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Technical and Economic Feasibility Assessment of Small Hydropower Development in the Deschutes River Basin

June 2013

Prepared by

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UT-BATTELLE

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Environmental Sciences Division

TECHNICAL AND ECONOMIC FEASIBILITY ASSESSMENT OF SMALL HYDROPOWER DEVELOPMENT IN THE DESCHUTES RIVER BASIN

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CONTENTS

Page

CONTENTS (cont'd)

LIST OF FIGURES

LIST OF TABLES

ACRONYMS AND ABBREVIATIONS

AF	axial flow
AID	Arnold Irrigation District
BSOA	Basin-Scale Opportunity Assessment
BCR	benefit-cost ratio
cfs	cubic feet per second
CHC	Canadian Hydro Components
COID	Central Oregon Irrigation District
CRF	capital recovery factor
DBBC	Deschutes Basin Board of Control
DOE	U.S. Department of Energy
DVWD	Deschutes Valley Water District
EIA	Energy Information Administration
ETO	Energy Trust of Oregon
FCR	fixed charge rate
FDC	flow duration curve
FERC	Federal Energy Regulatory Commission
FPC	Federal Power Commission
ft	foot or feet
GHG	greenhouse gas
GWh	gigawatt hour
GWP	global warming potential
HEEA	Hydropower Energy and Economic Assessment
IEA	International Energy Agency
Interior	U.S. Department of the Interior
IRR	internal rate of return
ITC	Investment Tax Credit
kW	Kilowatt
kWh	kilowatt hour
LCOE	levelized cost of energy
MOU	Memorandum of Understanding
MW	Megawatt
MWh	megawatt hour
NHAAP	National Hydropower Asset Assessment Project
NID	National Inventory of Dams
NPD	non-powered dam
NPPC	Northwest Power Planning Council
NRC	Natural Resources Canada
NUID	North Unit Irrigation District
O&M	operation and maintenance
O&M&R	operation and maintenance and replacement
ODE	Oregon Department of Energy
OID	Ochoco Irrigation District
ORNL	Oak Ridge National Laboratory
ORNL-HEEA	Oak Ridge National Laboratory-Hydropower Energy and Economic Assessment
OWRD	Oregan Water Resources Department
PGE	Portland General Electric
PM	permanent magnet

ACRONYMS AND ABBREVIATIONS (cont’d)

PNNL	Pacific Northwest National Laboratory
PPA	power purchase agreement
PTC	Production Tax Credit
Reclamation	Bureau of Reclamation
REC	Renewable Energy Certificate
RPS	Renewable Portfolio Standard
ROW	right-of-way
SID	Swalley Irrigation District
TID	Tumalo Irrigation District
TREC	Tradable Renewable Energy Certificate
TSID	Three Sisters Irrigation District
USACE	U.S. Army Corps of Engineers
USGS	U.S. Geological Survey
WACC	weighted average cost of capital
WECC	Western Electricity Coordinating Council

EXECUTIVE SUMMARY

In March 2010, the U.S. Department of Energy (DOE), the U.S. Department of the Interior (Interior), and the U.S. Department of the Army [through the Army Corps of Engineers (USACE)] signed the Memorandum of Understanding (MOU) for Hydropower. The purpose of the MOU is to "help meet the nation's needs for reliable, affordable, and environmentally sustainable hydropower by building a long-term working relationship, prioritizing similar goals, and aligning ongoing and future renewable energy development efforts." Specifically, the MOU aims to "(1) support the maintenance and sustainable optimization of existing federal and non-federal hydropower projects, (2) elevate the goal of increased hydropower generation as a priority of each agency to the extent permitted by their respective statutory authorities, (3) promote energy efficiency, and (4) ensure that new hydropower generation is implemented in a sustainable manner."

Under MOU Action Item B, "Integrated Basin-Scale Opportunity Assessments," the agencies committed to work toward:

> "A new basin-scale approach to hydropower and related renewable development that emphasizes sustainable, low-impact, or small hydropower and related renewable energies could identify ecosystems or river basins where hydropower generation could be increased while simultaneously improving biodiversity, and taking into account impacts on stream flows, water quality, fish, and other aquatic resources."

As part of this new Basin-Scale Opportunity Assessment (BSOA) approach, the agencies committed to "select one or more basins for a basin-scale opportunity assessment pilot project." In February 2011, the agencies, through the national BSOA Steering Committee, selected the Deschutes River Basin in central Oregon as the first pilot basin. The report *The Integrated Basin-Scale Opportunity Assessment Initiative, FY 2011 Year-End Report: Deschutes Basin Preliminary Hydropower Opportunity Assessment* (PNNL 2011) describes how the Deschutes Basin was selected as the pilot basin as well as progress to date and ongoing research efforts on the Deschutes BSOA.

The purpose of this technical and economic feasibility assessment is to identify and analyze opportunities for new small hydropower development in the Deschutes Basin, along with the technology needed to develop selected sites and the economic cost/benefit of developing those sites. The three most likely scenarios for additional hydropower generation in the Deschutes Basin are:

- add new generators at existing non-powered dams (NPDs) and diversion structures;
- add new generators in existing irrigation canals and conduits; and
- increase generation at existing hydropower facilities.

Because this assessment focuses on developing new hydropower projects, it includes only the first two of the three scenarios: adding new generators at (1) existing NPDs and diversion structures and (2) existing irrigation canals and conduits.

This assessment was conducted using the Hydropower Energy and Economic Assessment (HEEA) Tool being developed by Oak Ridge National Laboratory (ORNL). The ORNL-HEEA Tool uses site-specific hydrological data and basic site and project information to: (1) generate flow and power duration curves; (2) determine turbine design flow, net head, and technology type; (3) calculate monthly and annual power generation and determine design power capacity; (4) estimate project cost [both installation cost and levelized cost of energy (LCOE)]; and (5) perform benefits and economic evaluations. The Tool incorporates some significant improvements compared with other exiting tools, and provides consistent and effective predictions of energy output and economic feasibility for potential sites. The ORNL-HEEA Tool can be implemented as an independent software package to study the feasibility of individual small hydropower projects, or incorporated into the Basin-Scale Water Management Model being developed by Pacific Northwest National Laboratory (PNNL) to model varying water management scenarios to maximize hydropower generation while meeting environmental flow requirements and the needs of other water users.

This assessment used the ORNL-HEEA Tool to assess the technical and economic feasibility of 14 NPDs and 15 irrigation canal/conduit sites in the Deschutes Basin for which the necessary site information and flow data were available. The total potential generation capacity for these 29 sites would be approximately 27 megawatts (MW). Given the estimated lifecycle benefits and costs of each project, only four of the NPD sites and four of the canal sites appear to be economically feasible. As summarized in Tables ES-1 and ES-2, the eight feasible projects could add about 19 MW of hydroelectric capacity to the Deschutes Basin and could generate over 78 gigawatt hours (GWh) of renewable energy each year. This could power about 6,000 households year-round and avoid greenhouse gas (GHG) emissions of about 29,000 tone of CO_2 equivalent each year.

Table ES-1. Assessment results for potential hydropower development at non-powered dams in the Deschutes Basin

Site No.	Site Name	Design Head (ft)	Design Flow (cfs)	Recom-mended Turbine Type	Design Capac-ity (kW)	Annual Energy Gener-ation (MWh)	Eco-nomic Assess-ment Results
1	Wickiup Dam	67.0	1,400	Kaplan	7,118	29,010	**Feasible**
2	Bowman Dam	163.9	500	Francis	5,959	19,587	**Feasible**
3	North Canal Diversion Dam	33.0	461	Kaplan (Pit or Bulb)	1,135	5,145	**Feasible**
4	Ochoco Dam	60.0	94.2	Francis	366	2,992	**Feasible**
5	Crane Prairie	18.0	262	Kaplan (Pit or Bulb)	337	2,037	Infeasible
6	Crescent Lake Dam	33.0	82	Kaplan (Pit or Bulb)	200	657	Infeasible
7	Fehrenbacker #2	14.0	41.6	Propeller	39	289	Infeasible
8	Merwin Reservoir #2	72.0	8.3	Cross-Flow	39	179	Infeasible
9	Bonnie View Dam	36.0	12.7	Propeller	33	128	Infeasible
10	Gilchrist Log Pond	9.8	56.9	Propeller	31	160	Infeasible
11	Layton #2 Reservoir	18.0	23.6	Propeller	29	118	Infeasible
12	Bear Creek (Crook)	57.0	5.5	Cross-Flow	20	94	Infeasible
13	Allen Creek	76.0	3.3	Cross-Flow	16	75	Infeasible
14	Watson Reservoir	30.0	28.7	Propeller	15	59	Infeasible

Table ES-2. Assessment results for potential hydropower development at existing canals/conduits in the Deschutes Basin

Site No.	Site Name	Design Head (ft)	Design Flow (cfs)	Recom-mended Turbine Technology	Design Capac-ity (kW)	Annual Energy Gener-ation (MWh)	Eco-nomic Assess-ment Result
1	Mile-45	104.0	354.0	Turbinator	2,700	12,556	**Feasible**
2	Haystack Canal	85.0	270.6	Conventional Kaplan	1,730	8,078	**Feasible**
3	58-11 Lateral	240.0	7.8	Pelton	137	560	**Feasible**
4	58-9 Lateral	150.2	6.8	Pelton	75	305	**Feasible**
5	NC-2 Fall	17.0	407.7	Propeller (Pit) or Natel	445	1,854	Infeasible
6	Brinson Blvd.	30.5	444.9	Propeller (Pit)	1,015	4,004	Infeasible
7	Young Ave.	16.0	311.9	Kaplan (Pit) or Natel	352	1,461	Infeasible
8	10-Barr Road	23.0	237.0	Kaplan (Pit)	399	1,672	Infeasible
9	Dodds Road	79.0	245.0	Francis	1,396	6,690	Infeasible
10	Yew Ave.	42.0	164.0	Kaplan (S-type)	516	2,174	Infeasible
11	Smith Rock Drop	16.0	390.2	Propeller (Pit) or Natel	444	1,751	Infeasible
12	Ward Road	25.0	330.0	Propeller (Pit)	609	3,070	Infeasible
13	Shumway Road	79.0	150.0	Francis	850	4,071	Infeasible
14	Brasada Siphon	81.0	147.9	Francis	861	3,461	Infeasible
15	McKenzie Reservoir	96.0	30.0	Cross-Flow	187	942	Infeasible

1. INTRODUCTION

The purpose of this technical and economic feasibility assessment is to identify and analyze opportunities for new small hydropower development in the Deschutes River Basin, along with the technology needed to develop selected sites and the economic cost/benefit of developing those sites. The three most likely scenarios for additional hydropower generation in the Deschutes Basin are:

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1.1 BACKGROUND

In March 2010, the U.S. Department of Energy (DOE), the U.S. Department of the Interior (Interior), and the U.S. Department of the Army [through the Army Corps of Engineers (USACE)] signed the Memorandum of Understanding (MOU) for Hydropower. The purpose of the MOU is to "help meet the nation's needs for reliable, affordable, and environmentally sustainable hydropower by building a long-term working relationship, prioritizing similar goals, and aligning ongoing and future renewable energy development efforts." Specifically, the MOU aims to "(1) support the maintenance and sustainable optimization of existing federal and non-federal hydropower projects, (2) elevate the goal of increased hydropower generation as a priority of each agency to the extent permitted by their respective statutory authorities, (3) promote energy efficiency, and (4) ensure that new hydropower generation is implemented in a sustainable manner."

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As part of this new Basin-Scale Opportunity Assessment (BSOA) approach, the agencies committed to "select one or more basins for a basin-scale opportunity assessment pilot project." In February 2011, the agencies, through the national BSOA Steering Committee, selected the Deschutes River Basin in central Oregon as the first pilot basin. The report *The Integrated Basin-Scale Opportunity Assessment Initiative, FY 2011 Year-End Report: Deschutes Basin Preliminary Hydropower Opportunity Assessment* (PNNL 2011) describes how the Deschutes Basin was selected as the pilot basin as well as progress to date and ongoing research efforts on the Deschutes BSOA.

For the Deschutes BSOA, the Deschutes Basin is divided into three sub-basins. The Upper Deschutes extends from the river's headwaters in the Cascade Mountains downstream to the North Diversion Dam at Bend, Oregon (Fig. 1-1). The Middle Deschutes extends from the North Diversion Dam at Bend downstream to the Pelton-Round Butte Hydroelectric Project's Reregulating Dam, and includes Lake Billy Chinook. The Lower Deschutes extends from the Pelton-Round Butte Project's Reregulating Dam downstream to the river's terminus at the Columbia River. The Deschutes BSOA focuses on the Upper and Middle Deschutes basins because they offer more opportunities for increasing hydropower generation while improving environmental conditions than does the Lower Deschutes (PNNL 2011).

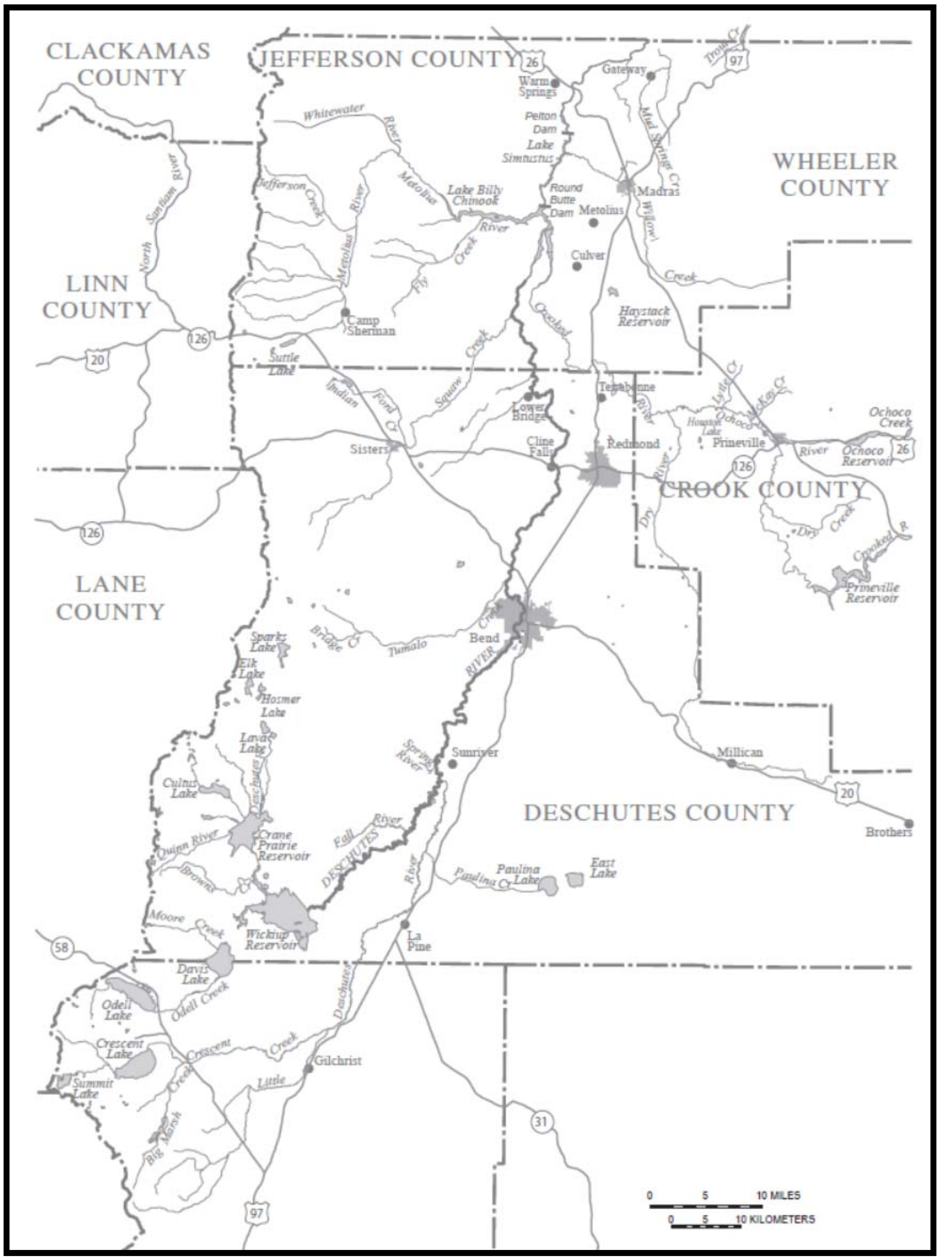


Fig. 1-1. The Deschutes and Crooked River Basins
(*Source*: Modified from USGS 2012a)

The Deschutes BSOA includes the Crooked River Basin because the Crooked River flows into the Deschutes River at Lake Billy Chinook and is integral to opportunities for increasing hydropower generation while improving environmental conditions in the Deschutes Basin (PNNL 2011). The assessment divides the Crooked River Basin into two sub-basins. The Upper Crooked includes the drainages above Bowman and Ochoco dams, including upper Ochoco Creek, the north and south forks of the Crooked River, Beaver Creek, and Camp Creek. The Lower Crooked includes the drainage below Bowman and Ochoco dams, including lower Ochoco Creek and McKay Creek.

