-131	Whalen Diversion Dam	Low	15	53	$549.3	$35,641	0.07	Negative
MP-23	Malone Diversion Dam	Medium	44	147	$1,835.6	$41,464	0.07	Negative
UC-56	Hammond Diversion Dam	Medium	35	148	$1,983.3	$57,350	0.07	Negative
UC-59	Huntington North Dam	High	20	51	$514.4	$25,611	0.07	Negative
GP-130	Webster Dam	High	66	164	$2,694.5	$40,704	0.06	Negative
UC-46	Fruitgrowers Dam	High	29	124	$2,116.5	$72,409	0.06	Negative
GP-91	Norton Dam	High	6	24	$232.0	$39,495	0.05	Negative
UC-137	Selig Canal	Low	23	98	$1,868.6	$82,287	0.05	Negative
GP-67	Lake Alice No. 2 Dam	Medium	18	50	$1,254.1	$69,333	0.04	Negative
UC-135	San Acacia Diversion Dam	Medium	20	86	$1,895.0	$94,272	0.04	Negative
UC-197	Weber-Provo Diversion Canal	Medium	173	517	$13,771.4	$79,382	0.04	Negative
UC-14	Blanco Diversion Dam	Medium	47	146	$4,656.2	$98,200	0.03	Negative
GP-4	Anchor Dam	High	62	126	$5,656.5	$90,738	0.02	Negative

Table E-2 Ranked Site Specific Results from Highest Benefit Cost Ratio to Lowest Benefit Cost Ratio Without Green Incentives

Site ID	Site Name/Facility	Data Confidence Level	Installed Capacity (kW)	Annual Production (MWh)	Total Development Cost ($)	$/Installed Capacity	BC Ratio without Green	IRR without Green
GP-146	Yellowtail Afterbay Dam	Medium	9203	68261	$19,852.4	$2,157	2.86	16.1%
UC-141	Sixth Water Flow Control	Medium	25800	114420	$38,227.9	$1,482	2.84	15.3%
GP-125	Twin Buttes Dam	Low	23124	97457	$33,654.2	$1,455	2.46	14.2%
LC-6	Bartlett Dam	Medium	7529	36880	$15,120.0	$2,008	2.25	12.0%
UC-185	Upper Diamond Fork Flow Control Structure	Medium	12214	52161	$22,058.5	$1,806	2.22	12.2%
GP-99	Pueblo Dam	High	13027	55620	$22,193.9	$1,704	2.2	12.5%
LC-20	Horseshoe Dam	Low	13857	59854	$30,123.0	$2,174	1.93	11.0%
PN-6	Arthur R. Bowman Dam	High	3293	18282	$8,994.9	$2,732	1.79	10.0%
UC-89	M&D Canal-Shavano Falls	Low	2862	15419	$7,260.4	$2,536	1.77	10.1%
GP-56	Huntley Diversion Dam	Medium	2426	17430	$8,361.0	$3,446	1.74	9.7%
PN-31	Easton Diversion Dam	High	1057	7400	$4,006.9	$3,792	1.58	8.8%
UC-159	Spanish Fork Flow Control Structure	Medium	8114	22920	$13,147.5	$1,620	1.57	8.6%
GP-46	Gray Reef Dam	High	2067	13059	$8,159.3	$3,947	1.49	7.8%
UC-49	Grand Valley Diversion Dam	Medium	1979	14246	$9,070.0	$4,584	1.45	7.7%
UC-52	Gunnison Tunnel	Medium	3830	19057	$11,385.5	$2,972	1.45	7.9%
GP-23	Clark Canyon Dam	High	3078	13689	$7,923.7	$2,575	1.42	7.6%
UC-19	Caballo Dam	Low	3260	15095	$10,197.9	$3,128	1.36	7.1%
PN-95	Sunnyside Dam	Medium	1362	10182	$6,912.0	$5,075	1.35	7.0%
UC-147	South Canal, Sta. 181+10, "Site #4"	Medium	3046	15536	$9,975.1	$3,275	1.35	7.2%
UC-144	Soldier Creek Dam	High	444	2909	$1,790.2	$4,033	1.31	7.0%
GP-52	Helena Valley Pumping Plant	High	2626	9608	$5,568.1	$2,120	1.29	6.8%
UC-131	Ridgway Dam	High	3366	14040	$9,885.1	$2,937	1.27	6.5%
UC-146	South Canal, Sta 19+ 10 "Site #1"	Medium	2465	12576	$8,883.4	$3,603	1.24	6.3%
GP-41	Gibson Dam	High	8521	30774	$19,928.0	$2,339	1.23	6.2%
UC-51	Gunnison Diversion Dam	Medium	1435	9220	$6,934.9	$4,832	1.2	6.0%
PN-88	Scootney Wasteway	Low	2276	11238	$8,014.4	$3,521	1.18	5.9%
UC-150	South Canal, Sta.106+65, "Site #3"	Medium	2224	11343	$8,399.7	$3,777	1.18	5.9%
GP-126	Twin Lakes Dam (USBR)	High	981	5648	$4,192.7	$4,274	1.17	5.8%
GP-95	Pathfinder Dam	High	743	5508	$4,476.4	$6,022	1.16	5.6%
UC-162	Starvation Dam	High	3043	13168	$10,530.6	$3,461	1.15	5.6%
GP-43	Granby Dam	High	484	2854	$2,144.1	$4,426	1.09	5.2%

Table E-2 Ranked Site Specific Results from Highest Benefit Cost Ratio to Lowest Benefit Cost Ratio Without Green Incentives

Site ID	Site Name/Facility	Data Confidence Level	Installed Capacity (kW)	Annual Production (MWh)	Total Development Cost ($)	$/Installed Capacity	BC Ratio without Green	IRR without Green
MP-30	Prosser Creek Dam	High	872	3819	$3,119.0	$3,576	1.06	4.9%
LC-21	Imperial Dam	Low	1079	5325	$4,617.5	$4,280	1.05	5.0%
UC-179	Taylor Park Dam	High	2543	12488	$10,991.2	$4,323	1.05	4.8%
GP-136	Willwood Diversion Dam	High	1062	6337	$5,741.7	$5,407	1.03	4.6%
GP-93	Pactola Dam	High	596	2725	$2,207.5	$3,706	1.01	4.5%
UC-57	Heron Dam	Medium	2701	8874	$8,020.4	$2,970	1	4.4%
UC-154	Southside Canal, Sta 171+ 90 thru 200+ 67 (2 canal drops)	Low	2026	6557	$5,595.9	$2,762	0.99	4.2%
UC-148	South Canal, Sta. 472+00, "Site #5"	Medium	1354	6905	$6,155.4	$4,548	0.98	4.2%
PN-34	Emigrant Dam	High	733	2619	$2,209.7	$3,013	0.93	3.7%
UC-177	Syar Tunnel	Medium	1762	7982	$8,246.1	$4,680	0.93	3.8%
PN-104	Wickiup Dam	High	3950	15650	$15,178.6	$3,843	0.92	3.7%
UC-174	Sumner Dam	Medium	822	4300	$4,193.5	$5,103	0.92	3.7%
GP-34	East Portal Diversion Dam	High	283	1799	$1,553.3	$5,495	0.9	3.3%
MP-2	Boca Dam	High	1184	4370	$4,393.0	$3,711	0.89	3.4%
PN-12	Cle Elum Dam	High	7249	14911	$13,692.3	$1,889	0.89	3.3%
PN-80	Ririe Dam	High	993	3778	$3,636.9	$3,661	0.89	3.3%
UC-155	Southside Canal, Sta 349+ 05 thru 375+ 42 (3 canal drops)	Low	1651	5344	$5,169.8	$3,131	0.88	3.2%
PN-87	Scoggins Dam	High	955	3683	$3,665.4	$3,838	0.86	3.1%
UC-132	Rifle Gap Dam	High	341	1740	$1,574.9	$4,621	0.86	2.9%
GP-5	Angostura Dam	Low	947	3218	$3,179.2	$3,358	0.84	2.8%
MP-8	Casitas Dam	High	1042	3280	$3,298.9	$3,165	0.84	2.8%
PN-59	McKay Dam	High	1362	4344	$4,274.0	$3,138	0.83	2.7%
GP-39	Fresno Dam	High	1661	6268	$6,013.9	$3,620	0.82	2.7%
GP-128	Vandalia Diversion Dam	Medium	326	1907	$1,779.4	$5,461	0.82	2.5%
GP-129	Virginia Smith Dam	Low	1607	9799	$11,467.6	$7,137	0.82	2.8%
PN-49	Keechelus Dam	High	2394	6746	$6,774.2	$2,830	0.81	2.5%
PN-44	Haystack	High	805	3738	$3,916.4	$4,866	0.8	2.4%
UC-72	Joes Valley Dam	High	1624	6596	$7,764.3	$4,780	0.8	2.6%
UC-145	South Canal Tunnels	Medium	884	4497	$5,005.8	$5,665	0.79	2.4%
MP-24	Marble Bluff Dam	High	1153	5624	$6,854.2	$5,943	0.78	2.4%
GP-92	Olympus Dam	High	284	1549	$1,552.4	$5,472	0.77	1.9%
GP-117	St. Mary Canal - Drop 4	High	2569	8919	$9,599.7	$3,736	0.77	2.2%
GP-42	Glen Elder Dam	High	1008	3713	$4,260.6	$4,229	0.76	2.0%

Table E-2 Ranked Site Specific Results from Highest Benefit Cost Ratio to Lowest Benefit Cost Ratio Without Green Incentives

Site ID	Site Name/Facility	Data Confidence Level	Installed Capacity (kW)	Annual Production (MWh)	Total Development Cost ($)	$/Installed Capacity	BC Ratio without Green	IRR without Green
LC-15	Gila Gravity Main Canal Headworks	Medium	223	1548	$1,702.6	$7,632	0.75	2.0%
UC-117	Paonia Dam	Medium	1582	5821	$7,092.5	$4,482	0.74	1.9%
PN-48	Kachess Dam	Medium	1227	3877	$4,335.9	$3,535	0.72	1.5%
GP-118	St. Mary Canal - Drop 5	High	1901	7586	$9,154.5	$4,817	0.7	1.4%
PN-57	Mason Dam	High	1649	5773	$7,276.4	$4,414	0.68	1.1%
UC-166	Steinaker Dam	High	603	1965	$2,388.4	$3,959	0.67	0.7%
GP-135	Willwood Canal	Medium	687	3134	$4,452.3	$6,481	0.66	1.0%
GP-22	Choke Canyon Dam	Low	194	1199	$1,506.0	$7,755	0.65	0.3%
GP-76	Merritt Dam	Low	1631	8438	$12,641.1	$7,752	0.64	0.9%
MP-32	Putah Diversion Dam	Medium	363	1924	$2,815.3	$7,745	0.62	0.2%
PN-101	Warm Springs Dam	High	1234	3256	$4,326.6	$3,507	0.62	0.1%
GP-141	Wyoming Canal - Station 1490	Low	538	2305	$3,249.5	$6,042	0.61	Negative
GP-50	Heart Butte Dam	High	294	1178	$1,562.5	$5,315	0.6	Negative
GP-120	Sun River Diversion Dam	High	2015	8645	$12,611.4	$6,259	0.6	0.4%
PN-97	Thief Valley Dam	Medium	369	1833	$2,601.0	$7,050	0.6	Negative
UC-22	Crawford Dam	High	303	1217	$1,592.4	$5,264	0.6	Negative
GP-24	Corbett Diversion Dam	High	638	2846	$4,782.3	$7,500	0.56	Negative
UC-126	Red Fleet Dam	High	455	1904	$3,031.9	$6,666	0.55	Negative
UC-140	Silver Jack Dam	High	748	2913	$4,863.9	$6,504	0.54	Negative
GP-18	Carter Lake Dam No. 1	High	842	2266	$3,642.7	$4,328	0.53	Negative
GP-138	Woods Project, Greenfield Main Canal Drop	Low	746	2680	$4,131.6	$5,540	0.53	Negative
PN-41	Golden Gate Canal	Low	514	2293	$3,991.6	$7,771	0.53	Negative
GP-114	St. Mary Canal - Drop 1	High	1212	4838	$7,901.8	$6,518	0.52	Negative
PN-56	Mann Creek	High	495	2097	$3,554.4	$7,174	0.52	Negative
UC-116	Outlet Canal	Medium	586	1839	$3,264.8	$5,570	0.49	Negative
GP-137	Wind River Diversion Dam	High	398	1595	$2,921.2	$7,344	0.48	Negative
MP-17	John Franchi Dam	Low	469	1863	$3,624.5	$7,728	0.48	Negative
UC-190	Vega Dam	Medium	548	1702	$3,012.5	$5,499	0.48	Negative
GP-115	St. Mary Canal - Drop 2	High	974	3887	$7,141.0	$7,333	0.47	Negative
GP-10	Belle Fourche Dam	High	497	1319	$2,376.3	$4,786	0.46	Negative
GP-145	Wyoming Canal - Station 997	Low	287	1228	$2,224.9	$7,751	0.46	Negative
GP-116	St. Mary Canal - Drop 3	High	887	3538	$6,832.5	$7,707	0.44	Negative
GP-108	Shadow Mountain Dam	High	119	777	$1,471.5	$12,316	0.43	Negative
UC-136	Scofield Dam	High	266	906	$1,780.5	$6,700	0.42	Negative

Table E-2 Ranked Site Specific Results from Highest Benefit Cost Ratio to Lowest Benefit Cost Ratio Without Green Incentives

Site ID	Site Name/Facility	Data Confidence Level	Installed Capacity (kW)	Annual Production (MWh)	Total Development Cost ($)	$/Installed Capacity	BC Ratio without Green	IRR without Green
GP-75	Medicine Creek Dam	High	276	1001	$2,103.6	$7,631	0.41	Negative
LC-24	Laguna Dam	Low	125	566	$1,100.0	$8,794	0.41	Negative
UC-36	East Canyon Dam	High	929	3549	$8,271.6	$8,907	0.41	Negative
GP-28	Deerfield Dam	High	138	694	$1,392.4	$10,109	0.4	Negative
UC-6	Avalon Dam	High	230	1031	$2,260.8	$9,818	0.4	Negative
GP-15	Bull Lake Dam	High	933	2302	$5,327.8	$5,709	0.39	Negative
GP-140	Wyoming Canal - Station 1016	Low	220	939	$2,036.0	$9,275	0.39	Negative
UC-93	Meeks Cabin Dam	High	1586	4709	$11,641.2	$7,341	0.38	Negative
GP-31	Dodson Diversion Dam	Low	140	566	$1,106.9	$7,895	0.37	Negative
UC-62	Hyrum Dam	High	491	2052	$5,081.3	$10,346	0.37	Negative
UC-124	Platoro Dam	High	845	3747	$10,106.2	$11,964	0.36	Negative
GP-107	Shadehill Dam	High	322	1536	$4,128.1	$12,806	0.35	Negative
GP-47	Greenfield Project, Greenfield Main Canal Drop	Low	238	830	$1,848.6	$7,779	0.34	Negative
MP-18	Lake Tahoe Dam	High	287	893	$2,494.8	$8,686	0.34	Negative
GP-8	Barretts Diversion Dam	Medium	102	546	$1,391.4	$13,596	0.33	Negative
GP-54	Horsetooth Dam	High	350	847	$2,202.8	$6,288	0.32	Negative
GP-142	Wyoming Canal - Station 1520	Low	175	749	$2,002.2	$11,454	0.32	Negative
UC-67	Inlet Canal	Medium	252	966	$2,596.6	$10,320	0.32	Negative
PN-2	Agency Valley	High	1179	3941	$11,353.3	$9,626	0.31	Negative
UC-187	Upper Stillwater Dam	Medium	581	1904	$6,064.5	$10,431	0.31	Negative
GP-103	Saint Mary Diversion Dam	High	177	720	$1,833.7	$10,340	0.3	Negative
UC-16	Brantley Dam	Medium	210	697	$1,991.3	$9,481	0.3	Negative
PN-43	Harper Dam	Low	434	1874	$5,901.2	$13,606	0.29	Negative
PN-58	Maxwell Dam	Medium	117	644	$2,075.4	$17,766	0.28	Negative
GP-132	Willow Creek Dam	High	272	863	$1,239.9	$14,980	0.27	Negative
PN-52	Little Wood River Dam	High	1493	4951	$17,931.2	$12,013	0.27	Negative
GP-144	Wyoming Canal - Station 1972	Low	285	1218	$4,237.5	$14,860	0.26	Negative
PN-105	Wild Horse - BIA	High	267	791	$2,873.0	$10,764	0.26	Negative
GP-37	Fort Shaw Diversion Dam	Medium	183	1111	$4,029.4	$22,014	0.25	Negative
GP-58	James Diversion Dam	High	193	825	$3,357.8	$17,377	0.23	Negative
GP-59	Jamestown Dam	High	113	338	$1,166.5	$10,338	0.23	Negative
GP-122	Trenton Dam	High	208	570	$2,180.7	$10,461	0.23	Negative
PN-20	Crane Prairie	High	306	1845	$7,751.3	$25,317	0.23	Negative
UC-102	Nambe Falls Dam	Low	147	593	$2,373.7	$16,097	0.23	Negative
GP-68	Lake Sherburne Dam	Medium	898	1502	$5,934.4	$6,605	0.22	Negative

Table E-2 Ranked Site Specific Results from Highest Benefit Cost Ratio to Lowest Benefit Cost Ratio Without Green Incentives

Site ID	Site Name/Facility	Data Confidence Level	Installed Capacity (kW)	Annual Production (MWh)	Total Development Cost ($)	$/Installed Capacity	BC Ratio without Green	IRR without Green
GP-98	Pishkun Dike - No. 4	High	610	1399	$5,574.0	$9,141	0.22	Negative
PN-1	Agate Dam	High	89	264	$821.5	$9,267	0.22	Negative
UC-23	Currant Creek Dam	High	146	1003	$4,611.2	$31,659	0.21	Negative
GP-35	Enders Dam	High	267	762	$3,492.3	$13,082	0.2	Negative
GP-60	Johnson Project, Greenfield Main Canal Drop	Medium	203	525	$2,038.9	$10,052	0.2	Negative
MP-1	Anderson-Rose Dam	Medium	29	126	$377.7	$12,916	0.2	Negative
MP-44	Upper Slaven Dam	Medium	158	720	$3,474.0	$21,974	0.2	Negative
UC-28	Dolores Tunnel	Medium	103	515	$2,277.1	$22,077	0.2	Negative
UC-100	Moon Lake Dam	High	634	1563	$7,328.5	$11,564	0.2	Negative
UC-169	Stillwater Tunnel	Medium	413	1334	$6,342.4	$15,340	0.2	Negative
PN-10	Bumping Lake	High	521	2200	$11,275.7	$21,650	0.19	Negative
PN-24	Deadwood Dam	High	871	3563	$19,510.1	$22,402	0.19	Negative
UC-84	Lost Creek Dam	High	410	1295	$6,599.2	$16,082	0.19	Negative
PN-53	Lytle Creek	Low	50	329	$1,603.2	$32,368	0.18	Negative
UC-98	Montrose and Delta Canal	Low	96	478	$2,343.8	$24,452	0.18	Negative
MP-33	Rainbow Dam	Medium	190	998	$5,915.9	$31,116	0.17	Negative
PN-37	Fish Lake	High	102	235	$1,176.0	$11,555	0.17	Negative
MP-3	Bradbury Dam	Medium	142	521	$3,093.8	$21,749	0.16	Negative
UC-44	Fort Sumner Diversion Dam	High	75	378	$2,213.6	$29,472	0.16	Negative
PN-65	Ochoco Dam	High	69	232	$1,286.3	$18,532	0.15	Negative
UC-15	Blanco Tunnel	Medium	276	849	$5,526.7	$20,041	0.15	Negative
GP-12	Bonny Dam	High	36	238	$1,476.8	$40,837	0.14	Negative
GP-38	Foss Dam	Low	49	242	$1,646.7	$33,582	0.13	Negative
MP-15	Gerber Dam	Medium	248	760	$5,358.0	$21,621	0.13	Negative
MP-31	Putah Creek Dam	Medium	28	166	$1,047.7	$38,062	0.13	Negative
PN-100	Unity Dam	Medium	307	1329	$9,462.0	$30,808	0.13	Negative
UC-196	Weber-Provo Canal	Low	424	1844	$14,266.2	$33,648	0.13	Negative
GP-63	Kirwin Dam	High	179	466	$3,578.9	$20,036	0.12	Negative
GP-102	Red Willow Dam	High	21	148	$780.7	$37,427	0.12	Negative
GP-143	Wyoming Canal - Station 1626	Low	52	195	$1,337.4	$25,531	0.12	Negative
PN-9	Bully Creek	High	313	1065	$8,062.9	$25,773	0.12	Negative
GP-14	Bretch Diversion Canal	Low	24	111	$712.3	$29,778	0.11	Negative
PN-78	Reservoir "A"	High	45	169	$1,262.2	$27,968	0.11	Negative
UC-4	Angostura Diversion	High	33	91	$564.2	$17,183	0.11	Negative
UC-5	Arthur V. Watkins Dam	High	31	122	$966.1	$31,426	0.1	Negative

Table E-2 Ranked Site Specific Results from Highest Benefit Cost Ratio to Lowest Benefit Cost Ratio Without Green Incentives

Site ID	Site Name/Facility	Data Confidence Level	Installed Capacity (kW)	Annual Production (MWh)	Total Development Cost ($)	$/Installed Capacity	BC Ratio without Green	IRR without Green
UC-7	Azeotea Creek and Willow Creek Conveyance Channel Station 1565+00	Low	72	240	$2,215.3	$30,674	0.1	Negative
GP-51	Helena Valley Dam	High	126	152	$1,069.4	$8,485	0.09	Negative
UC-8	Azeotea Creek and Willow Creek Conveyance Channel Station 1702+75	Low	68	223	$2,193.0	$32,238	0.09	Negative
UC-11	Azotea Tunnel	High	86	222	$2,284.4	$26,649	0.09	Negative
UC-13	Big Sandy Dam	Medium	286	884	$9,260.7	$32,416	0.09	Negative
PN-15	Cold Springs Dam	High	66	131	$1,308.8	$19,942	0.08	Negative
UC-9	Azeotea Creek and Willow Creek Conveyance Channel Station 1831+17	Low	60	199	$2,149.4	$35,760	0.08	Negative
UC-164	Stateline Dam	High	282	720	$8,492.4	$30,145	0.08	Negative
MP-23	Malone Diversion Dam	Medium	44	147	$1,835.6	$41,464	0.07	Negative
UC-56	Hammond Diversion Dam	Medium	35	148	$1,983.3	$57,350	0.07	Negative
UC-59	Huntington North Dam	High	20	51	$514.4	$25,611	0.07	Negative
GP-29	Dickinson Dam	High	7	31	$229.3	$32,329	0.06	Negative
GP-85	Nelson Dikes DA	High	48	116	$1,479.3	$30,895	0.06	Negative
GP-130	Webster Dam	High	66	164	$2,694.5	$40,704	0.06	Negative
GP-131	Whalen Diversion Dam	Low	15	53	$549.3	$35,641	0.06	Negative
GP-91	Norton Dam	High	6	24	$232.0	$39,495	0.05	Negative
UC-46	Fruitgrowers Dam	High	29	124	$2,116.5	$72,409	0.05	Negative
UC-137	Selig Canal	Low	23	98	$1,868.6	$82,287	0.05	Negative
UC-135	San Acacia Diversion Dam	Medium	20	86	$1,895.0	$94,272	0.04	Negative
UC-197	Weber-Provo Diversion Canal	Medium	173	517	$13,771.4	$79,382	0.04	Negative
GP-67	Lake Alice No. 2 Dam	Medium	18	50	$1,254.1	$69,333	0.03	Negative
UC-14	Blanco Diversion Dam	Medium	47	146	$4,656.2	$98,200	0.03	Negative
GP-4	Anchor Dam	High	62	126	$5,656.5	$90,738	0.02	Negative

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Table E-3
Great Plains Region Model Results

Facility Name		A-Drop Project, Greenfield Main Canal Drop	Altus Dam	Anchor Dam	Angostura Dam	Barretts Diversion Dam	Belle Fourche Dam	Bonny Dam	Box Butte Dam	Bretch Diversion Canal
Agency		Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation
Analysis Performed by		CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM
Project Location (State)		Montana	Oklahoma	Wyoming	South Dakota	Montana	South Dakota	Colorado	Nebraska	Oklahoma
Transmission Voltage	kV	115	115	115	69	138	69	115	115	115
T-Line Length	miles	2.48	5.17	15.95	1.01	1.44	0.35	3.58	5.58	1.34
Fish and Wildlife Mitigation		No	No	No	No	No	No	No	No	No
Recreation Mitigation		No	No	No	No	No	No	No	No	No
Historical & Archaeological		No	No	Yes	No	No	No	No	No	No
Water Quality Monitoring		No	No	No	No	Yes	No	No	No	No
Fish Passage Required		No	No	No	No	No	No	No	No	No
Results										
Input Data Analysis										
Data Set	years	6	20	43	53	9	22	30	4	13
Max Head	ft	34.0	178.9	123.5	124.2	15.5	55.9	74.4	38.1	7.7
Min Head	ft	34.0	0.0	9.3	97.7	15.5	14.7	48.0	14.0	7.7
Max Flow	cfs	3,842	5,860	377	23,525	471	945	133	167	21,100
Min Flow	cfs	0	0	0	0	0	0	3	0	0
Turbine Selection Analysis		Site has seasonal flows about 4 months per year; flows are too low for hydropower development at 30% flow exceedance	Site has seasonal flows about 2 months per year; flows are too low for hydropower development at 30% flow exceedance						Site has seasonal flows about 1-2 months per year; flows are too low for hydropower development at 30% flow exceedance	
Selected Turbine Type				Low Head	Francis	Kaplan	Kaplan	Low Head		Low Head
Selected Design Head	ft			60	119	15	50	70		8
Selected Design Flow	cfs			17	110	106	160	8		51
Generator Speed	rpm			600	600	600	600	600		600
Max Head Limit	ft			75.3	148.9	19.3	62.0	87.8		9.6
Min Head Limit	ft			39.1	77.4	10.1	32.3	45.7		5.0
Max Flow Limit	cfs			17	110	106	160	8		51
Min Flow Limit	cfs			3	22	21	32	2		10
Power Generation Analysis										
Installed Capacity	kW			62	947	102	497	36		24
Plant Factor				0.23	0.40	0.62	0.31	0.77		0.54
Projected Monthly Production:										
January	MWH			1	44	79	0	18		9
February*	MWH			1	59	70	0	18		9
March	MWH			3	144	81	6	19		10
April	MWH			13	169	81	23	19		11
May	MWH			23	401	0	131	21		11
June	MWH			17	518	0	327	21		14
July	MWH			16	655	0	366	22		9
August	MWH			14	642	0	276	22		6
September	MWH			15	439	0	182	21		8
October	MWH			12	66	74	8	20		8
November	MWH			6	43	82	0	18		9
December	MWH			3	37	79	0	18		9
Annual production*	MWH			126	3,218	546	1,319	238		111

* For non-leap year

Benefit/Cost Analysis										
Projected expenditure to implement project										
Total Construction Cost				$ 5,656,540	$ 3,179,239	$ 1,391,365	$ 2,376,313	$ 1,476,827		$ 712,303
Annual O&M Cost				$ 130,033	$ 121,373	$ 49,861	$ 90,474	$ 50,721		$ 35,664
Projected Total Cost over 50 year period				$ 7,459,993	$ 5,033,810	$ 2,146,281	$ 3,758,228	$ 2,239,764		$ 1,275,339
Projected revenue after implementation of project										
Power generation income for 2014 to 2060				$ 451,407	$ 11,936,970	$ 1,993,322	$ 4,891,813	$ 851,997		$ 409,255
Green Energy Sellback income for 2014 to 2060				$ 15,202	$ 389,396	$ 66,111	$ 159,657	$ 28,777		$ 13,453
Projected Total Revenue over 50 year period (with Green Incentives)				$ 170,867	$ 4,505,953	$ 751,998	$ 1,846,892	$ 324,805		$ 154,571
Projected Total Revenue over 50 year period (w/o Green Incentives)				$ 160,432	$ 4,238,654	$ 706,617	$ 1,737,296	$ 305,052		$ 145,336
Benefit/Cost Ratio (with Green incentives)				0.02	0.90	0.35	0.49	0.15		0.12
Benefit/Cost Ratio (w/o Green incentives)				0.02	0.84	0.33	0.46	0.14		0.11
Internal Rate of Return (with Green incentives)				Negative	3.3%	Negative	Negative	Negative		Negative
Internal Rate of Return (w/o Green incentives)				Negative	2.8%	Negative	Negative	Negative		Negative
Installed Cost $ per kW				$ 90,738	$ 3,358	$ 13,596	$ 4,786	$ 40,837		$ 29,778

Table E-3
Great Plains Region Model Results

Facility Name		Bull Lake Dam	Carter Lake Dam No. 1	Cedar Bluff Dam	Cheney Dam	Choke Canyon Dam	Clark Canyon Dam	Corbett Diversion Dam	Deerfield Dam	Dickinson Dam
Agency		Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation
Analysis Performed by		CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM
Project Location (State)		Wyoming	Colorado	Kansas	Kansas	Texas	Montana	Wyoming	South Dakota	North Dakota
Transmission Voltage	kV	69	13.8	115	138	138	138	69	69	69
T-Line Length	miles	4.68	3.17	10.68	7.13	1.44	0.33	2.80	1.70	0.26
Fish and Wildlife Mitigation		No	No	No	No	No	No	No	No	No
Recreation Mitigation		No	No	No	No	No	No	No	No	No
Historical & Archaeological		Yes	No	No	No	No	No	No	No	Yes
Water Quality Monitoring		No	No	No	No	No	Yes	No	No	No
Fish Passage Required		No	No	No	No	No	No	Yes	No	No
Results										
Input Data Analysis										
Data Set	years	37	28	18	30	17	41	9	30	53
Max Head	ft	65.3	154.1	131.7	39.4	82.3	110.7	12.0	109.1	31.7
Min Head	ft	12.3	57.1	49.8	26.0	16.8	36.0	12.0	39.2	17.6
Max Flow	cfs	3,091	613	400	1,750	1,820	2,586	7,447	85	4,531
Min Flow	cfs	0	0	0	0	0	23	0	0	0
Turbine Selection Analysis				Site has seasonal flows about 1-2 months per year; flows are too low for hydropower development at 30% flow exceedance						
Selected Turbine Type		Kaplan	Francis		Low Head	Francis	Francis	Kaplan	Francis	Low Head
Selected Design Head	ft	50	142		32	71	88	12	107	27
Selected Design Flow	cfs	299	82		2	38	484	850	18	4
Generator Speed	rpm	600	600		600	600	300	600	600	600
Max Head Limit	ft	62.3	177.5		39.7	88.4	110.1	15.0	133.4	33.8
Min Head Limit	ft	32.4	92.3		20.6	46.0	57.2	7.8	69.4	17.6
Max Flow Limit	cfs	299	82		2	38	484	850	18	4
Min Flow Limit	cfs	60	16		0	8	97	170	4	1
Power Generation Analysis										
Installed Capacity	kW	933	842		3	194	3,078	638	138	7
Plant Factor		0.29	0.31		0.48	0.72	0.52	0.52	0.59	0.51
Projected Monthly Production:										
January	MWH	28	0		1	95	744	0	32	1
February*	MWH	18	0		1	91	683	0	32	2
March	MWH	18	1		1	97	688	0	52	3
April	MWH	95	204		1	98	832	194	81	3
May	MWH	267	339		2	103	1,566	496	82	3
June	MWH	324	332		2	99	1,926	501	76	4
July	MWH	269	503		1	107	1,900	519	72	4
August	MWH	563	436		1	105	1,596	515	73	3
September	MWH	536	297		1	106	1,107	476	66	2
October	MWH	129	146		1	100	862	145	56	2
November	MWH	31	3		1	101	917	0	40	2
December	MWH	25	4		1	99	866	0	31	2
Annual production*	MWH	2,302	2,266		12	1,199	13,689	2,846	694	31
* For non-leap year										
Benefit/Cost Analysis										
Projected expenditure to implement project										
Total Construction Cost		$ 5,327,772	$ 3,642,689		$ 2,721,996	$ 1,505,996	$ 7,923,658	$ 4,782,286	$ 1,392,415	$ 229,309
Annual O&M Cost		$ 160,581	$ 126,152		$ 72,015	$ 60,268	$ 261,195	$ 122,767	$ 55,272	$ 25,169
Projected Total Cost over 50 year period		$ 7,690,016	$ 5,542,710		$ 3,754,264	$ 2,432,812	$ 11,826,515	$ 6,530,462	$ 2,241,477	$ 648,939
Projected revenue after implementation of project										
Power generation income for 2014 to 2060		$ 8,356,187	$ 8,188,695		$ 44,087	$ 4,468,361	$ 47,458,776	$ 10,270,060	$ 2,555,791	$ 115,083
Green Energy Sellback income for 2014 to 2060		$ 278,570	$ 274,161		$ 1,458	$ 145,205	$ 1,656,940	$ 344,353	$ 83,969	$ 3,772
Projected Total Revenue over 50 year period (with Green Incentives)		$ 3,158,576	$ 3,119,104		$ 16,661	$ 1,685,896	$ 17,975,609	$ 3,885,070	$ 965,363	$ 43,458
Projected Total Revenue over 50 year period (w/o Green Incentives)		$ 2,967,353	$ 2,930,908		$ 15,660	$ 1,586,221	$ 16,838,213	$ 3,648,690	$ 907,723	$ 40,869
Benefit/Cost Ratio (with Green incentives)		0.41	0.56		0.00	0.69	1.52	0.59	0.43	0.07
Benefit/Cost Ratio (w/o Green incentives)		0.39	0.53		0.00	0.65	1.42	0.56	0.40	0.06
Internal Rate of Return (with Green incentives)		Negative	Negative		Negative	0.7%	8.6%	0.1%	Negative	Negative
Internal Rate of Return (w/o Green incentives)		Negative	Negative		Negative	0.3%	7.6%	Negative	Negative	Negative
Installed Cost $ per kW		$ 5,709	$ 4,328		$ 937,996	$ 7,755	$ 2,575	$ 7,500	$ 10,109	$ 32,329