1.2 EXISTING HYDROPOWER FACILITIES IN THE DESCHUTES AND CROOKED BASINS

Water in the Deschutes River has been used to generate hydropower since the early 1900s. One of the two initial Federal Power Commission (FPC) [now Federal Energy Regulatory Commission (FERC)] assessments of hydropower potential in the United States was conducted on the Deschutes in 1921-1922: *Report to the Federal Power Commission on Uses of the Deschutes River, Oregon* (FPC 1922).

Since the 1922 FPC report was published, much of the hydropower potential of the mainstem Deschutes River has been developed, primarily with the construction of the Pelton-Round Butte Project (discussed below). According to the National Hydropower Asset Assessment Project (NHAAP) database (ORNL 2012), there are 71 existing dams and diversion structures in the Upper and Middle Deschutes Basin and the Crooked River Basin. Of these 71 dams and diversions, nine have hydropower facilities (Fig. 1-2 and Table 1-1).

The Pelton-Round Butte Project is the largest hydropower project in the Deschutes Basin and also the largest hydropower project located entirely in Oregon. Built between 1957 and 1964, the Pelton-Round Butte Project has a total installed capacity of 366.82 MW and generates nearly 1.6 million MWh per year averaged between 1999 and 2008. The project’s total length within the Deschutes River Canyon is about 20 river miles. The project consists of three developments. The uppermost development, completed in 1964, includes the Round Butte Development (247.12 MW) and the 4,000-acre Lake Billy Chinook. Lake Billy Chinook impounds about 9 miles of the Deschutes River, 7 miles of the Crooked River, and 13 miles of the Metolius River. The middle development, Pelton Development (100.8 MW), is located on the Deschutes River about 7 miles downstream from Round Butte Dam. Pelton Dam was completed in 1958 and impounded a 540-acre reservoir (Lake Simtustus) which begins at the base of Round Butte Dam. The most downstream development, the Re-Regulating Development (18.9 MW), was also completed in 1958. The Re-Regulating Development has a 190-acre reservoir on the Deschutes River that extends downstream 2.5 miles from the tailwater of Pelton Dam (LIHI 2007; UNEP 2011; PGE 2011a).

The Central Oregon Irrigation District (COID) Siphon Power Hydroelectric Project (FERC No. 7590) is located on a diversion from the Deschutes River in Bend, Oregon. The project was licensed by FERC in 1987, and began commercial service in 1989. The amount of water diverted for power generation at the Siphon Project varies from a minimum of about 80 cubic feet per second (cfs) up to about 640 cfs, depending on the capacity of the siphon pipe in excess of the irrigation demand and the minimum instream flow requirement of 400 cfs below the diversion. During the irrigation season, the amount of water available for power generation depends on irrigation flow releases from the upstream storage reservoirs. During the non-irrigation season, available flow ranges from 0 cfs to the maximum generation capacity of about 640 cfs. The

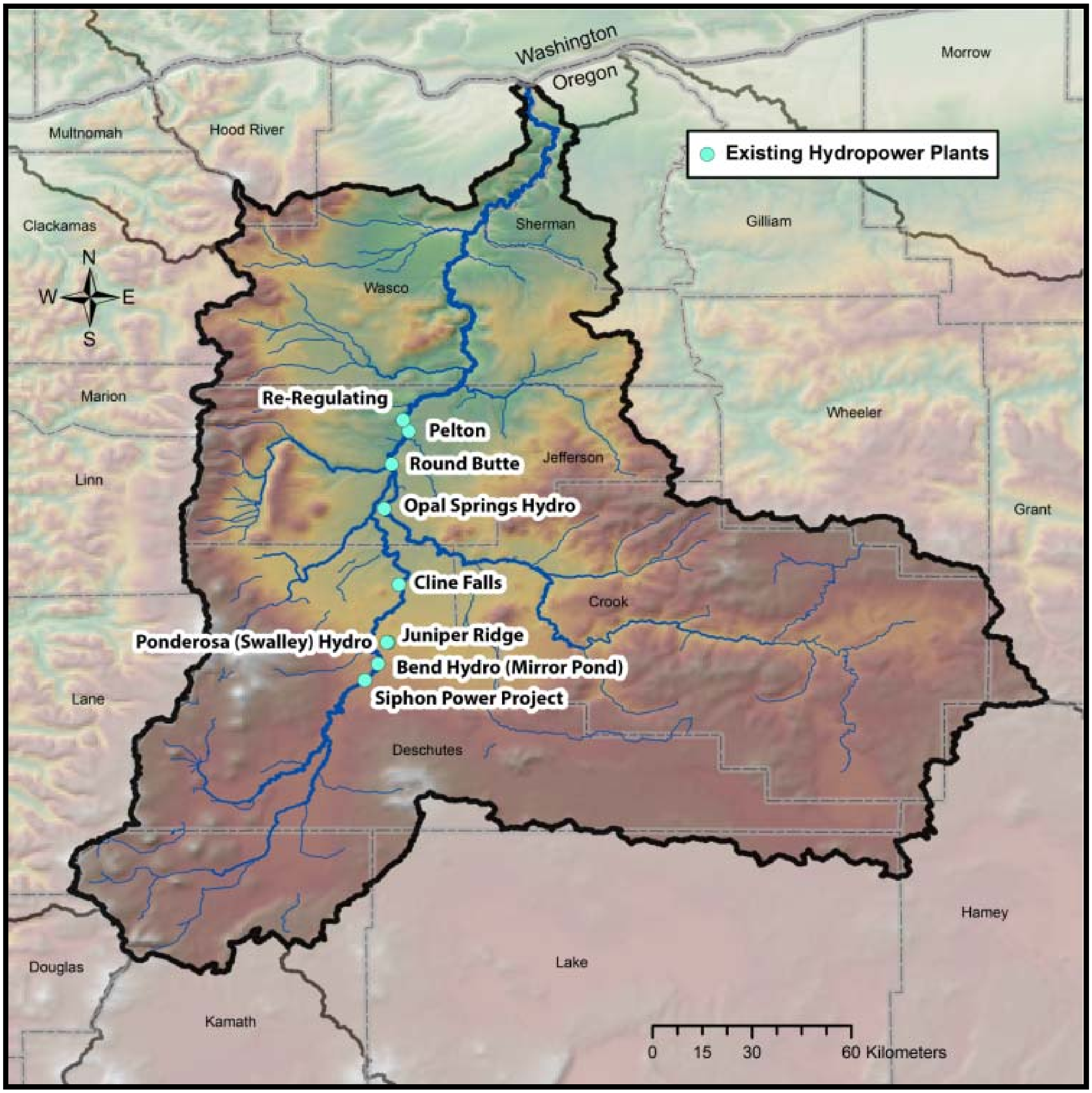


Fig. 1-2. Existing hydropower facilities in the Upper and Middle Deschutes and Crooked River Basins (*Source*: ORNL 2012; all data are provisional and are subject to change after verification)

Siphon Project has been certified as "Low Impact" by the Low Impact Hydro Institute (LIHI 2011).

The Deschutes Valley Water District (DVWD) Opal Springs Hydroelectric Project (FERC No. 5891) is located above Opal Springs on the lower Crooked River in Jefferson County, Oregon. The project was licensed by FERC in 1982, and construction was completed in 1985 (DVWD 2011).

Table 1-1. Existing hydropower facilities in the Upper and Middle Deschutes and Crooked River basins (as of 2012)

No.	Hydropower Plant Name	National Inventory of Dams ID	FERC No. / Type	Owner	Nameplate Capacity (MW)	Average 1999-2008 Annual Generation (MWh)	Dam Height (ft)	Flow (cfs)	Flow Note
1	Round Butte	OR00549	P-2030 / License	Portland General Electric Company	246.9	987902.7	440	11987	Annual Mean Flow[1]
2	Pelton	OR00548	P-2030 / License	Portland General Electric Company	109.8	416079.8	204	12166	Annual Mean Flow[1]
3	Re-Regulating	OR00547	P-2030 / License	Warm Springs Power Enterprises	19.6	156287.1	40	12184	Annual Mean Flow[1]
4	Siphon Power Plant	N/A	P-3571 / License	Central Oregon Irrigation District	5.4	5186.9	N/A	3913	Annual Mean Flow[1]
5	Opal Springs	N/A	P-5891 / License	Deschutes Valley Water District	4.3	23968.9	20	3685	Annual Mean Flow[1]
6	Bend Hydro (Mirror Pond)	OR00594	N/A	PacifiCorp	1.1	3327.1	18	4034	Annual Mean Flow[1]
7	Cline Falls	N/A	N/A	PacifiCorp	1.0	1677.1	N/A	5005	Annual Mean Flow[1]
8	Juniper Ridge	N/A	P-13607 / Exemption	Central Oregon Irrigation District	5.0	N/A	N/A	500	Design flow
9	Ponderosa (Swalley) Hydro	N/A	P-13470 / Exemption	Swalley Irrigation District	0.75	N/A	N/A	65	Design flow

[1] Annual Mean Flow data were computed by the USGS-EPA Plus.

(*Source:* ORNL 2012; all data are provisional and are subject to change after verification.)

The Bend (Mirror Pond) Hydroelectric Project was completed in 1910 in Bend, Oregon, and is owned by PacifiCorp. The project dam created Mirror Pond, the area of the Deschutes River between Galveston Bridge and Newport Avenue Bridge in downtown Bend (City of Bend 2011).

The Cline Falls Hydroelectric Project is an existing PacifiCorp facility located on the Deschutes River about 4 miles west of Redmond, Oregon. The original project was completed in 1943. In October 2010, COID filed with FERC an application for a preliminary permit (FERC No. 13858) to study the feasibility of upgrading and operating the Cline Falls Project. COID's proposed project would have an annual average generation of about 2 GWh (*Federal Register* 2010).

The Swalley Irrigation District (SID) Ponderosa Hydroelectric Project and the COID Juniper Ridge Hydroelectric Project were both completed in 2010. Both projects were constructed on existing irrigation canals and are classified by FERC as "conduit exemptions" from licensing. The 0.75-MW Ponderosa Project was built in conjunction with a 5-mile irrigation canal lining project, and operates at 65 cfs during the irrigation season (Butterfield 2011). The 5-MW Juniper Ridge Project was built in conjunction with a 2.25-mile irrigation canal lining project, and operates at 500 cfs during the irrigation season (Johnson 2011).

In addition to these nine existing hydropower projects, the Three Sisters Irrigation District (TSID) is currently developing a new project, the TSID Main Canal Hydro Project. This new project would be located on the north pipe of the TSID Main Canal pipeline. FERC issued the project an exemption in April 2012 (FERC No. P-14364/Exemption). The generation plant would be located on the TSID main office property approximately 3 miles southwest of Sisters, Oregon. Water would be diverted from Whychus Creek through a dam that was constructed in 1970, so no dam construction would occur. The project would have a capacity of 0.7 MW and average annual generation of between 3,100 and 3,400 MWh. The project would discharge water directly into the Watson regulating reservoir; from there, water would be delivered downstream through further canals and pipelines (TSID 2012).

1.3 POTENTIAL HYDROPOWER DEVELOPMENT AT NON-POWERED DAMS

The NHAAP database lists a total of 62 NPDs and diversions in the Upper and Middle Deschutes and Crooked basins (ORNL 2012). Of these 62 dams and diversions, the NHAAP database indicates that three have a potential hydropower capacity of over 3 MW each: North Unit Diversion Dam (4.65 MW), Wickiup Dam (3.95 MW), and Bowman Dam (3.29 MW) (Table 1-2). The other 33 dams listed in Table 1-2 each have a potential capacity >10 kW.

The Bureau of Reclamation (Reclamation) 2011 report *Hydropower Resource Assessment at Existing Reclamation Facilities* (Reclamation 2011) also models Wickiup Dam as having a potential capacity of 3.95 MW and Bowman Dam as having a potential capacity of 3.29 MW (Table 1-3). The report identifies and ranks potential hydropower sites at Reclamation dams in the Pacific Northwest region on the basis of benefit/cost ratios (with green incentives) above 0.75. Bowman Dam ranked the highest in the Pacific Northwest region with a benefit/cost ratio of 1.90 and an internal rate of return of 11.2%. The model used in Reclamation's analysis selected a Francis turbine for the Bowman Dam site, with an installed capacity of about 3.3 MW and annual energy production of about 18,000 MWh (Reclamation 2011).

As indicated in Table 1-3, two other dams in the Deschutes Basin had benefit/cost ratios over 0.75 in the 2011 Reclamation report: Wickiup Dam (0.98) and Haystack Canal (0.85). Three other Reclamation sites were evaluated but did not meet the 0.75 benefit/cost ratio threshold:

Table 1-2. Non-powered dams and diversions in the Upper and Middle Deschutes and Crooked River basins (estimated potential hydropower capacity >10 kW)

No.	Dam Name	Dam Height (ft)	Flow[1] (cfs)	Head (ft)	Potential Capacity (MW)	Estimated by	Distance to Trans-mission Line (miles)	Voltage of Closest Trans-mission Line (kV)
1	Wickiup Dam	100	1157.2	54.6	3.95	Reclamation	7.56	69
2	Arthur R. Bowman Dam	245	264	172.6	3.29	Reclamation	5.95	1000
3	North Unit Diversion Dam	35	869.7	33	4.65	ORNL	0.09	69
4	Ochoco Dam	152	19	60	0.069	Reclamation	2.1	69
5	Crane Prairie Dam	36	270.5	18.1	0.31	Reclamation	13.32	69
6	Crescent Lake Dam	41	32.1	33	0.17	ORNL	13.71	69
7	Fehrenbacker Reservoir 2	18	72.2	14	0.16	ORNL	2.32	115
8	Gilchrist Log Pond	14	63.4	9.8	0.1	ORNL	0.36	69
9	Merwin Reservoir #2	74	16.5	72	0.19	ORNL	22.52	765
10	Bonnie View Dam	42	25.4	36	0.15	ORNL	17	69
11	Layton #2 Reservoir	23	47.1	18	0.14	ORNL	8.21	765
12	Bear Creek (Crook)	63	10.9	57	0.1	ORNL	12.6	115
13	Allen Creek	83	6.5	76	0.08	ORNL	29.19	765
14	Watson Reservoir	34	14.4	30	0.07	ORNL	22.29	765
15	Haystack Canal[2]	NA	225	57.2	0.8	Reclamation	2.44	1000
16	Logan Butte Reservoir	50	10	34	0.055	ORNL	11.77	115
17	Lytle Creek	NA	264	3	0.05	Reclamation	3.22	1000
18	Mainline 1	57	5.4	55	0.048	ORNL	25.47	115
19	Morrow Brothers (Jefferson)	24.5	14.2	20	0.046	ORNL	1	1000
20	Pine Creek Dam (Crook)	35	8.1	33	0.044	ORNL	20.77	115
21	Lillard Dam	26.5	12	21	0.041	ORNL	5.43	765
22	Dick Dam	30	8.8	26	0.037	ORNL	24.33	69
23	Fisher-Joe Reservoir	54	4.6	49	0.036	ORNL	3.95	1000
24	Freezeout Reservoir	24	9.1	21	0.031	ORNL	5.75	765
25	Marks Lake Dam	20	9.3	18	0.027	ORNL	20.59	69
26	Johnson Creek Reservoir (Crook)	44	4.2	42	0.029	ORNL	3.22	69
27	Lower Twelvemile (Buker Reservoir)	25	7.2	19	0.022	ORNL	3.01	765
28	Peterson Creek Reservoir	25	5.5	23	0.021	ORNL	27.96	765

No.	Dam Name	Dam Height (ft)	Flow[1] (cfs)	Head (ft)	Potential Capacity (MW)	Estimated by	Distance to Trans-mission Line (miles)	Voltage of Closest Trans-mission Line (kV)
29	Antelope Flat (Crook)	36.5	4	31	0.02	ORNL	15.11	115
30	Kluchman Creek Dam	36	3.8	33	0.02	ORNL	12.83	115
31	Black Snag Reservoir	38	4.4	26.6	0.019	ORNL	2.22	765
32	Sherwood Creek Reservoir	27	4.9	24	0.019	ORNL	18.46	115
33	Grindstone Reservoir	34	3.7	32	0.019	ORNL	0.44	765
34	Swamp Creek Reservoir (Harney)	24	5.4	16	0.014	ORNL	1.76	765
35	Camp Creek Reservoir (Crook)	19	5.1	13	0.011	ORNL	11.84	115
36	Yancey Reservoir	28	3.3	26	0.014	ORNL	2.69	69

[1] Flows estimated by ORNL are mean stream flow, not design flow.