Table E-3
Great Plains Region Model Results

Facility Name		Dodson Diversion Dam	East Portal Diversion Dam	Enders Dam	Fort Cobb Dam	Fort Shaw Diversion Dam	Foss Dam	Fresno Dam	Gibson Dam	Glen Elder Dam
Agency		Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation
Analysis Performed by		CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM
Project Location (State)		Montana	Colorado	Nebraska	Oklahoma	Montana	Oklahoma	Montana	Montana	Kansas
Transmission Voltage	kV	138	13.8	115	115	69	115	69	69	115
T-Line Length	miles	0.42	0.01	6.73	6.53	8.21	3.76	1.69	19.11	3.35
Fish and Wildlife Mitigation		No	No	No	No	No	No	No	No	No
Recreation Mitigation		No	No	No	No	No	No	No	No	No
Historical & Archaeological		Yes	No	No	No	No	No	No	No	No
Water Quality Monitoring		No	No	No	No	No	No	No	No	No
Fish Passage Required		No	No	No	No	No	No	No	No	No
Results										
Input Data Analysis										
Data Set	years	15	31	54	30	11	20	58	66	19
Max Head	ft	26.0	10.0	75.9	20.0	9.0	35.0	59.3	173.2	154.5
Min Head	ft	26.0	10.0	27.0	20.0	9.0	35.0	12.4	12.7	50.2
Max Flow	cfs	6,445	569	1,107	1,270	8,485	1,370	6,554	51,860	5,001
Min Flow	cfs	0	0	0	0	19	2	0	0	0
Turbine Selection Analysis										
Selected Turbine Type		Kaplan	Kaplan	Francis	Low Head	Kaplan	Low Head	Kaplan	Francis	Francis
Selected Design Head	ft	26	10	62	20	9	35	47	140	69
Selected Design Flow	cfs	86	452	60	5	325	23	560	845	201
Generator Speed	rpm	600	600	600	600	600	600	300	300	600
Max Head Limit	ft	32.5	12.5	77.6	25.0	11.3	43.8	59.3	174.4	86.8
Min Head Limit	ft	16.9	6.5	40.3	13.0	5.8	22.8	30.8	90.7	45.1
Max Flow Limit	cfs	86	452	60	5	325	23	560	845	201
Min Flow Limit	cfs	17	90	12	1	65	5	112	169	40
Power Generation Analysis										
Installed Capacity	kW	140	283	267	6	183	49	1,661	8,521	1,008
Plant Factor		0.47	0.74	0.33	0.72	0.71	0.58	0.44	0.42	0.43
Projected Monthly Production:										
January	MWH	30	199	35	3	138	22	10	477	398
February*	MWH	36	180	40	3	127	22	13	420	337
March	MWH	84	160	46	3	95	23	125	608	338
April	MWH	42	116	56	3	82	25	580	2,461	285
May	MWH	50	139	64	3	100	24	1,229	5,961	333
June	MWH	64	113	91	3	126	25	1,245	7,092	388
July	MWH	60	165	166	3	37	18	1,188	6,469	427
August	MWH	52	165	119	3	44	16	973	3,735	412
September	MWH	35	142	50	3	51	16	663	1,545	204
October	MWH	46	102	35	3	83	16	211	669	77
November	MWH	43	127	30	3	102	18	24	714	145
December	MWH	23	192	30	3	128	18	7	624	368
Annual production*	MWH	566	1,799	762	35	1,111	242	6,268	30,774	3,713

* For non-leap year

Benefit/Cost Analysis

Projected expenditure to implement project		Dodson Diversion Dam	East Portal Diversion Dam	Enders Dam	Fort Cobb Dam	Fort Shaw Diversion Dam	Foss Dam	Fresno Dam	Gibson Dam	Glen Elder Dam
Total Construction Cost		$ 1,106,914	$ 1,553,341	$ 3,492,274	$ 2,234,608	$ 4,029,441	$ 1,646,694	$ 6,013,912	$ 19,928,044	$ 4,260,608
Annual O&M Cost		$ 49,679	$ 65,877	$ 100,748	$ 62,458	$ 107,625	$ 54,840	$ 201,075	$ 636,482	$ 144,180
Projected Total Cost over 50 year period		$ 1,881,857	$ 2,573,970	$ 4,962,139	$ 3,140,177	$ 5,575,279	$ 2,467,519	$ 9,025,432	$ 29,388,034	$ 6,424,219
Projected revenue after implementation of project										
Power generation income for 2014 to 2060		$ 1,977,569	$ 6,468,602	$ 2,846,432	$ 128,953	$ 3,898,174	$ 895,831	$ 20,949,782	$ 101,971,549	$ 13,827,108
Green Energy Sellback income for 2014 to 2060		$ 68,480	$ 217,775	$ 92,201	$ 4,210	$ 134,556	$ 29,350	$ 758,381	$ 3,724,023	$ 449,513
Projected Total Revenue over 50 year period (with Green Incentives)		$ 748,580	$ 2,465,030	$ 1,073,808	$ 48,673	$ 1,475,461	$ 338,228	$ 7,961,798	$ 38,795,651	$ 5,216,360
Projected Total Revenue over 50 year period (w/o Green Incentives)		$ 701,572	$ 2,315,540	$ 1,010,517	$ 45,783	$ 1,383,096	$ 318,081	$ 7,441,211	$ 36,239,315	$ 4,907,794
Benefit/Cost Ratio (with Green incentives)		0.40	0.96	0.22	0.02	0.26	0.14	0.88	1.32	0.81
Benefit/Cost Ratio (w/o Green incentives)		0.37	0.90	0.20	0.01	0.25	0.13	0.82	1.23	0.76
Internal Rate of Return (with Green incentives)		Negative	3.9%	Negative	Negative	Negative	Negative	3.2%	7.1%	2.4%
Internal Rate of Return (w/o Green incentives)		Negative	3.3%	Negative	Negative	Negative	Negative	2.7%	6.2%	2.0%
Installed Cost $ per kW		$ 7,895	$ 5,495	$ 13,082	$ 398,748	$ 22,014	$ 33,582	$ 3,620	$ 2,339	$ 4,229

Table E-3
Great Plains Region Model Results

Facility Name		Granby Dam	Gray Reef Dam	Greenfield Project, Greenfield Main Canal Drop	Heart Butte Dam	Helena Valley Dam	Helena Valley Pumping Plant	Horsetooth Dam	Hunter Creek Diversion Dam	Huntley Diversion Dam
Agency		Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation
Analysis Performed by		CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM
Project Location (State)		Colorado	Wyoming	Montana	North Dakota	Montana	Montana	Colorado	Colorado	Montana
Transmission Voltage	kV	13.8	115	69	69	69	69	115	115	115
T-Line Length	miles	1.23	0.01	1.49	0.50	0.56	0.56	2.47	2.47	5.00
Fish and Wildlife Mitigation		Yes	No	No	No	No	No	No	No	No
Recreation Mitigation		No	No	No	No	No	No	No	Yes	No
Historical & Archaeological		No	No	No	No	No	No	No	No	No
Water Quality Monitoring		No	No	No	No	No	No	No	No	No
Fish Passage Required		No	Yes	No	No	No	No	No	No	No
Results										
Input Data Analysis										
Data Set	years	31	44	9	56	4	30	31	29	20
Max Head	ft	214.9	24.6	38.0	80.7	23.0	173.0	135.1	50.0	8.0
Min Head	ft	126.5	6.1	38.0	9.5	0.0	61.0	0.0	50.0	8.0
Max Flow	cfs	430	8,877	150	4,100	552	467	1,402	109	80,100
Min Flow	cfs	0	113	0	0	0	0	0	0	800
									Site has seasonal flows about 1-2 months per year; flows are too low for hydropower development at 30% flow exceedance	
Turbine Selection Analysis										
Selected Turbine Type		Pelton	Kaplan	Kaplan	Francis	Kaplan	Francis	Francis		Kaplan
Selected Design Head	ft	202	22	38	58	10	140	119		8
Selected Design Flow	cfs	33	1,504	100	70	197	260	41		4,850
Generator Speed	rpm	600	600	600	600	600	600	600		600
Max Head Limit	ft	222.1	27.5	47.5	72.6	12.8	174.7	148.5		10.0
Min Head Limit	ft	131.3	14.3	24.7	37.8	6.6	90.8	77.2		5.2
Max Flow Limit	cfs	33	1,504	100	70	197	260	41		4,850
Min Flow Limit	cfs	7	301	20	14	39	52	8		970
Power Generation Analysis										
Installed Capacity	kW	484	2,067	238	294	126	2,626	350		2,426
Plant Factor		0.69	0.74	0.41	0.47	0.14	0.43	0.28		0.84
Projected Monthly Production:										
January	MWH	198	819	0	36	0	0	0		1,016
February*	MWH	179	769	0	39	0	0	0		961
March	MWH	186	930	0	82	0	43	0		1,108
April	MWH	190	1,063	0	117	6	1,025	32		1,471
May	MWH	309	1,219	102	129	64	1,641	125		1,961
June	MWH	326	1,372	196	155	62	1,824	104		1,997
July	MWH	327	1,564	196	182	20	1,853	196		1,939
August	MWH	309	1,463	196	171	0	1,835	182		1,489
September	MWH	194	1,127	135	104	0	1,329	125		1,364
October	MWH	223	985	6	69	0	36	82		1,568
November	MWH	208	902	0	48	0	22	2		1,419
December	MWH	204	848	0	45	0	0	0		1,139
Annual production*	MWH	2,854	13,059	830	1,178	152	9,608	847		17,430
* For non-leap year										
Benefit/Cost Analysis										
Projected expenditure to implement project										
Total Construction Cost		$ 2,144,126	$ 8,159,292	$ 1,848,639	$ 1,562,520	$ 1,069,417	$ 5,568,073	$ 2,202,828		$ 8,360,976
Annual O&M Cost		$ 80,601	$ 217,953	$ 69,105	$ 66,050	$ 48,785	$ 217,940	$ 80,031		$ 269,072
Projected Total Cost over 50 year period		$ 3,373,020	$ 11,289,871	$ 2,901,423	$ 2,585,414	$ 1,831,848	$ 8,909,641	$ 3,417,010		$ 12,365,360
Projected revenue after implementation of project										
Power generation income for 2014 to 2060		$ 10,249,608	$ 47,269,548	$ 2,816,878	$ 4,356,487	$ 454,699	$ 32,404,219	$ 3,075,285		$ 60,727,391
Green Energy Sellback income for 2014 to 2060		$ 345,484	$ 1,580,790	$ 100,453	$ 142,581	$ 18,365	$ 1,162,602	$ 102,507		$ 2,109,838
Projected Total Revenue over 50 year period (with Green Incentives)		$ 3,906,709	$ 17,881,395	$ 1,068,046	$ 1,645,011	$ 174,977	$ 12,300,829	$ 1,170,832		$ 22,996,002
Projected Total Revenue over 50 year period (w/o Green Incentives)		$ 3,669,554	$ 16,796,272	$ 999,090	$ 1,547,138	$ 162,370	$ 11,502,766	$ 1,100,467		$ 21,547,717
Benefit/Cost Ratio (with Green incentives)		1.16	1.58	0.37	0.64	0.10	1.38	0.34		1.86
Benefit/Cost Ratio (w/o Green incentives)		1.09	1.49	0.34	0.60	0.09	1.29	0.32		1.74
Internal Rate of Return (with Green incentives)		5.9%	8.7%	Negative	Negative	Negative	7.8%	Negative		10.9%
Internal Rate of Return (w/o Green incentives)		5.2%	7.8%	Negative	Negative	Negative	6.8%	Negative		9.7%
Installed Cost $ per kW		$ 4,426	$ 3,947	$ 7,779	$ 5,315	$ 8,485	$ 2,120	$ 6,288		$ 3,446

Table E-3
Great Plains Region Model Results

Facility Name		James Diversion Dam	Jamestown Dam	Johnson Project, Greenfield Main Canal Drop	Keyhole Dam	Kirwin Dam	Knights Project, Greenfield Main Canal Drop	Lake Alice Lower 1-1/2 Dam	Lake Alice No. 2 Dam	Lake Sherburne Dam
Agency		Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation
Analysis Performed by		CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM
Project Location (State)		South Dakota	North Dakota	Montana	Wyoming	Kansas	Montana	Nebraska	Nebraska	Montana
Transmission Voltage	kV	138	69	69	115	115	115	115	115	115
T-Line Length	miles	5.87	1.05	2.80	5.56	7.98	0.30	4.84	3.11	6.91
Fish and Wildlife Mitigation		No	No	No	No	No	No	No	No	Yes
Recreation Mitigation		No	Yes	No	No	No	No	No	No	No
Historical & Archaeological		No	No	No	No	No	No	No	No	Yes
Water Quality Monitoring		No	No	No	No	No	No	No	No	No
Fish Passage Required		No	No	No	No	No	No	No	No	No

Results

Input Data Analysis

Data Set	years	30	30	6	53	12	6	19.0	19	63
Max Head	ft	5.3	54.1	46.0	78.4	76.1	60.0	0.0	1.5	68.3
Min Head	ft	5.3	20.9	46.0	24.4	41.0	60.0	0.0	1.5	10.2
Max Flow	cfs	22,800	1,807	385	1,347	595	163	500	622	2,340
Min Flow	cfs	0	0	0	0	0	0	0	0	0
Turbine Selection Analysis					Site has seasonal flows about 2-3 months per year; flows are too low for hydropower development at 30% flow exceedance		Site has seasonal flows about 4 months per year; flows are too low for hydropower development at 30% flow exceedance	Site has no head for hydropower development		
Selected Turbine Type		Kaplan	Francis	Francis		Francis			Low Head	Kaplan
Selected Design Head	ft	5	31	46		69			3	45
Selected Design Flow	cfs	583	50	61		36			101	317
Generator Speed	rpm	600	600	600		600			600	600
Max Head Limit	ft	6.6	39.0	57.5		85.8			3.7	56.6
Min Head Limit	ft	3.4	20.3	29.9		44.6			1.9	29.4
Max Flow Limit	cfs	583	50	61		36			101	317
Min Flow Limit	cfs	117	10	12		7			20	63

Power Generation Analysis

Installed Capacity	kW	193	113	203		179			18	898
Plant Factor		0.50	0.35	0.30		0.30			0.32	0.19
Projected Monthly Production:										
January	MWH	17	3	0		31			0	0
February*	MWH	15	3	0		34			0	1
March	MWH	60	7	0		31			0	75
April	MWH	109	18	0		26			2	151
May	MWH	107	36	91		35			8	281
June	MWH	106	49	146		72			6	192
July	MWH	93	56	146		104			11	126
August	MWH	81	47	111		88			12	372
September	MWH	68	49	32		14			9	265
October	MWH	68	39	0		11			2	12
November	MWH	62	24	0		11			0	18
December	MWH	38	7	0		11			0	7
Annual production*	MWH	825	338	525		466			50	1,502

* For non-leap year

Benefit/Cost Analysis

Projected expenditure to implement project

Total Construction Cost		$ 3,357,799	$ 1,166,450	$ 2,038,894		$ 3,578,864			$ 1,254,077	$ 5,934,412
Annual O&M Cost		$ 95,692	$ 49,231	$ 70,693		$ 98,088			$ 45,329	$ 163,158
Projected Total Cost over 50 year period		$ 4,750,577	$ 1,928,727	$ 3,103,816		$ 4,995,357			$ 1,941,256	$ 8,292,091

Projected revenue after implementation of project

Power generation income for 2014 to 2060		$ 3,024,102	$ 1,254,035	$ 1,739,242		$ 1,742,466			$ 185,969	$ 5,166,059
Green Energy Sellback income for 2014 to 2060		$ 99,888	$ 40,877	$ 63,545		$ 56,381			$ 6,040	$ 181,697
Projected Total Revenue over 50 year period (with Green Incentives)		$ 1,142,945	$ 473,417	$ 661,275		$ 657,226			$ 70,173	$ 1,956,977
Projected Total Revenue over 50 year period (w/o Green Incentives)		$ 1,074,378	$ 445,357	$ 617,655		$ 618,524			$ 66,027	$ 1,832,252
Benefit/Cost Ratio (with Green incentives)		0.24	0.25	0.21		0.13			0.04	0.24
Benefit/Cost Ratio (w/o Green incentives)		0.23	0.23	0.20		0.12			0.03	0.22
Internal Rate of Return (with Green incentives)		Negative	Negative	Negative		Negative			Negative	Negative
Internal Rate of Return (w/o Green incentives)		Negative	Negative	Negative		Negative			Negative	Negative
Installed Cost $ per kW		$ 17,377	$ 10,338	$ 10,052		$ 20,036			$ 69,333	$ 6,605

Table E-3
Great Plains Region Model Results

Facility Name		Lily Pad Diversion Dam	Lovewell Dam	Mary Taylor Drop Structure	Medicine Creek Dam	Merritt Dam	Middle Cunningham Creek Diversion Dam	Mill Coulee Canal Drop, Upper and Lower Drops Combined	Minatare Dam	Nelson Dikes C
Agency		Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation
Analysis Performed by		CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM
Project Location (State)		Colorado	Kansas	Montana	Nebraska	Nebraska	Colorado	Montana	Nebraska	Montana
Transmission Voltage	kV	115	115	69	115	115	115	115	115	138
T-Line Length	miles	1.27	9.90	3.33	2.42	25.87	0.31	1.53	2.01	3.01
Fish and Wildlife Mitigation		No	No	No	No	No	No	No	No	No
Recreation Mitigation		No	No	No	No	No	No	No	Yes	No
Historical & Archaeological		No	No	No	No	No	No	No	No	No
Water Quality Monitoring		No	No	No	No	No	No	No	No	No
Fish Passage Required		No	No	No	No	No	No	No	No	No
Results										
Input Data Analysis										
Data Set	years	29	19	6	56	3	29	10	15	14.0
Max Head	ft	233.5	60.3	43.7	74.0	114.3	7.1	186.4	46.1	22.2
Min Head	ft	233.5	35.2	43.7	40.3	94.9	7.1	186.4	13.5	4.6
Max Flow	cfs	32	4,817	541	1,200	300	98	191	426	250
Min Flow	cfs	0	0	0	0	0	0	0	0	0
Turbine Selection Analysis		Site has less than 10 cfs 95% of the time; flows are too low for hydropower development at 30% flow exceedance	Site has seasonal flows about 5-6 months per year; flows are too low for hydropower development at 30% flow exceedance	Site has seasonal flows about 5 months per year; flows are too low for hydropower development at 30% flow exceedance			Site has less than 21 cfs 95% of the time and head is 7.5 feet; flows and head are too low for hydropower development	Site has seasonal flows about 4 months per year; flows are too low for hydropower development at 30% flow exceedance		Site has seasonal flows about 1-2 months per year; flows are too low for hydropower development at 30% flow exceedance
Selected Turbine Type					Francis	Francis			Low Head	
Selected Design Head	ft				66	113			35	
Selected Design Flow	cfs				58	200			2	
Generator Speed	rpm				600	600			600	
Max Head Limit	ft				82.2	141.0			44.3	
Min Head Limit	ft				42.7	73.3			23.0	
Max Flow Limit	cfs				58	200			2	
Min Flow Limit	cfs				12	40			0	
Power Generation Analysis										
Installed Capacity	kW				276	1,631			4	
Plant Factor					0.42	0.60			0.20	
Projected Monthly Production:										
January	MWH				50	1,140			0	
February*	MWH				60	1,082			0	
March	MWH				86	993			0	
April	MWH				95	1,026			0	
May	MWH				100	950			1	
June	MWH				148	949			0	
July	MWH				171	149			3	
August	MWH				145	84			2	
September	MWH				49	203			1	
October	MWH				26	160			0	
November	MWH				30	599			0	
December	MWH				41	1,104			0	
Annual production*	MWH				1,001	8,438			7	

* For non-leap year

Benefit/Cost Analysis										
Projected expenditure to implement project										
Total Construction Cost					$ 2,103,644	$ 12,641,116			$ 757,453	
Annual O&M Cost					$ 75,233	$ 321,191			$ 34,758	
Projected Total Cost over 50 year period					$ 3,242,362	$ 17,204,261			$ 1,301,027	
Projected revenue after implementation of project										
Power generation income for 2014 to 2060					$ 3,702,889	$ 30,916,350			$ 27,483	
Green Energy Sellback income for 2014 to 2060					$ 121,163	$ 1,021,887			$ 877	
Projected Total Revenue over 50 year period (with Green Incentives)					$ 1,398,073	$ 11,679,550			$ 10,355	
Projected Total Revenue over 50 year period (w/o Green Incentives)					$ 1,314,902	$ 10,978,083			$ 9,753	
Benefit/Cost Ratio (with Green incentives)					0.43	0.68			0.01	
Benefit/Cost Ratio (w/o Green incentives)					0.41	0.64			0.01	
Internal Rate of Return (with Green incentives)					Negative	1.2%			Negative	
Internal Rate of Return (w/o Green incentives)					Negative	0.9%			Negative	
Installed Cost $ per kW					$ 7,631	$ 7,752			$ 175,485	

Table E-3
Great Plains Region Model Results

Facility Name		Nelson Dikes DA	Norton Dam	Olympus Dam	Pactola Dam	Paradise Diversion Dam	Pathfinder Dam	Pishkun Dike - No. 4	Pueblo Dam	Rattlesnake Dam
Agency		Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation
Analysis Performed by		CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM
Project Location (State)		Montana	Kansas	Colorado	South Dakota	Montana	Wyoming	Montana	Colorado	Colorado
Transmission Voltage	kV	138	115	13.8	69	115	138	69	138	13.8
T-Line Length	miles	3.01	0.36	0.09	0.26	1.93	2.33	8.51	0.84	0.72
Fish and Wildlife Mitigation		No	No	No	No	No	No	No	Yes	No
Recreation Mitigation		No	No	No	Yes	No	Yes	No	No	No
Historical & Archaeological		No	No	No	No	No	No	No	No	No
Water Quality Monitoring		No	No	No	No	No	No	No	No	No
Fish Passage Required		No	No	No	No	No	Yes	No	No	No

Results
Input Data Analysis

Data Set	years	14	41	11	49	15	8	13	20	31
Max Head	ft	22.2	66.1	44.0	161.7	11.8	163.9	28.9	199.4	42.2
Min Head	ft	4.6	14.9	23.8	7.8	11.8	110.9	0.0	130.9	2.0
Max Flow	cfs	656	134	1,125	500	348	108	1,830	11,318	1
Min Flow	cfs	0	0	14	0	0	0	0	30	1

Turbine Selection Analysis						Site has seasonal flows about 3 months per year; flows are too low for hydropower development at 30% flow exceedance				Site has 1 cfs flow consistently; flows are too low for hydropower development
Selected Turbine Type		Low Head	Low Head	Kaplan	Francis		Francis	Kaplan	Francis	
Selected Design Head	ft	17	49	42	154		135	22	183	
Selected Design Flow	cfs	46	2	107	53		76	447	987	
Generator Speed	rpm	600	600	600	600		600	600	300	
Max Head Limit	ft	21.5	61.8	53.0	192.9		169.2	27.3	228.3	
Min Head Limit	ft	11.2	32.1	27.6	100.3		88.0	14.2	118.7	
Max Flow Limit	cfs	46	2	107	53		76	447	987	
Min Flow Limit	cfs	9	0	21	11		15	89	197	

Power Generation Analysis

Installed Capacity	kW	48	6	284	596		743	610	13,027	
Plant Factor		0.28	0.47	0.64	0.53		0.86	0.27	0.50	
Projected Monthly Production:										
January	MWH	0	1	40	137		429	0	1,322	
February*	MWH	0	1	37	129		408	0	1,613	
March	MWH	0	2	50	169		438	0	3,701	
April	MWH	2	2	100	231		435	12	6,190	
May	MWH	22	2	216	319		437	173	7,659	
June	MWH	18	3	231	329		453	251	8,555	
July	MWH	26	3	228	363		497	436	8,113	
August	MWH	25	2	217	343		481	328	7,051	
September	MWH	18	2	174	276		480	199	4,566	
October	MWH	6	2	136	156		474	0	3,392	
November	MWH	0	2	68	134		487	0	2,304	
December	MWH	0	2	52	137		487	0	1,154	
Annual production*	MWH	116	24	1,549	2,725		5,508	1,399	55,620	

* For non-leap year

Benefit/Cost Analysis
Projected expenditure to implement project

Total Construction Cost		$ 1,479,309	$ 232,028	$ 1,552,449	$ 2,207,515		$ 4,476,400	$ 5,574,009	$ 22,193,883	
Annual O&M Cost		$ 51,824	$ 25,134	$ 65,808	$ 87,171		$ 114,385	$ 155,180	$ 690,628	
Projected Total Cost over 50 year period		$ 2,261,239	$ 650,832	$ 2,571,963	$ 3,545,667		$ 6,103,537	$ 7,822,128	$ 32,412,133	

Projected revenue after implementation of project

Power generation income for 2014 to 2060		$ 395,687	$ 87,693	$ 5,559,444	$ 10,084,287		$ 19,924,351	$ 4,799,851	$ 198,904,244	
Green Energy Sellback income for 2014 to 2060		$ 14,010	$ 2,861	$ 187,514	$ 329,793		$ 666,731	$ 169,231	$ 6,731,308	
Projected Total Revenue over 50 year period (with Green Incentives)		$ 149,986	$ 33,102	$ 2,119,176	$ 3,807,240		$ 7,537,539	$ 1,818,118	$ 75,844,766	
Projected Total Revenue over 50 year period (w/o Green Incentives)		$ 140,369	$ 31,137	$ 1,990,458	$ 3,580,856		$ 7,079,866	$ 1,701,950	$ 71,224,099	
Benefit/Cost Ratio (with Green incentives)		0.07	0.05	0.82	1.07		1.23	0.23	2.34	
Benefit/Cost Ratio (w/o Green incentives)		0.06	0.05	0.77	1.01		1.16	0.22	2.20	
Internal Rate of Return (with Green incentives)		Negative	Negative	2.3%	5.1%		6.2%	Negative	14.0%	
Internal Rate of Return (w/o Green incentives)		Negative	Negative	1.9%	4.5%		5.6%	Negative	12.5%	
Installed Cost $ per kW		$ 30,895	$ 39,495	$ 5,472	$ 3,706		$ 6,022	$ 9,141	$ 1,704	

Table E-3
Great Plains Region Model Results

Facility Name		Red Willow Dam	Saint Mary Diversion Dam	Shadehill Dam	Shadow Mountain Dam	Soldier Canyon Dam	St. Mary Canal - Drop 1	St. Mary Canal - Drop 2	St. Mary Canal - Drop 3	St. Mary Canal - Drop 4
Agency		Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation
Analysis Performed by		CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM
Project Location (State)		Nebraska	Montana	South Dakota	Colorado	Colorado	Montana	Montana	Montana	Montana
Transmission Voltage	kV	115	69	69	13.8	115	69	69	69	69
T-Line Length	miles	1.71	1.96	7.32	1.96	2.46	10.33	9.83	9.60	8.58
Fish and Wildlife Mitigation		No	No	No	No	No	No	No	No	No
Recreation Mitigation		No	No	No	No	No	No	No	No	No
Historical & Archaeological		No	Yes	No	No	No	Yes	Yes	Yes	Yes
Water Quality Monitoring		No	No	No	No	No	No	No	No	No
Fish Passage Required		No	No	No	No	No	No	No	No	No
Results										
Input Data Analysis										
Data Set	years	43	19	53	19	4	20	20	20	20
Max Head	ft	74.1	9.4	75.4	38.8	203.1	36.1	29.0	26.4	66.2
Min Head	ft	50.7	0.0	51.6	31.3	75.1	36.1	29.0	26.4	66.2
Max Flow	cfs	364	708	4,120	3,366	25	745	745	745	745
Min Flow	cfs	0	0	0	0	0	0	0	0	0
Turbine Selection Analysis						Site has less than 2 cfs 95% of the time ; flows and head are too low for hydropower development				
Selected Turbine Type		Low Head	Kaplan	Francis	Francis		Kaplan	Kaplan	Kaplan	Francis
Selected Design Head	ft	68	5	64	37		36	29	26	66
Selected Design Flow	cfs	5	534	70	45		537	537	537	537
Generator Speed	rpm	600	600	600	600		600	600	600	300
Max Head Limit	ft	85.6	6.6	79.6	45.9		45.1	36.3	33.0	82.8
Min Head Limit	ft	44.5	3.5	41.4	23.9		23.5	18.8	17.2	43.0
Max Flow Limit	cfs	5	534	70	45		537	537	537	537
Min Flow Limit	cfs	1	107	14	9		107	107	107	107
Power Generation Analysis										
Installed Capacity	kW	21	177	322	119		1,212	974	887	2,569
Plant Factor		0.83	0.47	0.55	0.76		0.46	0.46	0.46	0.40
Projected Monthly Production:										
January	MWH	12	0	104	37		0	0	0	0
February*	MWH	11	0	94	33		0	0	0	0
March	MWH	12	15	113	36		131	105	96	236
April	MWH	12	79	137	48		543	436	397	988
May	MWH	13	137	139	67		894	718	654	1,650
June	MWH	14	137	155	85		879	706	643	1,625
July	MWH	14	135	156	86		894	718	654	1,654
August	MWH	14	135	156	80		876	703	640	1,620
September	MWH	12	76	141	73		544	437	398	1,004
October	MWH	11	5	119	69		77	62	57	142
November	MWH	11	0	112	81		0	0	0	0
December	MWH	12	0	109	82		0	0	0	0
Annual production*	MWH	148	720	1,536	777		4,838	3,887	3,538	8,919
* For non-leap year										
Benefit/Cost Analysis										
Projected expenditure to implement project										
Total Construction Cost		$ 780,729	$ 1,833,705	$ 4,128,108	$ 1,471,463		$ 7,901,765	$ 7,141,032	$ 6,832,460	$ 9,599,664
Annual O&M Cost		$ 52,056	$ 65,225	$ 115,814	$ 55,941		$ 218,294	$ 196,048	$ 187,241	$ 289,602
Projected Total Cost over 50 year period		$ 1,623,656	$ 2,820,126	$ 5,808,529	$ 2,325,734		$ 11,059,281	$ 9,973,142	$ 9,536,333	$ 13,860,616
Projected revenue after implementation of project										
Power generation income for 2014 to 2060		$ 531,725	$ 2,417,151	$ 5,708,089	$ 2,794,519		$ 16,281,480	$ 13,079,332	$ 11,906,730	$ 30,009,553
Green Energy Sellback income for 2014 to 2060		$ 17,952	$ 87,151	$ 185,963	$ 94,074		$ 585,442	$ 470,301	$ 428,137	$ 1,079,149
Projected Total Revenue over 50 year period (with Green Incentives)		$ 202,700	$ 918,137	$ 2,154,242	$ 1,065,058		$ 6,182,903	$ 4,966,885	$ 4,521,589	$ 11,396,164
Projected Total Revenue over 50 year period (w/o Green Incentives)		$ 190,377	$ 858,313	$ 2,026,589	$ 1,000,481		$ 5,781,029	$ 4,644,049	$ 4,227,696	$ 10,655,387
Benefit/Cost Ratio (with Green incentives)		0.12	0.33	0.37	0.46		0.56	0.50	0.47	0.82
Benefit/Cost Ratio (w/o Green incentives)		0.12	0.30	0.35	0.43		0.52	0.47	0.44	0.77
Internal Rate of Return (with Green incentives)		Negative	Negative	Negative	Negative		Negative	Negative	Negative	2.6%
Internal Rate of Return (w/o Green incentives)		Negative	Negative	Negative	Negative		Negative	Negative	Negative	2.2%
Installed Cost $ per kW		$ 37,427	$ 10,340	$ 12,806	$ 12,316		$ 6,518	$ 7,333	$ 7,707	$ 3,736

Table E-3
Great Plains Region Model Results

Facility Name		St. Mary Canal - Drop 5	Sun River Diversion Dam	Trenton Dam	Twin Buttes Dam	Twin Lakes Dam (USBR)	Vandalia Diversion Dam	Virginia Smith Dam	Webster Dam	Whalen Diversion Dam
Agency		Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation
Analysis Performed by		CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM
Project Location (State)		Montana	Montana	Nebraska	Texas	Colorado	Montana	Nebraska	Kansas	Wyoming
Transmission Voltage	kV	69	69	138	138	115	69	115	115	69
T-Line Length	miles	8.58	16.61	3.00	2.57	0.68	0.37	21.69	6.72	0.94
Fish and Wildlife Mitigation		No	No	No	No	Yes	No	No	No	No
Recreation Mitigation		No	No	No	No	No	No	No	No	No
Historical & Archaeological		Yes	Yes	No	No	No	No	No	No	No
Water Quality Monitoring		No	Yes	No	No	No	No	No	No	No
Fish Passage Required		No	No	No	No	No	No	No	No	No
Results										
Input Data Analysis										
Data Set	years	20	13	52	18	19	7	4	17	3
Max Head	ft	56.6	45.0	89.1	100.0	52.7	32.3	103.7	87.0	11.0
Min Head	ft	56.6	45.0	23.0	100.0	9.2	32.3	54.9	22.6	1.0
Max Flow	cfs	745	8,136	3,490	26,400	3,091	6,173	649	1,000	2,002
Min Flow	cfs	0	0	0	0	8	0	10	0	3
Turbine Selection Analysis										
Selected Turbine Type		Kaplan	Kaplan	Francis	Francis	Kaplan	Kaplan	Francis	Low Head	Low Head
Selected Design Head	ft	57	45	55	100	46	32	72	72	11
Selected Design Flow	cfs	537	716	52	3,199	344	161	310	15	23
Generator Speed	rpm	300	600	600	120	600	600	600	600	600
Max Head Limit	ft	70.8	56.3	69.3	125.0	57.0	40.4	89.6	90.6	13.8
Min Head Limit	ft	36.8	29.2	36.0	65.0	29.6	21.0	46.6	47.1	7.1
Max Flow Limit	cfs	537	716	52	3,199	344	161	310	15	23
Min Flow Limit	cfs	107	143	10	640	69	32	62	3	5
Power Generation Analysis										
Installed Capacity	kW	1,901	2,015	208	23,124	981	326	1,607	66	15
Plant Factor		0.46	0.50	0.32	0.49	0.67	0.68	0.71	0.29	0.40
Projected Monthly Production:										
January	MWH	0	128	16	2,609	453	177	1,070	11	0
February*	MWH	0	140	19	3,038	422	184	663	15	0
March	MWH	206	185	22	8,266	428	236	885	14	0
April	MWH	852	681	36	9,684	379	192	559	15	2
May	MWH	1,402	1,556	58	11,838	550	185	819	13	6
June	MWH	1,378	1,647	94	12,810	735	210	1,003	19	9
July	MWH	1,402	1,650	128	15,989	807	99	1,097	31	11
August	MWH	1,373	1,361	113	13,093	634	89	941	25	11
September	MWH	853	699	56	7,747	348	102	381	8	11
October	MWH	121	191	10	5,540	270	140	538	5	3
November	MWH	0	197	9	2,707	293	139	802	3	0
December	MWH	0	211	9	4,134	331	153	1,040	6	0
Annual production*	MWH	7,586	8,645	570	97,457	5,648	1,907	9,799	164	53

* For non-leap year

Benefit/Cost Analysis		St. Mary Canal - Drop 5	Sun River Diversion Dam	Trenton Dam	Twin Buttes Dam	Twin Lakes Dam (USBR)	Vandalia Diversion Dam	Virginia Smith Dam	Webster Dam	Whalen Diversion Dam
Projected expenditure to implement project										
Total Construction Cost		$ 9,154,535	$ 12,611,427	$ 2,180,678	$ 33,654,223	$ 4,192,652	$ 1,779,378	$ 11,467,643	$ 2,694,512	$ 549,274
Annual O&M Cost		$ 263,986	$ 318,523	$ 73,750	$ 1,206,198	$ 136,168	$ 71,965	$ 299,242	$ 75,445	$ 32,024
Projected Total Cost over 50 year period		$ 13,005,664	$ 17,130,524	$ 3,287,293	$ 51,917,003	$ 6,222,276	$ 2,887,615	$ 15,744,210	$ 3,788,753	$ 1,062,194
Projected revenue after implementation of project										
Power generation income for 2014 to 2060		$ 25,527,189	$ 29,121,388	$ 2,122,023	$ 359,252,188	$ 20,324,443	$ 6,653,468	$ 36,574,151	$ 613,807	$ 191,711
Green Energy Sellback income for 2014 to 2060		$ 917,895	$ 1,046,115	$ 69,019	$ 11,794,649	$ 683,695	$ 230,861	$ 1,186,150	$ 19,915	$ 6,382
Projected Total Revenue over 50 year period (with Green Incentives)		$ 9,693,967	$ 11,059,141	$ 800,826	$ 135,691,137	$ 7,745,080	$ 2,519,621	$ 13,795,960	$ 231,563	$ 72,476
Projected Total Revenue over 50 year period (w/o Green Incentives)		$ 9,063,882	$ 10,341,041	$ 753,448	$ 127,594,769	$ 7,275,762	$ 2,361,148	$ 12,981,735	$ 217,892	$ 68,095
Benefit/Cost Ratio (with Green incentives)		0.75	0.65	0.24	2.61	1.24	0.87	0.88	0.06	0.07
Benefit/Cost Ratio (w/o Green incentives)		0.70	0.60	0.23	2.46	1.17	0.82	0.82	0.06	0.06
Internal Rate of Return (with Green incentives)		1.8%	0.8%	Negative	16.0%	6.5%	3.0%	3.3%	Negative	Negative
Internal Rate of Return (w/o Green incentives)		1.4%	0.4%	Negative	14.2%	5.8%	2.5%	2.8%	Negative	Negative
Installed Cost $ per kW		$ 4,817	$ 6,259	$ 10,461	$ 1,455	$ 4,274	$ 5,461	$ 7,137	$ 40,704	$ 35,641

Table E-4
Lower Colorado Region Model Results

Facility Name		Bartlett Dam	Gila Gravity Main Canal Headworks	Horseshoe Dam	Imperial Dam	Laguna Dam
Agency		Reclamation	Reclamation	Reclamation	Reclamation	Reclamation
Analysis Performed by		CDM	CDM	CDM	CDM	CDM
Project Location (State)		Arizona	Arizona	Arizona	Arizona	Arizona
Transmission Voltage	kV	115	69	115	69	138
T-Line Length	miles	0.06	0.95	6.79	0.50	0.45
Fish and Wildlife Mitigation		Yes	No	Yes	Yes	No
Recreation Mitigation		Yes	No	Yes	No	No
Historical & Archaeological		No	No	No	No	Yes
Water Quality Monitoring		No	No	No	No	No
Fish Passage Required		No	No	No	No	No
Results						
Input Data Analysis						
Data Set	years	10	14	4	4	4
Max Head	ft	251.0	2.5	142.0	11.5	10.0
Min Head	ft	251.0	2.5	142.0	11.5	10.0
Max Flow	cfs	25,100	2,160	1,350	1,500	200
Min Flow	cfs	54	0	0	0	0
Turbine Selection Analysis						
Selected Turbine Type		Francis	Kaplan	Francis	Kaplan	Kaplan
Selected Design Head	ft	251	3	142	12	10
Selected Design flow	cfs	415	1,410	1,350	1,500	200
Generator Speed	rpm	600	600	240	600	600
Max Head Limit	ft	313.8	3.2	177.5	14.4	12.5
Min Head Limit	ft	163.1	1.6	92.3	7.5	6.5
Max Flow Limit	cfs	415	1,410	1,350	1,500	200
Min Flow Limit	cfs	83	282	270	300	40
Power Generation Analysis						
Installed Capacity	kW	7,529	223	13,857	1,079	125
Plant Factor		0.57	0.81	0.50	0.57	0.53
Projected Monthly Production:						
January	MWH	2,984	77	0	0	0
February*	MWH	3,494	87	0	0	0
March	MWH	3,002	135	0	0	0
April	MWH	3,238	153	9,728	865	51
May	MWH	2,902	161	9,977	888	103
June	MWH	3,025	165	9,977	888	103
July	MWH	2,781	162	9,977	888	103
August	MWH	2,364	150	9,977	888	103
September	MWH	1,742	153	9,977	888	103
October	MWH	3,790	132	241	21	0
November	MWH	3,976	104	0	0	0
December	MWH	3,581	70	0	0	0
Annual production*	MWH	36,880	1,548	59,854	5,325	566

* For non-leap year

Benefit/Cost Analysis						
Projected expenditure to implement project						
Total Construction Cost		$ 15,119,971	$ 1,702,571	$ 30,122,959	$ 4,617,474	$ 1,099,965
Annual O&M Cost		$ 435,183	$ 65,967	$ 792,451	$ 147,330	$ 48,908
Projected Total Cost over 50 year period		$ 21,466,246	$ 2,712,614	$ 41,468,135	$ 6,806,855	$ 1,862,035
Projected revenue after implementation of project						
Power generation income for 2014 to 2060		$ 135,502,787	$ 5,722,519	$ 224,545,969	$ 19,978,589	$ 2,142,557
Green Energy Sellback income for 2014 to 2060		$ 46,320,673	$ 1,943,494	$ 75,116,372	$ 6,683,349	$ 710,404
Projected Total Revenue over 50 year period (with Green Incentives)		$ 75,081,491	$ 3,164,182	$ 123,548,060	$ 10,992,475	$ 1,175,000
Projected Total Revenue over 50 year period (w/o Green Incentives)		$ 48,254,174	$ 2,038,561	$ 80,041,690	$ 7,121,571	$ 763,544
Benefit/Cost Ratio (with Green incentives)		3.50	1.17	2.98	1.61	0.63
Benefit/Cost Ratio (w/o Green incentives)		2.25	0.75	1.93	1.05	0.41
Internal Rate of Return (with Green incentives)		22.9%	6.4%	19.3%	10.3%	Negative
Internal Rate of Return (w/o Green incentives)		12.5%	1.7%	10.5%	4.8%	Negative
Installed Cost $ per kW		$ 2,008	$ 7,632	$ 2,174	$ 4,280	$ 8,794

Table E-5
Mid-Pacific Region Model Results

Facility Name		Anderson Rose Dam	Boca Dam	Bradbury Dam	Casitas Dam	Clear Lake Dam	Gerber Dam	John Franchi Dam	LakeTahoe Dam
Agency		Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation
Analysis Performed by		CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM
Project Location (State)		Oregon	California	California	California	California	Oregon	California	California
Transmission Voltage	kV	115	69	115	69	138	138	138	115
T-Line Length	miles	0.24	1.14	7.18	0.27	11.90	11.30	3.03	0.05
Fish and Wildlife Mitigation		No	No	No	No	No	No	Yes	Yes
Recreation Mitigation		No	Yes	No	No	Yes	No	No	Yes
Historical & Archaeological		No	Yes	No	No	No	No	No	No
Water Quality Monitoring		No	No	No	No	No	No	No	No
Fish Passage Required		No	No	No	No	No	No	No	Yes
Results									
Input Data Analysis									
Data Set	years	23	30	29	30	9	11	4	30
Max Head	ft	12.0	102.0	190.0	216.6	6.7	48.0	15.0	8.4
Min Head	ft	12.0	37.0	190.0	37.0	0.0	16.6	15.0	0.0
Max Flow	cfs	1,086	2,530	10	2,530	540	167	900	3,160
Min Flow	cfs	0	0	10	0	0	0	0	0
Turbine Selection Analysis						No head available for hydropower development			
Selected Turbine Type		Low Head	Francis	Pelton	Francis		Kaplan	Kaplan	Kaplan
Selected Design Head	ft	12	92	190	96		35	15	6
Selected Design flow	cfs	40	179	10	151		112	500	729
Generator Speed	rpm	600	600	600	600		600	600	600
Max Head Limit	ft	15.0	114.4	209.0	119.4		44.2	18.8	7.9
Min Head Limit	ft	7.8	59.5	123.5	62.1		23.0	9.8	4.1
Max Flow Limit	cfs	40	179	10	151		112	500	729
Min Flow Limit	cfs	8	36	2	30		22	100	146
Power Generation Analysis									
Installed Capacity	kW	29	1,184	142	1,042		248	469	287
Plant Factor		0.50	0.43	0.43	0.37		0.36	0.46	0.36
Projected Monthly Production:									
January	MWH	17	191	29	144		0	0	17
February*	MWH	15	195	40	138		0	0	29
March	MWH	9	276	51	199		0	0	59
April	MWH	9	493	61	366		11	0	108
May	MWH	12	611	65	451		122	309	130
June	MWH	6	519	62	377		173	384	103
July	MWH	6	469	60	361		191	386	101
August	MWH	4	376	50	278		162	386	139
September	MWH	11	412	34	295		99	386	106
October	MWH	12	372	24	291		2	12	58
November	MWH	9	262	21	213		0	0	25
December	MWH	15	196	24	167		0	0	17
Annual production*	MWH	126	4,370	521	3,280		760	1,863	893
* For non-leap year									
Benefit/Cost Analysis									
Projected expenditure to implement project									
Total Construction Cost		$ 377,653	$ 4,393,028	$ 3,093,843	$ 3,298,941		$ 5,358,017	$ 3,624,493	$ 2,494,825
Annual O&M Cost		$ 29,788	$ 144,379	$ 86,991	$ 127,317		$ 135,702	$ 109,802	$ 68,009
Projected Total Cost over 50 year period		$ 865,633	$ 6,549,305	$ 4,356,615	$ 5,247,277		$ 7,284,535	$ 5,241,266	$ 3,475,846
Projected revenue after implementation of project									
Power generation income for 2014 to 2060		$ 481,278	$ 16,495,441	$ 1,966,739	$ 12,396,703		$ 2,646,350	$ 7,071,407	$ 3,375,900
Green Energy Sellback income for 2014 to 2060		$ 15,313	$ 9,033,922	$ 1,076,517	$ 6,780,039		$ 91,906	$ 3,849,722	$ 1,845,091
Projected Total Revenue over 50 year period (with Green Incentives)		$ 181,371	$ 10,979,640	$ 1,308,649	$ 8,246,189		$ 1,004,697	$ 4,692,721	$ 2,244,889
Projected Total Revenue over 50 year period (w/o Green Incentives)		$ 170,859	$ 5,850,797	$ 697,483	$ 4,396,942		$ 941,609	$ 2,507,074	$ 1,197,368
Benefit/Cost Ratio (with Green incentives)		0.21	1.68	0.30	1.57		0.14	0.90	0.65
Benefit/Cost Ratio (w/o Green incentives)		0.20	0.89	0.16	0.84		0.13	0.48	0.34
Internal Rate of Return (with Green incentives)		Negative	11.3%	Negative	10.7%		Negative	3.0%	Negative
Internal Rate of Return (w/o Green incentives)		Negative	3.4%	Negative	2.8%		Negative	Negative	Negative
Installed Cost $ per kW		$ 12,916	$ 3,711	$ 21,749	$ 3,165		$ 21,621	$ 7,728	$ 8,686

Table E-5
Mid-Pacific Region Model Results

Facility Name		Malone Diversion Dam	Marble Bluff Dam	Prosser Creek Dam	Putah Creek Dam	Putah Diversion Dam	Rainbow Dam	Twitchell Dam	Upper Slaven Dam
Agency		Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation
Analysis Performed by		CDM	CDM	CDM	CDM	CDM	CDM		CDM
Project Location (State)		Oregon	Nevada	California	California	California	California		Nevada
Transmission Voltage	kV	115	115	69	138	115	115		115
T-Line Length	miles	4.60	7.22	0.50	1.94	2.23	13.88		7.25
Fish and Wildlife Mitigation		No	No	No	No	Yes	No		No
Recreation Mitigation		No	Yes	Yes	No	No	Yes		No
Historical & Archaeological		No	No	No	No	No	No		No
Water Quality Monitoring		No	No	No	No	No	No		No
Fish Passage Required		No	No	No	No	No	No		No

Results

Input Data Analysis

		Malone Diversion Dam	Marble Bluff Dam	Prosser Creek Dam	Putah Creek Dam	Putah Diversion Dam	Rainbow Dam	Twitchell Dam	Upper Slaven Dam
Data Set	years	5	30	30	34	33	2		19
Max Head	ft	8.5	49.0	132.0	11.3	11.3			8.0
Min Head	ft	0.0	37.5	73.3	0.0	0.0			8.0
Max Flow	cfs	150	19,300	1,810	14,557	14,569			8,320
Min Flow	cfs	0	3	0	5	1			0
								Site has inconsistent flows 2-3 months in some years, model estimated that flows are too low for hydropower development at 30% flow exceedance	

Turbine Selection Analysis

		Malone Diversion Dam	Marble Bluff Dam	Prosser Creek Dam	Putah Creek Dam	Putah Diversion Dam	Rainbow Dam	Twitchell Dam	Upper Slaven Dam
Selected Turbine Type		Low Head	Kaplan	Francis	Low Head	Kaplan	Kaplan		Kaplan
Selected Design Head	ft	8	38	127	11	11	29		8
Selected Design flow	cfs	95	479	95	43	553	105		316
Generator Speed	rpm	600	600	600	600	600	600		600
Max Head Limit	ft	9.6	48.1	158.8	13.1	13.1	36.3		10.0
Min Head Limit	ft	5.0	25.0	82.5	6.8	6.8	18.8		5.2
Max Flow Limit	cfs	95	479	95	43	553	105		316
Min Flow Limit	cfs	19	96	19	9	111	21		63

Power Generation Analysis

		Malone Diversion Dam	Marble Bluff Dam	Prosser Creek Dam	Putah Creek Dam	Putah Diversion Dam	Rainbow Dam	Twitchell Dam	Upper Slaven Dam
Installed Capacity	kW	44	1,153	872	28	363	190		158
Plant Factor		0.39	0.57	0.51	0.70	0.62	0.63		0.53
Projected Monthly Production:									
January	MWH	0	470	222	12	41	94		46
February*	MWH	0	403	257	10	63	126		66
March	MWH	0	523	424	14	110	156		107
April	MWH	2	692	493	18	208	137		112
May	MWH	24	751	462	18	267	137		119
June	MWH	29	585	389	19	294	107		115
July	MWH	31	412	307	19	300	76		66
August	MWH	33	301	319	15	288	61		16
September	MWH	26	347	375	10	216	28		4
October	MWH	0	385	281	10	104	21		12
November	MWH	0	379	118	11	16	23		23
December	MWH	0	375	172	11	18	32		34
Annual production*	MWH	147	5,624	3,819	166	1,924	998		720

* For non-leap year

Benefit/Cost Analysis

Projected expenditure to implement project

		Malone Diversion Dam	Marble Bluff Dam	Prosser Creek Dam	Putah Creek Dam	Putah Diversion Dam	Rainbow Dam	Twitchell Dam	Upper Slaven Dam
Total Construction Cost		$ 1,835,590	$ 6,854,227	$ 3,118,982	$ 1,047,689	$ 2,815,269	$ 5,915,882		$ 3,473,962
Annual O&M Cost		$ 57,904	$ 193,917	$ 113,524	$ 42,467	$ 90,574	$ 142,097		$ 95,615
Projected Total Cost over 50 year period		$ 2,694,374	$ 9,672,589	$ 4,841,769	$ 1,701,850	$ 4,163,135	$ 7,908,290		$ 4,855,939

Projected revenue after implementation of project

		Malone Diversion Dam	Marble Bluff Dam	Prosser Creek Dam	Putah Creek Dam	Putah Diversion Dam	Rainbow Dam	Twitchell Dam	Upper Slaven Dam
Power generation income for 2014 to 2060		$ 516,966	$ 21,302,210	$ 14,440,943	$ 632,485	$ 7,249,612	$ 3,737,394		$ 2,687,577
Green Energy Sellback income for 2014 to 2060		$ 17,748	$ 680,771	$ 7,896,125	$ 343,943	$ 3,976,637	$ 2,063,485		$ 87,112
Projected Total Revenue over 50 year period (with Green Incentives)		$ 196,038	$ 8,014,671	$ 9,604,843	$ 419,557	$ 4,828,813	$ 2,496,900		$ 1,012,476
Projected Total Revenue over 50 year period (w/o Green Incentives)		$ 183,854	$ 7,547,360	$ 5,122,003	$ 224,291	$ 2,571,140	$ 1,325,432		$ 952,679
Benefit/Cost Ratio (with Green incentives)		0.07	0.83	1.98	0.25	1.16	0.32		0.21
Benefit/Cost Ratio (w/o Green incentives)		0.07	0.78	1.06	0.13	0.62	0.17		0.20
Internal Rate of Return (with Green incentives)		Negative	2.8%	14.2%	Negative	6.3%	Negative		Negative
Internal Rate of Return (w/o Green incentives)		Negative	2.4%	4.9%	Negative	0.2%	Negative		Negative
Installed Cost $ per kW		$ 41,464	$ 5,943	$ 3,576	$ 38,062	$ 7,745	$ 31,116		$ 21,974

Table E-6
Pacific Northwest Region Model Results

Facility Name		Agate Dam	Agency Valley	Arthur R. Bowman Dam	Bully Creek Dam	Bumping Lake	Cle Elum Dam	Cold Springs Dam	Crane Prairie Dam	Deadwood Dam
Agency		Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation
Analysis Performed by		CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM
Project Location (State)		Oregon	Oregon	Oregon	Oregon	Washington	Washington	Oregon	Oregon	Idaho
Transmission Voltage	kV	115	138	138	138	138	115	115	138	138
T-Line Length	miles	0.75	22.46	5.94	19.01	22.78	2.02	2.51	17.41	45.01
Fish and Wildlife Mitigation		No	No	No	No	Yes	No	Yes	No	No
Recreation Mitigation		No	No	Yes	No	Yes	No	No	No	No
Historical & Archaeological		No	No	No	No	No	No	No	No	No
Water Quality Monitoring		No	No	No	No	No	No	No	No	No
Fish Passage Required		No	No	No	No	No	No	No	No	No

Results

Input Data Analysis

Data Set	years	10	35	29	24	28	31	12	22	28
Max Head	ft	65.0	79.8	190.1	95.5	38.1	128.9	51.5	21.4	127.3
Min Head	ft	26.4	2.2	109.7	35.7	2.9	3.4	0.0	9.0	72.4
Max Flow	cfs	1,940	2,060	3,280	3,483	2,486	5,111	360	822	2,220
Min Flow	cfs	0	0	7	0	2	0	0	21	0

Turbine Selection Analysis

Selected Turbine Type		Low Head	Francis	Francis	Francis	Kaplan	Francis	Low Head	Kaplan	Francis
Selected Design Head	ft	63	67	173	85	30	101	38	18	110
Selected Design flow	cfs	23	244	264	51	279	994	28	270	110
Generator Speed	rpm	600	600	600	600	600	300	600	600	600
Max Head Limit	ft	78.2	83.6	215.7	106.1	37.3	126.1	48.1	22.6	136.9
Min Head Limit	ft	40.7	43.5	112.2	55.2	19.4	65.6	25.0	11.8	71.2
Max Flow Limit	cfs	23	244	264	51	279	994	28	270	110
Min Flow Limit	cfs	5	49	53	10	56	199	6	54	22

Power Generation Analysis

Installed Capacity	kW	89	1,179	3,293	313	521	7,249	66	306	871
Plant Factor		0.35	0.39	0.65	0.40	0.49	0.24	0.23	0.70	0.48
Projected Monthly Production:										
January	MWH	2	30	875	27	87	477	14	130	175
February*	MWH	6	70	1,092	53	80	409	21	105	178
March	MWH	25	221	1,393	94	76	585	36	110	199
April	MWH	43	605	1,989	136	174	1,293	33	134	212
May	MWH	47	848	2,250	196	372	2,334	15	218	285
June	MWH	47	814	2,233	181	461	2,469	8	220	571
July	MWH	41	665	2,150	159	393	4,117	5	208	657
August	MWH	30	426	2,047	126	272	2,070	0	191	562
September	MWH	17	209	1,718	68	145	150	0	164	248
October	MWH	3	52	1,126	19	17	68	0	129	146
November	MWH	0	0	611	0	40	230	0	118	156
December	MWH	3	0	796	6	82	710	0	120	173
Annual production*	MWH	264	3,941	18,282	1,065	2,200	14,911	131	1,845	3,563

* For non-leap year

Benefit/Cost Analysis

Projected expenditure to implement project

Total Construction Cost		$ 821,490	$ 11,353,273	$ 8,994,918	$ 8,062,850	$ 11,275,688	$ 13,692,270	$ 1,308,787	$ 7,751,258	$ 19,510,113
Annual O&M Cost		$ 41,759	$ 283,599	$ 285,647	$ 189,112	$ 253,877	$ 491,071	$ 48,928	$ 183,632	$ 428,458
Projected Total Cost over 50 year period		$ 1,481,772	$ 15,366,732	$ 13,236,282	$ 10,699,018	$ 14,777,864	$ 21,128,211	$ 2,054,197	$ 10,317,389	$ 25,381,407

Projected revenue after implementation of project

Power generation income for 2014 to 2060		$ 920,311	$ 13,456,926	$ 66,632,205	$ 3,732,704	$ 7,679,909	$ 52,583,732	$ 480,840	$ 6,786,523	$ 13,450,614
Green Energy Sellback income for 2014 to 2060		$ 32,002	$ 476,937	$ 2,212,931	$ 128,948	$ 266,210	$ 1,804,591	$ 15,890	$ 223,362	$ 431,288
Projected Total Revenue over 50 year period (with Green Incentives)		$ 349,661	$ 5,123,348	$ 25,203,046	$ 1,417,294	$ 2,916,777	$ 19,946,301	$ 181,830	$ 2,565,012	$ 5,056,582
Projected Total Revenue over 50 year period (w/o Green Incentives)		$ 327,694	$ 4,795,957	$ 23,683,994	$ 1,328,778	$ 2,734,039	$ 18,707,549	$ 170,923	$ 2,411,687	$ 4,760,528
Benefit/Cost Ratio (with Green incentives)		0.24	0.33	1.90	0.13	0.20	0.94	0.09	0.25	0.20
Benefit/Cost Ratio (w/o Green incentives)		0.22	0.31	1.79	0.12	0.19	0.89	0.08	0.23	0.19
Internal Rate of Return (with Green incentives)		Negative	Negative	11.2%	Negative	Negative	3.8%	Negative	Negative	Negative
Internal Rate of Return (w/o Green incentives)		Negative	Negative	10.0%	Negative	Negative	3.3%	Negative	Negative	Negative
Installed Cost $ per kW		$ 9,267	$ 9,626	$ 2,732	$ 25,773	$ 21,650	$ 1,889	$ 19,942	$ 25,317	$ 22,402

Table E-6
Pacific Northwest Region Model Results

Facility Name		Easton Diversion Dam	Emigrant Dam	Fish Lake	Golden Gate Canal	Grassy Lake	Harper Dam	Haystack Canal	Howard Prairie	Kachess Dam
Agency		Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation
Analysis Performed by		CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM
Project Location (State)		Washington	Oregon	Oregon	Idaho		Oregon	Oregon		Washington
Transmission Voltage	kV	138	138	115	115		115	138		138
T-Line Length	miles	0.32	0.22	1.50	5.00		13.50	2.49		0.13
Fish and Wildlife Mitigation		No	No	Yes	No		No	No		No
Recreation Mitigation		No	No	No	No		No	No		No
Historical & Archaeological		No	No	No	No		No	No		No
Water Quality Monitoring		No	No	No	No		No	No		No
Fish Passage Required		No	No	No	No		No	No		No
Results										
Input Data Analysis										
Data Set	years	10	14	5	2		4	7		29
Max Head	ft	49.2	194.5	42.4			80.0	62.7		67.5
Min Head	ft	31.6	103.0	21.2			80.0	42.3		4.6
Max Flow	cfs	5,308	1,139	369			75	382		2,083
Min Flow	cfs	132	0	0			0	1		0
Turbine Selection Analysis						Site has seasonal flow for 3 months in some years;flows are too low for hydropower development at 30% flow exceedance			Site has flows less than 5 cfs 95% of the time; flows and head are too low for hydropower development	
Selected Turbine Type		Kaplan	Francis	Francis	Kaplan		Francis	Kaplan		Kaplan
Selected Design Head	ft	46	185	39	43		80	57		55
Selected Design flow	cfs	366	55	36	191		75	225		358
Generator Speed	rpm	600	600	600	600		600	600		600
Max Head Limit	ft	57.7	231.0	48.3	53.8		100.0	71.5		68.5
Min Head Limit	ft	30.0	120.1	25.1	27.9		52.0	37.2		35.6
Max Flow Limit	cfs	366	55	36	191		75	225		358
Min Flow Limit	cfs	73	11	7	38		15	45		72
Power Generation Analysis										
Installed Capacity	kW	1,057	733	102	514		434	805		1,227
Plant Factor		0.82	0.42	0.27	0.52		0.50	0.54		0.37
Projected Monthly Production:										
January	MWH	506	144	15	0		0	0		18
February*	MWH	451	140	17	0		0	0		52
March	MWH	537	189	14	0		3	0		93
April	MWH	757	285	11	0		312	418		192
May	MWH	733	196	14	416		312	617		561
June	MWH	738	278	14	378		312	589		855
July	MWH	786	498	37	423		312	594		790
August	MWH	801	438	44	423		312	593		660
September	MWH	560	261	42	371		310	609		490
October	MWH	538	36	12	283		0	319		115
November	MWH	500	23	11	0		0	0		19
December	MWH	491	130	4	0		0	0		32
Annual production*	MWH	7,400	2,619	235	2,293		1,874	3,738		3,877

* For non-leap year

Benefit/Cost Analysis										
Projected expenditure to implement project										
Total Construction Cost		$ 4,006,938	$ 2,209,654	$ 1,175,986	$ 3,991,565		$ 5,901,187	$ 3,916,382		$ 4,335,923
Annual O&M Cost		$ 143,036	$ 94,971	$ 48,322	$ 121,534		$ 152,352	$ 131,443		$ 154,639
Projected Total Cost over 50 year period		$ 6,171,299	$ 3,683,460	$ 1,921,667	$ 5,782,725		$ 8,073,375	$ 5,886,236		$ 6,675,542
Projected revenue after implementation of project										
Power generation income for 2014 to 2060		$ 27,455,501	$ 9,666,178	$ 894,226	$ 8,602,770		$ 6,583,707	$ 13,258,988		$ 13,579,772
Green Energy Sellback income for 2014 to 2060		$ 895,742	$ 317,055	$ 28,451	$ 277,478		$ 226,697	$ 452,334		$ 469,133
Projected Total Revenue over 50 year period (with Green Incentives)		$ 10,368,025	$ 3,649,488	$ 336,659	$ 3,234,683		$ 2,497,941	$ 5,027,304		$ 5,154,194
Projected Total Revenue over 50 year period (w/o Green Incentives)		$ 9,753,149	$ 3,431,848	$ 317,129	$ 3,044,209		$ 2,342,327	$ 4,716,802		$ 4,832,160
Benefit/Cost Ratio (with Green incentives)		1.68	0.99	0.18	0.56		0.31	0.85		0.77
Benefit/Cost Ratio (w/o Green incentives)		1.58	0.93	0.17	0.53		0.29	0.80		0.72
Internal Rate of Return (with Green incentives)		9.9%	4.3%	Negative	Negative		Negative	2.9%		1.9%
Internal Rate of Return (w/o Green incentives)		8.8%	3.7%	Negative	Negative		Negative	2.4%		1.5%
Installed Cost $ per kW		$ 3,792	$ 3,013	$ 11,555	$ 7,771		$ 13,606	$ 4,866		$ 3,535

Table E-6

Pacific Northwest Region Model Results

Facility Name		Keechelus Dam	Little Wood River Dam	Lytle Creek Diversion Dam	Mann Creek	Mason Dam	Maxwell Dam	McKay Dam	Ochoco Dam	Reservoir "A"
Agency		Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation
Analysis Performed by		CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM
Project Location (State)		Washington	Idaho	Oregon	Idaho	Oregon	Oregon	Oregon	Oregon	Idaho
Transmission Voltage	kV	138	138	138	138	115	115	138	138	138
T-Line Length	miles	1.07	37.37	3.22	4.59	10.82	3.99	2.22	2.22	2.29
Fish and Wildlife Mitigation		No	No	No	No	No	No	No	No	No
Recreation Mitigation		Yes	No	No	No	No	No	No	No	No
Historical & Archaeological		No	No	No	No	No	No	No	No	Yes
Water Quality Monitoring		No	No	No	No	No	No	No	No	No
Fish Passage Required		No	No	No	No	No	No	No	No	No
Results										
Input Data Analysis										
Data Set	years	29	24	29	2	37	20	16	26	6
Max Head	ft	92.9	119.1	3.0		156.6	4.0	137.9	79.7	63.2
Min Head	ft	5.8	12.9	3.0		71.1	4.0	43.4	0.0	51.1
Max Flow	cfs	2,370	2,126	3,280		592	14,500	1,400	565	32
Min Flow	cfs	0	0	7		0	1	0	0	0
					Insufficient data (< 3 years); Low Confidence Results					
Turbine Selection Analysis										
Selected Turbine Type		Francis	Francis	Kaplan	Francis	Francis	Kaplan	Francis	Low Head	Low Head
Selected Design Head	ft	75	103	3	113	139	4	122	60	60
Selected Design flow	cfs	444	200	264	61	164	467	154	19	12
Generator Speed	rpm	600	600	600	600	600	600	600	600	600
Max Head Limit	ft	93.3	129.1	3.8	141.6	173.4	5.0	152.9	75.0	75.5
Min Head Limit	ft	48.5	67.1	1.9	73.6	90.2	2.6	79.5	39.0	39.2
Max Flow Limit	cfs	444	200	264	61	164	467	154	19	12
Min Flow Limit	cfs	89	40	53	12	33	93	31	4	2
Power Generation Analysis										
Installed Capacity	kW	2,394	1,493	50	495	1,649	117	1,362	69	45
Plant Factor		0.33	0.39	0.77	0.50	0.41	0.64	0.37	0.39	0.44
Projected Monthly Production:										
January	MWH	205	84	17	14	39	80	36	13	0
February*	MWH	213	139	21	157	72	76	64	13	0
March	MWH	229	245	25	263	285	90	141	20	1
April	MWH	740	558	33	355	588	88	476	20	12
May	MWH	1,383	1,042	37	368	1,102	74	437	22	23
June	MWH	1,561	1,119	38	296	1,126	45	804	30	30
July	MWH	1,273	935	37	288	1,101	6	929	38	32
August	MWH	774	501	37	266	993	3	759	30	31
September	MWH	156	195	33	87	463	17	485	21	25
October	MWH	9	32	22	4	4	43	195	11	14
November	MWH	18	46	12	0	0	56	20	5	1
December	MWH	185	55	16	0	0	66	0	9	0
Annual production*	MWH	6,746	4,951	329	2,097	5,773	644	4,344	232	169
* For non-leap year										
Benefit/Cost Analysis										
Projected expenditure to implement project										
Total Construction Cost		$ 6,774,178	$ 17,931,211	$ 1,603,210	$ 3,554,446	$ 7,276,420	$ 2,075,386	$ 4,273,973	$ 1,286,281	$ 1,262,170
Annual O&M Cost		$ 223,994	$ 419,317	$ 54,377	$ 112,028	$ 220,210	$ 66,944	$ 155,651	$ 49,474	$ 47,381
Projected Total Cost over 50 year period		$ 10,122,860	$ 23,772,014	$ 2,419,501	$ 5,215,682	$ 10,518,264	$ 3,072,049	$ 6,636,265	$ 2,043,020	$ 1,984,436
Projected revenue after implementation of project										
Power generation income for 2014 to 2060		$ 23,024,064	$ 18,158,113	$ 1,206,608	$ 7,713,968	$ 20,039,378	$ 2,408,361	$ 15,476,231	$ 847,665	$ 634,225
Green Energy Sellback income for 2014 to 2060		$ 816,443	$ 599,229	$ 39,818	$ 253,921	$ 698,532	$ 77,974	$ 525,715	$ 28,056	$ 20,478
Projected Total Revenue over 50 year period (with Green Incentives)		$ 8,765,705	$ 6,842,890	$ 456,105	$ 2,906,180	$ 7,613,801	$ 909,338	$ 5,863,393	$ 320,425	$ 238,540
Projected Total Revenue over 50 year period (w/o Green Incentives)		$ 8,205,262	$ 6,431,553	$ 428,772	$ 2,731,878	$ 7,134,297	$ 855,813	$ 5,502,518	$ 301,166	$ 224,483
Benefit/Cost Ratio (with Green incentives)		0.87	0.29	0.19	0.56	0.72	0.30	0.88	0.16	0.12
Benefit/Cost Ratio (w/o Green incentives)		0.81	0.27	0.18	0.52	0.68	0.28	0.83	0.15	0.11
Internal Rate of Return (with Green incentives)		3.0%	Negative	Negative	Negative	1.5%	Negative	3.2%	Negative	Negative
Internal Rate of Return (w/o Green incentives)		2.5%	Negative	Negative	Negative	1.1%	Negative	2.7%	Negative	Negative
Installed Cost $ per kW		$ 2,830	$ 12,013	$ 32,368	$ 7,174	$ 4,414	$ 17,766	$ 3,138	$ 18,532	$ 27,968