[2] Haystack Canal is also considered as a canal site in other sections of this report.

(Source: ORNL 2012; all data are provisional and are subject to change after verification.)

Table 1-3. Non-powered dams and diversions in the Deschutes and Crooked river basins (by benefit/cost ratio) evaluated in Reclamation 2011

Site Name	River	Design Head (ft)	Design Flow (cfs)	Potential Installed Capacity (MW)	Potential Annual Production (MWh)	Plant Factor	Cost per Installed Capacity ($/kW)	Benefit/Cost Ratio with Green Incentives	IRR with Green Incentives (%)	Benefit/Cost Ratio without Green Incentives	IRR without Green Incentives (%)
Bowman Dam	Crooked	173	264	3.29	18,282	0.65	2,732	1.90	11.2	1.79	10.0
Wickiup Dam	Deschutes	55	1,157	3.95	15,650	0.46	3,843	0.98	4.2	0.92	3.7
Haystack Canal	Deschutes	57	225	0.805	3,738	0.54	4,866	0.85	2.9	0.8	2.4
Crane Prairie	Deschutes	18	270	0.306	1,845	0.7	25,317	0.25	<0	0.23	<0
Lytle Creek	Crooked	3	264	0.050	329	0.77	32,368	0.19	<0	0.18	<0
Ochoco Dam	Crooked	60	19	0.069	232	0.39	18,532	0.16	<0	0.15	<0

Source: Reclamation 2011

Crane Prairie, Lytle Creek, and Ochoco Dam. The report also mentions Arnold Dam, Diversion Canal Headworks (Crooked River), North Canal Diversion Dam, North Unit Main Canal, and Pilot Butte Canal but does not evaluate them in detail (Reclamation 2011).

North Unit Diversion Dam (also called North Canal Dam), which is located on the Deschutes River in Bend, Oregon, was completed in 1912 and is the diversion point for the Swalley, Pilot Butte, and Central Oregon canals. North Unit Diversion Dam is 33 ft tall and 200 ft wide.

Wickiup Dam, which is located on the Deschutes River near Pa Pine, Oregon, was completed in 1949 and is part of Reclamation's Deschutes Project. Wickiup Dam is 100 ft tall and 13,860 ft long, and Wickiup Reservoir provides about 200,000 acre-ft of storage for the North Unit Irrigation District (NUID). In March 2011, Symbiotics, LLC, filed with FERC a license application to construct and operate the Wickiup Dam Hydroelectric Project (FERC No. 12965) (Symbiotics 2011a). The proposed run-of-river project would have an installed capacity of 7.15 MW from one turbine/generator unit and on average would produce 21.15 GWh annually (Symbiotics 2011b).

Crane Prairie Dam, which is located on the Deschutes River upstream of Wickiup Dam, was completed in 1940 and is the uppermost dam in Reclamation's Deschutes Project. Crane Prairie Dam is 36 ft tall and 285 ft long, and Crane Prairie Reservoir provides about 55,000 acre-ft of storage for the NUID. Both the NHAAP database (ORNL 2012) and Reclamation's *Hydropower Resource Assessment at Existing Reclamation Facilities* (Reclamation 2011) indicate that Crane Prairie Dam has a potential hydropower capacity of about 0.306 MW.

Crescent Lake Dam, which is located on the Little Deschutes River near Gilchrist, Oregon, was completed in the early 1900s and rebuilt by Reclamation between 1954 and 1971. The dam is 41 ft tall, and Crescent Lake provides about 86,050 acre-ft of storage for the Tumalo Irrigation District (TID). The NHAAP database (ORNL 2012) indicates that this dam has a potential hydropower capacity of about 0.155 MW.

Bowman Dam (formerly Prineville Dam) is located on the Crooked River about 20 miles upstream from Prineville, Oregon. The dam was completed in 1961 as part of Reclamation's Crooked River Project. Bowman Dam is 245 ft tall and 800 ft long, and its reservoir (Prineville Reservoir) provides about 150,200 acre-ft (active 148,600 acre-ft) of storage. The Crooked River Project, which also includes Ochoco Dam, provides irrigation water for the Ochoco Irrigation District (OID). In March 2011, Portland General Electric (PGE) filed with FERC a preliminary application document for the Crooked River Hydroelectric Project (FERC No. 13527) at Bowman Dam. The proposed run-of-river project would have an installed capacity of 6.0 MW and on average would produce 23.0 GWh annually (PGE 2011b).

Ochoco Dam, which was completed in 1921 and is part of Reclamation's Crooked River Project, is located on Ochoco Creek about 6 miles east of Prineville, Oregon. In 1949, Reclamation rehabilitated the original dam, which is currently 152 ft tall and 1,350 ft long. Ochoco Reservoir has an active capacity of about 39,600 acre-ft. Reclamation's *Hydropower Resource Assessment at Existing Reclamation Facilities* (Reclamation 2011) indicates that Ochoco Dam has a potential hydropower capacity of about 0.069 MW.

1.4 POTENTIAL HYDROPOWER DEVELOPMENT AT CANALS AND CONDUITS

The potential for adding new hydropower generation in existing irrigation canals and conduits is exemplified by the Ponderosa, Juniper Ridge, and TSID Main Canal projects discussed in Section 1.2. As indicated in Fig. 1-3, there are seven Deschutes Basin Board of Control (DBBC) irrigation districts in the Deschutes and Crooked basins, some of which have identified opportunities for adding hydropower generation to their systems.

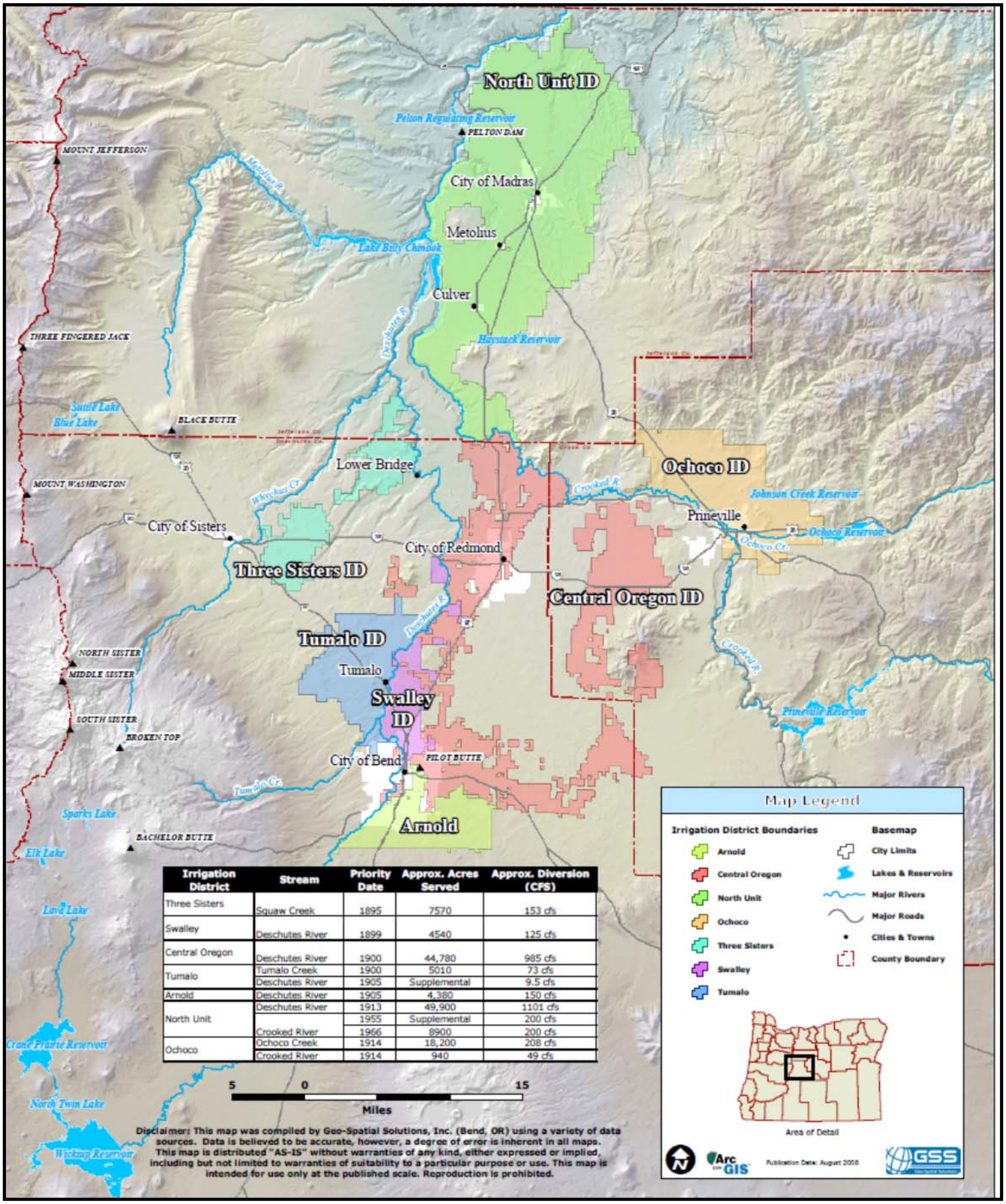
In 2009, Black Rock Consulting published a *Feasibility Study on Five Potential Hydroelectric Power Generation Locations in the North Unit Irrigation District* (Black Rock 2009). Three sites (Haystack Reservoir, 58-11 Lateral, and Brinson Boulevard) were deemed economically viable for hydropower development assuming that Energy Trust of Oregon (ETO) grants and investment tax credits could be attained and assuming low cost equipment and construction during project development (Table 1-4).

In 2010, ETO published *Irrigation Water Providers of Oregon: Hydropower Potential and Energy Savings Evaluation* to “evaluate the state’s largest irrigation water users to provide base feasibility evaluations which could result in subsequent development of hydropower projects in Oregon” (ETO 2010). The report evaluated nine potential hydropower sites associated with irrigation districts in Central Oregon (Table 1-5), six of which are owned by COID, one by TSID, and two by TID.

The 2010 ETO report excludes three (NUID, OID, and SID) of the seven DBBC irrigation districts from analysis because for them “preliminary investigations were already underway through Energy Trust.” The report concludes that four of the DBBC districts [Arnold Irrigation District (AID), COID, TSID, and TID)] deserve further evaluation for hydropower potential (ETO 2010).

In 2011, COID and the Oregon Department of Energy (ODE) published a *Feasibility Study for Six Central Oregon Irrigation District Potential Hydroelectric Power Generation Sites* (COID and ODE 2011). Two of the six COID sites (10 Barr and Yew Avenue) had been included in the 2010 ETO report. Two of the six COID sites included in the 2011 COID/ODE report had an estimated benefit/cost ratio >0.75: NC-2 Falls and Young Falls (Table 1-6).

In 2012, Reclamation published the report *Site Inventory and Hydropower Energy Assessment of Reclamation Owned Conduits* (Reclamation 2012). The report identifies and ranks potential canal and conduit sites that have a minimum head of 5 ft, could operate at least four months per year, and could produce 50 kW of capacity based on gross head and the maximum flow capacity of the canal. The report assesses the potential of 393 canal and conduit sites in 13 states and ranks the sites by potential annual energy (kWh) and potential installed capacity (kW). The report includes 39 NUID sites along the North Unit Main Canal, and four of the top 25 sites in all 13 states are NUID sites: Mile 45.02, Mile 47, Mile 52.58, and Mile 19.46 (Table 1-7).



Irrigation District	Stream	Priority Date	Approx. Acres Served	Approx. Diversion (CFS)
Three Sisters	Squaw Creek	1895	7570	153 cfs
Swalley	Deschutes River	1899	4540	125 cfs
Central Oregon	Deschutes River	1900	44,780	985 cfs
Tumalo	Tumalo Creek	1900	5010	73 cfs
	Deschutes River	1905	Supplemental	9.5 cfs
Arnold	Deschutes River	1905	4,380	150 cfs
North Unit	Deschutes River	1913	49,900	1101 cfs
	Crooked River	1955	Supplemental	200 cfs
		1966	8900	200 cfs
Ochoco	Ochoco Creek	1914	18,200	208 cfs
	Crooked River	1914	940	49 cfs

Disclaimer: This map was compiled by Geo-Spatial Solutions, Inc. (Bend, OR) using a variety of data sources. Data is believed to be accurate, however, a degree of error is inherent in all maps. This map is distributed "AS-IS" without warranties of any kind, either expressed or implied, including but not limited to warranties of suitability to a particular purpose or use. This map is intended for use only at the published scale. Reproduction is prohibited.

Fig. 1-3. Deschutes Basin Board of Control Irrigation Districts
(*Source*: SID 2011)

Table 1-4. North Unit Irrigation District canal sites (by benefit/cost ratio) evaluated in Black Rock 2009

Site	Benefit/Cost Ratio with Green Incentives and Low Cost Cases	Net Head (ft)	Design (cfs)	Rated Power (kW)	Revenue Year 2010 ($)
Haystack Reservoir	1.4	85	280	1809	489,857
58-11 Lateral	1.18	240	8.8	145	25,000
Brinson Boulevard	1.02	30.5	440	968	273,860
58-9 Lateral	0.75	150	9	93	14,000
Smith Rock	0.47	16	400	444	127,258

(*Source*: Black Rock 2009)

Table 1-5. Potential Irrigation District hydro sites in Central Oregon evaluated in ETO 2010

District	Site	Net Head (ft)	Average Flow Rate (cfs)	Peak Power (MW)	Annual Power (MWh)
Central Oregon	Ward Road	25	330	0.80	2,480
	Brinson Boulevard	17	370	0.50	2,000
	10 Barr Road	27	260	0.65	2,100
	Dodds Road	79	245	1.85	5,800
	Shumway Road	79-89	150	1.20-1.36	3,650-4,000
	Yew Avenue	45	190	0.94	2,600
Three Sisters	McKenzie Reservoir	96	30	0.28	907
Tumalo	Columbia Southern Main	1,005	30	2.10	9,040
	Columbia Southern Lateral	68-111	65	0.38-0.61	1,325-2,160

(*Source*: ETO 2010)

Table 1-6. Central Oregon Irrigation District canal sites (by benefit/cost ratio) evaluated in COID and ODE 2011

Site	**Benefit/Cost Ratio**	**Net Head (ft)**	**Average Flow Rate (cfs)**	**Rated Power (kW)**	**Average Annual Revenue ($)**
NC-2 Falls	1.01-1.79	17	315	313	121,328
Young Avenue	0.79	16	288	273	89,342
10 Barr	0.74	23	200	440	94,883
Yew Avenue	0.45	42	124	700	166,589
Brasada Siphon	0.19	81	115	1,183	209,206
Bert Chute	N/A	7	N/A	N/A	19,000

(*Source*: COID and ODE 2011)

Table 1-7. North Unit Irrigation District Main Canal sites (ranked by potential installed capacity) evaluated in Reclamation 2012

Site	Structure Type	Potential Installed Capacity (kW)	Potential Annual Energy (kWh)	Design Head (ft)	Max Turbine Flow (cfs)	Plant Factor (%)	Months of Potential Generation
Mile 45.02	Vertical drop	1,714	6,266,652	85	279	43	7
Mile 47	Vertical drop	1,392	5,089,258	69	279	43	7
Mile 52.58	Chute	1,213	4,332,528	68	245	42	7
Mile 19.46	Vertical drop	927	3,313,699	23	561	42	7
Mile 1.78	Vertical drop	818	2,925,117	20	561	42	7
Mile 47.47	Vertical drop	740	2,727,320	37	279	43	7
Mile 20.91	Vertical drop	679	2,428,994	17	561	42	7
Mile 26.12	Vertical drop	543	1,942,909	14	561	42	7
Monroe Drop	Vertical drop	526	1,733,511	15	491	40	7
Mile 11.13	Chute	524	1,875,516	13	561	42	7
Mile 2.11	Vertical drop	472	1,687,679	12	561	42	7
Mile 3.67	Vertical drop	465	1,661,869	12	561	42	7
Mile 1.95	Vertical drop	439	1,571,534	11	561	42	7
Mile 22.62	Vertical drop	374	1,336,377	9	561	42	7
Mile 13.05	Chute	341	1,220,233	9	561	42	7
Mile 2.57	Vertical drop	322	1,149,973	8	561	42	7
Mile 18.34	Vertical drop	303	1,082,580	8	561	42	7
Mile 2.41	Vertical drop	291	1,039,564	7	561	42	7
Mile 3.52	Vertical drop	265	947,795	7	561	42	7
Mile 15.92	Vertical drop	252	901,911	6	561	42	7
Mile 11.34	Chute	222	792,937	6	561	42	7
Mile 6.44	Chute	212	757,089	5	561	42	7
Mile 11.15	Chute	203	725,544	5	561	42	7
Mile 47.98	Vertical drop	200	737,530	10	279	43	7
Mile 50	Vertical drop	199	735,325	10	279	43	7
Mile 48.49	Vertical drop	180	664,733	9	279	43	7
Mile 52.75	Vertical drop	167	602,841	10	245	42	7
Mile 52.89	Vertical drop	167	602,841	10	245	42	7
Mile 52.94	Vertical drop	167	604,739	10	245	42	7
Mile 53.69	Vertical drop	121	449,823	7	228	43	7
Mile 53.84	Vertical drop	114	423,825	7	228	43	7
Mile 56.45	Vertical drop	108	401,481	7	220	43	7
Mile 54.17	Vertical drop	90	336,233	6	220	43	7
Mile 62.32	Vertical drop	33	116,493	6	88	41	7
Mile 62.49	Vertical drop	29	103,528	5	88	41	7