Table E-6
Pacific Northwest Region Model Results

Facility Name		Ririe Dam	Scoggins Dam	Scootney Wasteway	Soda Creek	Soldier's Meadow	Sunnyside Diversion Dam	Thief Valley Dam	Unity Dam	Warm Springs Dam
Agency		Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation
Analysis Performed by		CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM
Project Location (State)		Idaho	Oregon	Washington	Oregon	Idaho	Washington	Oregon	Oregon	Oregon
Transmission Voltage	kV	115	115	115	115		115	115	115	138
T-Line Length	miles	2.27	2.66	3.65	2.66		5.98	2.29	25.28	0.67
Fish and Wildlife Mitigation		No	No	No	No		No	No	No	No
Recreation Mitigation		No	No	No	No		No	Yes	No	No
Historical & Archaeological		No	No	No	No		Yes	No	No	No
Water Quality Monitoring		No	No	No	No		No	No	No	No
Fish Passage Required		No	No	No	No		No	No	No	No
Results										
Input Data Analysis										
Data Set	years	31	27	4	7		20	28	28	31
Max Head	ft	150.0	99.7	13.0	1.3		6.0	45.2	55.5	74.1
Min Head	ft	86.7	41.8	13.0	0.0		6.0	2.4	10.5	0.0
Max Flow	cfs	1,750	1,940	2,800	20		44,000	2,370	1,030	3,030
Min Flow	cfs	0	3	0	0		565	0	0	0
Turbine Selection Analysis						Site has flows less than 12 cfs 95% of the time; flows are too low for hydropower development				
Selected Turbine Type		Francis	Francis	Kaplan	Low Head		Kaplan	Kaplan	Kaplan	Kaplan
Selected Design Head	ft	132	96	13	0		6	39	46	57
Selected Design flow	cfs	104	138	2,800	2		3,630	150	106	346
Generator Speed	rpm	600	600	600	600		600	600	600	600
Max Head Limit	ft	165.2	119.7	16.3	0.4		7.5	49.2	57.9	71.3
Min Head Limit	ft	85.9	62.2	8.4	0.2		3.9	25.6	30.1	37.1
Max Flow Limit	cfs	104	138	2,800	2		3,630	150	106	346
Min Flow Limit	cfs	21	28	560	0		726	30	21	69
Power Generation Analysis										
Installed Capacity	kW	993	955	2,276	0		1,362	369	307	1,234
Plant Factor		0.44	0.45	0.57	0.42		0.87	0.58	0.50	0.31
Projected Monthly Production:										
January	MWH	6	286	0	0		733	143	26	83
February*	MWH	31	204	0	0		736	188	40	106
March	MWH	118	320	15	0		865	278	102	177
April	MWH	213	267	1,873	0		1,002	244	209	422
May	MWH	559	274	1,873	0		1,067	257	266	419
June	MWH	608	332	1,873	0		1,055	256	243	466
July	MWH	481	581	1,873	0		1,048	196	209	606
August	MWH	487	548	1,873	0		1,021	105	158	530
September	MWH	584	409	1,858	0		828	36	51	319
October	MWH	440	184	0	0		575	22	7	88
November	MWH	209	89	0	0		603	36	4	0
December	MWH	42	189	0	0		648	71	15	40
Annual production*	MWH	3,778	3,683	11,238	0		10,182	1,833	1,329	3,256
* For non-leap year										
Benefit/Cost Analysis										
Projected expenditure to implement project										
Total Construction Cost		$ 3,636,873	$ 3,665,383	$ 8,014,357	$ 853,506		$ 6,912,015	$ 2,601,044	$ 9,461,990	$ 4,326,638
Annual O&M Cost		$ 131,486	$ 130,635	$ 258,314	$ 35,904		$ 205,420	$ 87,239	$ 213,525	$ 154,162
Projected Total Cost over 50 year period		$ 5,630,262	$ 5,641,621	$ 11,859,644	$ 1,409,200		$ 9,926,009	$ 3,908,299	$ 12,409,269	$ 6,658,705
Projected revenue after implementation of project										
Power generation income for 2014 to 2060		$ 14,091,162	$ 13,747,159	$ 39,492,334	$ 306		$ 37,665,681	$ 6,579,371	$ 4,600,990	$ 11,670,861
Green Energy Sellback income for 2014 to 2060		$ 457,184	$ 445,780	$ 1,359,839	$ 10		$ 1,232,646	$ 221,951	$ 160,890	$ 394,076
Projected Total Revenue over 50 year period (with Green Incentives)		$ 5,302,485	$ 5,185,751	$ 14,983,889	$ 115		$ 14,227,525	$ 2,492,769	$ 1,749,216	$ 4,419,601
Projected Total Revenue over 50 year period (w/o Green Incentives)		$ 4,988,654	$ 4,879,748	$ 14,050,434	$ 109		$ 13,381,383	$ 2,340,412	$ 1,638,774	$ 4,149,090
Benefit/Cost Ratio (with Green incentives)		0.94	0.92	1.26	0.00		1.43	0.64	0.14	0.66
Benefit/Cost Ratio (w/o Green incentives)		0.89	0.86	1.18	0.00		1.35	0.60	0.13	0.62
Internal Rate of Return (with Green incentives)		3.8%	3.6%	6.6%	Negative		7.8%	0.1%	Negative	0.4%
Internal Rate of Return (w/o Green incentives)		3.3%	3.1%	5.9%	Negative		7.0%	Negative	Negative	0.1%
Installed Cost $ per kW		$ 3,661	$ 3,838	$ 3,521	$ 18,704,752		$ 5,075	$ 7,050	$ 30,808	$ 3,507

Table E-6
Pacific Northwest Region Model Results

Facility Name		Wasco Dam	Wikiup Dam	Wildhorse Dam
Agency		Reclamation	Reclamation	Reclamation
Analysis Performed by		CDM	CDM	CDM
Project Location (State)		Oregon	Oregon	Nevada

Transmission Voltage	kV	138	115	138
T-Line Length	miles	7.89	12.43	4.22
Fish and Wildlife Mitigation		No	No	No
Recreation Mitigation		No	Yes	No
Historical & Archaeological		No	No	No
Water Quality Monitoring		No	No	No
Fish Passage Required		No	No	No

Results

Input Data Analysis

Data Set	years	8	22	24
Max Head	ft	36.1	57.8	79.6
Min Head	ft	9.8	9.8	34.6
Max Flow	cfs	38	1,947	1,340
Min Flow	cfs	0	13	0

Turbine Selection Analysis

Selected Turbine Type		Low Head	Kaplan	Francis
Selected Design Head	ft	25	55	70
Selected Design flow	cfs	9	1,157	53
Generator Speed	rpm	600	200	600
Max Head Limit	ft	30.9	68.2	87.1
Min Head Limit	ft	16.1	35.5	45.3
Max Flow Limit	cfs	9	1,157	53
Min Flow Limit	cfs	2	231	11

Power Generation Analysis

Installed Capacity	kW	13	3,950	267
Plant Factor		0.24	0.46	0.35
Projected Monthly Production:				
January	MWH	0	494	13
February*	MWH	0	553	15
March	MWH	0	642	33
April	MWH	1	1,558	43
May	MWH	1	2,774	101
June	MWH	4	2,915	149
July	MWH	6	2,663	162
August	MWH	7	1,633	149
September	MWH	5	1,015	92
October	MWH	1	626	29
November	MWH	0	343	3
December	MWH	0	435	2
Annual production*	MWH	26	15,650	791

* For non-leap year

Benefit/Cost Analysis

Projected expenditure to implement project

Total Construction Cost		$ 2,968,531	$ 15,178,550	$ 2,872,969
Annual O&M Cost		$ 77,340	$ 422,297	$ 89,658
Projected Total Cost over 50 year period		$ 4,073,446	$ 21,295,643	$ 4,200,189

Projected revenue after implementation of project

Power generation income for 2014 to 2060		$ 95,732	$ 54,829,886	$ 3,065,195
Green Energy Sellback income for 2014 to 2060		$ 3,132	$ 1,894,063	$ 95,763
Projected Total Revenue over 50 year period (with Green Incentives)		$ 36,115	$ 20,820,512	$ 1,152,074
Projected Total Revenue over 50 year period (w/o Green Incentives)		$ 33,965	$ 19,520,344	$ 1,086,338
Benefit/Cost Ratio (with Green incentives)		0.01	0.98	0.27
Benefit/Cost Ratio (w/o Green incentives)		0.01	0.92	0.26
Internal Rate of Return (with Green incentives)		Negative	4.2%	Negative
Internal Rate of Return (w/o Green incentives)		Negative	3.7%	Negative

Installed Cost $ per kW		$ 231,744	$ 3,843	$ 10,764

Table E-7
Upper Colorado Region Model Results

Facility Name		Angostura Diversion Dam	Arthur V. Watkins	Avalon Dam	Azeotea Creek and Willow Creek Conveyance Channel Station 1565+00	Azeotea Creek and Willow Creek Conveyance Channel Station 1702+75	Azeotea Creek and Willow Creek Conveyance Channel Station 1831+17	Azeotea Creek and Willow Creek Conveyance Channel Outlet	Azotea Tunnel	Big Sandy Dam	Blanco Diversion Dam
Agency		Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation
Analysis Performed by		CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM
Project Location (State)		New Mexico	Utah	New Mexico	New Mexico	New Mexico	New Mexico	New Mexico	New Mexico	Wyoming	New Mexico
Transmission Voltage	kV	115	115	115	115	115	115	115	115	138	115
T-Line Length	miles	0.65	1.99	2.76	5.00	5.00	5.00	5.00	5.00	21.09	12.93
Fish and Wildlife Mitigation		No	No	No	No	No	No	No	No	No	No
Recreation Mitigation		Yes	No	No	Yes	Yes	Yes	Yes	Yes	No	Yes
Historical & Archaeological		No	No	No	No	No	No	No	No	No	No
Water Quality Monitoring		No	No	No	No	No	No	No	No	No	No
Fish Passage Required		No	No	No	No	No	No	No	No	No	No
Results											
Input Data Analysis											
Data Set	years	9	12	30	30	30	30	30	30	20	28
Max Head	ft	5.2	27.5	21.4	22.0	20.0	18.0	5.0	31.8	58.7	31.0
Min Head	ft	0.0	8.9	0.0	18.0	17.0	15.0	0.0	21.0	22.2	22.0
Max Flow	cfs	344	1,388	15,600	1,080	1,080	1,080	1,220	1,080	1,059	500
Min Flow	cfs	0	0	0	0	0	0	0	0	0	0
Turbine Selection Analysis											
Selected Turbine Type		Low Head	Low Head	Kaplan	Low Head	Low Head	Low Head	Low Head	Low Head	Kaplan	Low Head
Selected Design Head	ft	3	25	17	18	17	15	0	22	51	22
Selected Design flow	cfs	190	20	216	65	65	65	94	65	89	35
Generator Speed	rpm	600	600	600	600	600	600	600	600	600	600
Max Head Limit	ft	3.5	31.3	21.3	22.8	21.5	19.0	0.5	27.1	64.3	27.8
Min Head Limit	ft	1.8	16.3	11.1	11.9	11.2	9.9	0.3	14.1	33.4	14.5
Max Flow Limit	cfs	190	20	216	65	65	65	94	65	89	35
Min Flow Limit	cfs	38	4	43	13	13	13	19	13	18	7
Power Generation Analysis											
Installed Capacity	kW	33	31	230	72	68	60	2	86	286	47
Plant Factor		0.32	0.46	0.52	0.39	0.38	0.38	0.11	0.30	0.36	0.36
Projected Monthly Production:											
January	MWH	0	8	13	0	0	0	0	0	6	0
February*	MWH	0	7	21	0	0	0	0	0	1	0
March	MWH	4	8	47	11	11	9	0	14	2	7
April	MWH	11	11	145	48	45	40	0	51	7	27
May	MWH	12	14	126	56	52	46	0	36	112	34
June	MWH	15	11	142	52	48	43	0	36	242	30
July	MWH	16	9	136	33	31	27	0	38	237	19
August	MWH	16	11	123	19	18	16	0	22	190	13
September	MWH	12	10	109	10	10	9	0	12	73	8
October	MWH	4	9	106	8	7	7	0	9	3	6
November	MWH	0	12	42	2	2	2	0	2	4	2
December	MWH	0	12	22	0	0	0	0	0	8	0
Annual production*	MWH	91	122	1,031	240	223	199	1	222	884	146
* For non-leap year											
Benefit/Cost Analysis											
Projected expenditure to implement project											
Total Construction Cost		$ 564,218	$ 966,053	$ 2,260,822	$ 2,215,338	$ 2,192,959	$ 2,149,375	$ 1,703,120	$ 2,284,357	$ 9,260,737	$ 4,656,151
Annual O&M Cost		$ 33,395	$ 40,893	$ 76,530	$ 66,572	$ 65,920	$ 64,654	$ 52,168	$ 68,588	$ 211,642	$ 110,656
Projected Total Cost over 50 year period		$ 1,099,804	$ 1,599,467	$ 3,409,315	$ 3,194,123	$ 3,162,200	$ 3,100,126	$ 2,472,810	$ 3,292,616	$ 12,191,619	$ 6,203,700
Projected revenue after implementation of project											
Power generation income for 2014 to 2060		$ 340,315	$ 451,377	$ 3,825,368	$ 873,836	$ 814,153	$ 723,424	$ 3,964	$ 815,564	$ 3,220,406	$ 533,360
Green Energy Sellback income for 2014 to 2060		$ 11,019	$ 14,785	$ 124,822	$ 29,022	$ 27,032	$ 24,023	$ 128	$ 26,859	$ 106,982	$ 17,685
Projected Total Revenue over 50 year period (with Green Incentives)		$ 128,605	$ 170,075	$ 1,446,138	$ 330,920	$ 308,311	$ 273,956	$ 1,497	$ 308,685	$ 1,217,430	$ 201,945
Projected Total Revenue over 50 year period (w/o Green Incentives)		$ 121,041	$ 159,926	$ 1,360,454	$ 310,998	$ 289,756	$ 257,466	$ 1,410	$ 290,248	$ 1,143,993	$ 189,806
Benefit/Cost Ratio (with Green incentives)		0.12	0.11	0.42	0.10	0.10	0.09	0.00	0.09	0.10	0.03
Benefit/Cost Ratio (w/o Green incentives)		0.11	0.10	0.40	0.10	0.09	0.08	0.00	0.09	0.09	0.03
Internal Rate of Return (with Green incentives)		Negative	Negative	Negative	Negative	Negative	Negative	Negative	Negative	Negative	Negative
Internal Rate of Return (w/o Green incentives)		Negative	Negative	Negative	Negative	Negative	Negative	Negative	Negative	Negative	Negative
Installed Cost $ per kW		$ 17,183	$ 31,426	$ 9,818	$ 30,674	$ 32,238	$ 35,760	$ 772,084	$ 26,649	$ 32,416	$ 98,200

Table E-7
Upper Colorado Region Model Results

Facility Name		Blanco Tunnel	Brantley Dam	Caballo Dam	Crawford Dam	Currant Creek Dam	Dolores Tunnel	Duschesne Tunnel	East Canal	East Canyon Dam	Eden Dam
Agency		Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation
Analysis Performed by		CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM
Project Location (State)		New Mexico	New Mexico	New Mexico	Colorado	Utah	Colorado	Utah	Colorado	Utah	Wyoming
Transmission Voltage	kV	115	115	115	138	115	115	138	115	138	115
T-Line Length	miles	12.93	2.18	1.55	0.94	11.62	5.00	21.19	4.24	15.32	18.48
Fish and Wildlife Mitigation		No	No	Yes	No	No	No	No	No	No	No
Recreation Mitigation		Yes	No	No	No	Yes	Yes	Yes	No	No	No
Historical & Archaeological		No	No	No	No	No	No	No	No	No	No
Water Quality Monitoring		No	No	No	No	No	No	No	No	No	No
Fish Passage Required		No	No	No	No	No	No	No	No	No	No
Results											
Input Data Analysis											
Data Set	years	23	30	4	28	16	8	5	11	10	7
Max Head	ft	109.0	48.6	50.4	135.0	119.0	83.9	64.0	2.0	186.3	17.5
Min Head	ft	109.0	8.2	23.8	135.0	109.8	83.9	64.0	2.0	133.9	0.0
Max Flow	cfs	500	1,200	2,603	67	545	650	171	175	262	200
Min Flow	cfs	0	0	0	6	0	0	7	0	4	0
Turbine Selection Analysis											Site has seasonal flows about 1-2 months per year; flows are too low for hydropower development at 30% flow exceedance
Selected Turbine Type		Francis	Kaplan	Kaplan	Francis	Francis	Francis	Low Head	Low Head	Francis	
Selected Design Head	ft	109	15	43	135	118	84	64	2	170	
Selected Design flow	cfs	35	219	1,213	31	17	17	21	119	76	
Generator Speed	rpm	600	600	600	600	600	600	600	600	600	
Max Head Limit	ft	136.3	19.2	53.7	168.8	146.9	104.9	80.0	2.5	212.4	
Min Head Limit	ft	70.8	10.0	27.9	87.8	76.4	54.6	41.6	1.3	110.4	
Max Flow Limit	cfs	35	219	1,213	31	17	17	21	119	76	
Min Flow Limit	cfs	7	44	243	6	3	3	4	24	15	
Power Generation Analysis											
Installed Capacity	kW	276	210	3,260	303	146	103	84	14	929	
Plant Factor		0.36	0.39	0.52	0.47	0.80	0.58	0.64	0.50	0.44	
Projected Monthly Production:											
January	MWH	1	6	0	0	70	40	21	0	44	
February*	MWH	0	15	141	35	62	31	19	0	164	
March	MWH	50	26	1,386	0	71	42	21	0	289	
April	MWH	167	112	1,851	1	95	58	60	6	328	
May	MWH	192	90	1,840	140	97	63	60	10	276	
June	MWH	167	90	2,675	218	98	61	60	10	566	
July	MWH	104	87	2,460	218	99	36	60	10	675	
August	MWH	73	92	2,501	218	101	24	49	10	634	
September	MWH	49	89	1,499	217	93	32	29	10	457	
October	MWH	35	77	742	132	73	43	30	6	116	
November	MWH	11	9	0	38	70	47	26	0	0	
December	MWH	1	4	0	0	75	41	22	0	0	
Annual production*	MWH	849	697	15,095	1,217	1,003	515	458	62	3,549	

* For non-leap year

Benefit/Cost Analysis											
Projected expenditure to implement project											
Total Construction Cost		$ 5,526,661	$ 1,991,280	$ 10,197,851	$ 1,592,447	$ 4,611,204	$ 2,277,109	$ 8,420,779	$ 1,559,241	$ 8,271,647	
Annual O&M Cost		$ 137,515	$ 70,470	$ 305,007	$ 66,662	$ 114,821	$ 69,176	$ 185,037	$ 50,644	$ 216,884	
Projected Total Cost over 50 year period		$ 7,471,006	$ 3,056,212	$ 14,678,321	$ 2,623,568	$ 6,234,955	$ 3,296,195	$ 10,956,801	$ 2,314,114	$ 11,374,450	
Projected revenue after implementation of project											
Power generation income for 2014 to 2060		$ 3,094,131	$ 2,581,596	$ 56,225,713	$ 4,384,774	$ 3,712,475	$ 1,829,432	$ 1,688,097	$ 221,110	$ 13,166,786	
Green Energy Sellback income for 2014 to 2060		$ 102,758	$ 84,379	$ 1,826,599	$ 147,225	$ 121,359	$ 62,298	$ 55,479	$ 7,471	$ 429,575	
Projected Total Revenue over 50 year period (with Green Incentives)		$ 1,171,681	$ 976,203	$ 21,252,507	$ 1,670,662	$ 1,398,772	$ 698,040	$ 636,609	$ 84,299	$ 4,964,580	
Projected Total Revenue over 50 year period (w/o Green Incentives)		$ 1,101,143	$ 918,282	$ 19,998,648	$ 1,569,600	$ 1,315,466	$ 655,276	$ 598,525	$ 79,171	$ 4,669,701	
Benefit/Cost Ratio (with Green incentives)		0.16	0.32	1.45	0.64	0.22	0.21	0.06	0.04	0.44	
Benefit/Cost Ratio (w/o Green incentives)		0.15	0.30	1.36	0.60	0.21	0.20	0.05	0.03	0.41	
Internal Rate of Return (with Green incentives)		Negative	Negative	7.9%	Negative	Negative	Negative	Negative	Negative	Negative	
Internal Rate of Return (w/o Green incentives)		Negative	Negative	7.1%	Negative	Negative	Negative	Negative	Negative	Negative	
Installed Cost $ per kW		$ 20,041	$ 9,481	$ 3,128	$ 5,264	$ 31,659	$ 22,077	$ 100,480	$ 107,915	$ 8,907	

Table E-7
Upper Colorado Region Model Results

Facility Name		Fruitgrowers Dam	Fort Sumner Diversion Dam	Garnet Diversion Dam	Grand Valley Diversion Dam	Gunnison Diversion Dam	Gunnison Tunnel	Hammond Diversion Dam	Heron Dam	Huntington North Dam	Hyrum Dam
Agency		Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation
Analysis Performed by		CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM
Project Location (State)		Colorado	New Mexico	Colorado	Colorado	Colorado	Colorado	New Mexico	New Mexico	Utah	Utah
Transmission Voltage	kV	115	115	115	115	115	115	115	69	138	138
T-Line Length	miles	5.66	5.00	5.00	5.00	5.00	5.00	5.00	4.97	0.76	8.61
Fish and Wildlife Mitigation		No	No	No	Yes	Yes	No	No	Yes	No	No
Recreation Mitigation		No	No	No	Yes	No	No	No	No	No	No
Historical & Archaeological		No	No	No	Yes	No	No	No	No	No	No
Water Quality Monitoring		No	No	No	No	No	No	No	No	No	No
Fish Passage Required		No	No	No	No	No	No	No	No	No	No
Results											
Input Data Analysis											
Data Set	years	7	30	11	15	28	30	6	29	11	7
Max Head	ft	32.6	15.2	2.0	14.0	17.0	70.0	7.9	274.9	58.2	83.0
Min Head	ft	8.1	11.0	2.0	14.0	17.0	70.0	7.9	234.0	38.9	47.3
Max Flow	cfs	67	141	65	29,600	10,600	1,191	92	2,780	37	1,300
Min Flow	cfs	0	0	0	58	65	0	0	0	0	0
Turbine Selection Analysis											
Selected Turbine Type		Low Head	Low Head	Low Head	Kaplan	Kaplan	Kaplan	Low Head	Francis	Low Head	Francis
Selected Design Head	ft	28	14	2	14	17	70	8	249	55	75
Selected Design flow	cfs	17	90	44	2,260	1,350	875	71	150	6	90
Generator Speed	rpm	600	600	600	600	600	300	600	600	600	600
Max Head Limit	ft	34.9	17.1	2.5	17.5	21.3	87.5	9.9	311.4	68.7	94.4
Min Head Limit	ft	18.1	8.9	1.3	9.1	11.0	45.5	5.2	161.9	35.7	49.1
Max Flow Limit	cfs	17	90	44	2,260	1,350	875	71	150	6	90
Min Flow Limit	cfs	3	18	9	452	270	175	14	30	1	18
Power Generation Analysis											
Installed Capacity	kW	29	75	5	1,979	1,435	3,830	35	2,701	20	491
Plant Factor		0.50	0.59	0.46	0.84	0.75	0.58	0.49	0.38	0.30	0.49
Projected Monthly Production:											
January	MWH	1	1	0	1,239	804	1,555	0	719	0	122
February*	MWH	4	8	0	1,156	752	1,458	0	882	0	111
March	MWH	6	41	0	1,341	796	1,567	0	1,458	1	126
April	MWH	8	47	2	1,148	695	1,577	13	1,384	3	303
May	MWH	14	48	4	1,525	796	1,586	25	232	8	348
June	MWH	19	51	4	1,550	782	1,594	25	252	9	308
July	MWH	21	47	4	1,144	791	1,601	25	622	9	290
August	MWH	21	45	4	836	756	1,610	25	587	10	193
September	MWH	18	46	3	815	736	1,616	25	601	5	72
October	MWH	11	44	1	881	716	1,624	12	346	4	32
November	MWH	0	0	0	1,357	772	1,631	0	828	2	72
December	MWH	1	0	0	1,252	825	1,637	0	961	1	74
Annual production*	MWH	124	378	21	14,246	9,220	19,057	148	8,874	51	2,052
* For non-leap year											
Benefit/Cost Analysis											
Projected expenditure to implement project											
Total Construction Cost		$ 2,116,455	$ 2,213,565	$ 1,713,350	$ 9,070,007	$ 6,934,923	$ 11,385,453	$ 1,983,291	$ 8,020,434	$ 514,449	$ 5,081,267
Annual O&M Cost		$ 62,163	$ 67,117	$ 52,658	$ 241,266	$ 200,416	$ 366,632	$ 60,175	$ 246,583	$ 31,715	$ 140,872
Projected Total Cost over 50 year period		$ 3,026,516	$ 3,201,979	$ 2,490,737	$ 12,532,346	$ 9,859,889	$ 16,842,323	$ 2,869,582	$ 11,660,934	$ 1,024,829	$ 7,120,367
Projected revenue after implementation of project											
Power generation income for 2014 to 2060		$ 446,536	$ 1,397,602	$ 75,816	$ 50,846,185	$ 33,030,874	$ 68,261,837	$ 552,467	$ 32,859,372	$ 190,503	$ 7,523,900
Green Energy Sellback income for 2014 to 2060		$ 15,045	$ 45,783	$ 2,556	$ 1,724,626	$ 1,116,154	$ 2,307,102	$ 17,886	$ 1,074,468	$ 6,223	$ 248,418
Projected Total Revenue over 50 year period (with Green Incentives)		$ 170,188	$ 528,556	$ 28,899	$ 19,392,086	$ 12,592,700	$ 26,025,179	$ 208,761	$ 12,413,640	$ 71,840	$ 2,838,438
Projected Total Revenue over 50 year period (w/o Green Incentives)		$ 159,860	$ 497,129	$ 27,144	$ 18,208,229	$ 11,826,524	$ 24,441,485	$ 196,483	$ 11,676,080	$ 67,568	$ 2,667,913
Benefit/Cost Ratio (with Green incentives)		0.06	0.17	0.01	1.55	1.28	1.55	0.07	1.06	0.07	0.40
Benefit/Cost Ratio (w/o Green incentives)		0.05	0.16	0.01	1.45	1.20	1.45	0.07	1.00	0.07	0.37
Internal Rate of Return (with Green incentives)		Negative	Negative	Negative	8.6%	6.7%	8.8%	Negative	4.9%	Negative	Negative
Internal Rate of Return (w/o Green incentives)		Negative	Negative	Negative	7.7%	6.0%	7.9%	Negative	4.4%	Negative	Negative
Installed Cost $ per kW		$ 72,409	$ 29,472	$ 321,090	$ 4,584	$ 4,832	$ 2,972	$ 57,350	$ 2,970	$ 25,611	$ 10,346

Table E-7
Upper Colorado Region Model Results

Facility Name		Inlet Canal	Ironstone Canal	Isleta Diversion Dam	Joes Valley Dam	Layout Creek	Little Oso Div Dam	Lost Creek Dam	Lost Lake Dam	Loutzenheizer Canal	M&D Canal - Shavano Falls
Agency		Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation
Analysis Performed by		CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM
Project Location (State)		Colorado	Colorado	New Mexico	Utah	Utah	Colorado	Utah	Utah		Colorado
Transmission Voltage	kV	115	115	115	138	138	115	115	138	115	115
T-Line Length	miles	5.00	5.00	5.00	7.68	9.65	5.00	15.99	25.55	5.00	5.00
Fish and Wildlife Mitigation		No	No	No	Yes	No	No	No	No	No	No
Recreation Mitigation		No	No	No	Yes	Yes	Yes	No	Yes	No	No
Historical & Archaeological		No	No	Yes	No	No	No	No	No	No	No
Water Quality Monitoring		No	No	No	No	No	No	No	No	No	No
Fish Passage Required		No	No	No	No	No	No	No	No	No	No

Results

Input Data Analysis

Data Set	years	16	11	9	9	10	30	13	13	11	1
Max Head	ft	159.0	0.0	2.2	175.3	249.0	9.5	187.4	24.0	0.0	
Min Head	ft	159.0	0.0	0.0	122.5	249.0	9.5	15.0	0.5	0.0	
Max Flow	cfs	900	343	2,066	743	7	165	499	61	168	
Min Flow	cfs	0	0	0	2	0	0	0	0	0	

Turbine Selection Analysis			No head available for hydropower potential							No head available for hydropower potential	Insufficient data (< 3 years); Low Confidence Results
Selected Turbine Type		Pelton		Kaplan	Francis	Low Head	Low Head	Pelton	Low Head		Francis
Selected Design Head	ft	159		0	159	249	10	164	17		165
Selected Design flow	cfs	22		433	141	2	8	34	1		240
Generator Speed	rpm	600		600	600	600	600	600	600		600
Max Head Limit	ft	174.9		0.4	199.0	311.3	11.9	180.6	21.7		206.3
Min Head Limit	ft	103.3		0.2	103.5	161.8	6.2	106.7	11.3		107.2
Max Flow Limit	cfs	22		433	141	2	8	34	1		240
Min Flow Limit	cfs	4		87	28	0	2	7	0		48

Power Generation Analysis

Installed Capacity	kW	252		8	1,624	24	4	410	1		2,862
Plant Factor		0.45		0.00	0.47	0.79	0.55	0.37	0.14		0.62
Projected Monthly Production:											
January	MWH	12		0	85	13	1	68	0		0
February*	MWH	15		0	80	13	1	74	0		0
March	MWH	68		0	78	13	2	71	0		902
April	MWH	166		0	297	13	3	74	0		1,967
May	MWH	174		0	1,033	15	3	83	0		2,061
June	MWH	165		0	1,223	15	3	134	0		2,061
July	MWH	121		0	1,183	13	2	176	0		2,061
August	MWH	105		0	1,082	13	1	213	0		2,061
September	MWH	83		0	854	12	1	181	0		1,975
October	MWH	28		0	468	14	1	91	0		1,405
November	MWH	19		0	116	15	1	65	0		927
December	MWH	9		0	98	15	1	66	0		0
Annual production*	MWH	966		0	6,596	165	21	1,295	1		15,419

* For non-leap year

Benefit/Cost Analysis

Projected expenditure to implement project

Total Construction Cost		$ 2,596,626		$ 1,788,655	$ 7,764,309	$ 3,781,806	$ 1,703,386	$ 6,599,196	$ 9,471,038		$ 7,260,364
Annual O&M Cost		$ 82,694		$ 54,365	$ 210,501	$ 93,657	$ 52,352	$ 164,224	$ 199,500		$ 256,570
Projected Total Cost over 50 year period		$ 3,825,093		$ 2,589,632	$ 10,797,307	$ 5,104,575	$ 2,476,246	$ 8,921,256	$ 12,173,333		$ 11,136,740

Projected revenue after implementation of project

Power generation income for 2014 to 2060		$ 3,422,764		$ 1,024	$ 24,386,164	$ 609,928	$ 75,045	$ 4,839,145	$ 4,549		$ 55,009,926
Green Energy Sellback income for 2014 to 2060		$ 116,868		$ 34	$ 798,219	$ 19,923	$ 2,561	$ 156,801	$ 147		$ 1,865,729
Projected Total Revenue over 50 year period (with Green Incentives)		$ 1,306,269		$ 387	$ 9,197,841	$ 229,733	$ 28,639	$ 1,822,418	$ 1,713		$ 20,981,443
Projected Total Revenue over 50 year period (w/o Green Incentives)		$ 1,226,046		$ 364	$ 8,649,908	$ 216,057	$ 26,881	$ 1,714,783	$ 1,612		$ 19,700,723
Benefit/Cost Ratio (with Green incentives)		0.34		0.00	0.85	0.05	0.01	0.20	0.00		1.88
Benefit/Cost Ratio (w/o Green incentives)		0.32		0.00	0.80	0.04	0.01	0.19	0.00		1.77
Internal Rate of Return (with Green incentives)		Negative		Negative	3.0%	Negative	Negative	Negative	Negative		11.4%
Internal Rate of Return (w/o Green incentives)		Negative		Negative	2.6%	Negative	Negative	Negative	Negative		10.1%
Installed Cost $ per kW		$ 10,320		$ 217,625	$ 4,780	$ 155,835	$ 381,880	$ 16,082	$ 8,970,928		$ 2,536