Site	Structure Type	Potential Installed Capacity (kW)	Potential Annual Energy (kWh)	Design Head (ft)	Max Turbine Flow (cfs)	Plant Factor (%)	Months of Potential Generation
Mile 62.62	Vertical drop	29	103,718	5	88	41	7
Mile 62.73	Vertical drop	29	103,718	5	88	41	7
Mile 63.28	Vertical drop	14	47,968	5	41	41	7
Mile 63.52	Vertical drop	14	47,968	5	41	41	7

(*Source*: Reclamation 2012)

2. ASSESSMENT METHODOLOGY AND TOOL

Four phases of engineering work are usually required to develop a hydropower project at a potential site:

- Reconnaissance surveys and hydraulic studies
- Pre-feasibility study
- Feasibility study
- System planning and project engineering (NRC 2004)

This assessment of potential hydropower sites in the Deschutes Basin is based on site-specific information obtained from previous investigations and multiple data sources, as discussed in Chapter 1. Thus, this assessment represents a step between a pre-feasibility study and a feasibility study. The energy and economic analyses of the potential sites assessed in this report are intended to differentiate between economically feasible and infeasible sites. The assessment aggregates and ranks the feasible sites, and discusses their project cost, levelized cost of energy (LCOE), and economic returns in the context of site-specific conditions and the availability of green incentives. The assessment also investigates the sensitivity of each site's economic feasibility to different types of turbine equipment from domestic and international suppliers.

This chapter describes the methodology and tool used to determine the potential hydropower capacity and energy production, estimate the project cost, and calculate the economic benefits of potential hydropower projects at the existing NPDs and canals/conduits in the Deschutes Basin.

2.1 OVERVIEW OF ASSESSMENT METHODOLOGY AND TOOL DEVELOPMENT

With funding from the DOE Wind and Water Power Program, Oak Ridge National Laboratory (ORNL) is developing an assessment methodology and software tool to consistently evaluate the energy and economic feasibility of potential hydropower sites. The ORNL-Hydropower Energy and Economic Assessment (HEEA) Tool is an Excel workbook with embedded macro functions programmed in Visual Basic using Microsoft Excel 2010 (see Appendix A for a detailed description of the ORNL-HEEA Tool). The goal of developing this tool is to create a rapid and reasonably accurate means of predicting the energy output and economic feasibility of a site-specific hydropower project.

Based on a review of the small hydropower assessment tools currently available worldwide, only Reclamation's HydroAssessment Tool 2.0 (Reclamation 2011) and Natural Resources Canada's (NRC) RETScreen4 (NRC 2004) have the features necessary to conduct a site-specific hydropower energy and economic assessment that could be used to assess small hydropower projects in the United States. However, RETScreen4 is designed to evaluate international clean energy projects and requires a great deal of engineering preparation before it can be used to assess hydropower projects. Reclamation's HydroAssessment Tool 2.0 is designed to screen potential hydropower sites within Reclamation's area of authority in 17 western states. Neither of these existing tools is appropriate for assessing small hydropower opportunities in the Deschutes Basin because they do not provide sufficient flexibility in terms of inputting: (1) available hydrologic data under various scenarios at multiple sites; (2) some of the green incentives that the Deschutes Basin projects could entail; (3) the different turbine types and suppliers available to hydropower developers; and (4) the cost of "soft" items (e.g., contingency, engineering, licensing, and permitting costs) relevant for developing NPD and canal/conduit sites (e.g., projects that meet FERC exemption criteria have lower licensing and permitting costs than projects that require a FERC license). With regard to the existing Reclamation and NRC tools, the ORNL-HEEA Tool provides: (1) more flexibility in required hydrological data inputs (to make it adaptable to different levels of data availability); (2) a more user-friendly interface for inputting data and user involvement in the project decision-making process; (3) inclusion of more alternative turbine technologies (including emerging new small hydropower technologies); and (4) improved methodologies for turbine selection, creating efficiency curves, and project costing.

The ORNL-HEEA Tool can be used to assess any run-of-river or run-of-reservoir small hydropower project (below 50 MW), including projects at new sites, NPDs operated as run-of-reservoir, and existing canals/conduits. The targeted application for the Deschutes Basin is sites with potential power capacity ranging from 100 kW to 10 MW, but the model could be used for assessing micro to medium hydropower projects with a capacity from 10 kW to 50 MW. Given the relatively small scales in terms of power and flow at the potential Deschutes Basin sites, as well as the proximity of their locations, the ORNL-HEEA Tool used in this assessment assumed that: (1) only one single unit would be installed at each potential site; and (2) the generating unit would be connected to the central grid system, and thus all available power would be absorbed by the power grid system. That is, the available power on the site is the power output of the turbine unit.

The ORNL-HEEA Tool requires some basic site and project information (such as location, financial structure, etc.), as well as daily or monthly average flow and hydraulic head to describe the time variability of water discharge. The energy and economic assessment for a potential site is completed by running different modules for hydrology data processing, flow duration curve, net head duration curve, design parameters, turbine type selection, power generation calculation, project costing, and benefits and economic evaluation.

The ORNL-HEEA Tool is being developed as an independent software product, but the package can be incorporated into the Deschutes Basin-Scale Water Management Model by:

- collecting basic project and site information as input to the Basin-Scale Model;
- accepting flow and head data input from various flow scenarios simulated in the Basin-Scale Model; and
- producing site-specific energy and economic assessment results as output of the Basin-Scale Model.

Although it was initiated by the Deschutes BSOA project, the ORNL-HEEA Tool is designed to allow ubiquitous application in the 50 United States by incorporating multiple alternatives for inputting and embedding information and algorithms. This will allow the Tool to be used in subsequent BSOA projects and at potential sites nationwide.

2.2 DESIGN FLOW AND NET HEAD DETERMINATION WITH HYDROLOGY DATA INPUT

Turbine design flow (or rated flow) is defined as the maximum flow passing through the turbine at the rated head and full gate opening; the rated head (net head) is the gross head less the maximum hydraulic losses (i.e., at the design flow condition) (NRC 2004). Based on a “rule of thumb” in screening and pre-feasibility studies of run-of-river small hydropower projects, the ORNL-HEEA Tool determines default turbine design flow as the 30% exceedance value of the duration curve for the available flow for power generation. The default rated net head is also determined as the 30% exceedance value of the net head duration curve for the sites where historic head data are available (Reclamation 2011) (see Appendix A).

To generate a statistically meaningful flow duration curve, the ORNL-HEEA Tool requires the user to input a time series of daily or monthly average flows for 6 complete water years (or calendar years)

(Copestake and Young 2008). However, the Tool can operate with a minimum of 1 year of flow data, assuming the 1-year flows represent the typical or average water year case. For this Deschutes Basin assessment, historic daily flows were obtained from the U.S. Geological Survey (USGS) website (USGS 2012b) for Wickiup Dam and Crescent Lake Dam, and from the Oregon Water Resources Department (OWRD) website (OWRD 2012) for Bowman Dam, North Canal Dam, and Crane Prairie Dam. For all other NPD sites, the assessment uses monthly average flow data from the NHAAP database (ORNL 2012), which were estimated using monthly runoff data and drainage areas. It is worth noting that the 30% exceedance flow values at a specific site can differ significantly between USGS historic flow data and NHAAP estimated monthly flow data. For the potential canal and conduit sites, daily or monthly available flows are from the previous assessments discussed in Section 1.4.

2.3 HYDRO TURBINE TECHNOLOGY AND SELECTION

The ORNL-HEEA Tool develops a matrix of turbine types, including the Francis, Kaplan, Propeller, Pelton, and Cross-Flow turbines and their corresponding design flow and net head intervals, by referencing several existing charts (ESHA 2004; ASME-HPTC 1996) (see Appendix A). The Tool automatically selects turbine type based on the ranges of rated net head and turbine unit design flow. However, the user can override the Tool-recommended turbine type by manually inputting a preferred type, which is then used to calculate efficiency and generation and estimate project costs. The user can select Turgo, Natel, and Turbinator technology rather than Francis, Kaplan, Propeller, Pelton, and Cross-Flow turbines. In addition to turbine type, the user can specify the name of the turbine supplier to account for the significant cost differences among domestic, Canadian, and Chinese turbine suppliers.

In the ORNL-HEEA Tool turbine selection matrix, flow ranges from 0.7 cfs to 2500 cfs and net head ranges from 6.6 ft to 3000 ft, which encompass micro- to medium-scale hydro turbines. The Pelton type is suitable for high-head cases, the Francis and Cross-Flow types are suitable for medium head and flow conditions, and the Kaplan and Propeller types are suitable for relatively lower heads and higher flows. To reduce the cost of micro-scale hydropower projects (i.e., power capacity $\leq$ 100 kW), the current version of the ORNL-HEEA Tool assumes a Propeller turbine rather than a Kaplan turbine if net head is <10 ft, and assumes a Cross-Flow turbine rather than a Francis turbine if net head is <100 ft. In the boundary areas within the turbine selection matrix, where multiple turbine types could be well-suited for a site (e.g., Kaplan or Francis for medium head and medium flow), the current version of the ORNL-HEEA Tool selects only one turbine type.

2.4 TURBINE AND GENERATOR EFFICIENCY

The ORNL-HEEA Tool determines turbine efficiency based on several empirical efficiency curves (NRC 2004; Gordon 2001; Manness and Doering 2005) (see Appendix A). Turbine peak efficiency is determined based on the selected turbine type, turbine design flow, and rated net head, and turbine operating efficiency varies with turbine operating flow at the rated head.

The Tool calculates generator efficiencies during partial load operations using a generic efficiency curve that corresponds to the selected best efficiency value (Haglind and Elmegaard 2009). The best generator efficiency depends upon the rated speed and rated power capacity of the generator. Because the current version of the ORNL-HEEA Tool assumes one single unit for each potential site, turbine-generator unit efficiency (turbine efficiency multiplied by generator efficiency) is the plant efficiency.

2.5 POWER GENERATION AND ENERGY CALCULATIONS

Once the ORNL-HEEA Tool has determined turbine type, design flow, and rated net head, it sets the upper and lower limits of operating head and flow for power generation (see Appendix A). Table 2-1 provides the suggested ranges of operating flow and net head for different turbine types, in terms of the percentages of turbine design flow and rated net head.

Table 2-1. Turbine operating range of flow and net head for power generation

Turbine Type	*Hmax* (%H_d) (upper limit operating head)	*Hmin* (%H_d) (lower limit operating head)	*Qmax* (%Q_d) (upper limit operating flow)	*Qmin* (%Q_d) (lower limit operating flow)
Kaplan	125	50	100	15
Francis	125	65	100	20
Propeller	110	80	100	35
Pelton	110	75	100	10
Turgo	110	75	100	10
Cross-Flow	110	75	100	8
Turbinator	110	75	100	40
Natel	110	75	100	20

Sources: ESHA 2004; Natel Energy 2012; Hadjerioua and Stewart 2013.

The Tool's energy calculation module checks the time series of available flows for power generation. If the available flow exceeds the upper limit of turbine operating flow, the Tool sets the generating flow as the upper limit flow. If the available flow is below the lower limit of turbine operating flow, the Tool sets the generating flow as zero, which implies that the turbine unit will not take any power load. If the net head is beyond the range of allowable turbine operating heads, the Tool sets the generating head at zero, which implies that the turbine unit will be turned off.

Once the Tool has determined the allowable generating flow and head in time series, it calculates the turbine and generator efficiencies (in time series) based on the selected turbine type and generating flows and heads. Finally, the Tool calculates daily or monthly power and energy values, which are used for producing power duration curves and statistics of average monthly and annual power and energy generation.

2.6 INITIAL INVESTMENT COST ESTIMATE

To develop a reasonably accurate estimate of the initial investment for hydroelectric project development and construction, the ORNL-HEEA Tool requires the following user inputs:

- Type of potential site: would the project be developed at an existing dam or conduit/canal? Licensing and civil works costs can be significantly reduced for existing dam or conduit/canal projects.
- New Pipeline/Penstock Length: the cost of a long pipeline for an in-canal site without steep hydraulic drop could render a potential site economically infeasible.

- New Transmission Line Length and Voltage: the cost of obtaining a new transmission line right-of-way (ROW) and constructing a new transmission line could render a potential site economically infeasible.
- Environmental Cost Indicator: the additional project cost due to the site's environmental features and any corresponding mitigations required.
- Cost of Land and Water Right: the initial lump-sum cost of purchasing or leasing the property and facilities for project development.

Based on these user inputs, the ORNL-HEEA Tool estimates the initial project cost as the "overnight development cost," which does not include financing costs or cost escalation during the construction period. Financing costs vary significantly among projects depending, among other things, on the developer type. For that reason, the Tool does not include financing costs when comparing the installation costs ($/kW) for a group of potential sites. However, the Tool does account for the interest paid during construction, the escalation/inflation factor, and the discount rate [weighted average cost of capital (WACC)] in the LCOE and economic analyses. Appendix A of this report contains a detailed discussion of how the Tool estimates initial project costs, including equipment and mitigation costs.

2.7 ANNUAL OPERATION AND MAINTENANCE AND PERIODIC REPLACEMENT COST ESTIMATE

The annual operation and maintenance (O&M) costs of a hydropower project include the costs of labor and supplies for routine plant operation and maintenance, property taxes, insurance, regulatory compliance (e.g., FERC annual charges), and rents if any. Annual O&M costs also include the costs of interim overhauls and replacements (occurring every 3-5 years). The current version of the ORNL-HEEA Tool calculates annual O&M cost as a percentage of the project's overnight development cost based on the size of the plant's design capacity (MW) (Appendix A).

The recurring expenditures included in the O&M category are not enough to maximize the life and optimize the performance of a small hydropower project. Periodic replacement of key components extends project life, maintains or improves efficiency, and minimizes unplanned outages. Therefore, periodic replacement expenditures need to be included in lifecycle cost calculations. The ORNL-HEEA Tool assumes replacements over pre-specified periods ranging from 10 to 50 years for the turbine, generator, auxiliary mechanical and electrical components, transformer and switchyard equipment, and civil works/structures (Appendix A).

2.8 LEVELIZED COST OF ENERGY

LCOE can be interpreted as the minimum price at which a project owner must sell the electricity generated by a project to make the project economically feasible. To develop an estimate of a project's LCOE, the ORNL-HEEA Tool requires the following inputs:

- Project design life
- Construction time period
- Debt fraction of capital structure
- Interest rate on debt
- Minimum return on equity
- Inflation rate
- Initial incentive funds

With the exception of initial incentive funds, the ORNL-HEEA Tool sets these inputs as default values, but the user can override the defaults and input project-specific data. As described in detail in Appendix A, the methodology used to compute LCOE in the ORNL-HEEA Tool is based on the methodology outlined in *Electricity Utility Planning and Regulation* (Kahn 1991).

2.9 BENEFIT EVALUATION

If a project's LCOE is higher than the forecasted electricity price, it does not automatically mean that the project would not be economically feasible because revenue from the sale of electricity is not the only revenue stream a project might generate. For example, the project's provision of capacity, in addition to energy generation, has an economic value. In addition, for renewable technologies like hydropower, green-based financial incentives are often available from federal, state, or municipal agencies. The following subsections briefly describe how the ORNL-HEEA Tool calculates benefits for the potential sites in the Deschutes Basin, with a more detailed discussion in Appendix A.

2.9.1 Energy and Capacity Benefits

Most of the potential small hydropower projects in the Deschutes Basin would be owned by independent developers or irrigation districts. Neither of these types of entities has the authority to sell electricity directly to commercial, residential, or industrial consumers. Therefore, they would likely sell the electricity generated by their projects to a utility through a long-term power purchase agreement (PPA). PPAs typically offer a fixed price for energy and/or capacity over 15-20 years.

The energy component in a PPA reflects the cost that the purchasing utility would have to pay for electricity in the spot market. The capacity component acknowledges the cost avoided by the utility by buying electricity through the PPA rather than building an alternative power plant.

To estimate the potential revenue from electricity sales for a small hydropower project, a long-time price forecast matching the life of the project is needed. As described in detail in Appendix A, the ORNL-HEEA Tool uses two sources to develop the price forecast displayed in Fig. 2-1:

1. the base price projection used by the Northwest Power Planning Council for the Sixth Power Plan (NPPC 2010); and
2. state-level, monthly retail electricity prices from the Energy Information Administration (EIA) (EIA 2012).

The NPPC Sixth Power Plan provides an annual forecast value for the state of Oregon from 2013 to 2031. The EIA report provides monthly, historical data. Both sources were combined to develop a monthly price forecast for the Deschutes Basin projects assessed using the ORNL-HEEA Tool. The EIA report was used to compute seasonal adjustment coefficients. Then, those coefficients were applied to the annual price forecasts obtained from the NPPC Power Plan. Two assumptions were made:

- the seasonal profile of electricity prices observed in the last 2 years will be constant for the next 50 years
- the annual price forecast was kept constant after 2031.

Figure 2-1 depicts a moderate upward trend in electricity prices for Oregon over the next 20 years. The average annual growth rate is 4% for the first half of the forecast period and 2% for the second half. Some of the key factors that could alter the overall electricity price trend for Oregon over the next few decades are the evolution of natural gas prices and possible changes in regulation that would result in the introduction of a carbon tax or cap-and-trade system for CO_2 permits.[1]

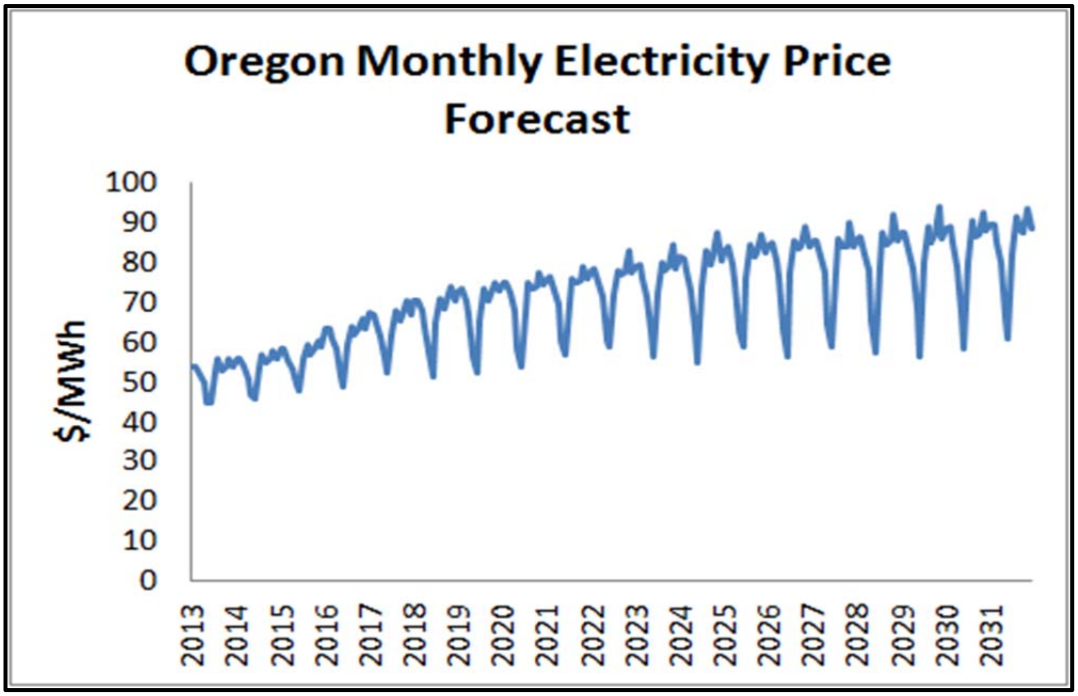


Fig. 2.1. Oregon monthly electricity price forecast
(*Source*: Based on NPPC 2010 and EIA 2012)

The capacity revenue for each potential project in the Deschutes Basin was computed as follows:

> Capacity revenue ($) = [Dependable capacity (%) * Levelized capital cost of combustion turbine ($/MWh)]*Energy production (MWh)

For the levelized capital cost of combustion turbines, the ORNL-HEEA Tool used the EIA estimate (EIA 2012) converted to 2012 dollars, producing a value of $50.92/MWh. However, a combustion turbine is dispatchable while a run-of-river hydropower project is not, so the levelized capital cost was adjusted by a factor that reflects the percentage of a small hydropower project’s capacity that can be considered firm capacity (see Appendix A).

2.9.2 Green Incentive Benefits

Federal, state, or municipal-level incentives could play a crucial role in enabling some of the small hydropower projects in the Deschutes Basin. Some of the incentives (e.g., grants and low-interest loans) are focused on reducing the net initial cost of the project and are independent of its utilization factor. Other incentives, however, are performance-based (e.g., Renewable Energy Certificates, Production Tax Credit).

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[1] The price forecast used in this report assumes that natural gas prices will be in the $5-$7/MM Btu range, considerable higher from currently observed prices. No carbon tax is assumed.

At the federal level, private developers have a choice between claiming the Renewable Electricity Production Tax Credit (PTC) or the Business Energy Investment Tax Credit (ITC). The PTC is currently set to expire in December 2013, but for this assessment the ORNL-HEEA Tool assumes that it would be renewed for another 5 years. The ITC is available for eligible systems placed in service through 2016. Appendix A contains a description of how the PTC and ITC are included in the Deschutes Basin assessment.

At the state level, ODE administers a Renewable Energy Development Grant Program that can help enable small hydropower projects. Other state-level programs in Oregon that can help in small hydropower development are the Community Renewable Energy Feasibility Fund Program and the Small-Scale Energy Loan Program (Appendix A).

Because Oregon has a Renewable Portfolio Standard (RPS), eligible facilities can register and produce Renewable Energy Certificates (REC) (one REC per MWh produced), which then can be sold, bundled with electricity or unbundled, to the obligated parties under RPS legislation. There are two main outlets for RECs produced in Oregon: sales to obligated parties under Oregon's RPS and sales to obligated parties under California's RPS. As discussed in detail in Appendix A, RECs are not included in this assessment because of their low expected value in Oregon and uncertainty about their value in California. The uncertainty associated with REC revenues suggests that they should not play a large role in assessing a potential project's economic viability.

2.9.3 Greenhouse Gas Emissions Benefit

Avoided greenhouse gas (GHG) emissions are one of the positive attributes of hydropower generation. Previous research shows that hydropower is generally competitive, from the standpoint of life-cycle GHG emissions, with other renewable energy technologies such as wind and solar power generation (Zhang et. al. 2007). Appendix A discusses how avoided GHG emissions can be estimated for a hydropower project. However, because there is no carbon market in North America, the ORNL-HEEA Tool does not assign a dollar value to a project's carbon reduction potential.

2.10 BENEFIT-COST RATIO AND INTERNAL RATE OF RETURN

Benefit-cost ratio (BCR) and internal rate of return (IRR) are two standard metrics for evaluating the economic feasibility of a project. BCR is calculated as the ratio of the net present value of lifecycle benefits to the net present value of lifecycle costs. This means that the timing of revenues versus expenditures, as well as the amount of revenues versus expenditures, is important for determining the feasibility of the project.

Lifecycle benefits and costs are compared to develop BCRs and pre-tax IRRs for a potential project. IRR is the annual rate of return for which the net present value of lifecycle net benefits (i.e., benefits minus costs in each period) equals zero.

As discussed in Appendix A, the ORNL-HEEA Tool uses the following criteria to define an economically viable site:

1. BCR $\geq$1.00; and
2. IRR > WACC (weighted average cost of capital).

3. ASSESSMENT RESULTS FOR POTENTIAL HYDROPOWER SITES

This Chapter summarizes the results of the technical and economic feasibility assessment of small hydropower projects at NPDs and canals/conduits in the Deschutes Basin. As discussed in Chapter 2 and Appendix A, the assessment was conducted using the ORNL-HEEA Tool.

3.1 NON-POWERED DAM SITES

This assessment evaluated the technical and economic feasibility of 14 NPD sites in the Deschutes Basin (Fig. 3-1). Table 3-1 summarizes the assessment results for the three NPD projects with a potential capacity >1 MW, and Table 3-2 summarizes the results for the remaining 11 NPD projects with a potential capacity <1 MW. For each of the 14 NPD sites, the assessment evaluated multiple options of turbine technologies and suppliers to examine cost sensitivity. Tables 3-1 and 3-2 include all the viable turbine type and supplier options for feasible projects, but only the single best option for infeasible projects.

Table 1-2 in Chapter 1 lists other NPDs that were not assessed because adequate flow/head data are not available for them or they are too small in terms of head and/or potential power to be worth investigating. For example, the net head at Lytle Creek Dam is only 3 ft, and thus no conventional hydropower technology is available for this extremely low-head development. Also, some projects are difficult to assess because of data inconsistencies regarding flow and head information in different databases and previous assessments. For example, Reclamation estimates the design head at Wickiup Dam to be 54.6 ft (Reclamation 2011), while Symbiotics, LLC, estimates it to be 67 ft (Symbiotics 2011a). Another example is the discrepancy between the monthly flow reported at Lytle Creek Dam in the NHAAP database (2.5 - 10.5 cfs) (ORNL 2012) and the design head flow assessed by Reclamation (264 cfs) (Reclamation 2011).

3.1.1 Input Data and Data Sources for Non-Powered Dam Sites

Historic daily flows for Wickiup Dam and Crescent Lake Dam were obtained from the USGS website (USGS 2012b), while historic daily flows for Bowman Dam, North Canal Dam, and Crane Prairie Dam were obtained from the OWRD website (OWRD 2012). For all other NPD sites, the assessment uses monthly average flow data from the NHAAP database (ORNL 2012), which were estimated using monthly runoff data and drainage areas.

Other input data used to assess the NPD sites with the ORNL-HEEA Tool include:

- The ORNL-HEEA Tool default financial parameters (Appendix A) were used for all NPD sites to ensure consistency among sites. The construction period was assumed to be 2 years for all NPD sites with capacity >1 MW (Table 3-1) and 1 year for sites with capacity <1 MW (Table 3-2).

- The Environmental Cost Indicator was assumed to be 10% for all NPD sites, which indicates that an additional 10% of direct construction cost has been added to the total initial investment cost for the purpose of environmental mitigations. This additional cost was assumed for the Deschutes Basin NPD projects because mitigation requirements, especially those associated with fish passage and screening, are common in Oregon.

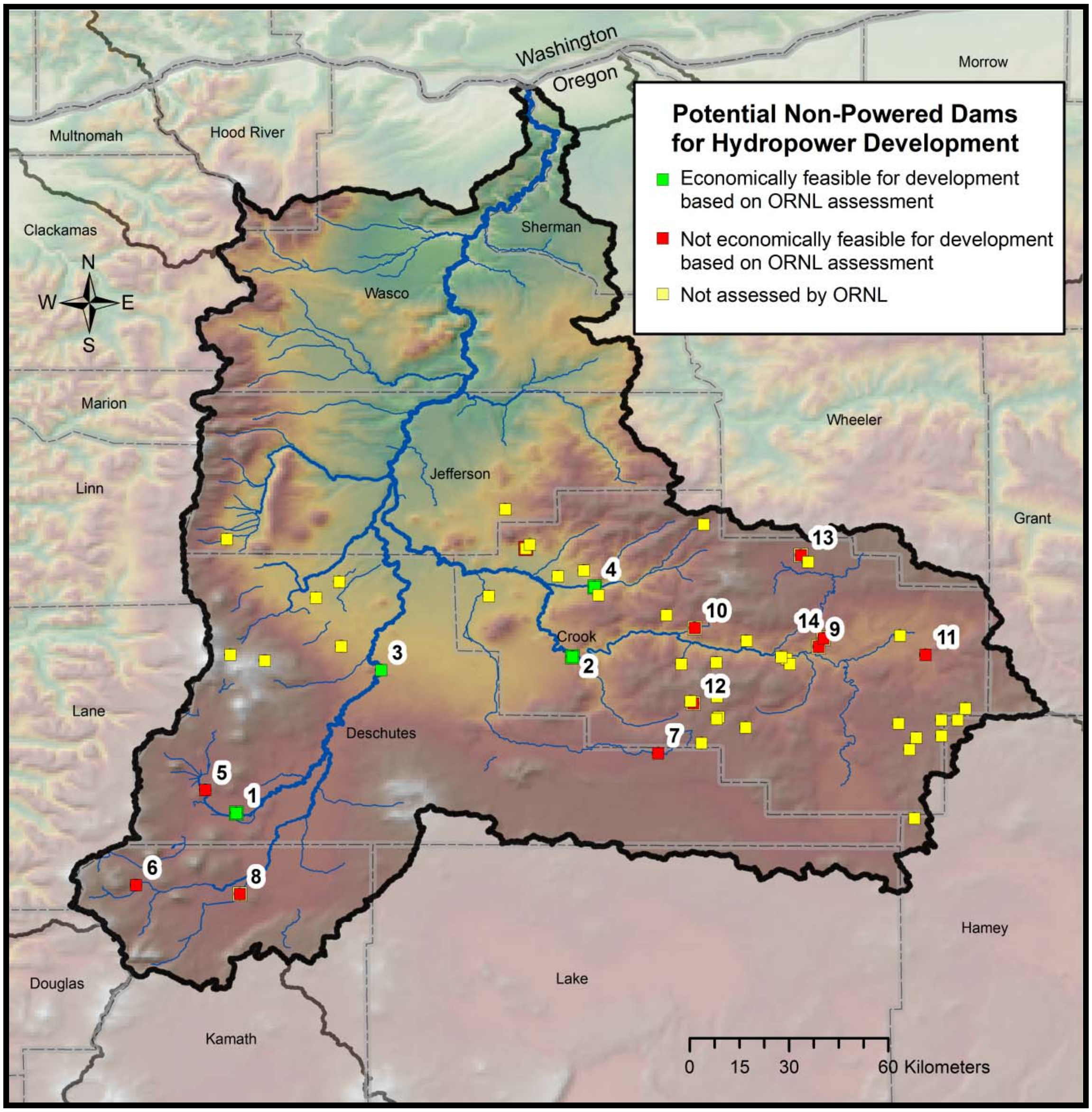


Fig. 3-1. Map of potential non-powered dam sites in the Deschutes and Crooked basins
(site numbers correspond with Table 1-2 of this report)
(*Source:* ORNL 2012)

- Data for new pipeline length and transmission line length and voltage are from Reclamation (Reclamation 2011) and the NHAAP database (ORNL 2012). There is no significant difference in pipeline/penstock length among the NPD sites assessed, but transmission line length varies significantly from site to site (Tables 3-1 and 3-2).