Table E-7
Upper Colorado Region Model Results

Facility Name		Meeks Cabin Dam	Montrose and Delta Canal	Moon Lake Dam	Nambe Falls Dam	Newton Dam	Oso Diversion Dam	Outlet Canal	Paonia Dam	Platoro Dam	Red Fleet Dam
Agency		Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation
Analysis Performed by		CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM
Project Location (State)		Wyoming	Colorado	Utah	New Mexico	Utah	Colorado	Colorado	Colorado	Colorado	Utah
Transmission Voltage	kV	138	115	138	69	115	115	115	115	115	115
T-Line Length	miles	21.00	5.00	13.18	4.18	1.79	5.00	5.00	8.32	23.64	4.04
Fish and Wildlife Mitigation		No	No	No	No	No	No	No	Yes	No	No
Recreation Mitigation		No	No	Yes	No	No	No	No	No	No	No
Historical & Archaeological		No	No	No	Yes	No	No	No	No	No	No
Water Quality Monitoring		No	No	No	No	No	No	No	No	No	No
Fish Passage Required		No	No	No	No	No	No	No	No	No	No
Results											
Input Data Analysis											
Data Set	years	11	11	7	6	3	30	16	16	53	15
Max Head	ft	156.4	3.0	82.6	120.0	75.9	0.0	252.0	172.8	131.0	125.5
Min Head	ft	59.1	3.0	27.9	120.0	45.1	0.0	252.0	73.0	131.0	81.8
Max Flow	cfs	1,485	604	1,339	109	232	1,181	97	3,404	328	300
Min Flow	cfs	2	0	0	1	0	7	0	0	10	0
Turbine Selection Analysis						Site has low seasonal flow for 5 months per year; flows are too low for hydropower development at 30% flow exceedance	No head available for hydropower potential				
Selected Turbine Type		Francis	Kaplan	Francis	Francis			Pelton	Francis	Francis	Francis
Selected Design Head	ft	130	3	66	120			252	149	131	115
Selected Design flow	cfs	169	511	134	17			32	147	89	55
Generator Speed	rpm	600	600	600	600			600	600	600	600
Max Head Limit	ft	162.4	3.8	81.9	150.0			277.2	186.2	163.8	143.1
Min Head Limit	ft	84.4	1.9	42.6	78.0			163.8	96.8	85.1	74.4
Max Flow Limit	cfs	169	511	134	17			32	147	89	55
Min Flow Limit	cfs	34	102	27	3			6	29	18	11
Power Generation Analysis											
Installed Capacity	kW	1,586	96	634	147			586	1,582	845	455
Plant Factor		0.35	0.58	0.29	0.47			0.37	0.43	0.52	0.49
Projected Monthly Production:											
January	MWH	0	0	0	1			0	41	0	33
February*	MWH	0	0	0	6			0	85	0	20
March	MWH	0	0	0	38			0	321	0	32
April	MWH	8	50	94	77			3	582	355	130
May	MWH	769	77	412	94			233	953	608	313
June	MWH	1,234	79	442	96			388	952	608	340
July	MWH	1,075	79	276	91			396	863	608	319
August	MWH	812	79	229	81			394	942	608	304
September	MWH	581	69	83	66			290	587	311	230
October	MWH	198	47	27	33			92	219	264	103
November	MWH	31	0	0	10			31	171	384	40
December	MWH	0	0	0	0			13	104	0	39
Annual production*	MWH	4,709	478	1,563	593			1,839	5,821	3,747	1,904
* For non-leap year											
Benefit/Cost Analysis											
Projected expenditure to implement project											
Total Construction Cost		$ 11,641,242	$ 2,343,763	$ 7,328,461	$ 2,373,716			$ 3,264,806	$ 7,092,462	$ 10,106,167	$ 3,031,941
Annual O&M Cost		$ 302,269	$ 70,840	$ 185,752	$ 73,702			$ 108,642	$ 203,733	$ 246,518	$ 100,063
Projected Total Cost over 50 year period		$ 15,956,360	$ 3,386,402	$ 9,965,976	$ 3,463,755			$ 4,890,695	$ 10,062,365	$ 13,575,512	$ 4,527,407
Projected revenue after implementation of project											
Power generation income for 2014 to 2060		$ 17,030,332	$ 1,713,426	$ 5,698,281	$ 2,196,546			$ 6,658,669	$ 20,822,512	$ 13,465,942	$ 7,023,602
Green Energy Sellback income for 2014 to 2060		$ 569,825	$ 57,885	$ 189,096	$ 71,730			$ 222,567	$ 704,385	$ 453,404	$ 230,388
Projected Total Revenue over 50 year period (with Green Incentives)		$ 6,441,788	$ 653,253	$ 2,152,277	$ 830,579			$ 2,535,836	$ 7,939,048	$ 5,132,795	$ 2,649,457
Projected Total Revenue over 50 year period (w/o Green Incentives)		$ 6,050,634	$ 613,519	$ 2,022,473	$ 781,340			$ 2,383,056	$ 7,455,527	$ 4,821,559	$ 2,491,308
Benefit/Cost Ratio (with Green incentives)		0.40	0.19	0.22	0.24			0.52	0.79	0.38	0.59
Benefit/Cost Ratio (w/o Green incentives)		0.38	0.18	0.20	0.23			0.49	0.74	0.36	0.55
Internal Rate of Return (with Green incentives)		Negative	Negative	Negative	Negative			Negative	2.3%	Negative	Negative
Internal Rate of Return (w/o Green incentives)		Negative	Negative	Negative	Negative			Negative	1.9%	Negative	Negative
Installed Cost $ per kW		$ 7,341	$ 24,452	$ 11,564	$ 16,097			$ 5,570	$ 4,482	$ 11,964	$ 6,666

Table E-7
Upper Colorado Region Model Results

Facility Name		Ridgway Dam	Rhodes Diversion Dam	Rifle Gap Dam	San Acacia Diversion Dam	Scofield Dam	Selig Canal	Silver Jack Dam	Sixth Water Flow Control	Soldier Creek Dam	South Canal Tunnel
Agency		Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation
Analysis Performed by		CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM
Project Location (State)		Colorado	Utah	Colorado	New Mexico	Utah	Colorado	Colorado	Utah	Utah	Colorado
Transmission Voltage	kV	138	138	138	115	138	115	115	138	138	115
T-Line Length	miles	6.62	14.78	0.04	5.00	0.82	5.00	7.59	6.14	0.56	5.00
Fish and Wildlife Mitigation		Yes	No	Yes	Yes	No	No	No	Yes	Yes	No
Recreation Mitigation		No	Yes	No	Yes	No	No	No	Yes	No	No
Historical & Archaeological		No	No	No	No	No	No	No	No	No	No
Water Quality Monitoring		No	No	No	No	No	No	No	No	No	No
Fish Passage Required		No	No	No	No	No	No	No	No	No	No
Results											
Input Data Analysis											
Data Set	years	19	22	6	4	11	11	7	12	13	19
Max Head	ft	192.9	7.0	103.5	7.5	49.4	2.0	127.0	1149.0	243.5	18.0
Min Head	ft	80.9	7.0	65.8	7.5	18.8	2.0	53.8	1149.0	191.0	18.0
Max Flow	cfs	1,141	83	165	156	365	254	899	623	2,648	999
Min Flow	cfs	27	0	0	0	0	0	0	20	0	0
Turbine Selection Analysis											
Selected Turbine Type		Francis	Low Head	Francis	Low Head	Kaplan	Low Head	Francis	Pelton	Pelton	Kaplan
Selected Design Head	ft	181	7	101	8	39	2	103	1,149	233	18
Selected Design flow	cfs	257	2	46	44	110	186	101	309	26	785
Generator Speed	rpm	600	600	600	600	600	600	600	360	600	600
Max Head Limit	ft	226.8	8.8	126.9	9.4	48.3	2.5	128.6	1263.9	256.2	22.5
Min Head Limit	ft	117.9	4.5	66.0	4.9	25.1	1.3	66.9	746.8	151.4	11.7
Max Flow Limit	cfs	257	2	46	44	110	186	101	309	26	785
Min Flow Limit	cfs	51	0	9	9	22	37	20	62	5	157
Power Generation Analysis											
Installed Capacity	kW	3,366	1	341	20	266	23	748	25,800	444	884
Plant Factor		0.49	0.53	0.59	0.50	0.40	0.50	0.46	0.52	0.76	0.59
Projected Monthly Production:											
January	MWH	275	0	51	4	4	0	36	3,732	193	0
February*	MWH	256	0	120	4	22	0	60	2,741	180	0
March	MWH	461	0	126	6	35	0	39	1,081	193	92
April	MWH	1,315	0	137	5	46	10	107	6,323	294	519
May	MWH	1,865	0	213	8	97	16	471	13,092	302	659
June	MWH	2,164	0	233	10	148	16	648	17,137	305	674
July	MWH	2,334	0	223	13	210	16	608	18,576	299	710
August	MWH	2,157	0	203	12	166	16	516	18,576	278	724
September	MWH	1,406	0	179	11	117	15	293	17,716	270	662
October	MWH	968	0	136	7	60	9	83	6,806	205	447
November	MWH	480	0	65	4	1	0	13	4,445	196	11
December	MWH	360	0	55	4	0	0	38	4,196	193	0
Annual production*	MWH	14,040	3	1,740	86	906	98	2,913	114,420	2,909	4,497

* For non-leap year

Benefit/Cost Analysis		Ridgway Dam	Rhodes Diversion Dam	Rifle Gap Dam	San Acacia Diversion Dam	Scofield Dam	Selig Canal	Silver Jack Dam	Sixth Water Flow Control	Soldier Creek Dam	South Canal Tunnel
Projected expenditure to implement project											
Total Construction Cost		$ 9,885,093	$ 5,493,846	$ 1,574,920	$ 1,895,014	$ 1,780,472	$ 1,868,629	$ 4,863,860	$ 38,227,881	$ 1,790,237	$ 5,005,819
Annual O&M Cost		$ 296,172	$ 124,171	$ 65,544	$ 57,158	$ 69,280	$ 57,079	$ 145,567	$ 1,031,860	$ 72,626	$ 154,919
Projected Total Cost over 50 year period		$ 14,237,188	$ 7,208,479	$ 2,587,998	$ 2,735,950	$ 2,841,858	$ 2,710,340	$ 7,002,454	$ 53,081,723	$ 2,909,106	$ 7,295,714
Projected revenue after implementation of project											
Power generation income for 2014 to 2060		$ 50,461,877	$ 12,251	$ 6,221,934	$ 321,933	$ 3,373,167	$ 352,567	$ 10,496,981	$ 425,322,178	$ 10,754,052	$ 16,096,447
Green Energy Sellback income for 2014 to 2060		$ 1,699,018	$ 401	$ 210,659	$ 10,375	$ 109,679	$ 11,911	$ 352,529	$ 13,847,026	$ 352,147	$ 544,183
Projected Total Revenue over 50 year period (with Green Incentives)		$ 19,232,309	$ 4,616	$ 2,372,467	$ 121,542	$ 1,271,727	$ 134,418	$ 3,999,429	$ 160,305,114	$ 4,052,759	$ 6,137,241
Projected Total Revenue over 50 year period (w/o Green Incentives)		$ 18,066,028	$ 4,341	$ 2,227,861	$ 114,420	$ 1,196,438	$ 126,241	$ 3,757,437	$ 150,799,901	$ 3,811,030	$ 5,763,689
Benefit/Cost Ratio (with Green incentives)		1.35	0.00	0.92	0.04	0.45	0.05	0.57	3.02	1.39	0.84
Benefit/Cost Ratio (w/o Green incentives)		1.27	0.00	0.86	0.04	0.42	0.05	0.54	2.84	1.31	0.79
Internal Rate of Return (with Green incentives)		7.3%	Negative	3.5%	Negative	Negative	Negative	Negative	17.1%	7.9%	2.8%
Internal Rate of Return (w/o Green incentives)		6.5%	Negative	2.9%	Negative	Negative	Negative	Negative	15.3%	7.0%	2.4%
Installed Cost $ per kW		$ 2,937	$ 7,579,045	$ 4,621	$ 94,272	$ 6,700	$ 82,287	$ 6,504	$ 1,482	$ 4,033	$ 5,665

Table E-7
Upper Colorado Region Model Results

Facility Name		South Canal, Sta 19+10 "Site #1"	South Canal, Sta. 106+65, "Site #3"	South Canal, Sta. 181+10, "Site #4"	South Canal, Sta. 427+00, "Site #5"	Southside Canal (2 drops)	Southside Canal (3 drops)	Spanish Fork Flow Control Structure	Strawberry Tunnel Turnout	Starvation Dam	Stateline Dam
Agency		Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation
Analysis Performed by		CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM
Project Location (State)		Colorado	Colorado	Colorado	Colorado			Utah	Utah	Utah	Utah
Transmission Voltage	kV	115	115	115	115	115	115	138	138	13.8	69
T-Line Length	miles	5.00	5.00	5.00	5.00	5.00	5.00	3.50	7.67	8.90	19.35
Fish and Wildlife Mitigation		No	No	No	No	No	No	Yes	No	Yes	No
Recreation Mitigation		No	No	No	No	No	No	No	Yes	No	Yes
Historical & Archaeological		No	No	No	No	No	No	No	No	No	No
Water Quality Monitoring		No	No	No	No	No	No	No	No	No	No
Fish Passage Required		No	No	No	No	No	No	No	No	No	No
Results											
Input Data Analysis											
Data Set	years	14	14	14	14	1	1	3	7	23	11
Max Head	ft	51.0	46.0	63.0	28.0			900.0	2.0	149.7	118.3
Min Head	ft	51.0	46.0	63.0	28.0			900.0	2.0	111.9	58.5
Max Flow	cfs	928	928	928	928			380	71	1,900	560
Min Flow	cfs	0	0	0	0			0	8	0	0
						Insufficient data (< 3 years); Low Confidence Results	Insufficient data (< 3 years); Low Confidence Results				
Turbine Selection Analysis											
Selected Turbine Type		Kaplan	Kaplan	Kaplan	Kaplan	Francis	Francis	Pelton	Low Head	Francis	Francis
Selected Design Head	ft	51	46	63	28	346	282	900	2	144	89
Selected Design flow	cfs	773	773	773	773	81	81	124	28	292	44
Generator Speed	rpm	300	300	300	600	600	600	600	600	600	600
Max Head Limit	ft	63.8	57.5	78.8	35.0	432.5	352.5	990.0	2.5	180.3	111.1
Min Head Limit	ft	33.1	29.9	40.9	18.2	224.9	183.3	585.0	1.3	93.7	57.8
Max Flow Limit	cfs	773	773	773	773	81	81	124	28	292	44
Min Flow Limit	cfs	155	155	155	155	16	16	25	6	58	9
Power Generation Analysis											
Installed Capacity	kW	2,465	2,224	3,046	1,354	2,026	1,651	8,114	3	3,043	282
Plant Factor		0.59	0.59	0.59	0.59	0.38	0.38	0.33	0.90	0.50	0.30
Projected Monthly Production:											
January	MWH	0	0	0	0	0	0	1,947	2	431	4
February*	MWH	0	0	0	0	0	0	1,796	2	354	3
March	MWH	309	279	382	170	0	0	1,947	2	562	3
April	MWH	1,448	1,306	1,788	795	0	0	18	2	1,147	3
May	MWH	1,799	1,623	2,222	988	722	589	0	2	1,847	95
June	MWH	1,868	1,685	2,308	1,026	1,459	1,189	2,624	2	1,763	104
July	MWH	1,978	1,784	2,444	1,086	1,459	1,189	3,895	2	1,872	115
August	MWH	2,025	1,826	2,501	1,112	1,459	1,189	3,887	2	1,946	146
September	MWH	1,814	1,637	2,241	996	1,459	1,189	2,927	2	1,541	146
October	MWH	1,212	1,093	1,497	665	0	0	16	2	708	81
November	MWH	123	111	152	68	0	0	1,916	2	514	17
December	MWH	0	0	0	0	0	0	1,947	2	483	4
Annual production*	MWH	12,576	11,343	15,536	6,905	6,557	5,344	22,920	27	13,168	720

* For non-leap year

Benefit/Cost Analysis											
Projected expenditure to implement project											
Total Construction Cost		$ 8,883,365	$ 8,399,672	$ 9,975,064	$ 6,155,413	$ 5,595,900	$ 5,169,794	$ 13,147,522	$ 2,916,952	$ 10,530,617	$ 8,492,411
Annual O&M Cost		$ 280,479	$ 264,038	$ 318,048	$ 193,082	$ 199,495	$ 180,435	$ 435,866	$ 75,744	$ 302,563	$ 195,072
Projected Total Cost over 50 year period		$ 13,043,815	$ 12,313,226	$ 14,700,796	$ 9,016,206	$ 8,613,986	$ 7,890,686	$ 19,666,466	$ 3,998,265	$ 14,941,396	$ 11,197,363
Projected revenue after implementation of project											
Power generation income for 2014 to 2060		$ 45,022,711	$ 40,608,655	$ 55,616,422	$ 24,718,363	$ 23,709,467	$ 19,323,897	$ 86,975,912	$ 98,660	$ 48,637,539	$ 2,673,199
Green Energy Sellback income for 2014 to 2060		$ 1,521,755	$ 1,372,561	$ 1,879,820	$ 835,474	$ 793,365	$ 646,616	$ 2,774,730	$ 3,220	$ 1,593,607	$ 87,062
Projected Total Revenue over 50 year period (with Green Incentives)		$ 17,165,886	$ 15,482,932	$ 21,204,968	$ 9,424,413	$ 9,029,597	$ 7,359,381	$ 32,698,440	$ 37,163	$ 18,339,736	$ 1,007,824
Projected Total Revenue over 50 year period (w/o Green Incentives)		$ 16,121,285	$ 14,540,744	$ 19,914,575	$ 8,850,906	$ 8,484,995	$ 6,915,515	$ 30,793,746	$ 34,952	$ 17,245,814	$ 948,061
Benefit/Cost Ratio (with Green incentives)		1.32	1.26	1.44	1.05	1.05	0.93	1.66	0.01	1.23	0.09
Benefit/Cost Ratio (w/o Green incentives)		1.24	1.18	1.35	0.98	0.99	0.88	1.57	0.01	1.15	0.08
Internal Rate of Return (with Green incentives)		7.1%	6.6%	8.0%	4.8%	4.8%	3.7%	9.6%	Negative	6.2%	Negative
Internal Rate of Return (w/o Green incentives)		6.3%	5.9%	7.2%	4.2%	4.2%	3.2%	8.6%	Negative	5.6%	Negative
Installed Cost $ per kW		$ 3,603	$ 3,777	$ 3,275	$ 4,548	$ 2,762	$ 3,131	$ 1,620	$ 848,278	$ 3,461	$ 30,145

Table E-7
Upper Colorado Region Model Results

Facility Name		Steinaker Dam	Stillwater Tunnel	Sumner Dam	Swasey Dam	Syar Tunnel	Taylor Park Dam	Trial Lake Dam	Upper Diamond Fork Flow Control Structure	Upper Stillwater Dam	Vat Diversion Dam
Agency		Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation
Analysis Performed by		CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM	CDM
Project Location (State)		Utah	Utah	New Mexico	Utah	Utah	Colorado	Utah	Utah	Utah	Utah
Transmission Voltage	kV	115	138	115	138	138	115	115	138	115	115
T-Line Length	miles	0.99	12.24	3.94	5.40	7.68	14.62	26.36	4.34	12.27	16.11
Fish and Wildlife Mitigation		No	No	Yes	No	Yes	Yes	No	Yes	No	No
Recreation Mitigation		No	Yes	No	No	Yes	No	Yes	Yes	Yes	Yes
Historical & Archaeological		No	No	No	No	No	No	Yes	No	No	No
Water Quality Monitoring		No	No	No	No	No	No	No	No	No	No
Fish Passage Required		No	No	No	No	No	No	No	No	No	No
Results											
Input Data Analysis											
Data Set	years	10	13	30	11	5	44	12	12	13	22
Max Head	ft	131.6	65.0	131.2	5.1	125.0	155.7	36.3	547.0	185.8	20.5
Min Head	ft	62.2	65.0	74.3	5.1	125.0	0.0	0.0	547.0	40.1	20.5
Max Flow	cfs	200	299	1,690	86	471	1,830	119	623	1,322	298
Min Flow	cfs	0	0	0	0	0	4	0	20	0	0
Turbine Selection Analysis											Site has low seasonal flows about 3-5 months per year, flows are too low for hydropower development at 30% flow exceedance
Selected Turbine Type		Francis	Francis	Francis	Low Head	Francis	Francis	Low Head	Francis	Francis	
Selected Design Head	ft	120	65	114	5	125	141	28	547	161	
Selected Design flow	cfs	70	88	100	9	195	250	6	309	50	
Generator Speed	rpm	600	600	600	600	600	600	600	600	600	
Max Head Limit	ft	149.9	81.3	142.1	6.4	156.3	175.9	34.9	683.8	201.4	
Min Head Limit	ft	78.0	42.3	73.9	3.3	81.3	91.5	18.1	355.5	104.7	
Max Flow Limit	cfs	70	88	100	9	195	250	6	309	50	
Min Flow Limit	cfs	14	18	20	2	39	50	1	62	10	
Power Generation Analysis											
Installed Capacity	kW	603	413	822	3	1,762	2,543	10	12,214	581	
Plant Factor		0.38	0.38	0.61	0.34	0.53	0.57	0.18	0.50	0.38	
Projected Monthly Production:											
January	MWH	18	24	86	0	585	450	0	1,481	108	
February*	MWH	24	24	160	0	517	419	1	1,050	83	
March	MWH	26	129	480	0	494	589	1	401	36	
April	MWH	101	162	521	0	191	850	0	2,759	0	
May	MWH	340	202	520	1	434	1,128	1	6,010	33	
June	MWH	406	190	531	1	1,110	1,542	1	8,139	298	
July	MWH	384	198	493	2	1,269	1,825	4	8,794	372	
August	MWH	342	153	482	2	1,268	1,801	4	8,794	276	
September	MWH	246	54	486	2	1,032	1,619	2	8,436	216	
October	MWH	77	86	468	0	80	1,089	1	2,868	208	
November	MWH	0	79	24	0	491	657	0	1,797	154	
December	MWH	0	34	48	0	514	518	0	1,632	121	
Annual production*	MWH	1,965	1,334	4,300	8	7,982	12,488	14	52,161	1,904	
* For non-leap year											
Benefit/Cost Analysis											
Projected expenditure to implement project											
Total Construction Cost		$ 2,388,352	$ 6,342,411	$ 4,193,547	$ 2,068,546	$ 8,246,112	$ 10,991,162	$ 8,736,488	$ 22,058,484	$ 6,064,467	
Annual O&M Cost		$ 93,879	$ 159,495	$ 129,966	$ 59,591	$ 222,716	$ 299,266	$ 183,982	$ 613,581	$ 158,508	
Projected Total Cost over 50 year period		$ 3,828,574	$ 8,603,044	$ 6,115,089	$ 2,937,707	$ 11,452,557	$ 15,306,981	$ 11,228,415	$ 30,945,981	$ 8,330,562	
Projected revenue after implementation of project											
Power generation income for 2014 to 2060		$ 7,252,940	$ 4,893,373	$ 15,888,591	$ 29,467	$ 29,996,946	$ 44,947,236	$ 54,676	$ 193,905,323	$ 7,189,848	
Green Energy Sellback income for 2014 to 2060		$ 237,780	$ 161,477	$ 520,469	$ 950	$ 966,242	$ 1,511,417	$ 1,748	$ 6,312,296	$ 230,506	
Projected Total Revenue over 50 year period (with Green Incentives)		$ 2,736,370	$ 1,846,375	$ 6,007,888	$ 11,102	$ 11,289,262	$ 17,128,090	$ 20,577	$ 73,088,349	$ 2,705,578	
Projected Total Revenue over 50 year period (w/o Green Incentives)		$ 2,573,147	$ 1,735,530	$ 5,650,615	$ 10,450	$ 10,625,991	$ 16,090,586	$ 19,377	$ 68,755,309	$ 2,547,348	
Benefit/Cost Ratio (with Green incentives)		0.71	0.21	0.98	0.00	0.99	1.12	0.00	2.36	0.32	
Benefit/Cost Ratio (w/o Green incentives)		0.67	0.20	0.92	0.00	0.93	1.05	0.00	2.22	0.31	
Internal Rate of Return (with Green incentives)		1.0%	Negative	4.2%	Negative	4.3%	5.4%	Negative	13.6%	Negative	
Internal Rate of Return (w/o Green incentives)		0.7%	Negative	3.7%	Negative	3.8%	4.8%	Negative	12.2%	Negative	
Installed Cost $ per kW		$ 3,959	$ 15,340	$ 5,103	$ 783,359	$ 4,680	$ 4,323	$ 918,302	$ 1,806	$ 10,431	

Table E-7
Upper Colorado Region Model Results

Facility Name		Vega Dam	Washington Lake Dam	Water Hollow Diversion Dam	Weber-Provo Canal	Weber-Provo Diversion Channel	West Canal
Agency		Reclamation	Reclamation	Reclamation	Reclamation	Reclamation	Reclamation
Analysis Performed by		CDM	CDM	CDM	CDM	CDM	CDM
Project Location (State)		Colorado	Utah	Utah	Utah	Utah	Colorado
Transmission Voltage	kV	138	115	115	138	138	115
T-Line Length	miles	2.81	26.42	6.81	34.88	34.88	5.00
Fish and Wildlife Mitigation		No	No	No	No	No	No
Recreation Mitigation		No	Yes	Yes	No	No	No
Historical & Archaeological		No	No	No	No	No	No
Water Quality Monitoring		No	No	No	No	No	No
Fish Passage Required		No	No	No	No	No	No

Results
Input Data Analysis

Data Set	years	8	12	11	12	31	11
Max Head	ft	128.6	33.7	14.9	184.0	100.0	1.0
Min Head	ft	58.4	4.0	14.9	184.0	100.0	1.0
Max Flow	cfs	284	63	25	828	918	175
Min Flow	cfs	1	0	0	0	0	0

Turbine Selection Analysis

Selected Turbine Type		Francis	Low Head	Low Head	Pelton	Francis	Low Head
Selected Design Head	ft	90	29	15	184	100	1
Selected Design flow	cfs	84	3	3	32	24	119
Generator Speed	rpm	600	600	600	600	600	600
Max Head Limit	ft	112.5	36.5	18.6	202.4	125.0	1.3
Min Head Limit	ft	58.5	19.0	9.7	119.6	65.0	0.6
Max Flow Limit	cfs	84	3	3	32	24	119
Min Flow Limit	cfs	17	1	1	6	5	24

Power Generation Analysis

Installed Capacity	kW	548	5	2	424	173	7
Plant Factor		0.36	0.38	0.68	0.51	0.35	0.50
Projected Monthly Production:							
January	MWH	0	1	1	158	45	0
February*	MWH	0	1	1	162	36	0
March	MWH	0	1	1	227	43	0
April	MWH	6	1	1	285	68	3
May	MWH	195	1	1	301	95	5
June	MWH	381	3	1	199	90	5
July	MWH	384	3	1	109	40	5
August	MWH	387	3	1	21	2	5
September	MWH	337	2	1	10	0	5
October	MWH	13	1	1	51	7	3
November	MWH	0	1	1	164	43	0
December	MWH	0	1	1	157	48	0
Annual production*	MWH	1,702	17	14	1,844	517	31

* For non-leap year

Benefit/Cost Analysis

Projected expenditure to implement project

Total Construction Cost		$ 3,012,472	$ 8,705,886	$ 2,289,067	$ 14,266,202	$ 13,771,350	$ 1,734,517
Annual O&M Cost		$ 103,725	$ 183,104	$ 63,105	$ 311,348	$ 291,378	$ 53,246
Projected Total Cost over 50 year period		$ 4,573,291	$ 11,185,018	$ 3,201,461	$ 18,525,466	$ 17,723,163	$ 2,520,412

Projected revenue after implementation of project

Power generation income for 2014 to 2060		$ 6,162,744	$ 64,510	$ 50,692	$ 6,720,761	$ 1,883,096	$ 110,555
Green Energy Sellback income for 2014 to 2060		$ 205,990	$ 2,095	$ 1,663	$ 223,203	$ 62,535	$ 3,735
Projected Total Revenue over 50 year period (with Green Incentives)		$ 2,346,838	$ 24,310	$ 19,101	$ 2,534,715	$ 710,319	$ 42,150
Projected Total Revenue over 50 year period (w/o Green Incentives)		$ 2,205,437	$ 22,872	$ 17,959	$ 2,381,498	$ 667,392	$ 39,585
Benefit/Cost Ratio (with Green incentives)		0.51	0.00	0.01	0.14	0.04	0.02
Benefit/Cost Ratio (w/o Green incentives)		0.48	0.00	0.01	0.13	0.04	0.02
Internal Rate of Return (with Green incentives)		Negative	Negative	Negative	Negative	Negative	Negative
Internal Rate of Return (w/o Green incentives)		Negative	Negative	Negative	Negative	Negative	Negative
Installed Cost $ per kW		$ 5,499	$ 1,655,054	$ 970,027	$ 33,648	$ 79,382	$ 240,093

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Appendix F Constraint Evaluation Results

This appendix presents detailed results of the regulatory constraints evaluation for the potential hydropower sites. Regulatory constraints do not include existing rights or authority to develop a site for hydropower. Table 2-3 and Chapter 5 indicate known development rights.

F.1 Regulatory Constraints

For this analysis, constraints are defined as land or water use regulations that could potentially affect development of hydropower sites. Constraints can either block development completely or add significant costs for mitigation, permitting, or further investigation of the site. This study considers the following regulatory designations as potential constraints to hydropower development.

If a site is associated with a constraint(s), mitigation costs are added to the total development costs of a project (See Chapter 3). It should be noted that this analysis does not assume that development of a site is precluded because of a potential constraint; however, this may be a very likely scenario. Further, the constraints analysis is not inclusive of all potential regulatory requirements for development of a site. Site specific analysis related to Federal, state, and local regulations must be conducted for further evaluation of site development.

National Wildlife Refuges

National Wildlife Refuge is a designation for certain protected areas of the United States managed by the United States Fish and Wildlife Service. The National Wildlife Refuge System is a system of public lands and waters set aside to conserve America's fish, wildlife and plants. The mission of the Refuge System is to manage a national network of lands and waters for the conservation, management, and where appropriate, restoration of fish, wildlife and plant resources and their habitat.

Wild and Scenic Rivers

The Wild and Scenic Rivers Act preserves selected rivers in free-flowing condition and protects those rivers and their immediate environments for the benefit and enjoyment of present and future generations. The National Wild and Scenic Rivers System is primarily administered by four Federal agencies: the Bureau of Land Management, National Park Service, U.S. Fish and Wildlife Service, and USDA Forest Service. These agencies are charged with protecting and managing the wild and scenic rivers of the United States.

National Parks

The National Park System includes all properties managed by the National Park Service. The system encompasses approximately 84.4 million acres ranging in size from 13,200,000 acres to 0.02 acres. National Parks are established only as an act of the United States Congress and have the fundamental purpose "to conserve the scenery and the natural and historic objects and the wildlife therein and to provide for the enjoyment of these while leaving them unimpaired for the enjoyment of future generations."

National Monuments

National Monuments are a protected area similar to a National Park except that the President of the United States can declare an area of the United States to be a National Monument without the approval of Congress. National Monuments afford fewer protections to wildlife than National Parks, but monuments can be part of Wilderness Areas which have an even greater degree of protection than a National Park would alone.

Wilderness Study Areas

A wilderness study area (WSA) contains undeveloped United States federal land retaining its primeval character and influence, without permanent improvements or human habitation, and managed to preserve its natural conditions. WSAs are not included in the National Wilderness Preservation System until the United States Congress passes wilderness legislation.

On Bureau of Land Management (BLM) lands, a WSA is a roadless area that has been inventoried (but not designated by Congress) and found to have wilderness characteristics as described in the Federal Land Policy and Management Act of 1976 and the Wilderness Act of 1964. BLM manages wilderness study areas under the National Landscape Conservation System to protect their value as wilderness until Congress decides whether or not to designate them as wilderness.

Critical Habitat

Under the Endangered Species Act, critical habitat is an area essential to the conservation of a listed species, though the area need not actually be occupied by the species at the time it is designated. Critical habitat must be designated for all threatened and endangered species under the Act (with certain specified exceptions). Critical habitat designations must be based on the best scientific information available, in an open public process, within specific timeframes. Before designating critical habitat, careful consideration must be given to the economic impacts, impacts on national security, and other relevant impacts of specifying any particular area as critical habitat. An area may be excluded from critical habitat if the benefits of exclusion outweigh the benefits of designation, unless excluding the area will result in the extinction of the species concerned.

Wilderness Preservation Area

Wilderness areas are areas of undeveloped Federal land that retain their primeval character and influence, without permanent improvements or human habitation, which are protected and managed to preserve their natural conditions. These areas are established as part of the National Wilderness Preservation System according to the Wilderness Act of 1964. They are owned or administered by the Bureau of Land Management, the U.S. Fish and Wildlife Service, the U.S. Department of Agriculture Forest Service, or the National Park Service.

National Forest

National Forests are federally owned areas, primarily forest and woodland, managed by the United States Forest Service. Management of these areas focuses on timber harvesting, livestock grazing, water, wildlife and recreation. Unlike National Parks and other federal lands managed by the National Park Service, commercial use of national forests is permitted.

National Historic Areas

National Historic Sites are protected areas of national historic significance owned and administered by the federal government. All historic areas in the National Park System, including National Historic Parks and Historic Sites, are listed on the National Register of Historic Places. The National Park Service is the lead Federal preservation agency for preserving the Nation's cultural heritage.

Indian Lands

Indian lands are areas with boundaries established by treaty, statute, and (or) executive or court order, recognized by the Federal Government as territory in which American Indian tribes have primary governmental authority. The Bureau of Indian Affairs is responsible for the administration and management of 55.7 million acres of land held in trust by the United States for American Indians, Indian tribes, and Alaska Natives.

Local Information for Fish and Wildlife and Fish Passage Constraints

Reclamation's regional and area offices provided additional information on potential fish and wildlife and fish passage constraints. Fish and wildlife and fish passage issues could add significant development costs to a project site. Although this analysis cannot identify specific issues for each site, it has attempted to capture if potential issues may be present at the site. If Reclamation's offices identified that fish and wildlife and fish passage were a potential constraint at the site, mitigation costs were added to the total development costs of the site. Because of the preliminary nature and geographic scope of the analysis, all sites could not be evaluated individually for fish and wildlife concerns.

F.2 Constraint Mapping

The above regulatory constraints were mapped using available data. Digital map data suitable for use with ESRI ArcMap 9.3.1 Geographic Information System (GIS) was procured from a variety of sources.

Reclamation provided a table of site coordinates identifying the latitude and longitude of the majority of the identified hydropower assessment sites; 509 of the 530 total identified hydropower assessment sites or 96 percent. These coordinate locations were imported into ArcMap and converted into a point shapefile.

The United States Department of the Interior's National Atlas of the United States found at www.nationalatlas.gov was used to obtain the following polygon and/or polyline map layers; Indian lands, National Forest, National Historic Areas, National Monument, National Park, Wild and Scenic River, Wilderness Preservation Area, Wilderness Study Area and Wildlife Refuge. The Critical Habitat polygon map layer was obtained from the U. S. Fish & Wildlife Service's Critical Habitat Portal found at http://criticalhabitat.fws.gov/.

The National Register of Historic Places point data was obtained from the National Park Service's National Register of Historic Places Google Earth layer found at http://nrhp.focus.nps.gov/natreg/docs/Download.html. This Google Earth layer was converted to features classes suitable for use within the ESRI ArcMap GIS software.

The constraints analysis was completed utilizing the coordinates of the each identified hydropower assessment site and performing an intersection function on each of the polygon map layers. If a hydropower assessment site coordinate location fell within the polygon, an "intersect", it was tabulated as a positive potential constraint.

In some instances constraints map layers were represented lines (rivers) or points (historical buildings). In those cases a proximity analysis was completed to identify whether a given assessment site was within 0.2 miles (1,056 feet) and if so, it was tabulated as a positive potential constraint.

F.3 Results Matrix

Tables F-1 through F-5 show the regulatory constraints applicable to each hydropower site in the Great Plains, Lower Colorado, Mid-Pacific, Pacific Northwest, and Upper Colorado regions, respectively. All 530 sites are included in the tables. The tables also identify sites that do not have coordinates available.

F.4 Constraint Maps

Figures F-1 through F-10 illustrates regulatory constraints relative to the hydropower assessment site locations. The regions are divided into several maps in order to show higher resolution of sites relative to constraints.

Table F-1
Great Plains Constraints

Site ID	Facility Name	State	Critical Habitat	Wildlife Refuge	National Forest	National Historic Areas	National Park	Wild & Scenic River	Wilderness Preservation Area	Wildlife Refuge	Wilderness Study Area	National Monument	Indian Lands	Fish and Wildlife Constraint	Fish Passage Constraint
GP-1	Drop	Montana													
GP-2	Almena Diversion Dam	Kansas													
GP-3	Altus Dam	Oklahoma													
GP-4	Anchor Dam	Wyoming											X		
GP-5	Angostura Dam	South Dakota													
GP-6	Anita Dam	Montana													
GP-7	Arbuckle Dam	Oklahoma													
GP-8	Barretts Diversion Dam	Montana													
GP-9	Bartley Diversion Dam	Nebraska													
GP-10	Belle Fourche Dam	South Dakota													
GP-11	Belle Fourche Diversion Dam	South Dakota				X									
GP-12	Bonny Dam	Colorado													
GP-13	Box Butte Dam	Nebraska													
GP-14	Bretch Diversion Canal	Oklahoma													
GP-15	Bull Lake Dam	Wyoming											X		
GP-16	Cambridge Diversion Dam	Nebraska													
GP-17	Carter Creek Diversion Dam	Colorado							X						
GP-18	Carter Lake Dam No. 1	Colorado													
GP-19	Cedar Bluff Dam	Kansas													
GP-20	Chapman Diversion Dam	Colorado			X										
GP-21	Cheney Dam	Kansas													
GP-22	Choke Canyon Dam	Texas													
GP-23	Clark Canyon Dam	Montana													
GP-24	Corbett Diversion Dam	Wyoming													
GP-25	Culbertson Diversion Dam	Nebraska													
GP-26	Davis Creek Dam	Nebraska													
GP-27	Deaver Dam	Wyoming													
GP-28	Deerfield Dam	South Dakota													
GP-29	Dickinson Dam	North Dakota													
GP-30	Dixon Canyon Dam	Colorado													
GP-31	Dodson Diversion Dam	Montana											X		
GP-32	Dry Spotted Tail Diversion Dam	Nebraska													
GP-33	Dunlap Diversion Dam	Nebraska													
GP-34	East Portal Diversion Dam	Colorado													
GP-35	Enders Dam	Nebraska													
GP-36	Fort Cobb Dam	Oklahoma													
GP-37	Fort Shaw Diversion Dam	Montana													
GP-38	Foss Dam	Oklahoma													
GP-39	Fresno Dam	Montana													
GP-40	Fryingpan Diversion Dam	Colorado							X						
GP-41	Gibson Dam	Montana													

Table F-1
Great Plains Constraints

Site ID	Facility Name	State	Critical Habitat	Wildlife Refuge	National Forest	National Historic Areas	National Park	Wild & Scenic River	Wilderness Preservation Area	Wildlife Refuge	Wilderness Study Area	National Monument	Indian Lands	Fish and Wildlife Constraint	Fish Passage Constraint
GP-42	Glen Elder Dam	Kansas													
GP-43	Granby Dam	Colorado												X	
GP-44	Granby Dikes 1-4	Colorado													
GP-45	Granite Creek Diversion Dam	Colorado							X						
GP-46	Gray Reef Dam	Wyoming													X
GP-47	Canal Drop	Montana													
GP-48	Halfmoon Creek Diversion Dam	Colorado													
GP-49	Hanover Diversion Dam	Wyoming													
GP-50	Heart Butte Dam	North Dakota													
GP-51	Helena Valley Dam	Montana													
GP-52	Helena Valley Pumping Plant	Montana													
GP-53	Horse Creek Diversion Dam	Wyoming													
GP-54	Horsetooth Dam	Colorado													
GP-55	Hunter Creek Diversion Dam	Colorado							X						
GP-56	Huntley Diversion Dam	Montana													
GP-57	Ivanhoe Diversion Dam	Colorado			X										
GP-58	James Diversion Dam	South Dakota													
GP-59	Jamestown Dam	North Dakota													
GP-60	Drop	Montana													
GP-61	Kent Diversion Dam	Nebraska													
GP-62	Keyhole Dam	Wyoming													
GP-63	Kirwin Dam	Kansas													
GP-64	Drop	Montana													
GP-65	Lake Alice Lower 1-1/2 Dam	Nebraska		X						X					
GP-66	Lake Alice No. 1 Dam	Nebraska		X						X					
GP-67	Lake Alice No. 2 Dam	Nebraska													
GP-68	Lake Sherburne Dam	Montana											X		
GP-69	Lily Pad Diversion Dam	Colorado			X										
GP-70	Little Hell Creek Diversion Dam	Colorado			X										
GP-71	Lovewell Dam	Kansas													
GP-72	Lower Turnbull Drop Structure	Montana													
GP-73	Lower Yellowstone Diversion Dam	Montana												X	X
GP-74	Mary Taylor Drop Structure	Montana													
GP-75	Medicine Creek Dam	Nebraska													
GP-76	Merritt Dam	Nebraska													
GP-77	Merritt Dam	Nebraska													
GP-78	Dam	Colorado			X										
GP-79	Midway Creek Diversion Dam	Colorado							X						
GP-80	Lower Drops Combined	Montana													
GP-81	Minatare Dam	Nebraska		X						X					
GP-82	Mormon Creek Diversion Dam	Colorado			X										

Table F-1
Great Plains Constraints

Site ID	Facility Name	State	Critical Habitat	Wildlife Refuge	National Forest	National Historic Areas	National Park	Wild & Scenic River	Wilderness Preservation Area	Wildlife Refuge	Wilderness Study Area	National Monument	Indian Lands	Fish and Wildlife Constraint	Fish Passage Constraint
GP-83	Mountain Park Dam	Oklahoma													
GP-84	Nelson Dikes	Montana													
GP-85	Nelson Dikes	Montana													
GP-86	No Name Creek Diversion Dam	Colorado							X						
GP-87	Norman Dam	Oklahoma													
GP-88	Dam	Colorado			X										
GP-89	North Fork Diversion Dam	Colorado							X						
GP-90	North Poudre Diversion Dam	Colorado			X			X							
GP-91	Norton Dam	Kansas													
GP-92	Olympus Dam	Colorado													
GP-93	Pactola Dam	South Dakota			X										
GP-94	Paradise Diversion Dam	Montana													
GP-95	Pathfinder Dam	Wyoming				X									X
GP-96	Pathfinder Dike	Wyoming													
GP-97	Pilot Butte Dam	Wyoming											X		
GP-98	Pishkun Dike - No. 4	Montana													
GP-99	Pueblo Dam	Colorado												X	
GP-100	Ralston Dam	Wyoming													
GP-101	Rattlesnake Dam	Colorado													
GP-102	Red Willow Dam	Nebraska													
GP-103	Saint Mary Diversion Dam	Montana											X		
GP-104	Sanford Dam	Texas													
GP-105	Satanka Dike	Colorado													
GP-106	Sawyer Creek Diversion Dam	Colorado							X						
GP-107	Shadehill Dam	South Dakota													
GP-108	Shadow Mountain Dam	Colorado													
GP-109	Soldier Canyon Dam	Colorado													
GP-110	Dam	Colorado			X										
GP-111	South Fork Diversion Dam	Colorado							X						
GP-112	South Platte Supply Canal Diverion Dam	Colorado													
GP-113	Spring Canyon Dam	Colorado													
GP-114	St. Mary Canal - Drop 1	Montana											X		
GP-115	St. Mary Canal - Drop 2	Montana											X		
GP-116	St. Mary Canal - Drop 3	Montana											X		
GP-117	St. Mary Canal - Drop 4	Montana											X		
GP-118	St. Mary Canal - Drop 5	Montana											X		
GP-119	St. Vrain Canal	Colorado	*	*	*	*	*	*	*	*	*	*	*		
GP-120	Sun River Diversion Dam	Montana			X										
GP-121	Superior-Courtland Diversion Dam	Nebraska													
GP-122	Trenton Dam	Nebraska													
GP-123	Trenton Dam	Nebraska													

Table F-1
Great Plains Constraints

Site ID	Facility Name	State	Critical Habitat	Wildlife Refuge	National Forest	National Historic Areas	National Park	Wild & Scenic River	Wilderness Preservation Area	Wildlife Refuge	Wilderness Study Area	National Monument	Indian Lands	Fish and Wildlife Constraint	Fish Passage Constraint
GP-124	Tub Springs Creek Diversion Dam	Nebraska													
GP-125	Twin Buttes Dam	Texas													
GP-126	Twin Lakes Dam (USBR)	Colorado												X	
GP-127	Upper Turnbull Drop Structure	Montana													
GP-128	Vandalia Diversion Dam	Montana													
GP-129	Virginia Smith Dam	Nebraska													
GP-130	Webster Dam	Kansas													
GP-131	Whalen Diversion Dam	Wyoming													
GP-132	Willow Creek Dam	Colorado													
GP-133	Willow Creek Dam	Montana													
GP-134	Willow Creek Forebay Diversion Dam	Colorado													
GP-135	Willwood Canal	Wyoming													X
GP-136	Willwood Diversion Dam	Wyoming													X
GP-137	Wind River Diversion Dam	Wyoming				X							X		
GP-138	Drop	Montana													
GP-139	Woodston Diversion Dam	Kansas													
GP-140	Wyoming Canal - Sta 1016	Wyoming													
GP-141	Wyoming Canal - Sta 1490	Wyoming													
GP-142	Wyoming Canal - Sta 1520	Wyoming											X		
GP-143	Wyoming Canal - Sta 1626	Wyoming													
GP-144	Wyoming Canal - Sta 1972	Wyoming													
GP-145	Wyoming Canal - Sta 997	Wyoming													
GP-146	Yellowtail Afterbay Dam	Montana													
		Total	**0**	**3**	**11**	**3**	**0**	**1**	**9**	**3**	**0**	**0**	**13**	**4**	**5**

MISSING SITE COORDINATE

Table F-2
Lower Colorado Constraints

Site ID	Facility Name	State	Critical Habitat	Wildlife Refuge	National Forest	National Historic Areas	National Park	Wild & Scenic River	Wilderness Preservation Area	Wildlife Refuge	Wilderness Study Area	National Monument	Indian Lands	Fish and Wildlife Constraint	Fish Passage Constraint
LC-1	Agua Fria River Siphon	Arizona													
LC-2	Agua Fria Tunnel	Arizona													
LC-3	All American Canal	California													
LC-4	Headworks	California	X												
LC-5	Arizona Canal	Arizona													
LC-6	Bartlett Dam	Arizona			X									X	
LC-7	Buckskin Mountain Tunnel	Arizona													
LC-8	Burnt Mountain Tunnel	Arizona													
LC-9	Centennial Wash Siphon	Arizona													
LC-10	Coachella Canel	California													
LC-11	Consolidated Canal	Arizona													
LC-12	Cross Cut Canal	Arizona													
LC-13	Cunningham Wash Siphon	Arizona													
LC-14	Eastern Canal	Arizona													
LC-15	Headworks	Arizona													
LC-16	Gila River Siphon	Arizona													
LC-17	Grand Canal	Arizona													
LC-18	Granite Reef Diversion Dam	Arizona-California													
LC-19	Hassayampa River Siphon	Arizona													
LC-20	Horseshoe Dam	Arizona			X									X	
LC-21	Imperial Dam	Arizona-California	X												
LC-22	Interstate Highway Siphon	Arizona													
LC-23	Jackrabbit Wash Siphon	Arizona													
LC-24	Laguna Dam	Arizona-California											X		
LC-25	New River Siphon	Arizona													
LC-26	Palo Verde Diversion Dam	Arizona-California	X												
LC-27	Reach 11 Dike	Arizona													
LC-28	Salt River Siphon Blowoff	Arizona											X		
LC-29	Tempe Canal	Arizona													
LC-30	Western Canal	Arizona													
		Total	**3**	**0**	**2**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**2**	**2**	**0**

MISSING SITE COORDINATE

Table F-3
Mid-Pacific Constraints

Site ID	Facility Name	State	Critical Habitat	Wildlife Refuge	National Forest	National Historic Areas	National Park	Wild & Scenic River	Wilderness Preservation Area	Wildlife Refuge	Wilderness Study Area	National Monument	Indian Lands	Fish and Wildlife Constraint	Fish Passage Constraint
MP-1	Anderson-Rose Dam	Oregon													
MP-2	Boca Dam	California			X	X									
MP-3	Bradbury Dam	California													
MP-4	Buckhorn Dam (Reclamation)	California													
MP-5	Camp Creek Dam	California													
MP-6	Carpenteria	California													
MP-7	Carson River Dam	Nevada													
MP-8	Casitas Dam	California													
MP-9	Clear Lake Dam	California			X										
MP-10	Contra Loma Dam	California													
MP-11	Derby Dam	Nevada				X									
MP-12	Dressler Dam	Nevada	*	*	*	*	*	*	*	*	*	*	*		
MP-13	East Park Dam	California													
MP-14	Funks Dam	California													
MP-15	Gerber Dam	Oregon													
MP-16	Glen Anne Dam	California			X										
MP-17	John Franchi Dam	California	X												
MP-18	Lake Tahoe Dam	California			X	X								X	X
MP-19	Lauro Dam	California													
MP-20	Little Panoche Detention Dam	California													
MP-21	Los Banos Creek Detention Dam	California													
MP-22	Lost River Diversion Dam	Oregon													
MP-23	Malone Diversion Dam	Oregon													
MP-24	Marble Bluff Dam	Nevada											X		
MP-25	Martinez Dam	California													
MP-26	Miller Dam	Oregon													
MP-27	Mormon Island Auxiliary Dike	California													
MP-28	Northside Dam	California	X												
MP-29	Ortega Dam	California													
MP-30	Prosser Creek Dam	California			X										
MP-31	Putah Creek Dam	California													
MP-32	Putah Diversion Dam	California												X	
MP-33	Rainbow Dam	California			X										
MP-34	Red Bluff Dam	California		X						X					
MP-35	Robles Dam	California													

Table F-3
Mid-Pacific Constraints

Site ID	Facility Name	State	Critical Habitat	Wildlife Refuge	National Forest	National Historic Areas	National Park	Wild & Scenic River	Wilderness Preservation Area	Wildlife Refuge	Wilderness Study Area	National Monument	Indian Lands	Fish and Wildlife Constraint	Fish Passage Constraint
MP-36	Rye Patch Dam	Nevada													
MP-37	San Justo Dam	California													
MP-38	Sheckler Dam	Nevada													
MP-39	Sly Park Dam	California													
MP-40	Spring Creek Debris Dam	California													
MP-41	Sugar Pine Dam	California													
MP-42	Terminal Dam	California													
MP-43	Twitchell Dam	California													
MP-44	Upper Slaven Dam	Nevada													
		Total	**2**	**1**	**6**	**3**	**0**	**0**	**0**	**1**	**0**	**0**	**1**	**2**	**1**

MISSING SITE COORDINATE

Table F-4
Pacific Northwest Constraints

Site ID	Facility Name	State	Critical Habitat	Wildlife Refuge	National Forest	National Historic Areas	National Park	Wild & Scenic River	Wilderness Preservation Area	Wildlife Refuge	Wilderness Study Area	National Monument	Indian Lands	Fish and Wildlife Constraint	Fish Passage Constraint
PN-1	Agate Dam	Oregon													
PN-2	Agency Valley	Oregon													
PN-3	Antelope Creek	Oregon	X												
PN-4	Arnold Dam	Oregon						X							
PN-5	Arrowrock Dam	Idaho				X									
PN-6	Arthur R. Bowman Dam	Oregon						X							
PN-7	Ashland Lateral	Oregon													
PN-8	Beaver Dam Creek	Oregon			X										
PN-9	Bully Creek	Oregon													
PN-10	Bumping Lake	Washington	X						X						
PN-11	Cascade Creek	Idaho													
PN-12	Cle Elum Dam	Washington													
PN-13	Clear Creek	Washington			X										
PN-14	Col W.W. No 4	Washington	*	*	*	*	*	*	*	*	*		*		
PN-15	Cold Springs	Oregon		X						X					
PN-16	Conconully	Washington				X									
PN-17	Conde Creek	Oregon													
PN-18	Cowiche	Washington													
PN-19	Crab Creek Lateral #4	Washington													
PN-20	Crane Prairie	Oregon			X										
PN-21	Cross Cut	Idaho													
PN-22	Daley Creek	Oregon			X										
PN-23	Dead Indian	Oregon													
PN-24	Deadwood Dam	Idaho			X										
PN-25	Deer Flat East Dike	Idaho		X						X					
PN-26	Deer Flat Middle	Idaho		X						X					
PN-27	Deer Flat North Lower	Idaho		X						X					
PN-28	Deer Flat Upper	Idaho		X						X					
PN-29	Diversion Canal Headworks	Oregon													
PN-30	Dry Falls - Main Canal Headworks	Washington													
PN-31	Easton Diversion Dam	Washington													
PN-32	Eltopia Branch Canal	Washington													
PN-33	Eltopia Branch Canal 4.6	Washington													
PN-34	Emigrant	Oregon													
PN-35	Esquatzel Canal	Washington													
PN-36	Feed Canal	Oregon													
PN-37	Fish Lake	Oregon	X		X										
PN-38	Fourmile Lake	Oregon			X										
PN-39	French Canyon	Washington													
PN-40	Frenchtown	Montana													

Table F-4
Pacific Northwest Constraints

Site ID	Facility Name	State	Critical Habitat	Wildlife Refuge	National Forest	National Historic Areas	National Park	Wild & Scenic River	Wilderness Preservation Area	Wildlife Refuge	Wilderness Study Area	National Monument	Indian Lands	Fish and Wildlife Constraint	Fish Passage Constraint
PN-41	Golden Gate Canal	Idaho	*	*	*	*	*	*	*	*	*		*		
PN-42	Grassy Lake	Wyoming													
PN-43	Harper Dam	Oregon													
PN-44	Haystack	Oregon													
PN-45	Howard Prairie Dam	Oregon													
PN-46	Hubbard Dam	Idaho													
PN-47	Hyatt Dam	Oregon													
PN-48	Kachess Dam	Washington			X										
PN-49	Keechelus Dam	Washington			X										
PN-50	Keene Creek	Oregon													
PN-51	Little Beaver Creek	Oregon													
PN-52	Little Wood River Dam	Idaho													
PN-53	Lytle Creek	Oregon													
PN-54	Main Canal No. 10	Idaho									X				
PN-55	Main Canal No. 6	Idaho													
PN-56	Mann Creek	Idaho													
PN-57	Mason Dam	Oregon													
PN-58	Maxwell Dam	Oregon													
PN-59	McKay Dam	Oregon													
PN-60	Mile 28 - on Milner Gooding Canal	Idaho													
PN-61	Mora Canal Drop	Idaho													
PN-62	North Canal Diversion Dam	Oregon													
PN-63	North Unit Main Canal	Oregon	*	*	*	*	*	*	*	*	*		*		
PN-64	Oak Street	Oregon				X									
PN-65	Ochoco Dam	Oregon													
PN-66	Orchard Avenue	Washington	*	*	*	*	*	*	*	*	*		*		
PN-67	Owyhee Tunnel No. 1	Oregon													
PN-68	PEC Mile 26.3	Washington	*	*	*	*	*	*	*	*	*		*		
PN-69	Phoenix Canal	Oregon													
PN-70	Pilot Butte Canal	Oregon	*	*	*	*	*	*	*	*	*		*		
PN-71	Pinto Dam	Washington													
PN-72	Potholes Canal Headworks	Washington													
PN-73	Potholes East Canal - PEC 66.0	Washington													
PN-74	Potholes East Canal 66.0	Washington													
PN-75	Prosser Dam	Washington													
PN-76	Quincy Chute Hydroelectric	Washington													
PN-77	RB4C W. W. Hwy26 Culvert	Washington													
PN-78	Reservoir "A"	Idaho											X		
PN-79	Ringold W. W.	Washington													
PN-80	Ririe Dam	Idaho													

Table F-4
Pacific Northwest Constraints

Site ID	Facility Name	State	Critical Habitat	Wildlife Refuge	National Forest	National Historic Areas	National Park	Wild & Scenic River	Wilderness Preservation Area	Wildlife Refuge	Wilderness Study Area	National Monument	Indian Lands	Fish and Wildlife Constraint	Fish Passage Constraint
PN-81	Rock Creek	Montana			X										
PN-82	Roza Diversion Dam	Washington													
PN-83	Russel D Smith	Washington													
PN-84	Saddle Mountain W. W.	Washington													
PN-85	Salmon Creek	Washington													
PN-86	Salmon Lake	Washington													
PN-87	Scoggins Dam	Oregon													
PN-88	Scootney Wasteway	Washington													
PN-89	Soda Creek	Oregon													
PN-90	Soda Lake Dike	Washington		X						X					
PN-91	Soldier´s Meadow	Idaho													
PN-92	South Fork Little Butte Creek	Oregon	X		X										
PN-93	Spectacle Lake Dike	Washington													
PN-94	Summer Falls on Main Canal	Washington													
PN-95	Sunnyside Dam	Washington											X		
PN-96	Sweetwater Canal	Idaho													
PN-97	Thief Valley Dam	Oregon						X							
PN-98	Three Mile Falls	Oregon													
PN-99	Tieton Diversion	Washington	X												
PN-100	Unity Dam	Oregon													
PN-101	Warm Springs Dam	Oregon													
PN-102	Wasco Dam	Oregon			X										
PN-103	Webb Creek	Idaho											X		
PN-104	Wickiup Dam	Oregon			X										
PN-105	Wild Horse - BIA	Nevada													
		Total	**5**	**6**	**13**	**3**	**0**	**3**	**1**	**6**	**1**	**0**	**3**	**0**	**0**
	MISSING SITE COORDINATE														

Table F-5
Upper Colorado Constraints

Site ID	Facility Name	State	Critical Habitat	Wildlife Refuge	National Forest	National Historic Areas	National Park	Wild & Scenic River	Wilderness Preservation Area	Wildlife Refuge	Wilderness Study Area	National Monument	Indian Lands	Fish and Wildlife Constraint	Fish Passage Constraint
UC-1	Alpine Tunnel	Utah			X										
UC-2	Alpine-Draper Tunnel	Utah													
UC-3	American Diversion Dam	New Mexico				X									
UC-4	Angostura Diversion	New Mexico	X										X		
UC-5	Arthur V. Watkins Dam	Utah													
UC-6	Avalon Dam	New Mexico													
UC-7	Station 1565+00	New Mexico			X										
UC-8	Station 1702+75	New Mexico			X										
UC-9	Station 1831+17	New Mexico			X										
UC-10	Outlet	New Mexico			X										
UC-11	Azotea Tunnel	New Mexico			X										
UC-12	Beck's Feeder Canal	Utah			X										
UC-13	Big Sandy Dam	Wyoming													
UC-14	Blanco diversion Dam	New Mexico			X										
UC-15	Blanco Tunnel	New Mexico							X						
UC-16	Brantley Dam	New Mexico													
UC-17	Broadhead Diversion Dam	Utah			X										
UC-18	Brough's Fork Feeder Canal	Utah			X										
UC-19	Caballo Dam	New Mexico												X	
UC-20	Cedar Creek Feeder Canal	Utah			X										
UC-21	Cottonwood Creek/Huntington Canal	Utah													
UC-22	Crawford Dam	Colorado													
UC-23	Currant Creek Dam	Utah			X										
UC-24	Currant Tunnel	Utah			X										
UC-25	Dam No. 13	New Mexico													
UC-26	Dam No. 2	New Mexico													
UC-27	Davis Aqueduct	Utah			X										
UC-28	Dolores Tunnel	Colorado									X				
UC-29	Docs Diversion Dam	Utah			X										
UC-30	Duchesne Diversion Dam	Utah			X										
UC-31	Duchesne Tunnel	Utah			X										
UC-32	Duchense Feeder Canal	Utah													
UC-33	East Canal	Utah													
UC-34	East Canal	Colorado													
UC-35	East Canal Diversion Dam	Colorado													
UC-36	East Canyon Dam	Utah													
UC-37	East Fork Diversion Dam	Colorado			X										
UC-38	Eden Canal	Wyoming													
UC-39	Eden Dam	Wyoming													
UC-40	Ephraim Tunnel	Utah			X										
UC-41	Farmington Creek Stream Inlet	Utah			X										
UC-42	Fire Mountain Diversion Dam	Colorado													
UC-43	Florida Farmers Diversion Dam	Colorado	*	*	*	*	*	*	*	*	*		*		

Table F-5
Upper Colorado Constraints

Site ID	Facility Name	State	Critical Habitat	Wildlife Refuge	National Forest	National Historic Areas	National Park	Wild & Scenic River	Wilderness Preservation Area	Wildlife Refuge	Wilderness Study Area	National Monument	Indian Lands	Fish and Wildlife Constraint	Fish Passage Constraint
UC-44	Fort Sumner Diversion Dam	New Mexico													
UC-45	Fort Thornburgh Diversion Dam	Utah													
UC-46	Fruitgrowers Dam	Colorado													
UC-47	Garnet Diversion Dam	Colorado													
UC-48	Gateway Tunnel	Utah			X										
UC-49	Grand Valley Diversion Dam	Colorado				X								X	
UC-50	Great Cut Dike	Colorado			X									X	
UC-51	Gunnison Diversion Dam	Colorado												X	
UC-52	Gunnison Tunnel	Colorado													
UC-53	Hades Creek Diversion Dam	Utah			X										
UC-54	Hades Tunnel	Utah			X										
UC-55	Haights Creek Stream Inlet	Utah	*	*	*	*	*	*	*	*	*		*		
UC-56	Hammond Diversion Dam	New Mexico	*	*	*	*	*	*	*	*	*		*		
UC-57	Heron Dam	New Mexico												X	
UC-58	Highline Canal	Utah													
UC-59	Huntington North Dam	Utah													
UC-60	Huntington North Feeder Canal	Utah													
UC-61	Huntington North Service Canal	Utah													
UC-62	Hyrum Dam	Utah													
UC-63	Hyrum Feeder Canal	Utah													
UC-64	Hyrum-Mendon Canal	Utah													
UC-65	Indian Creek Crossing Div. Dam	Utah	*	*	*	*	*	*	*	*	*		*		
UC-66	Indian Creek Dike	Utah	*	*	*	*	*	*	*	*	*		*		
UC-67	Inlet Canal	Colorado													
UC-68	Ironstone Canal	Colorado													
UC-69	Ironstone Diversion Dam	Colorado													
UC-70	Isleta Diversion Dam	New Mexico											X		
UC-71	Jackson Gulch Dam	Colorado													
UC-72	Joes Valley Dam	Utah			X									X	
UC-73	Jordanelle Dam	Utah													
UC-74	Knight Diversion Dam	Utah													
UC-75	Layout Creek Diversion Dam	Utah			X										
UC-76	Layout Creek Tunnel	Utah			X										
UC-77	Layton Canal	Utah													
UC-78	Leasburg Diversion Dam	New Mexico				X									
UC-79	Leon Creek Diversion Dam	Colorado													
UC-80	Little Navajo River Siphon	New Mexico			X										
UC-81	Little Oso Diversion Dam	Colorado			X										
UC-82	Little Sandy Diversion Dam	Wyoming													
UC-83	Little Sandy Feeder Canal	Wyoming													
UC-84	Lost Creek Dam	Utah													
UC-85	Lost Lake Dam	Utah			X										
UC-86	Loutzenheizer Canal	Colorado													

Table F-5
Upper Colorado Constraints

Site ID	Facility Name	State	Critical Habitat	Wildlife Refuge	National Forest	National Historic Areas	National Park	Wild & Scenic River	Wilderness Preservation Area	Wildlife Refuge	Wilderness Study Area	National Monument	Indian Lands	Fish and Wildlife Constraint	Fish Passage Constraint
UC-87	Loutzenheizer Diversion Dam	Colorado													
UC-88	Lucero Dike	New Mexico	*	*	*	*	*	*	*	*	*		*		
UC-89	M&D Canal-Shavano Falls	Colorado													
UC-90	Madera Diversion Dam	Texas													
UC-91	Main Canal	Utah													
UC-92	Means Canal	Wyoming													
UC-93	Meeks Cabin Dam	Wyoming													
UC-94	Mesilla Diversion Dam	New Mexico													
UC-95	Middle Fork Kays Creek Stream Inlet	Utah			X										
UC-96	Midview Dam	Utah													
UC-97	Mink Creek Canal	Idaho													
UC-98	Montrose and Delta Canal	Colorado													
UC-99	Montrose and Delta Div. Dam	Colorado													
UC-100	Moon Lake Dam	Utah			X										
UC-101	Murdock Diversion Dam	Utah			X										
UC-102	Nambe Falls Dam	New Mexico											X		
UC-103	Navajo Dam Diversion Works	New Mexico													
UC-104	Newton Dam	Utah													
UC-105	Ogden Brigham Canal	Utah													
UC-106	Ogden Valley Canal	Utah													
UC-107	Ogden Valley Diversion Dam	Utah													
UC-108	Ogden-Brigham Canal	Utah													
UC-109	Olmstead Diversion Dam	Utah			X										
UC-110	Olmsted Tunnel	Utah			X										
UC-111	Open Channel #1	Utah			X										
UC-112	Open Channel #2	Utah			X										
UC-113	Oso Diversion Dam	Colorado													
UC-114	Oso Feeder Conduit	New Mexico			X										
UC-115	Oso Tunnel	New Mexico			X										
UC-116	Outlet Canal	Colorado													
UC-117	Paonia Dam	Colorado												X	
UC-118	Park Creek Diversion Dam	Colorado													
UC-119	Percha Arroyo Diversion Dam	New Mexico													
UC-120	Percha Diversion Dam	New Mexico				X									
UC-121	Picacho North Dam	New Mexico	*	*	*	*	*	*	*	*	*		*		
UC-122	Picacho South Dam	New Mexico	*	*	*	*	*	*	*	*	*		*		
UC-123	Pineview Dam	Utah			X										
UC-124	Platoro Dam	Colorado													
UC-125	Provo Reservoir Canal	Utah			X										
UC-126	Red Fleet Dam	Utah													
UC-127	Rhodes Diversion Dam	Utah			X										
UC-128	Rhodes Flow Control Structure	Utah			X										
UC-129	Rhodes Tunnel	Utah			X										

Table F-5
Upper Colorado Constraints

Site ID	Facility Name	State	Critical Habitat	Wildlife Refuge	National Forest	National Historic Areas	National Park	Wild & Scenic River	Wilderness Preservation Area	Wildlife Refuge	Wilderness Study Area	National Monument	Indian Lands	Fish and Wildlife Constraint	Fish Passage Constraint
UC-130	Ricks Creek Stream Inlet	Utah			X										
UC-131	Ridgway Dam	Colorado												X	
UC-132	Rifle Gap Dam	Colorado												X	
UC-133	Riverside Diversion Dam	Texas													
UC-134	S.Ogden Highline Canal Div. Dam	Utah			X										
UC-135	San Acacia Diversion Dam	New Mexico	X	X						X					
UC-136	Scofield Dam	Utah													
UC-137	Selig Canal	Colorado													
UC-138	Selig Diversion Dam	Colorado													
UC-139	Sheppard Creek Stream Inlet	Utah			X										
UC-140	Silver Jack Dam	Colorado													
UC-141	Sixth Water Flow Control	Utah			X									X	
UC-142	Slaterville Diversion Dam	Utah													
UC-143	Smith Fork Diversion Dam	Colorado													
UC-144	Soldier Creek Dam	Utah												X	
UC-145	South Canal Tunnels	Colorado	*	*	*	*	*	*	*	*	*		*		
UC-146	South Canal, Sta 19+ 10 "Site #1"	Colorado													
UC-147	South Canal, Sta. 181+10, "Site #4"	Colorado													
UC-148	South Canal, Sta. 472+00, "Site #5"	Colorado													
UC-149	South Canal, Sta. 72+50, Site #2"	Colorado													
UC-150	South Canal, Sta.106+65, "Site #3"	Colorado													
UC-151	South Feeder Canal	Utah			X										
UC-152	South Fork Kays Creek Stream Inlet	Utah			X										
UC-153	Southside Canal	Colorado													
UC-154	Southside Canal, Sta 171+ 90 thru 200+ 67 (2 canal drops)	Colorado													
UC-155	Southside Canal, Sta 349+ 05 thru 375+ 42 (3 canal drops)	Colorado													
UC-156	Southside Canal, Station 1245 + 56	Colorado													
UC-157	Southside Canal, Station 902 + 28	Colorado													
UC-158	Spanish Fork Diversion Dam	Utah													
UC-159	Spanish Fork Flow Control Structure	Utah												X	
UC-160	Spring City Tunnel	Utah			X										
UC-161	Staight Creek Stream Inlet	Utah	*	*	*	*	*	*	*	*	*		*		
UC-162	Starvation Dam	Utah												X	
UC-163	Starvation Feeder Conduit Tunnel	Utah													
UC-164	Stateline Dam	Utah			X										
UC-165	Station Creek Tunnel	Utah													
UC-166	Steinaker Dam	Utah													
UC-167	Steinaker Feeder Canal	Utah													
UC-168	Steinaker Service Canal	Utah													
UC-169	Stillwater Tunnel	Utah			X										
UC-170	Stoddard Diversion Dam	Utah													
UC-171	Stone Creek Stream Inlet	Utah			X										
UC-172	Strawberry Tunnel Turnout	Utah			X										