Table 3-1. ORNL-HEEA Tool assessment results for potential NPD projects (capacity >1 MW)

Site Name	Design Head (ft)	Design Flow (cfs)	Design Capacity (kW)	Turbine Type	Runner Dia. (ft)	Turbine Supplier	Annual Energy Generation (MWh)	Plant Capacity Factor	Total Project Initial Cost ($)	Installation Cost ($/kW)	LCOE ($/MWh)	BCR w/Green Incentives	BCR w/o Green Incentives	IRR w/Green Incentives	IRR w/o Green Incentives	Avoided GHG Emission (t CO_2 e/Year)	T-L Length (miles)	T-L Voltage (kV)
Wickiup Dam	67.0	1400	**7,118**	Kaplan	7.7	Chinese	29,010	0.46	13,316,890	1,871	50.9	1.63	1.44	13.2%	10.3%	10,748	12.43	115.0
	67.0	1400	**7,118**	Kaplan	7.7	CHC	29,010	0.46	16,321,572	2,293	62.5	1.35	1.17	10.4%	7.8%	10,748		
	67.0	1400	**7,118**	Kaplan	7.7	Domestic	29,010	0.46	17,823,913	2,504	68.3	1.25	1.07	9.2%	6.7%	10,748		
	67.0	1400	**6,406**	Propeller	7.7	Domestic	21,977	0.39	15,213,963	2,375	76.6	1.13	0.95	7.7%	5.3%	8,142		
	54.6	1080	**4,463**	Kaplan	6.8	Chinese	21,183	0.54	11,235,565	2,517	61.8	1.36	1.18	10.6%	8.0%	7,848		
	54.6	1080	**4,463**	Kaplan	6.8	CHC	21,183	0.54	13,586,107	3,044	74.9	1.14	0.97	8.0%	5.6%	7,848		
	54.6	1080	**4,017**	Propeller	6.8	CHC	17,104	0.49	11,779,298	2,932	80.0	1.07	0.91	7.0%	4.7%	6,337		
	54.6	1080	**4,463**	Kaplan	6.8	Domestic	21,183	0.54	14,761,378	3,308	81.5	1.06	0.89	6.8%	4.5%	7,848		
Bowman Dam	163.9	500	**5,959**	Francis	5.3	Domestic	19,587	0.37	9,311,813	1,563	53.2	1.66	1.47	13.6%	10.7%	7,257	3.60	112.0
	163.9	264	**3,132**	Francis	3.9	Domestic	17,393	0.63	6,118,778	1,954	41.3	2.08	1.89	18.1%	14.8%	6,444		
	163.9	264	**3,132**	Francis	3.9	CHC	17,393	0.63	5,603,074	1,789	37.8	2.26	2.06	19.7%	16.3%	6,444		
	163.9	264	**3,132**	Francis	3.9	Chinese	17,393	0.63	4,571,668	1,460	30.8	2.75	2.53	23.7%	20.1%	6,444		
	163.9	264	**3,235**	V. Kaplan	3.9	Chinese	18,132	0.64	4,891,475	1,512	31.7	2.68	2.46	23.2%	19.6%	6,718		
North Canal Diversion Dam	33.0	461	**1,135**	Kaplan (Pit or Bulb)	5.1	Domestic	5,145	0.52	4,898,292	4,316	113.9	0.88	0.72	3.5%	1.2%	1,906	0.09	69.0
	33.0	461	**1,135**	Kaplan (Pit or Bulb)	5.1	Chinese	5,145	0.52	3,152,682	2,778	73.9	1.28	1.12	10.0%	7.4%	1,906		
	33.0	461	**1,135**	Kaplan (Pit or Bulb)	5.1	CHC	5,145	0.52	4,316,422	3,803	100.5	0.98	0.82	5.5%	3.2%	1,906		
	33.0	461	**1,022**	Propeller	5.1	CHC	4,134	0.46	3,379,145	3,306	97.8	1.01	0.85	6.1%	3.7%	1,532		
	33.0	461	**1,106**	Turbinator	5.1	Norway	4,415	0.45	3,628,587	3,281	98.3	1.00	0.85	6.0%	3.7%	1,636		

Table 3-2. ORNL-HEEA Tool assessment results for potential NPD projects (capacity <1 MW)

Site Name	Design Head (ft)	Design Flow (cfs)	Design Capacity (kW)	Turbine Type	Runner Dia. (ft)	Turbine Supplier	Annual Energy Generation (MWh)	Plant Capacity Factor	Total Project Initial Cost ($)	Installation Cost ($/kW)	LCOE ($/MWh)	BCR w/Green Incentives	BCR w/o Green Incentives	IRR w/Green Incentives	IRR w/o Green Incentives	Avoided GHG Emission (t CO_2 e/Year)	T-L Length (miles)	T-L Voltage (kV)
Ochoco Dam	60.0	94.2	366	Francis	2.4	Chinese	2,992	0.93	1,750,402	4,783	69.8	1.92	1.74	17.6%	14.0%	1,108	2.22	138.0
	60.0	94.2	366	Francis	2.4	CHC	2,992	0.93	2,105,149	5,752	84.2	1.61	1.44	14.3%	11.0%	1,108		
	60.0	94.2	366	Francis	2.4	Domestic	2,992	0.93	2,282,523	6,236	91.4	1.50	1.33	12.9%	9.8%	1,108		
Crane Prairie	18.0	26.2	337	Kaplan (Pit or Bulb)	3.9	Chinese	2,037	0.69	7,656,371	22,719	436.5	0.35	0.20	Negative	Negative	755	17.41	138.0
				Transmission Line Cost Removed					1,753,158	5,202	107.1	0.97	0.81	5.4%	2.9%	755		
Crescent Lake Dam	33.0	82	200	Kaplan (Pit or Bulb)	2.2	Chinese	657	0.37	4,541,498	22,707	793.7	0.25	0.10	Negative	Negative	243	13.71	69.0
				Transmission Line Cost Removed					796,724	3,984	146.2	0.67	0.52	Negative	Negative	243		
Fehrenbacker #2	14.0	41.6	39	Propeller	1.6	Chinese	289	0.84	1,032,536	26,408	402.0	0.44	0.29	Negative	Negative	107	2.32	115.0
Merwin Res. #2	72.0	8.3	39	Cross-Flow	0.8	Chinese	179	0.52	7,031,365	180,291	4457.1	0.17	0.02	Negative	Negative	66	22.52	765.0
				Transmission Line Cost Removed					99,487	2,551	67.0	1.40	1.22	11.6%	8.5%	66		
Bonnie View Dam	36.0	12.7	33	Propeller	0.9	Chinese	128	0.44	4,812,047	144,941	4293.5	0.17	0.02	Negative	Negative	47	17.00	69.0
				Transmission Line Cost Removed					168,636	5,079	158.7	0.67	0.51	Negative	Negative	47		
Gilchrist Log Pond	9.8	56.9	31	Propeller	1.9	Chinese	160	0.59	507,983	16,387	388.6	0.37	0.23	Negative	Negative	59	0.36	69.0
Layton #2 Reservoir	18.0	23.6	29	Propeller	1.3	Chinese	118	0.46	937,750	31,896	918.9	0.24	0.09	Negative	Negative	44	2.32	115.0
Bear Creek (Crook)	57.0	5.5	20	Cross-Flow	0.7	Chinese	94	0.54	3,938,923	196,946	4779.9	0.17	0.02	Negative	Negative	35	12.60	115.0
				Transmission Line Cost Removed					60,519	3,026	77.8	1.23	1.05	9.3%	6.5%	35		
Allen Creek	76.0	3.3	16	Cross-Flow	0.5	Chinese	75	0.53	9,032,999	564,562	13741.2	0.15	0.01	Negative	Negative	28	29.19	765.0
				Transmission Line Cost Removed					48,030	3,002	77.3	1.23	1.06	9.4%	6.6%	28		
Watson Reservoir	30.0	28.7	15	Propeller	0.7	Chinese	59	0.44	6,968,663	452,511	13389.2	0.15	0.01	Negative	Negative	22	22.29	765.0
				Transmission Line Cost Removed					107,582	6,986	217.6	0.53	0.38	Negative	Negative	22		

3.1.2 Assessment Results for Non-Powered Dam Sites

For this assessment, a project is considered economically feasible if it meets two criteria:

- BCR $\geq$1.0
- IRR > WACC (weighted average cost of capital; assumed to be 5.9%).

All of the potential projects assessed in this report met either both or neither of these two criteria.

Based on ORNL-HEEA Tool modeling, Wickiup Dam, Bowman Dam, North Canal Dam, and Ochoco Dam, ranked by potential power capacity, all are economically feasible for development (Tables 3-1 and 3-2). Their ranking in terms of financial attractiveness, as expressed by BCR and IRR, is Bowman, Ochoco, Wickiup, and North Canal. The total power potential at these four feasible NPD sites is about 14.6 MW (out of 15.4 MW for all 14 NPDs assessed), and potential annual energy generation is about 56.7 GWh (out of 60.5 GWh for all 14 NPDs assessed). The 10 NPD sites determined to be infeasible are all too small to be developed economically with available technology.

The Wickiup Dam assessment was based on USGS daily flow data for the period 1938-1990. The ORNL-HEEA Tool recommended a design flow of 1080 cfs (i.e., the 30% exceedance flow at the flow duration curve). However, to compare two development scenarios at Wickiup Dam, two sets of design head and flow were used. The lower power cases (4.5 MW) are based on a design head of 54.6 ft (Reclamation 2011) and a design flow of 1080 cfs (ORNL 2012). The higher power cases (7.1 MW) reference the Wickiup Project FERC license application (Symbiotics 2011a) and use a design head of 67 ft and a design flow of 1400 cfs. In both power cases, the Kaplan type turbine provided by a Chinese suppler was the best option at Wickiup Dam (Table 3-1). The best economic results are achieved by increasing the design head to 67 ft, which seems feasible for Wickiup Dam with a structural height of 100 ft and hydraulic height of 81 ft (Symbiotics 2011a).

At Bowman Dam, the ORNL-HEEA Tool-recommended design flow (264 cfs) and a design net head results in an installed power capacity of 3.1 MW. Under this scenario, the Francis type turbine provided by a Chinese suppler was the best option at Bowman Dam (Table 3-1). This development scenario is more financially attractive than a design flow of 500 cfs, which corresponds with the 6 MW of installed capacity in the PGE FERC license document (PGE 2010b).

In general, the NPD sites with higher head and higher potential power would be more economically attractive for capital investment and project development. For the sites with <1 MW design capacity (Table 3-2), only Ochoco Dam looks economically feasible. For some micro projects at NPDs located far away from existing transmission facilities (e.g., Merwin #2 Reservoir –22 .5 miles; Bear Creek – 12.6 miles; and Allen Creek –29.2 miles), the cost of a new transmission line could contribute >90% of total project capital cost, representing a significant barrier for hydropower development. Sensitivity tests showed that without the cost of a new transmission line, some of these micro projects could become economically feasible (Table 3-2). Thus, these projects might be suitable for a microgrid or could become attractive if additional power projects in the area bring interconnection points with the central grid closer to the site.

3.2 EXISTING CANAL/CONDUIT SITES

Figure 3-2 shows 17 potential canal/conduit sites in the Deschutes Basin; however, this assessment evaluated only the 15 sites for which adequate data were available (Table 3-3). For each site, the

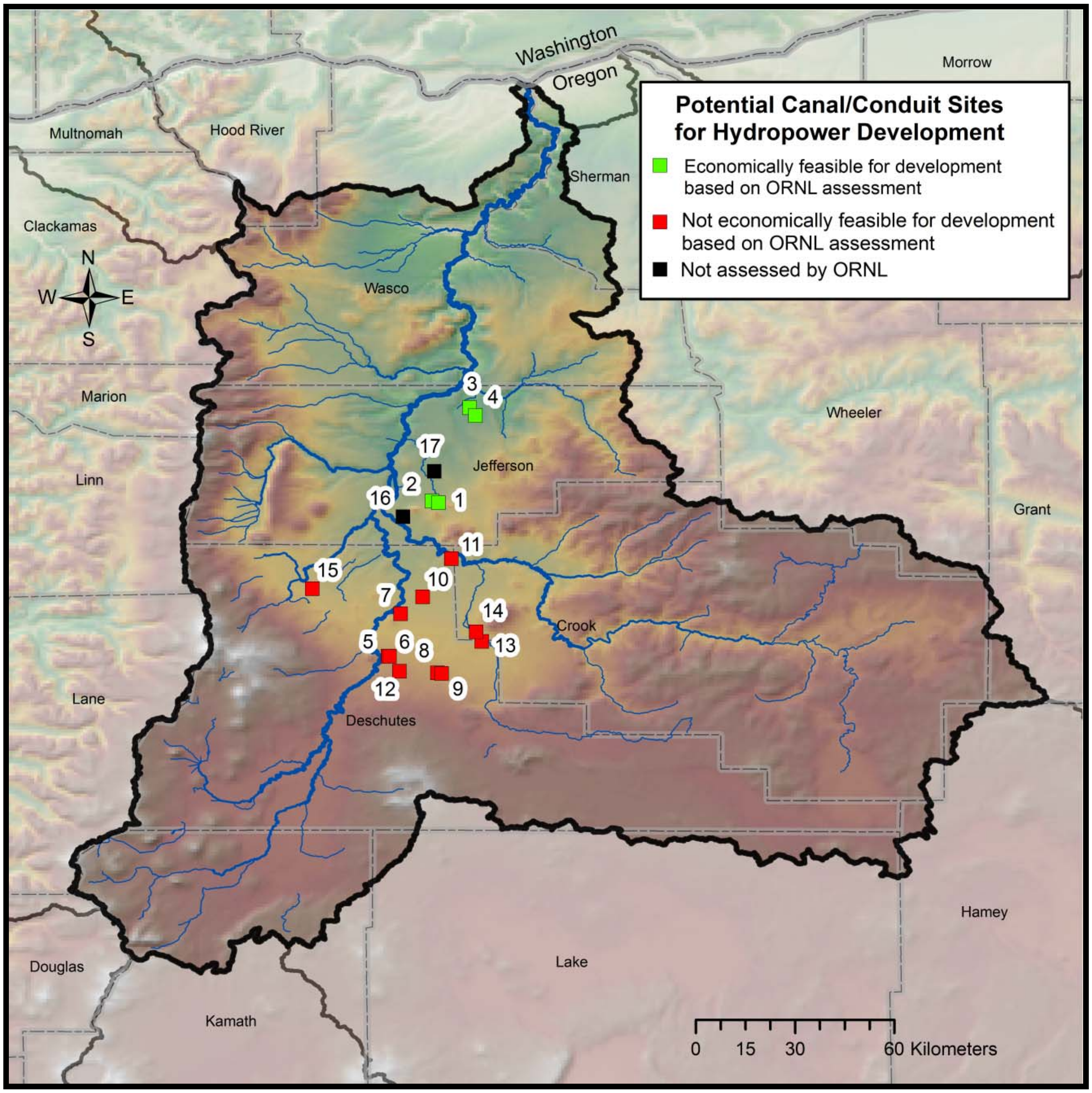


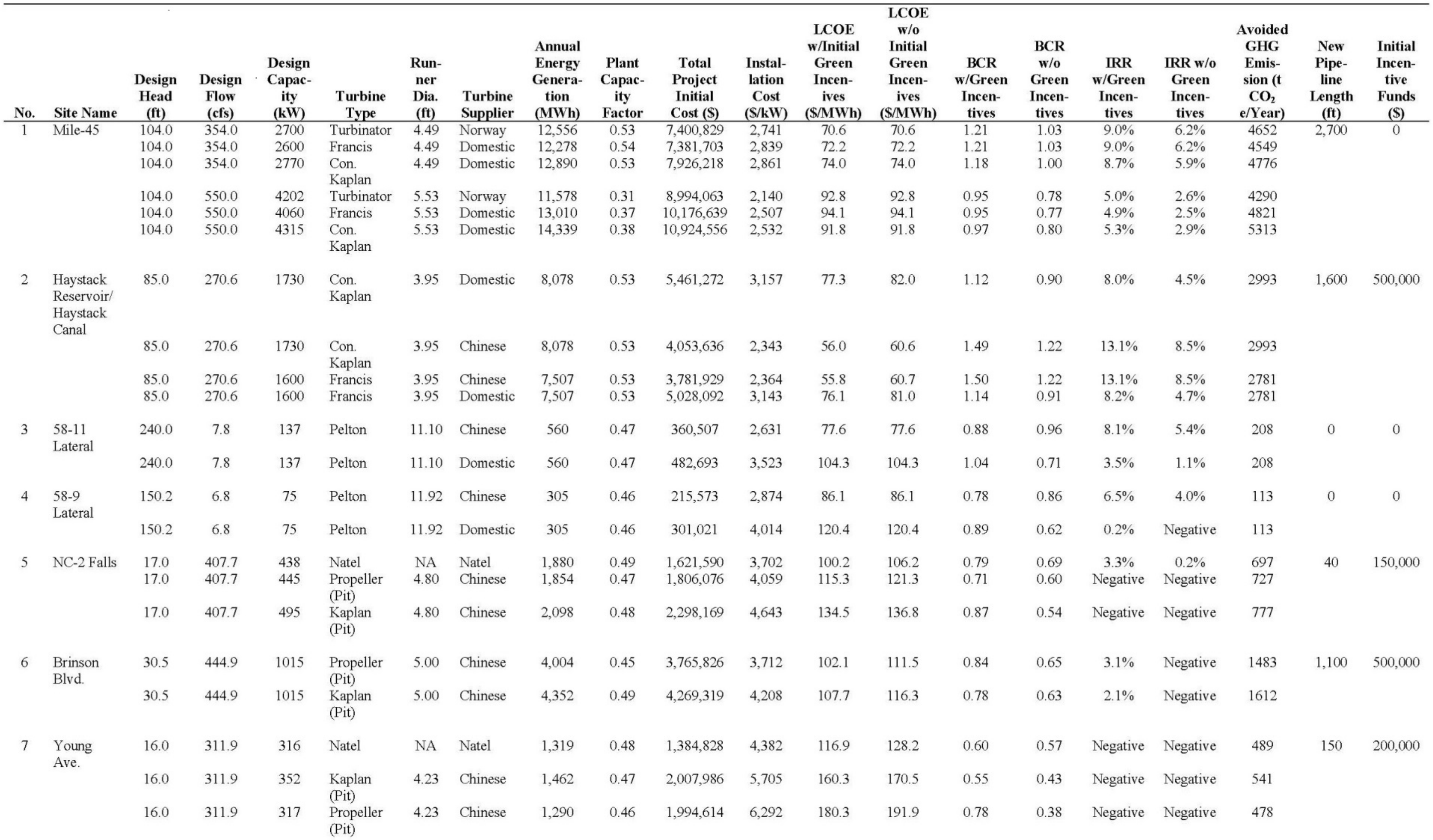
Fig. 3-2. Map of potential canal and conduit sites in the Deschutes and Crooked basins
(site numbers correspond with project listing in Table 3-3 of this report)
(*Source:* ORNL 2012)

assessment evaluated multiple options of turbine technologies and suppliers to examine cost sensitivity. Table 3-3 includes all the viable turbine type and supplier options for feasible projects, but only the single best option for infeasible projects.