Table F-5
Upper Colorado Constraints

Site ID	Facility Name	State	Critical Habitat	Wildlife Refuge	National Forest	National Historic Areas	National Park	Wild & Scenic River	Wilderness Preservation Area	Wildlife Refuge	Wilderness Study Area	National Monument	Indian Lands	Fish and Wildlife Constraint	Fish Passage Constraint
UC-173	Stubblefield Dam	New Mexico	*	*	*	*	*	*	*	*	*		*		
UC-174	Sumner Dam	New Mexico												X	
UC-175	Swasey Diversion Dam	Utah													
UC-176	Syar Inlet	Utah			X										
UC-177	Syar Tunnel	Utah			X									X	
UC-178	Tanner Ridge Tunnel	Utah			X										
UC-179	Taylor Park Dam	Colorado												X	
UC-180	Towoac Canal	Colorado									X				
UC-181	Trial Lake Dam	Utah			X	X									
UC-182	Tunnel #1	Colorado													
UC-183	Tunnel #2	Colorado													
UC-184	Tunnel #3	Colorado													
UC-185	Upper Diamond Fork Flow Control Structure	Utah			X									X	
UC-186	Upper Diamond Fork Tunnel	Utah			X										
UC-187	Upper Stillwater Dam	Utah			X										
UC-188	Vat Diversion Dam	Utah			X										
UC-189	Vat Tunnel	Utah			X										
UC-190	Vega Dam	Colorado													
UC-191	Vermejo Diversion Dam	New Mexico													
UC-192	Washington Lake Dam	Utah			X										
UC-193	Water Hollow Diversion Dam	Utah			X										
UC-194	Water Hollow Tunnel	Utah			X										
UC-195	Weber Aqueduct	Utah			X										
UC-196	Weber-Provo Canal	Utah													
UC-197	Weber-Provo Diversion Canal	Utah													
UC-198	Weber-Provo Diversion Dam	Utah													
UC-199	Wellsville Canal	Utah													
UC-200	West Canal	Colorado													
UC-201	West Canal Tunnel	Colorado													
UC-202	Willard Canal	Utah													
UC-203	Win Diversion Dam	Utah			X										
UC-204	Win Flow Control Structure	Utah	*	*	*	*	*	*	*	*	*		*		
UC-205	Yellowstone Feeder Canal	Utah	*	*	*	*	*	*	*	*	*		*		
		Total	**2**	**1**	**69**	**5**	**0**	**0**	**1**	**1**	**2**	**0**	**3**	**17**	**0**

MISSING SITE COORDINATE

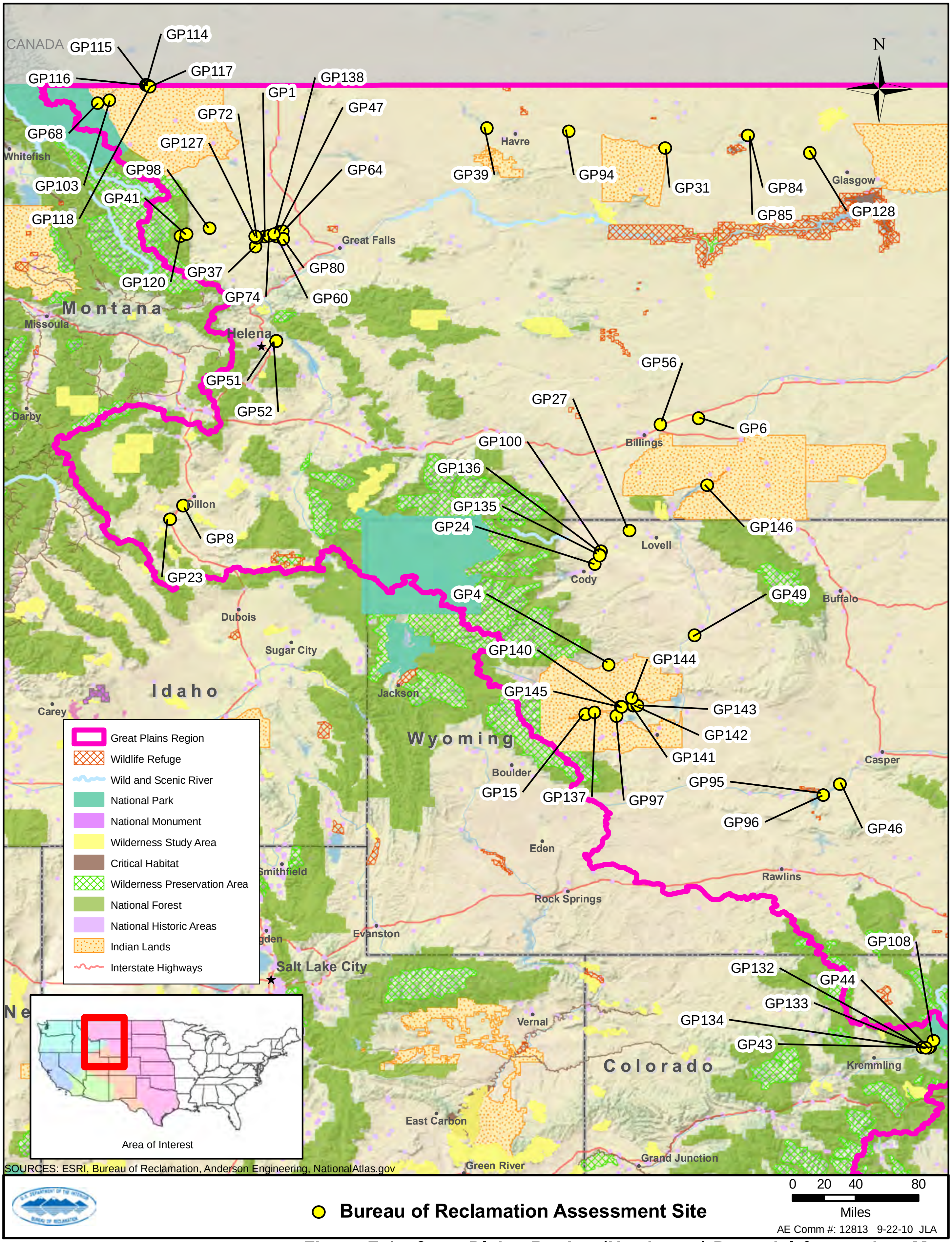

Figure F-1 : Great Plains Region (Northwest) Potential Constraints Map

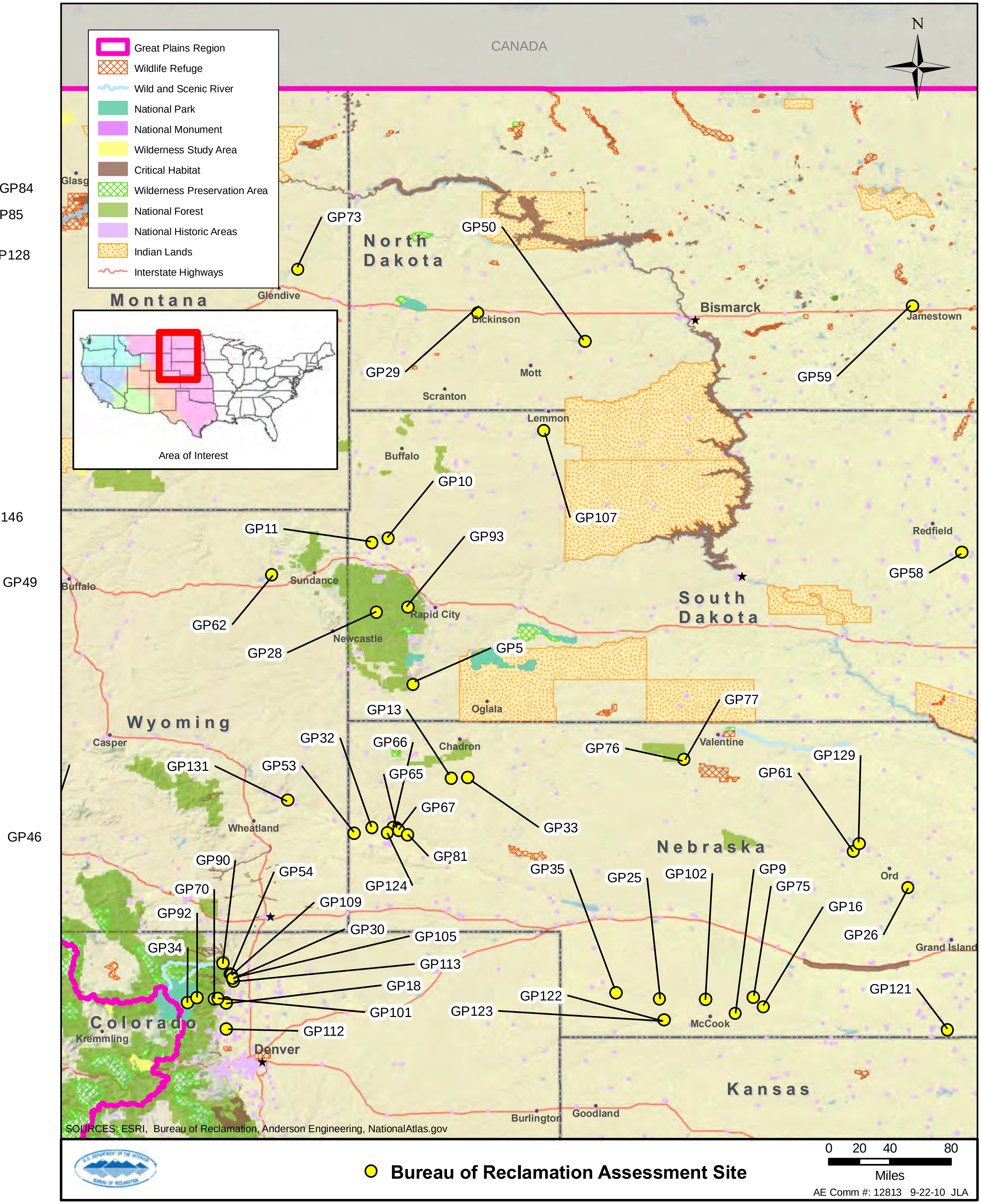

Figure F-2 : Great Plains Region (Northeast) Potential Constraints Map

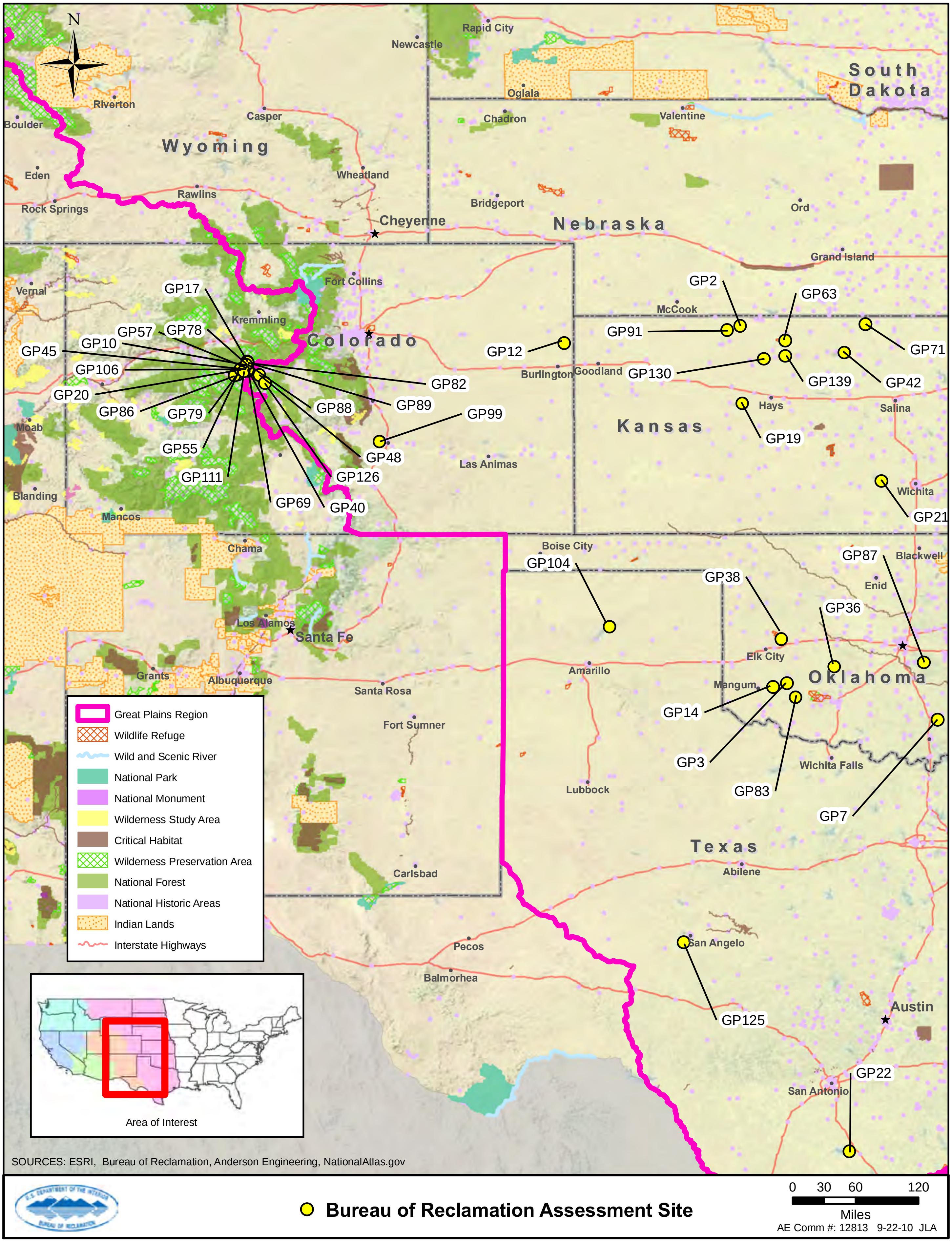

Figure F-3 : Great Plains Region (South) Potential Constraints Map

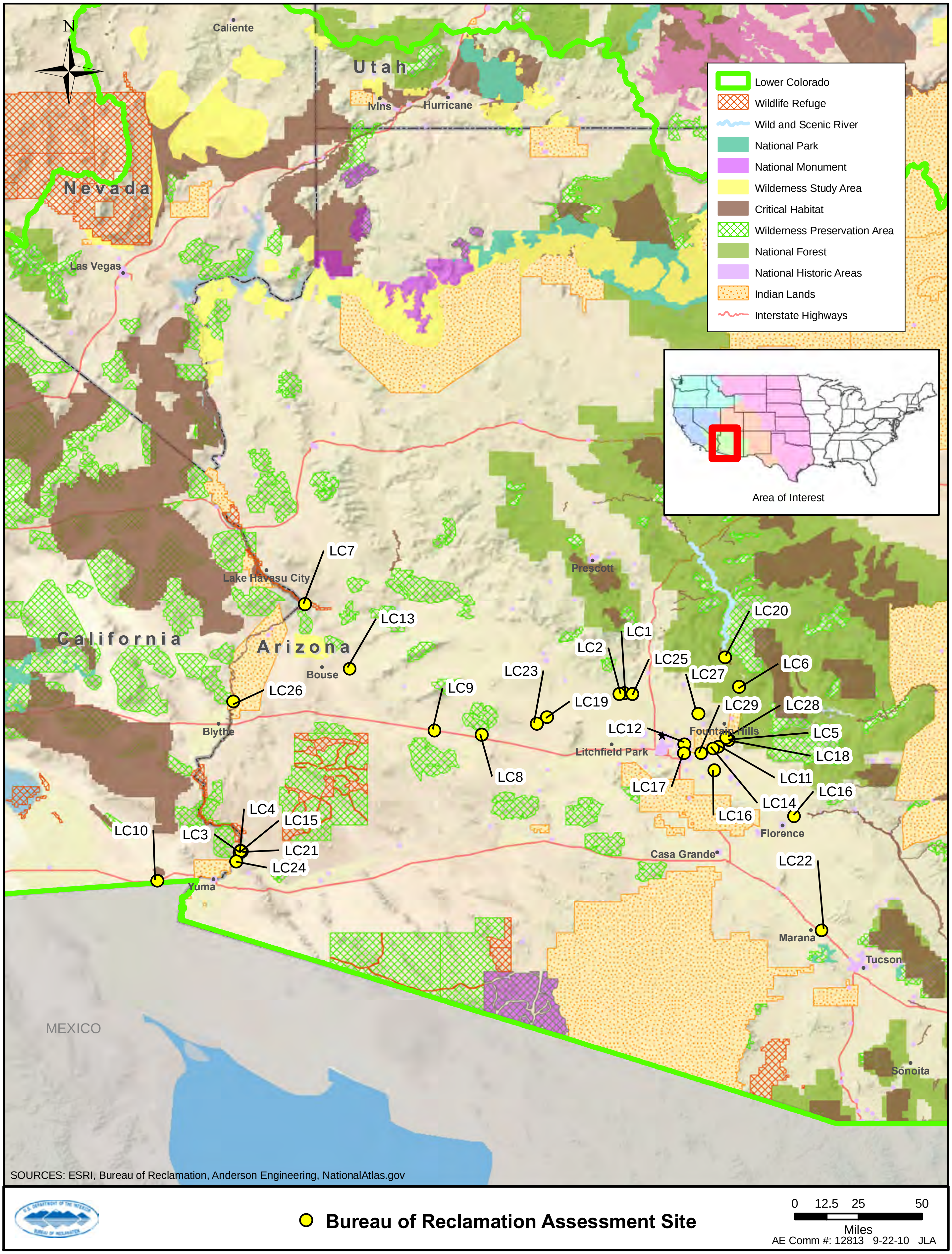

Figure F-4 : Lower Colorado Region Potential Constraints Map

Figure F-5 : Mid-Pacific Region (North) Potential Constraints Map

Figure F-6 : Mid-Pacific Region (South) Potential Constraints Map

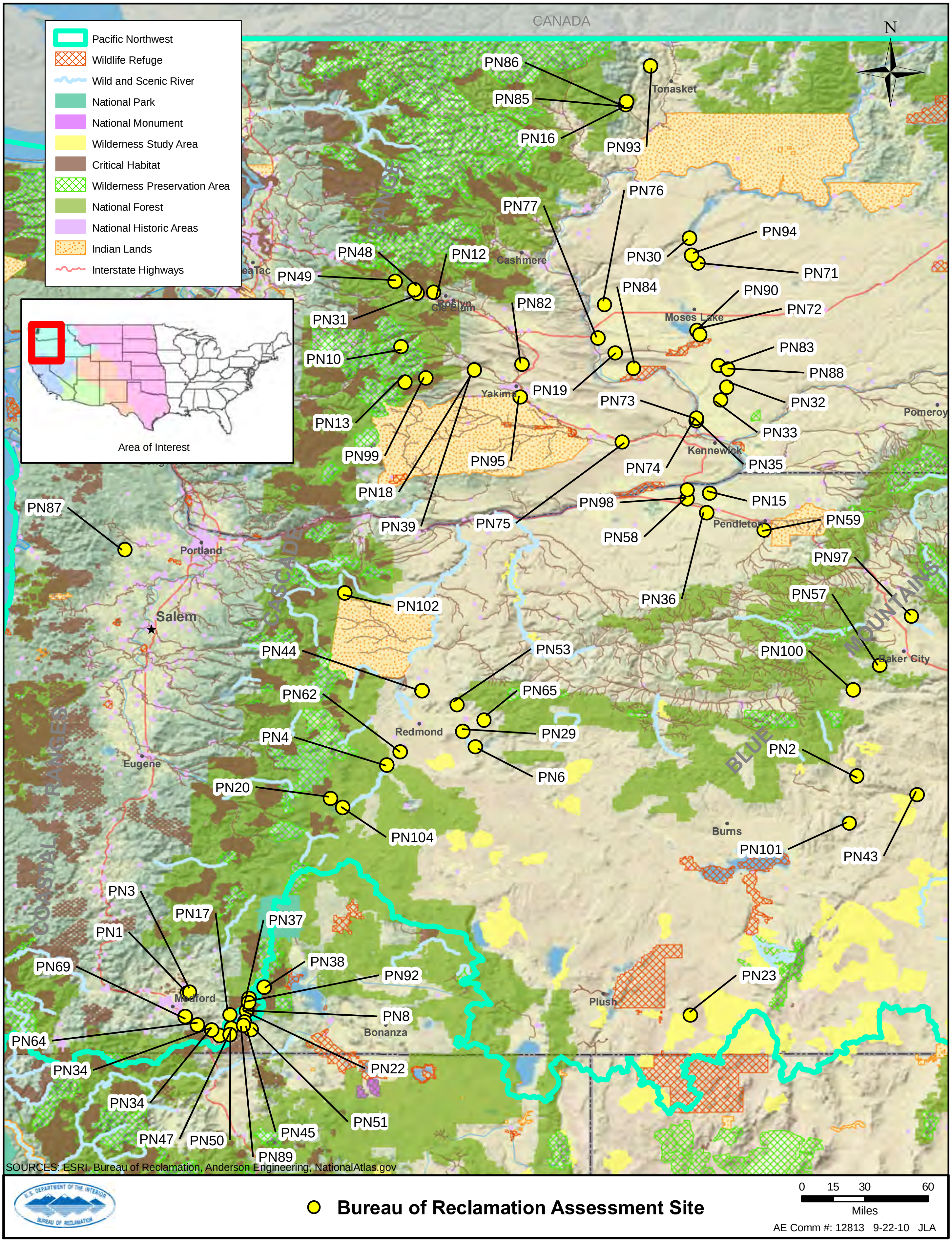

Figure F-7 : Pacific Northwest Region (West) Potential Constraints Map

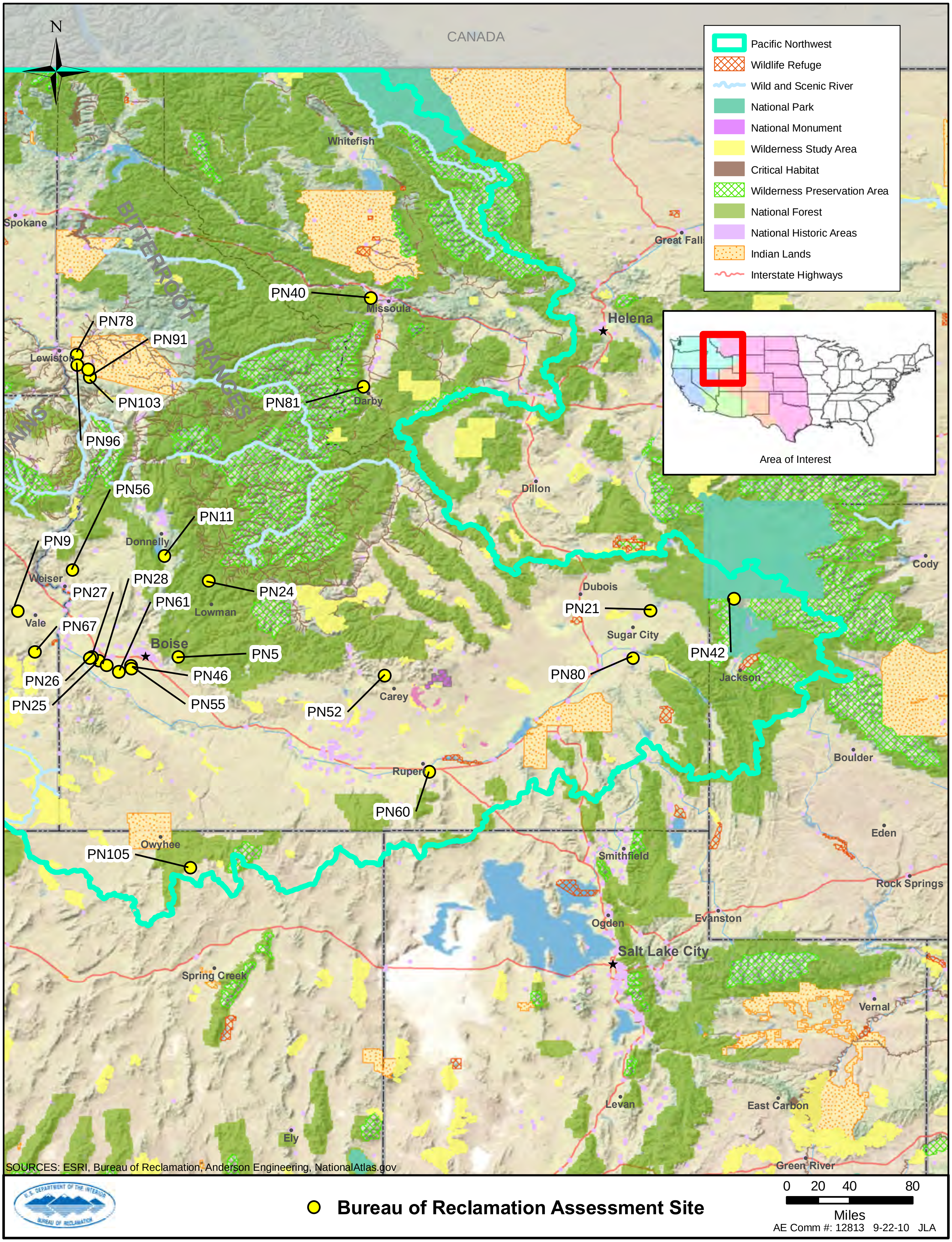

Figure F-8 : Pacific Northwest Region (East) Potential Constraints Map

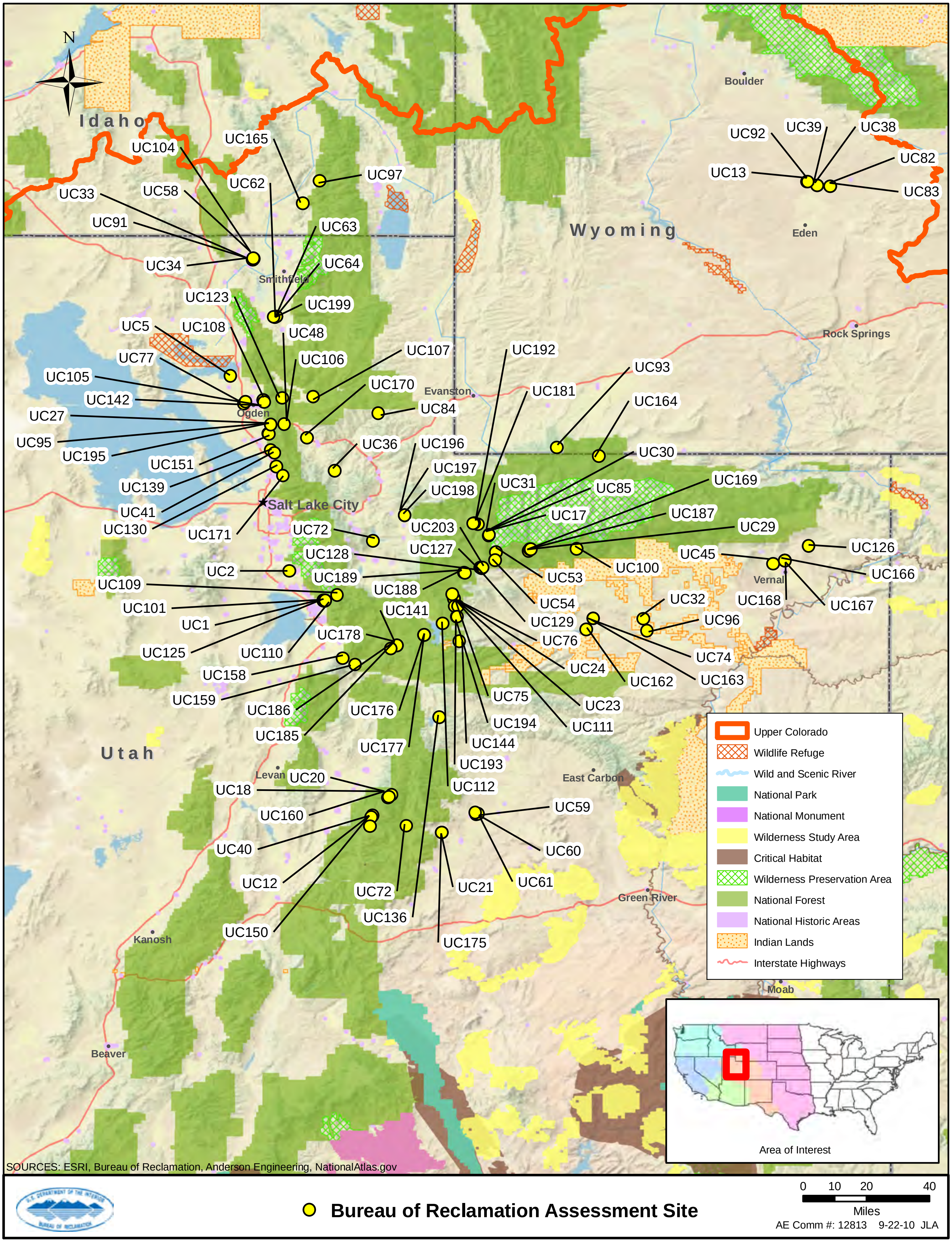

Figure F-9 : Upper Colorado Region (West) Potential Constraints Map

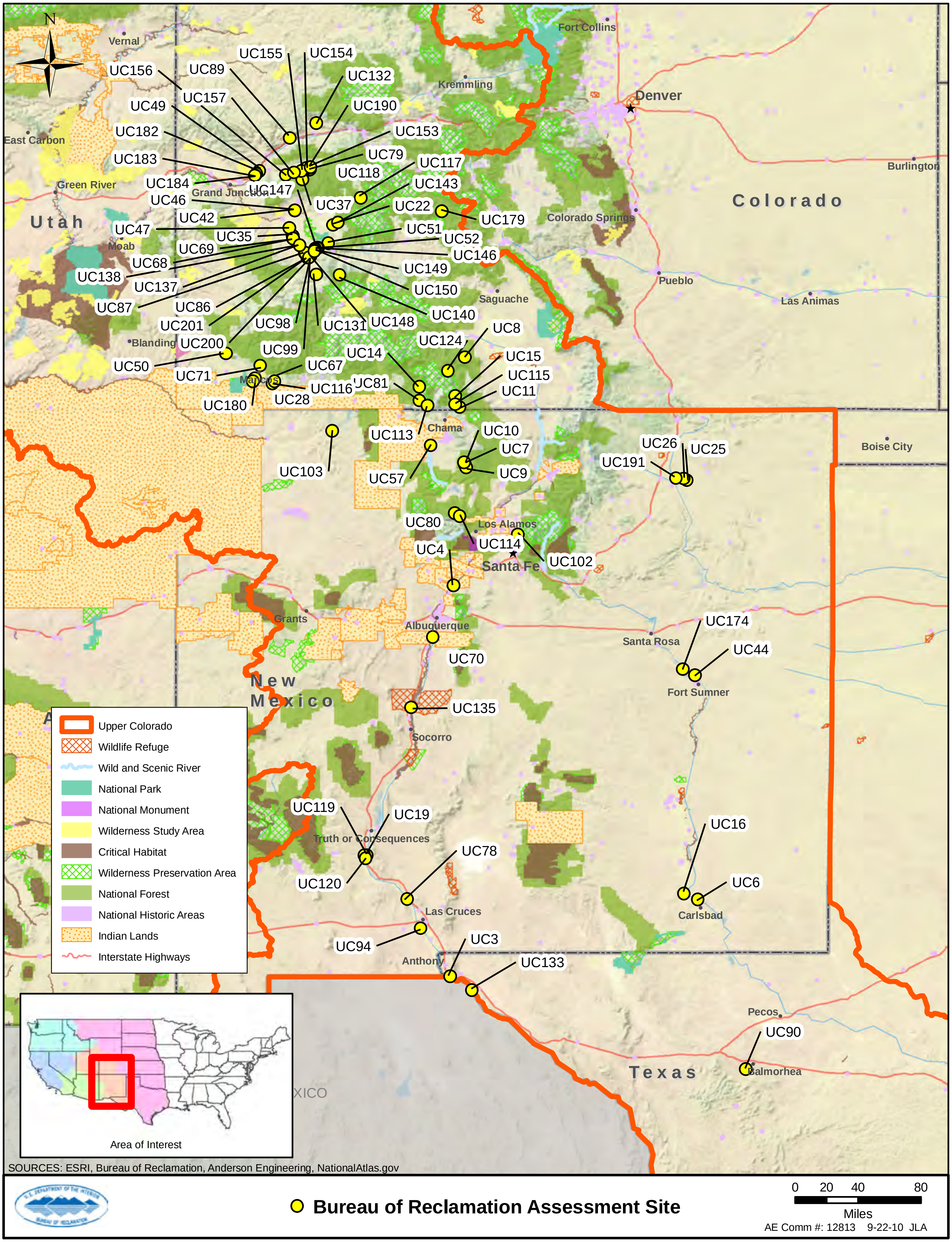

Figure F-10 : Upper Colorado Region (East) Potential Constraints Map

Appendix G Public Comment Summary

This appendix includes public comments received on the Draft Resource Assessment. Reclamation published a notice in the Federal Register on November 4, 2010 soliciting public comments on the draft report. The public comment period was scheduled through December 3, 2010. On December 28, 2010, Reclamation reissued a notice in the Federal Register extending the comment period through January 27, 2011, in response to public requests for an extension. The table below lists agencies or individuals that submitted comments on the draft report.

Name	Agency (if applicable)
Mike Bahleda	Halcrow
Carl Brouwer	Northern Water
Ron Corso	N/A
Robert S. Lynch	Irrigation and Electrical District Association of Arizona
Reed Murray	Department of the Interior
Linda Church Ciocci	National Hydropower Association
Alexis Phillips	Hydro Green Energy, LLC
Gene Shawcroft	Central Utah Water Conservancy District
Carl Vansant	HCI-Partners
David Woodward	Black & Veatch Corporation

The public submitted editorial comments and general comments on the objectives, scope, approach, and findings of the Resource Assessment. Reclamation incorporated editorial and general comments into the final report, as appropriate. Many comments received on the draft report were positive and consistent with Reclamation's objectives for hydropower development at existing facilities. Reclamation has noted all public comments and thanks the public for their interest in the draft report.

G.1 Comment Responses

Reclamation addressed comments in the final report, as appropriate, however, chose to provide some responses in this appendix to comments received in multiple letters or comments that could not be addressed in the report. This section presents comments and Reclamation's responses.

Comments received reflected understanding of the preliminary level of analysis of the Resource Assessment. Reclamation wants to reiterate that this final report is not a feasibility study. Site-specific feasibility level analysis is needed for any potential development of a site identified in the Resource Assessment.

General Comment: The total realistic potential from the type of facilities contemplated in the report is perhaps 1 percent or less of Reclamation's existing hydropower capability.
Response: The Resource Assessment findings indicated that 268 MW of capacity is available producing up to 1,200,000 MWh. This amount is small relative to Reclamation's existing hydropower generation facilities; however, sites showing positive economic results do present a cost-effective, new renewable energy source. Sites in the Resource Assessment are sized at a 30 percent exceedance level. Total capacity would increase if sites were sized at a lower exceedance, such as 20 percent; however, costs would also increase, which can make fewer sites appear economically feasible. Section 5.7 presents a sensitivity analysis on use of exceedance levels.

Reclamation undertook the Resource Assessment to determine potential new sources of hydropower at existing facilities, even small hydropower, to help meet national renewable energy goals. This Resource Assessment does not guarantee development of any site, but Reclamation will work with developers interested in a potential hydropower project identified in the analysis.

General Comment: Is Reclamation evaluating increasing capacity at existing hydropower plants?
Response: Reclamation owns 58 hydropower plants that have capacity of approximately 15,000 MW. Reclamation is assessing potential capacity increases at the 58 hydropower plants through the Hydropower Modernization Initiative. The report, *Assessment of Potential Capacity Increases at Existing Hydropower Plants*, documents Reclamation's methods and findings for potential capacity additions at existing hydropower plants. The report can be accessed at http://www.usbr.gov/power/. This Resource Assessment focuses on developing new hydropower capacity at Reclamation's facilities; and, it is not within the scope of the study to evaluate upgrades to existing hydropower plants.

General Comment: Some sites analyzed in the Resource Assessment have additional development constraints, such as existing permits or rights to develop hydropower at the sites.
Response: Reclamation recognizes that some sites included in the Resource Assessment have FERC preliminary permits or development rights issued on them. Reclamation has included these sites because they fit the study scope of identifying hydropower potential at Reclamation-owned sites with no existing hydropower facilities. Reclamation will not interfere with existing plans or authority for hydropower development at sites included in the analysis. If any site is pursued in the future, Reclamation will examine and comply with existing rights. The final report, specifically Table 2-3 and Chapter 5, identifies sites with existing development plans, permits, or rights to development known to Reclamation.

General Comment: Along with identifying the potential for hydropower development, it is important to accurately describe the current options and the administrative process for hydropower development.
Response: Reclamation-owned hydropower sites could be developed through a Lease of Power Privilege as opposed to a FERC license, as described in Chapter 6. The Resource Assessment does not go into detail on administrative processes as they vary by Regional Office. Reclamation can be contacted for additional information and will work with any public or private developers interested in pursuing a site to understand development processes and requirements.

General Comment: The cost estimates in the model could be conservative.
Response: The model uses cost functions for total development costs, including construction, licensing and mitigation, and annual operating costs to estimate costs for 530 sites. The functions are intended to indicate a preliminary estimate of potential costs that can be compared to project benefits to identify potential sites to be further considered for hydropower development. For the scope of this Resource Assessment, results of the cost estimates are appropriate for this purpose. Cost estimate results for some sites may be conservative, and all costs need to be reexamined in the feasibility stage for any site pursued for hydropower development.

General Comment: Other environmental or regulatory constraints could exist that would affect mitigation costs.
Response: The constraints analysis in the Resource Assessment provides a broad overview of potential environmental or regulatory constraints that could be present at each site. It is important to note that other constraints could exist or constraints identified could prohibit development at a site. Furthermore, some constraints can have significant mitigation costs that would increase total development costs of the site. Because of the number of sites and extensive geographic range, it was not possible in this report to do a detailed analysis of potential constraints and associated mitigation costs at each site. Environmental and regulatory constraints and mitigation costs need to be further investigated during feasibility analysis.

General Comment: Can the tool be used for sites with high flows, greater than 5,000 cfs, and sites located outside of the states in Reclamation’s service area?
Response: The tool focuses on sites with flows less than 5,000 cfs and is not appropriate for use for higher flow sites. This flow limit is appropriate for sites analyzed in the Resource Assessment. Reclamation added an option for “Other” states in the summary worksheet of the Hydropower Assessment Tool. The user must input appropriate energy prices and green incentives rates if choosing the “Other” states option. Note the disclaimer statement in the tool.

G.2 Public Comment Letters

This section includes public comment letters received on the draft report. Email addresses and contact information were removed for privacy purposes.

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From:
Sent: Wednesday, November 10, 2010 10:01 AM
To: Pulskamp, Michael
Subject: Question Regarding the Hydropower Assessment Tool

Dear Mr. Pulskamp,

First off, I wanted to let you know that your Hydropower Assessment Tool workbook is fantastic. I find it to be a very helpful tool at work.

Anyway, the primary reason for this email is that I've dealt with some significant errors in the workbook. I've figured out through trial and error that your hydropower assessment workbook does not allow me to implement flow data over 5,000 cfs and add states that are not listed in your drop down menu on the start sheet.

My company's project sites can have flows that exceed 50,000 cfs and are in unlisted states. I was wondering if there is a way to fix this so that I can get a "rough" generation estimate?

Thank you very much. Look forward to hearing from you.

Best regards,

Alexis Phillips
Hydro Green Energy, LLC

-----Original Message-----
From: Soeth, Peter D
Sent: Thursday, November 04, 2010 9:15 AM
To: Pulskamp, Michael
Subject: Fw: Submission to Reclamation

Comment on final report.

----- Original Message -----
From:
To: Gabour, Robert; Soeth, Peter D
Sent: Thu Nov 04 08:35:20 2010
Subject: Submission to Reclamation

From Ron Corso on 11/04/2010 at 08:11:13MSGBODY:
Regarding the draft report - "Draft Hydropower Assessment at Reclamation Facilities", dated November 2010, while I have not read the entire document, there is one formula the USBR may want to check on Page 2-12, Parag. 2-2, Site Hydrologic Data. The formula mentioned is not the power generation formula, it is the power potential in kW. The rule of thumb formula for kWh = 1.0241 * Flow (cfs)/.00138 * Net Head (feet) * Efficiency * Plant Factor. If one knows the plant factor (usually 50 % or less depending on hydrology), the kWh should be reduced by that plant factor.

Previous Page: http://www.usbr.gov/main/comments.cfm

From: Bahleda, Mike
Sent: Friday, November 12, 2010 8:31 AM
To: Pulskamp, Michael
Cc: McCalman, Kerry L; Gabriel, Mark
Subject: RE: Hydro Resource Assessment

Mike

I had a chance to look over the report and was impressed by the thoroughness of your approach to reexamining the sites based on the existing data. I have a couple of minor points I would suggest you consider. Since your cost assumptions are based on the 2002 INEL work, they may still be a little conservative for some of the marginal projects. You may want to expand the discussion of this area to make it clear to readers that this is a conservative assessment particularly as it relates to mitigation cost. Also, I might have subcategorized the sites on the Indian lands and Federal Forests as having additional challenges as opposed to constraints since both areas are potentially open to development as opposed to wildlife refuges and national monuments where it would be virtually impossible to site a project. You may want to consider subcategorizing and re-titleing the constraints category to give users a better sense of the continuum represented from additional challenges to virtually impossible.

All this being said the report is a great step forward and shows that there is significant opportunity for development within the Bureau's holdings. The added attraction is that these projects represent the potential for additional incremental firming capacity in a region of the country that is seeing extensive development of intermittent wind power that will also benefit from the build out of this capacity.

With 192 developable sites and 65 of those with positive b/c ratios using the conservative INEL assumptions it looks like there will be some interesting opportunities for the Bureau to work with the private sector. Will the final report lay out a Bureau plan to develop the sites beyond the procedural steps for development presented in the draft? I suspect you can't and possibly don't want to lay out a detailed plan, but it would help to encourage development if the Bureau came out with a general plan as to how you hope to approach development and to send a strong message that the Bureau wants to work with developer and the environmental community to add this capacity as quickly and with as little impact as practical. Given that most of these projects represent existing impoundments that should be achievable.

Having managed similar upgrade and capacity addition projects while I was with AEP and having produced EPRI's Life Extension and Modernization Guideline, I can appreciate the challenges you will face adding this capacity to your existing system. Please consider me a resource you can draw on regarding issues of capacity improvements or capacity additions at sites currently without generation. With Halcrow's worldwide talent pool, our Denver office with a focus on Water & Energy projects and my own background in this area, I think we have a lot to offer the Bureau as you look to develop this additional capacity.

On a related note this year's Hydrovision Policy and Regulations track has two panels that might provide a good forum to discuss the challenges of bringing this potential capacity on-line. Jeff Wright of FERC is moderating a session titled Focus on Small Hydro: Policies Favorable to Development and Tim Oakes is leading a session called Understanding the Relationship between Hydro and other Renewables. If you are interesting in either of these sessions as a panelist to talk about the Bureau's perspective, I will pass your contact information along to the moderators.

If there is anything that Halcrow and I can do to help the Bureau as you look to implement a plan to bring this capacity on-line please call on me.

Regards,

Mike Bahleda

Sr. Energy Consultant
Halcrow

From: Woodward, David
Sent: Thursday, November 04, 2010 12:13 PM
To: Pulskamp, Michael
Subject: FW: [Hpcommittee] Bureau of Reclamation Releases Report of Development at Reclamation Facilities for Comment

Dear M. Pulskamp,

I would like to provide one comment on the draft Hydropower Resource Assessment at Existing Reclamation Facilities:

The formula in Section 2.2, reads:

Power [kWh] = (Flow [cfs] * Net Head [feet] * Efficiency)/11.81

I believe the units of power should be kilowatts (kW), not kWh (kilowatt-hours).

David Woodward, P.E., Senior Project Engineer

From: Carl Vansant
Sent: Monday, December 06, 2010 2:43 PM
To: Pulskamp, Michael
Subject: Comments - Draft Hydropower Resource Assessment at Existing Reclamation Facilites

Dear Mr. Pulskamp:

I am grateful for the opportunity to examine and comment on the report, "Draft Hydropower Resource Assessment at Existing Reclamation Facilities" (November 2010).

First, this report is vastly more informative than the 2007 "1834 Study."

I have only a few comments regarding broad premises and findings.

Regarding the bottom line reported in Table ES-2: i.e., a total of 259.7 MW of hydropower potential at benefit/cost ratios exceeding zero (or 167 MW of hydropower potential at a benefit/cost ratio exceeding 1.0); this is a powerful result. At the level of national policy, this leads to the conclusion: "Why bother?" … The total realistic potential from the type of facilities contemplated in the report is perhaps 1% or less of Reclamation's existing hydro capability.

As the nation's second-largest hydropower producer (after the Corps of Engineers), I think it's reasonable for the nation's leaders and policymakers to look to Reclamation for energy solutions. Further, Reclamation has made substantial progress in recent years in hydro facilities upgrading – increasing the power and energy production capabilities. Would it not be appropriate for Reclamation to report on it's accomplishments in this regard? Also, there are surely additional cost-effective opportunities for getting more out of existing facilities that Reclamation could pursue (and likely is pursuing) … could these be discussed?

Targeting the assessment to "municipalities and private developers" [as stated in "Purpose," page ES-1] may be an appropriate – especially considering the nature of the result (i.e., development opportunities in the range of 125 kW to 26 MW capacity). Yet, within the scope of Reclamation's operations, supporting such developments might well be a costly nuisance. It seems reasonable that the broad aim of enabling more energy production might be better achieved through other means.

Finally, I'll ask: Are there "thinking outside the box" – i.e., large scale – opportunities within Reclamation's purview that could make meaningful contributions to the nation's energy supply?

Best regards,

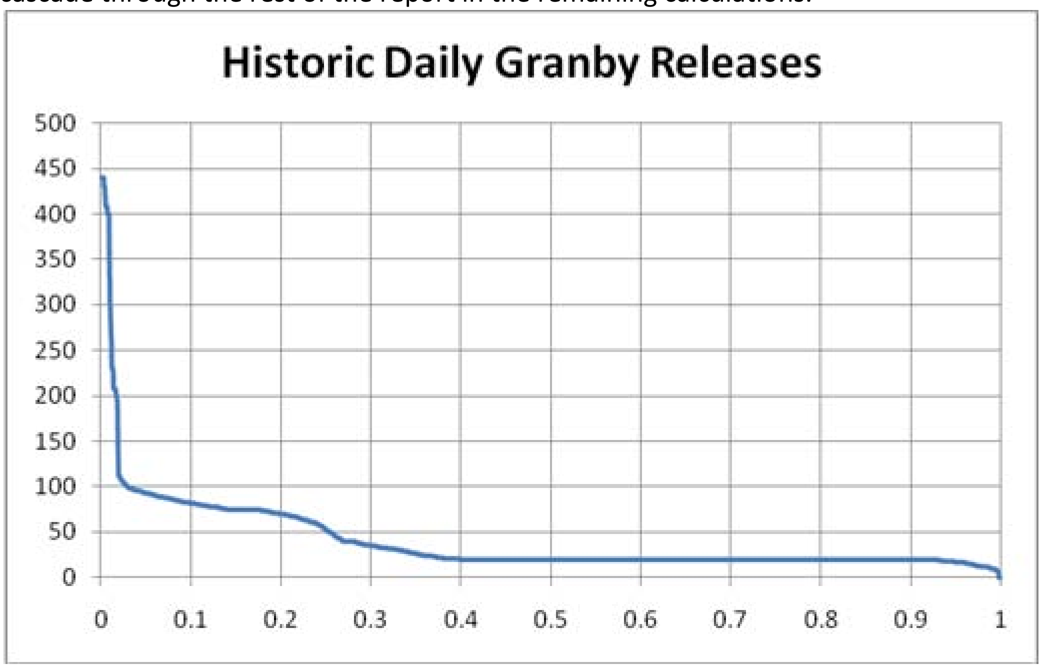
Carl Vansant

From: Carl Brouwer
Sent: Thursday, January 20, 2011 11:51 AM
To: Pulskamp, Michael
Cc: Don Carlson
Subject: Northern Water comments on Hydropower Resource Assessment report

Dear Mr. Pulskamp;

Northern Water has reviewed the Draft Hydropower Resource Assessment Report by Reclamation as it pertains to potential hydropower on certain Colorado-Big Thompson Project (C-BT) facilities. We offer to the following comments on the report.

Granby Dam. Granby Dam is used as an example throughout the report. Unfortunately, the wrong flow data was used. Based on Figure 3.2, it appears that the flow data included the amount pumped from Lake Granby into Shadow Mountain Reservoir as well as the actual releases from the dam. The result in making the correction will reduce the capacity to about 1.4MW and an output of approximately 4,000 MWhrs as opposed to the 7MW and 30,000 MWhrs shown in the report. This correction will need to cascade through the rest of the report in the remaining calculations.



Carter Lake. The head information for Carter Lake given in Table E.3 is not correct. The reservoir elevation is 5759. The outlet elevation is 5605. Therefore the maximum head is 154 feet before headlosses are included. It is unclear what flow information is utilized.

Horsetooth Reservoir. The maximum head in Table E.3 is shown to be 3,097 feet. The actual maximum head would be the maximum water level of 5430 less the outlet valve elevation of 5295 for a total of 135 feet. The design flow of 41 cfs seems very low for this site. Please note that additional releases are made from Horsetooth Reservoir out of the Soldier Canyon dam. The head at this site is higher, and the design flow of 41 cfs may be more appropriate at that site.

We appreciate the opportunity to offer these comments. If you have any questions, do not hesitate to contact me.

Sincerely,

Carl Brouwer, P.E., PMP
Manager, Project Management Department
Northern Water

IRRIGATION & ELECTRICAL DISTRICTS
ASSOCIATION OF ARIZONA

R.D. JUSTICE
PRESIDENT

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SECRETARY-TREASURER

ROBERT S. LYNCH
COUNSEL AND
ASSISTANT SECRETARY-TREASURER

E-MAILED ONLY
(mpulskamp@usbr.gov)

December 6, 2010

Mr. Michael Pulskamp
Bureau of Reclamation
Denver Federal Center, Bldg. 67
P.O. Box 25007
Denver, Colorado 80225

RE: Hydropower Resource Assessment at Existing Reclamation Facilities – Draft Report, 75 Fed.Reg. 67993-4 (November 4, 2010)

Dear Mr. Pulskamp:

We are writing to submit comments on the Draft Report which the Federal Register notice indicates are due by Monday, December 6, 2010. We recognize that this Draft Report stems from the 2010 federal Memorandum of Understanding for Hydropower and provisions of the Energy Policy Act of 2005. We wish to compliment Reclamation on the effort it has put into this Draft Report. It is clear to us that clean, renewable hydropower generated at Reclamation facilities is an important national resource and, especially in our region, a very valuable tool in managing power supply and offsetting carbon-based electricity generation needs. We hope that this study will lead to the possibility of feasibility level analyses for at least some of the identified sites.

Having said that, we wish to note that, on page 4 of the Draft's Executive Summary, you have placed a chart (Table ES-2) that identifies hydropower potential listed by benefit cost ratio ranges. Of the 192 sites examined, you identified 31 with a BC ratio of 1.0 to 2.0 and 9 with a BC ratio equal to or greater than 2.0, for a collective installed capacity increase of 167 megawatts out of a total of 259.7 megawatts identified.

While we have no quibble with this analysis, it points out how difficult finding new sites is and us wondering how more easily additional capacity could be found at existing hydropower plants without expensive construction.

For instance, Glen Canyon Dam operates at a maximum release of 16,000 cfs under current water conditions. That generates 604 megawatts of capacity at a facility that has a nameplate capacity of 1400 megawatts and an operational capacity in the range of 1340 megawatts. Raising the current maximum water releases at Glen Canyon Dam less than 30%, an operational change requiring no additional capital cost, would more than cover the proposed generation in your chart of projects that have at least a one to one BC ratio. In short, tweaking Glen Canyon Dam operations would more than cover everything you've identified as potentially feasible. Operating Glen Canyon Dam at its current maximum allowable water release (25,000 cfs) for the short period during the day that this kind of peaking power is produced would generate more additional capacity than that potentially available at all of the sites you studied, economically feasible or not.

We very much appreciate the significant effort that went into developing this Draft Report. We hope that you now will study operational changes at existing facilities like Glen Canyon Dam to identify more operational adjustments that can produce increased hydropower generation opportunities.

Sincerely,

/s/

Robert S. Lynch
Counsel and Assistant Secretary/Treasurer

RSL:psr
cc: Kellie Donnelly, Republican Deputy Chief Counsel, Senate Energy and Natural Resources Committee
Kiel Weaver, Republican Staff Director, Water and Power Subcommittee, House Natural Resources Committee
Tim Meeks, WAPA Administrator
Michael L. Connor, Commissioner of Reclamation
Larry Walkoviak, Regional Director, Bureau of Reclamation
Leslie James, Executive Director, CREDA
IEDA Presidents/Chairman and Managers

Central Utah Water Conservancy District

355 WEST UNIVERSITY PARKWAY, OREM, UTAH 84058-7303
TELEPHONE (801) 226-7100, FAX (801) 226-7107
TOLL FREE 1-800-261-7103
WEBSITE www.cuwcd.com

OFFICERS
Michael H. Jensen, President
Randy Crozier, Vice President

Don A. Christiansen, General Manager
Secretary/Treasurer

December 6, 2010

Mr. Michael Pulskamp
Bureau of Reclamation
Denver Federal Center, Bldg. 67
P.O. Box 25007
Denver, CO 80225

VIA EMAIL

Subject: Hydropower Resource Assessment at Existing Reclamation Facilities—Draft Report

Dear Mr. Pulskamp:

We appreciate the opportunity to review the subject report and support the concept of environmentally sustainable generation.

As has been communicated with Reclamation officials over many years, the Central Utah Water Conservancy District (District) has interest in hydropower development where ever feasible at Central Utah Project (CUP) facilities. You are well aware of our successful Jordanelle hydropower project and the associated partnerships.

As you know, the District is the sponsoring entity of the Bonneville Unit of the CUP with specific authority for completion of the CUP under the Central Utah Project Completion Act (CUPCA). In 2002 CUPCA was amended, which authorized federal funding for development of hydropower on the Bonneville Unit. Additionally, the District is under contract with the United States for construction, repayment, operation and maintenance of the project features. Therefore, we understand the Department of the Interior (DOI) would take the lead on hydropower development on such facilities and we respectfully request the opportunity to consult with DOI and Reclamation as necessary as development options are considered on CUP Bonneville Unit facilities.

If you have questions, please feel free to me at (801) 226-7120.

Sincerely,

Gene Shawcroft, P.E.
Assistant General Manager

cc: Lee Wimmer
Rich Tullis
Reed Murray (DOI)
Curt Pledger (USBR)

File Code: 3.P1.101

United States Department of the Interior

OFFICE OF THE SECRETARY
Program Director
CUP Completion Act Office
302 East 1860 South
Provo, Utah 84606-7317

TAKE PRIDE IN AMERICA

IN REPLY REFER TO:

CA-1500
PRJ-17.00

DEC 06 2010

Mr. Michael Pulskamp
Bureau of Reclamation
Denver Federal Center, Building 67
P.O. Box 25007
Denver, CO 80225

Subject: Draft Hydropower Resource Assessment at Existing Reclamation Facilities, Central Utah Project Facilities, Section 208, Central Utah Project Completion Act

Dear Mr. Pulskamp:

We have reviewed the Draft Hydropower Resource Assessment at Existing Reclamation Facilities (Draft Report) and appreciate the opportunity to submit comments. Although the Draft Report includes regulatory constraints considered in the evaluation, there are other constraints that should be considered such as pre-existing arrangements for hydropower development.

With regard to the Central Utah Project (CUP), there are associated laws, contracts, planning documents, National Environmental Policy Act documents, and Records of Decision that govern hydropower development on the CUP. In 1992, Public Law 102-575, of which Titles II through VI comprise the Central Utah Project Completion Act (CUPCA), transferred the responsibility for CUP construction to the Central Utah Water Conservancy District with Federal oversight by the Department of the Interior's CUPCA Office. The Sixth Water, Upper Diamond Fork, and Spanish Fork Flow Control structures, mentioned in the Draft Report, are part of the CUP, Bonneville Unit.

The CUPCA legislation authorized Federal hydropower development on Bonneville Unit features. Significant planning on the CUP has been completed including hydropower development. In 2004, documents were published which include plans for the Sixth Water and Upper Diamond Fork sites. These documents include the: September 2004, Utah Lake System Final Environmental Impact Statement; October 2004, Supplement to the 1988 Definite Plan Report on the Bonneville Unit; and December 22, 2004, Record of Decision. These documents are available at www.cupcao.gov.

In addition, there is pending legislation in Congress entitled the 'Bonneville Unit Clean Hydropower Facilitation Act.' This proposed legislation specifically addresses hydropower development on the Bonneville Unit, Diamond Fork System and is relevant to the facilities mentioned in the Draft Report.

Although the planning and environmental documents anticipate Federal power development, we recognize that private power development may also be a preferable option. Any private power development would be implemented by the CUPCA Office under a Lease of Power Privilege. This would be subject to an open and competitive process in compliance with Interior's guidelines and criteria including publication of a Federal Register Notice.

Along with identifying the potential for hydropower development, it is important to accurately describe the current options and the administrative process for hydropower development. We would be happy to discuss hydropower development on the CUP with you at your convenience. Should you have any questions, or to arrange for a meeting, please call Mr. Lynn Hansen at 801-379-1238.

Sincerely,

Reed R. Murray

Reed R. Murray
Program Director

cc: Mr. Gene Shawcroft
Assistant General Manager, Central Utah
Water Conservancy District
355 West University Parkway
Orem, UT 84058-7303

National Hydropower Association
25 Massachusetts Ave. NW, Ste. 450, Washington, D.C. 20001 • Tel 202-682-1700 • Fax 202-682-9478 • www.hydro.org

Mr. Michael Pulskamp
Bureau of Reclamation
Denver Federal Center, Bldg. 67
P.O. Box 25007
Denver, CO 80225

January 27, 2011

Mr. Pulskamp,

The National Hydropower Association[1] ("NHA") appreciates the opportunity to provide the following comments on the Bureau of Reclamation's ("Reclamation") *Draft Hydropower Resource Assessment at Existing Reclamation Facilities ("Assessment")* released in November 2010.

NHA applauds the work Reclamation has undertaken as part of the 2010 Federal Memorandum of Understanding (MOU) for Hydropower to update its review of power potential at existing Reclamation facilities.[2]

While the Assessment highlights opportunities for growth on Reclamation's system, NHA and the industry were surprised by the comparatively low number of megawatts reported. From discussion with industry experts, we believe the potential is even greater than 260 MW. NHA views the Assessment as a good first step, and we urge continued analysis.

Congress and the Administration, as well as the states, have set ambitious energy goals for the country, seeking the short and long term benefits of significantly increased renewable energy generation, such as reduced emission of greenhouse gases and air pollutants. NHA believes that hydropower can and should play a leading role in meeting these goals by bringing significant new renewable energy generation online.

As the federal system makes up about half of the hydropower generation in the United States today, and as there is significant existing non-powered federal infrastructure that could be converted to generating resources, NHA and the hydropower industry believe Reclamation (as well as the Corps of Engineers) is uniquely situated to support the deployment of new hydropower resources to meet these goals.

General comments are provided in the following section. This letter also includes specific responses to the details of the Assessment.

---

[1] NHA is a non-profit national association dedicated exclusively to advancing the interests of the U.S. hydropower industry, including conventional, pumped storage and new hydrokinetic technologies. NHA's membership consists of more than 180 organizations including public utilities, investor owned utilities, independent power producers, project developers, equipment manufacturers, environmental and engineering consultants and attorneys.
[2] 2010 Federal Memorandum of Understanding for Hydropower, May 24, 2010.

Overview

In general, NHA is pleased to note that this Assessment determined an increase in hydropower potential over the previous Reclamation assessment released in 2007 as part of the Section 1834 report prepared in accordance with the Energy Policy Act of 2005[3]. Though the 260 MW of potential capacity represents a more than 300 percent increase over the 52.7 MW in potential capacity identified at Reclamation facilities in the Section 1834 report, NHA believes that this amount remains a conservative estimate and does not document the full range of opportunities available on Reclamation's system.

NHA appreciates that the Assessment clearly states that it is not a feasibility study. (It is important to emphasize, as the Assessment does, that it utilized "broad power and economic criteria and it is only intended for preliminary assessments of potential hydropower sites."[4] Hydropower project development is a complex and detailed site-specific venture, with the individual characteristics of the site playing a paramount role. The Assessment acknowledges that "[h]ydropower plants can be designed to meet specific site characteristics" and that "[d]esign features can significantly affect the power production and costs of a project."[5] . As such, readers of the Assessment should be aware that more detailed study of individual sites may result in a different conclusion than that reached by the Assessment. However, utilizing the document as a screening level assessment of hydropower projects is a good start.

Finally, the updated Assessment, by its terms, was undertaken only to evaluate potential new projects at existing non-powered Reclamation dams. To more fully implement the 2010 MOU, NHA encourages Reclamation to assess and make available (if it has not done so already) data for upgrades or additions of capacity at existing hydropower projects throughout Reclamation's system. With this data on upgrades and backlogged O&M projects, Reclamation would be able to present a more complete picture of its potential contribution to increased hydropower generation. These issues were explored in the 2007 Section 1834 report, but NHA believes the analysis deserves a second look. With new turbine technology and other advancements, such upgrades and expansions have the dual benefit of increased power and improved environmental performance.

Specific comments on the Assessment methodology

The following comments were developed by NHA through a staff review of the Assessment and in consultation with industry members with expertise in project identification, screening, feasibility and due diligence review. In fact, several of NHA's member companies have engaged in analysis of Reclamation infrastructure for potential development by non-federal entities.

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[3] Section 1834 of the Energy Policy Act of 2005 required the Secretary of the Interior, the Secretary of the Army, and the Secretary of Energy to "jointly conduct a study assessing the potential for increasing electric power production at federally owned or operated water regulation, storage, and conveyance facilities."

[4] Draft Hydropower Resource Assessment at Existing Reclamation facilities, November 2010. Section 4.3, p. 4-3.

[5] Ibid. Section 4.4, p. 4-4.

Data is incomplete and may also underrepresent potential.

In Table ES-1, the Assessment indicates that Reclamation was unable to obtain hydrological data for 92 of the 530 sites analyzed. This represents a significant data gap of nearly 18 percent of the total possible sites. NHA commends the efforts of Reclamation staff in utilizing several data sources for the Assessment. However, we urge Reclamation to examine how it may locate the necessary information to evaluate these remaining sites, and to include funding to close this data gap as part of its FY 2012 budget proposal. A partnership with the Department of the Interior, through the United States Geological Survey's National Streamflow Information Program, may be able to provide the data to address this issue.

Our members also have concerns that the Assessment underestimates the potential capacity of projects. To estimate plant capacities and associated energy production, the Assessment "develops flow and net head exceedance curves and sets design flow and design net head at a 30-percent exceedance level to calculate installed capacity."[6] Using the 30-percent exceedance flow and associated head to determine capacity could under-predict the best economic capacity for sites with skewed head and flow duration curves.

For example, an independent analysis by an NHA member company found that technical potential of one project, Cle Elum Dam in Washington State, was nearly three times that of the potential reported in the Assessment. Certainly, this is only one example of a difference in analysis between Reclamation and the industry. While this difference may not apply to all sites addressed in the Assessment, it does suggest that the sites warrant further investigation, and perhaps collaboration with industry experts, to provide the most complete picture of the potential for hydropower development at Reclamation facilities.

Additionally, Table ES-1 demonstrates that 182 sites contained no hydropower potential whatsoever. The Assessment states that at these sites "[l]ocal area knowledge or available hydrological data indicated that the site does not have hydropower potential because flows or net head are too low for hydropower development."[7] This number represents approximately 34 percent of the total sites.

Generally , this summary conclusion analysis could be accurate, but for NHA it remains a surprisingly high number and begs several questions. Is the available hydrological data for these sites current and accurate? Is there a need to update this data? The Assessment would seem to indicate that projects at these sites are not viable utilizing conventional, traditional technology. At a minimum, there appears to be a research and development opportunity for which the Reclamation could partner with the Department of Energy to investigate and test new applications that take advantage of the multitude of low-head or low-flow sites. In fact, Reclamation staff have suggest ed that Reclamation could play a lead role in creating a technology demonstration park utilizing existing hydraulic and electrical infrastructure to support the evolution of new, low head technologies that could be specifically used in irrigation canal drops and other water delivery systems.

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[6] Ibid, Executive Summary, p. ES-2.
[7] Ibid, Executive Summary, p. ES-3.

Economic analysis may contain imperfect cost assumptions

NHA also is concerned with the economic analysis used to produce the Assessment.

First, the cost estimates developed in the Assessment are based on a regression analysis of the cost of installed hydropower projects completed by the Idaho National Lab (INL) in 2002. While this represents the most recent government data available, NHA notes that it is now almost 9 years old and that the economic climate in 2011 varies dramatically from that in 2002. Because of this, industry members raise the possibility that the INL cost data does not now accurately reflect actual facility development, design, and construction costs, and that real-world experience provides a better gauge of these costs.

For example, INL cost factors have been escalated by 30 percent to account for inflationary cost increases occurring since 2002. Industry members believe this escalation factor may be too high based on the recent history of inflation rates experienced over the last several years and the existing economic climate.

Additionally, the Assessment's assumptions on mitigation costs may need to be reconsidered. In section 3.3.2 of the Assessment, Reclamation discusses assumptions related to mitigation costs for potential hydropower projects stating:

> "Other costs that may apply, depending on the specific site, include fish passage requirements, historical and archaeological studies, water quality monitoring, and mitigation for fish and wildlife, and recreation. The magnitude of the above mitigation costs is dependent on the installed capacity of the project. In general, mitigation costs would increase the larger the project…In general, mitigation costs are very site specific and should be reevaluated if a site is further analyzed. Mitigation costs could differ significantly than those presented in this analysis." (P.3-17)

Given that mitigation costs for hydropower are highly site specific, it may not be appropriate to assume that these costs are dependent on the installed capacity of the project. It might be more appropriate to increase the contingency on the construction costs to account for potential mitigation measures with the general belief that higher project construction costs correlate with larger project sizes better able to support mitigation expenses. Understandably, smaller projects have little margin to absorb significant mitigation expenses.

Assessment excludes important incentives from analysis

In the Assessment, Reclamation attempts to inventory and consider policy incentives that benefit hydropower development (p.3-14). While the Assessment explores several incentives, such as the Federal Production Tax Credit and specific state performance incentives, other critical financial incentives, specifically installation-based federal incentives, are not adequately addressed.

While it is true that such incentives can vary based on factors such as ownership and date of implementation, NHA believes that excluding these policies undervalues the role they play in supporting project development. Indeed, two programs in particular have proved to be valuable investment tools over the past few years. Programs like the Section 1603 "grants in lieu of tax credits" program and

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Clean Renewable Energy Bonds have provided over $570 million to private and public electric companies to expand and upgrade current hydro facilities since 2007.

Additionally, looking at the Benefit Cost Ratio that Reclamation employed in this analysis illustrates that an opportunity exists to further incentivize the development of clean, renewable and reliable hydropower resources. Sixty-five sites, totaling 210 MW of installed capacity, are identified as being most cost efficient based on Reclamation's scale. That number could be increased by more than 10 percent if the next group of cost efficient projects (those ranked between .5 and .75) were bolstered by stronger incentive policies. That's an additional 88,143 MWh a year in generation, enough to power almost 8,000 American households annually.[8]

Conclusion

NHA once again commends Reclamation on updating its review of non-federal hydropower development opportunities on existing non-powered Reclamation dams. The Assessment highlights several key issues:

> 1) maximizing existing infrastructure is low-hanging fruit to meet the goal of developing more U.S. renewable energy resources;
>
> 2) the federal hydropower system, and in particular Reclamation, has an important role to play in realizing this untapped potential;
>
> 3) incentives for development can expand the universe of hydropower projects that are economically viable.
>
> 4) continued study of hydropower potential in general, and federal potential in particular, is necessary to fill data gaps and present the best information and most accurate picture of growth opportunities.

Thank you again for this opportunity to comment. NHA hopes that these comments provide useful recommendations to improve upon the Assessment methodology. The Association stands ready to work with Reclamation and other federal agencies to expand hydropower generation in the United States and meet the administration's renewable energy goals.

Sincerely,

Linda Church Ciocci

Linda Church Ciocci
Executive Director

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[8] Based on EIA estimation of annual average household electricity consumption of 11,040 kWh.