3.2.1 Input Data and Data Sources for Canal/Conduit Sites

For the Mile-45 site, this assessment used the time series of monthly average flow (from 2000 to 2009) and other project data from the application document for FERC Exemption (EBD Hydro 2010). The time series of net head for the 45-Mile site are from calculations contained in *Assessment and Evaluation of*

Table 3-3. ORNL-HEEA Tool assessment results for potential NPD projects (capacity <1 MW)



No.	Site Name	Design Head (ft)	Design Flow (cfs)	Design Capac-ity (kW)	Turbine Type	Run-ner Dia. (ft)	Turbine Supplier	Annual Energy Genera-tion (MWh)	Plant Capac-ity Factor	Total Project Initial Cost ($)	Instal-lation Cost ($/kW)	LCOE w/Initial Green Incen-ives ($/MWh)	LCOE w/o Initial Green Incen-ives ($/MWh)	BCR w/Green Incen-tives	BCR w/o Green Incen-tives	IRR w/Green Incen-tives	IRR w/o Green Incen-tives	Avoided GHG Emis-sion (t CO_2 e/Year)	New Pipe-line Length (ft)	Initial Incen-tive Funds ($)
1	Mile-45	104.0	354.0	2700	Turbinator	4.49	Norway	12,556	0.53	7,400,829	2,741	70.6	70.6	1.21	1.03	9.0%	6.2%	4652	2,700	0
		104.0	354.0	2600	Francis	4.49	Domestic	12,278	0.54	7,381,703	2,839	72.2	72.2	1.21	1.03	9.0%	6.2%	4549		
		104.0	354.0	2770	Con. Kaplan	4.49	Domestic	12,890	0.53	7,926,218	2,861	74.0	74.0	1.18	1.00	8.7%	5.9%	4776		
		104.0	550.0	4202	Turbinator	5.53	Norway	11,578	0.31	8,994,063	2,140	92.8	92.8	0.95	0.78	5.0%	2.6%	4290		
		104.0	550.0	4060	Francis	5.53	Domestic	13,010	0.37	10,176,639	2,507	94.1	94.1	0.95	0.77	4.9%	2.5%	4821		
		104.0	550.0	4315	Con. Kaplan	5.53	Domestic	14,339	0.38	10,924,556	2,532	91.8	91.8	0.97	0.80	5.3%	2.9%	5313		
2	Haystack Reservoir/ Haystack Canal	85.0	270.6	1730	Con. Kaplan	3.95	Domestic	8,078	0.53	5,461,272	3,157	77.3	82.0	1.12	0.90	8.0%	4.5%	2993	1,600	500,000
		85.0	270.6	1730	Con. Kaplan	3.95	Chinese	8,078	0.53	4,053,636	2,343	56.0	60.6	1.49	1.22	13.1%	8.5%	2993		
		85.0	270.6	1600	Francis	3.95	Chinese	7,507	0.53	3,781,929	2,364	55.8	60.7	1.50	1.22	13.1%	8.5%	2781		
		85.0	270.6	1600	Francis	3.95	Domestic	7,507	0.53	5,028,092	3,143	76.1	81.0	1.14	0.91	8.2%	4.7%	2781		
3	58-11 Lateral	240.0	7.8	137	Pelton	11.10	Chinese	560	0.47	360,507	2,631	77.6	77.6	0.88	0.96	8.1%	5.4%	208	0	0
		240.0	7.8	137	Pelton	11.10	Domestic	560	0.47	482,693	3,523	104.3	104.3	1.04	0.71	3.5%	1.1%	208		
4	58-9 Lateral	150.2	6.8	75	Pelton	11.92	Chinese	305	0.46	215,573	2,874	86.1	86.1	0.78	0.86	6.5%	4.0%	113	0	0
		150.2	6.8	75	Pelton	11.92	Domestic	305	0.46	301,021	4,014	120.4	120.4	0.89	0.62	0.2%	Negative	113		
5	NC-2 Falls	17.0	407.7	438	Natel	NA	Natel	1,880	0.49	1,621,590	3,702	100.2	106.2	0.79	0.69	3.3%	0.2%	697	40	150,000
		17.0	407.7	445	Propeller (Pit)	4.80	Chinese	1,854	0.47	1,806,076	4,059	115.3	121.3	0.71	0.60	Negative	Negative	727		
		17.0	407.7	495	Kaplan (Pit)	4.80	Chinese	2,098	0.48	2,298,169	4,643	134.5	136.8	0.87	0.54	Negative	Negative	777		
6	Brinson Blvd.	30.5	444.9	1015	Propeller (Pit)	5.00	Chinese	4,004	0.45	3,765,826	3,712	102.1	111.5	0.84	0.65	3.1%	Negative	1483	1,100	500,000
		30.5	444.9	1015	Kaplan (Pit)	5.00	Chinese	4,352	0.49	4,269,319	4,208	107.7	116.3	0.78	0.63	2.1%	Negative	1612		
7	Young Ave.	16.0	311.9	316	Natel	NA	Natel	1,319	0.48	1,384,828	4,382	116.9	128.2	0.60	0.57	Negative	Negative	489	150	200,000
		16.0	311.9	352	Kaplan (Pit)	4.23	Chinese	1,462	0.47	2,007,986	5,705	160.3	170.5	0.55	0.43	Negative	Negative	541		
		16.0	311.9	317	Propeller (Pit)	4.23	Chinese	1,290	0.46	1,994,614	6,292	180.3	191.9	0.78	0.38	Negative	Negative	478		

No.	Site Name	Design Head (ft)	Design Flow (cfs)	Design Capacity (kW)	Turbine Type	Runner Dia. (ft)	Turbine Supplier	Annual Energy Generation (MWh)	Plant Capacity Factor	Total Project Initial Cost ($)	Installation Cost ($/kW)	LCOE w/Initial Green Incenives ($/MWh)	LCOE w/o Initial Green Incenives ($/MWh)	BCR w/Green Incentives	BCR w/o Green Incentives	IRR w/Green Incentives	IRR w/o Green Incentives	Avoided GHG Emission (t CO_2 e/Year)	New Pipeline Length (ft)	Initial Incentive Funds ($)
8	10-Barr Road	23.0	237.0	399	Kaplan (Pit)	3.71	Chinese	1,672	0.48	1,778,829	4,458	118.7	127.6	0.65	0.58	Negative	Negative	620	150	200,000
9	Dodds Road	79.0	245.0	1396	Francis	3.77	Chinese	6,690	0.55	8,911,732	6,384	154.1	154.1	0.64	0.48	Negative	Negative	2478	8,433	0
10	Yew Ave.	42.0	164.0	516	Kaplan (S-Type)	3.12	Chinese	2,174	0.48	3,082,637	5,979	152.2	166.0	0.61	0.45	Negative	Negative	806	2,550	400,000
11	Smith Rock Drop	16.0	390.2	395	Natel	NA	Natel	1,749	0.50	2,337,905	5,919	161.0	161.0	0.58	0.46	Negative	Negative	644	600	0
		16.0	390.2	444	Propeller (Pit)	4.70	Chinese	1,751	0.45	2,571,687	5,787	174.0	174.0	0.55	0.42	Negative	Negative	649		
		16.0	390.2	444	Kaplan (Pit)	4.70	Chinese	1,900	0.49	3,003,182	6,758	187.3	187.3	0.55	0.39	Negative	Negative	704		
12	Ward Road	25.0	330.0	609	Propeller (Pit)	4.34	Chinese	3,070	0.57	5,023,396	8,246	190.0	190.2	0.52	0.39	Negative	Negative	1138	2,700	0
13	Shumway Road	79.0	150.0	850	Francis	2.99	Chinese	4,071	0.55	7,270,700	8,559	206.0	206.0	0.52	0.36	Negative	Negative	1508	11,438	0
14	Brasada Siphon	81.0	147.9	861	Francis	2.97	Chinese	3,461	0.46	7,181,449	8,341	226.4	239.4	0.48	0.31	Negative	Negative	1282	11,500	600,000
15	McKenzie Reservoir	96.0	30.0	187	Cross-Flow	1.47	Chinese	942	0.57	2,216,682	11,867	270.3	270.3	0.43	0.28	Negative	Negative	349	27,750	0

Sources: EBD Hydro 2010; Black Rock 2009; COID & ODE 2011; ETO 2010

New Small Hydropower Technology to be Deployed to the United States 45-Mile Project: "The Turbinator" (Hadjerioua and Stewart 2013). With this monthly flow and net head input, the ORNL-HEEA Tool recommends a design flow of 354 cfs and a rated net head of 104 ft for the Mile-45 site.

For the five NUID sites and the five COID sites assessed in this report, only a few years of daily or monthly flow data were available from the previous assessment reports discussed in Section 1.4 (Black Rock 2009; COID and ODE 2011). The ETO report (ETO 2010) provides only an average flow number for the sites it assesses, but includes information on the months in which there would be sufficient flow available for electricity production (corresponding to the irrigation season). For four of the sites assessed in the ETO 2010 report, the ORNL-HEEA Tool uses a monthly flow profile for a generic/normal year based on average flow in the months in which there would be electricity production. Three of the sites assessed in ETO 2010 (Brinson Boulevard, 10 Barr, and Yew Avenue) were also assessed in either the NUID or COID assessments discussed in Section 1.4, so the ORNL-HEEA Tool used flow and head data from those assessments.

Other input data used to assess the canal/conduit sites with the ORNL-HEEA Tool include:

- The ORNL-HEEA Tool default financial parameters (Appendix A) were used for all canal/conduit sites to ensure consistency among sites. The construction period was assumed to be 1 year for all canal/conduit sites.

- The Environmental Cost Indicator was assumed to be 0% for all canal/conduit sites, which indicates that no additional environmental mitigation costs have been added to the total initial project cost.

- The amount of initial incentive funds and data for new pipeline length and transmission line length and voltage are from the previous assessments discussed in Section 1.4 (Black Rock 2009; ETO 2010; COID and ODE 2011). The new transmission line that would be needed at each of the canal/conduit sites would be relatively short and would not have a significant effect on overall project cost (Table 3-3).

3.2.2 Assessment Results for Canal/Conduit Sites

For this assessment, a project is considered economically feasible if it meets two criteria:

- BCR $\geq$1.0
- IRR > WACC (weighted average cost of capital; assumed to be 5.9%).

Based on ORNL-HEEA Tool modeling, the Mile-45, Haystack Canal, 58-11 Lateral, and 58-9 Lateral sites are all economically feasible for hydropower development assuming green incentives (Table 3-3). Without green incentives, only the Mile-45 and Haystack Canal sites are economically feasible. The total power potential at these four canal/conduit sites is about 4.6 MW (out of about 11.7 MW for all 15 canal/conduit sites), and potential annual energy generation is about 21.5 GWh (out of 52.6 GWh for all 15 canal/conduit sites).

For the Mile-45 project, the ORNL-HEEA Tool used a design net head of 104 ft, but assessed two different design flows:

- Case 1: the ORNL-HEEA Tool recommended design flow (354 cfs), and
- Case 2: the design flow (550 cfs) referenced in the FERC Exemption application (EBD Hydro 2010).

Compared with Case 1, the increased design flow in Case 2 results in less favorable economic results (making the project economically infeasible when assuming a domestic turbine supplier or the Turbinator technology), although unit installation costs are reduced and installed power capacity and annual generation are increased. This demonstrates that plant capacity factor should not be too low (such as below 0.4) for a small hydropower project design. The 30% exceedance flow is largely appropriate for the design flow of a small hydropower project.

For canal/conduit sites without a steep water drop, pipeline construction costs can be a significant contributor to the total initial project cost. At the Dodds Road, Shumway Road, Brasada Siphon, and McKenzie Reservoir sites, the design hydraulic heads appears to be large enough for development, but the cost of constructing a long, new pipeline makes them economically infeasible (Table 3-3).

4. CONCLUSIONS

The purpose of this technical and economic feasibility assessment is to identify and analyze opportunities for new small hydropower development in the Deschutes Basin, along with the technology needed to develop selected sites and the economic cost/benefit of developing those sites. The assessment focused on adding new generators at existing NPDs and in existing irrigation canals and conduits. The assessment was conducted using the ORNL-HEEA Tool, which uses site-specific hydrological data and basic site and project information to: (1) generate flow and power duration curves; (2) determine turbine design flow, net head, and technology type; (3) calculate monthly and annual power generations and determine plant design power capacity; (4) estimate project cost (both installation cost and LCOE); and (5) perform benefits and economic evaluations.

This assessment evaluated the technical and economic feasibility of 14 NPDs and 15 irrigation canal/conduit sites in the Deschutes Basin. The total potential generation capacity for these 29 sites is about 27 MW. Given the estimated lifecycle benefits and costs of each project, only four of the NPD sites and four of the canal/conduit sites appear to be economically feasible. As summarized in Tables ES-1 and ES-2, these feasible projects could add about 19 MW of hydroelectric capacity to the Deschutes Basin and could generate over 78 GWh of renewable energy each year. This could power about 6,000 households year-round and avoid GHG emissions of about 29,000 tone of CO_2 equivalent each year.

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APPENDIX A.

THE OAK RIDGE NATIONAL LABORATORY HYDROPOWER ENERGY AND ECONOMIC ASSESSMENT TOOL

Appendix A. The Oak Ridge National Laboratory Hydropower Energy and Economic Assessment Tool

A.1 INTRODUCTION

With funding from the U.S. Department of Energy (DOE) Water Power Program, Oak Ridge National Laboratory (ORNL) is developing a software tool to consistently evaluate the energy and economic feasibility of potential hydropower sites. The ORNL-Hydropower Energy and Economic Assessment (HEEA) Tool (Version 1.0) is an Excel workbook with embedded macro functions programmed in Visual Basic using Microsoft Excel 2010. The goal of developing this tool is to create a rapid and reasonably accurate means of predicting the energy output and economic feasibility of a site-specific hydropower project.

A.2 BACKGROUND

For its work on several DOE Water Power Program projects, including the Deschutes Basin-Scale Opportunity Assessment, ORNL needs a software tool with which to consistently evaluate the energy and economic feasibility of potential hydropower sites, including non-powered dam (NPD) sites and irrigation canal/conduit sites. Based on a review of the small hydropower assessment tools currently available worldwide, as listed in Table A-1, ORNL staff concluded that only the Bureau of Reclamation's (Reclamation) HydroAssessment Tool 2.0 (Reclamation 2011) and Natural Resources Canada (NRC) RETScreen4 (NRC 2004a) had the features necessary to conduct a site-specific hydropower energy and economic assessment. However, these existing tools are not appropriate for assessing small hydropower opportunities in all situations because they do not provide the user sufficient flexibility in terms of inputting: (1) available hydrologic data under various scenarios at multiple sites; (2) some of the "green incentives" that potential projects could entail (e.g., Federal and state grants); (3) the different turbine types and suppliers available to hydropower developers; and (4) the cost of "soft" items (e.g., contingency, engineering, licensing, and permitting costs) relevant for developing some hydropower sites.

Based on the results of its review of existing software tools, ORNL staff is developing the ORNL-HEEA Tool (Version 1.0). With regard to the existing Reclamation and NRC tools, the ORNL-HEEA Tool offers: (1) greater flexibility in inputting hydrological data; (2) a more user-friendly interface, and; (3) greater flexibility and accuracy in turbine type selection, efficiency curves, and project costing. Table A-2 provides a summary comparison of the ORNL-HEEA Tool (Version 1.0), Reclamation's HydroAssessment Tool 2.0, and NRC's RETScreen4.

The ORNL-HEEA Tool can be used to assess any run-of-river or run-of-reservoir small hydropower project (below 50 MW), including projects at new sites, NPDs operated as run-of-reservoir, and existing canals/conduits. For projects with water storage for power generation scheduling, the Tool requires the user to input the time series of regulated flows and heads resulting from reservoir operation. The targeted application for the Deschutes Basin is sites with potential power capacity ranging from 100 kW to 10 MW, but the Tool could be used for assessing micro to medium hydropower projects with capacity from 10 kW to 50 MW.

A.3 ORNL-HEEA TOOL STRUCTURE, INPUTS, AND OUTPUTS

As discussed in the following sections, the ORNL-HEEA Tool requires some basic site and project information (such as location, financial structure, etc.), as well as daily or monthly mean flow and hydraulic head to describe the time variability of water discharge. The energy and economic

Table A-1. Review of Small Hydropower Assessment Software

Assessment Tool				Features								
Product Name	**Developer**	**Applicable Regions/Countries, Individual Sites?**	**Accessibility**	**GIS-Based**	**Hydrology**	**Accounting for Other Water Uses, Minimum Flow Releases**	**Power & Energy**	**Costing**	**Economic Evaluation**	**Proximity Information & Environmental Attributes**	**Preliminary Design**
HEEA 1.0 - Hydropower Energy and Economic Assessment	ORNL, US DOE	USA (intended for individual sites)	TBD	No	Input flow time series to produce the FDC	X	X	X	X	X	
HydroAsessment 2.0	USBR	(intended for individual sites)	Open access	No	series to produce the FDC		X	X	X	X	
VHP - Virtual Hydropower Prospector	INL, US DOE	USA (not intended for individual sites)	Open access, interactive Web-based maps	Yes	MAF		X	X	X	X	
HES - Hydropower Evaluation Software	INL, US DOE	USA (not intended for individual sites)	Open access	No	MAF						
HydroHELP 1.4 (Turbine selection) HydroHELP 2.4-6.4	Gordon J. L. and OEL-HydroSys, Canada	International (intended for individual sites)	Open access for HydroHELP 1.4	No	Plant Design Flow			X		X	X
RETScreen 4®	NRC, Canada	International (intended for individual sites)	Open access		FDC	X	X	X	X	X	X
IMP 5.0 - Integrated Method for Power Analysis	NRC and POWEL, Canada	International (intended for individual sites)	Open access	No	Model for ungauged hydro site		X				
RHAM- Rapid Hydropower Assessment Model	Kerr Wood Leidal Associates Ltd.	BC province, Canada (not intended for individual sites)	Open access, interactive Web-based maps	Yes	MAF/FDC	X	X	X	X	X	
Remote Small Hydro	NRC and Ottawa Engineering Ltd.	Remote Communities, Canada	Un-searchable	Yes	X			X			
Green Kenue™ (Hydrological Modeling)	NRC-Canadian Hydraulics Center, Environmental Canada	International (Hydrologic Model only)	Open access	Yes	X						
PEACH	ISL Bureau d'Ingenieurs Conseils, France	France (Intended for Individual sites)	Open access	No	FDC		X	X	X		X
Smart Mini Idro	ERSE SpA, Italy	Italy (Intended for Individual sites)	Open access	No	FDC		X	X	X		
VAPIDRO ASTE 4.0	ERSE SpA, Italy	Italy (not intended for individual sites)	Open access, interactive Web-based maps	Yes	MAF	X	X	X	X	X	
NVE Atlas. Potential for SHP Plants	Norwegian Water Resources and Energy Directorate (NVE)	Norway (intended for individual sites)	Open access, interactive Web-based maps	Yes	MAF		X	X	X	X	
Hydrobot	Nick Forrest Associates Ltd., et al.	Scotland (intended for individual sites)	Limited access (need to pay)	Yes	FDC	X	X	X	X	X	

MAF=Mean annual flow; FDC=Flow Duration Curve

(*Sources:* Petras et al. 2011; IEA and NRC 2008; IEA 2000; Reclamation 2011; INL 2012a; INL 2012b; OEL-HydroSys 2012; NRC 2004a; NRC 2004b; Kerr Wood Leidal Associates Ltd. 2012; NRCC 2012; SHARE 2012; SEE HydroPower 2012; Nick Forrest Associates 2012)

Table A-2. Comparison of the ORNL-HEEA Tool (Version 1.0), Reclamation's HydroAssessment Tool 2.0, and Natural Resource Canada's RETScreen4

Tool Components	ORNL-HEEA Tool 1.0	USBR-HydroAssessment Tool 2.0	RETScreen 4®
Applicability	For central-grid connected: power system absorbs all available energy, Energy delivered = Energy available	No description but it is for central-grid connected projects (Energy delivered = Energy Available)	For central-grid, or isolated-grid/off-grid applications (Energy delivered< Energy Available)
	For pre-feasibility studies of micro, mini and small sites (capacity < 50 MW)	For pre-feasibility studies of small hydro sites (no specifications for the site scales)	For pre-feasibility studies and preliminary design of micro, mini and small sites (capacity < 50 MW)
	One single unit at one site	One single unit at one site	Multiple units are allowed and number of units is user-defined
	50 States in the USA	Western States in the USA	International
Input Flow and Head data	Supporting both daily and monthly flow/head inputs, different scenarios for water level/head inputs. FDC is produced by the model.	Only supporting daily flow/head inputs. FDC is produced by model.	FDC is manually input or generated by MAF and run off model. Head variation is not included in RETScreen model.
	Accounting for other water uses or required minimum in-stream flow	The input flow is for power generation.	Accounting for other water uses or required minimum in-stream flow
	Headlosses are estimated to get net head time series.	No headlosses considered.	Headlosss is calculated.
	Warning and suggestions are provided when the input historic flow is less than 6 years	Stop running when the input historic flow is shorter than required.	NA
Design Flow and Net Head	30% exceedance at FDC and/or Net head duration curve	30% exceedance at FDC and/or Net head duration curve	NA
	User input to override the model recommended values	User input to override the model recommended values	User-defined values
Turbine Type Selection	Turbine type selection matrix has been refined by reference to multiple charts	Turbine type selection matrix is provided	NA
	Pelton, Francis, Kaplan, Propeller, Cross-Flow for model automatic selection	Pelton, Francis, Kaplan and Low-head types for model automatic selection (the concept of Low-head type is vague)	NA
	User can override by choosing more turbine types (Turgo, Natel)	No more types for user overriding	Pelton, Turgo, Francis, Kaplan, Propeller, Cross-Flow for user selection
	Turbine is largely sized	No turbine sizing	Turbine is largely sized
Turbine Efficiency	Based on empirical efficiency curves for different turbine types and design parameters (recognized worldwide)	Based on a single example of turbine Hill Diagram or Prototype efficiency curve for Pelton, Francis and Kaplan	Based on empirical efficiency curves for different turbine types and design parameters (recognized worldwide)
	Turbine efficiency curves are presented and verified	No turbine efficiency curve presented and a constant efficiency value (75%) for Low-head type	Turbine efficiency curves are presented and verified
Power and Energy Generation Calculation	Upper and lower limits of operating flow and head are determined for different turbine types, which referenced multiple data sources	The upper and lower limits of operating flow and head are not reasonable for some turbine types	Daily and annual delivered and excess energy are calculated
	Generic Generator Efficiency Curve is provided	No description	No description
	Different algorithm for daily and monthly input time series	NA	NA
Costing	(1) Initial overnight development cost, (2) annual O&M cost and (3) periodic replacement cost	(1) Initial overnight development cost, (2) annual O&M&R cost	(1) Initial overnight development cost, (2) annual O&M&R cost
	Costing for different turbine-generator suppliers	No supplier brand names considered	Costing for different turbine-generator suppliers
	Referenced multiple and more recent cost models and will be updated with ORNL's progress on cost data collection	Mainly based on INL costing formulae (2002), some mitigation costs are unclear between initial cost and O&M cost	Formula costing or detailed costing, requires too many user-defined parameters
Benefits Evaluation	Green incentives include initial financial assistance, production-based credit or investment tax credit	Only production-based green incentives are accounted	Incentive and grants accounted but unclear how they are accounted
	Projected energy prices and green incentives for 50 US states	Projected energy prices and green incentives for Western States only	unclear how the energy prices projected
	Avoided Greenhouse Gas (GHG) emissions are estimated but no dollar values	No GHG emissions mentioned	Avoided Greenhouse Gas (GHG) emissions are estimated with realized or potential dollar values
Economic Analysis	LCOE, BCR and Pre-Tax IRR	BCR and Pre-Tax IRR	Pre-tax IRRs for equity and asset, pay back years (simple, equity)
	Timing and escalation of costs	No escalation for costs	Cost escalation
	Cost flows, Yearly cash flows during the project lifetime	Cost flows, Yearly cash flows during the project lifetime	Cumulative cash flow graph

assessment for a potential site is completed by running different modules for hydrology data processing, flow duration curve, net head duration curve, design parameters, turbine type selection, power generation calculation, project costing, and benefits and economic evaluation.

Figure A-1 shows the steps and dynamic "data flows" for simulating and assessing a small hydropower project. The ORNL-HEEA Tool is being developed based on this flowchart. In Fig. A-1, the blue-colored frames and wider arrows indicate the major assessment steps, while the green-colored frames indicate more detailed simulation steps. During a project simulation, there are active interactions among different modules through information exchanges (i.e., "data flows"). The line-arrows in Fig. A-1 indicate the data "inflows" and "outflows" among different modules. The left side of the flowchart is for cost analysis and the right side for benefit analysis. "Rules of thumb" and empirical equations are embedded in the process of turbine selection and sizing, but users are allowed to customize the input to the design decision-making process to ensure their preferred design options are used and evaluated in the project feasibility assessment.

The ORNL-HEEA Tool consists of 16 spreadsheets (i.e., tabs), including:

1) *Disclaimer* – provides the Disclaimer Statement and assumptions made for model development.
2) *Start* – provides instructions, steps, and buttons for users to run individual modules and complete site assessments. This tab also receives and shows the input and calculated site and project basic information/parameters.
3) *Q-H Input* – receives, stores, and pre-processes the daily or monthly flow, water level, or head data. For different input data scenarios, the net heads and available flows for power generation are prepared in this tab.
4) *Flow Exceedance* – gets the time series data for the available flow from the *Q-H Input* tab, presents the flow duration curve (FDC), the recommended turbine design flow (30% exceedance), and firm flow (90% exceedance).
5) *Net Head Exceedance* – gets the time series of net head data from the *Q-H Input* tab, presents the net head duration curve and the recommended turbine rated net head (30% exceedance). If a constant net head (i.e., the turbine rated head) is given by the user, a window message is shown while this tab remains empty.
6) *Turbine Type* – presents the matrix of turbine type vs. flow and head, as well as the ranges of operating flow and heads for different turbine types. The selected turbine type is highlighted as yellow at the corresponding flow and head combination.
7) *Generator Efficiency Curve* – presents a generic generator efficiency curve and a table for the best generator efficiency values vs. installed unit power capacity.
8) *Generation* – gets the time series data for the net head and available flow from the *Q-H Input* tab, provides the time series of generation flow and head constrained by the selected turbine operating ranges, and performs power and energy generation calculations. The turbine unit and plant design parameters, turbine efficiency curve, monthly and annual power and energy amounts are shown in the tab.
9) *Power Exceedance* – gets the time series of power generation calculated in the *Generation* tab and presents the power duration curve.
10) *Project Cost* – estimates and presents the equipment, civil construction, and other component costs and total development cost, as well as the annual operation and maintenance cost and periodic replacement costs.
11) *Economic Analysis* – lists the parameters used, and presents the results of the Levelized Cost of Energy (LCOE), Benefit-Cost Ratio (BCR), and Internal Rate of Return (IRR) calculations.

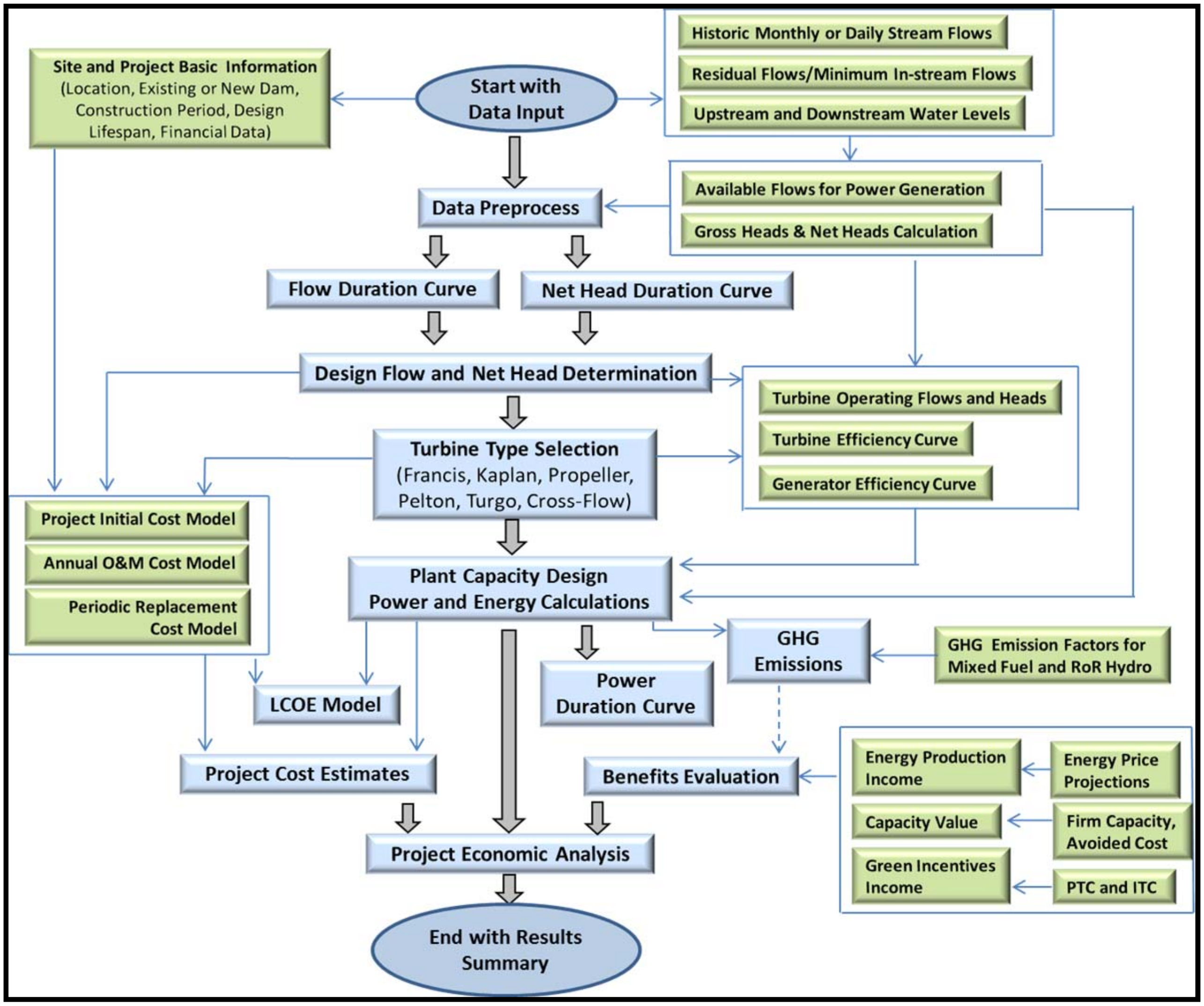


Fig. A-1. ORNL HEEA Tool Flowchart

12) *GHG* – estimates and presents the avoided greenhouse gas (GHG) emissions from the hydropower project.
13) *Results* – assembles the basic project and turbine unit parameters, energy generation, project cost and economic analysis results.
14) *Energy Price Projections* – provides the monthly electric power price forecasts through 2062 for each state in the United States to calculate the energy generation benefits through the project life cycle.
15) *Generation-based Green Incentives* – includes the small hydropower generation-based green incentives used for each state to calculate the green incentive benefits.
16) *Example* – stores all the required input data for running a demo project. The data are automatically written into the *Start* and *Q-H Input* tabs when the button "Use Demo Input data" is pressed. This tab is also used as a template to prepare the input data for assessing projects.

Table A-3 shows an example input list from the *Start* tab for the 45-Mile in-canal site in the Deschutes Basin.

Behind the 16 spreadsheets (tabs), there are 10 modules, corresponding to 10 buttons in the *Start* tab, embedded in the ORNL-HEEA Tool. The module names and functions are as follows:

1) StartOver – to clear all the input and calculated data in the tabs.
2) DemoInputs – to copy the input data from the *Example* tab to some cells of the *Start* and *Q-H Input* tabs.
3) DataPreprocess – to calculate the net heads and flows available for power generation based on different scenarios of input data, and to give warnings if the input historic flow is <6 years.
4) FlowExceedance – to rank and calculate the frequencies of daily or monthly available flows in the *Flow Exceedance* tab.
5) HeadExceedance – to rank and calculate the frequencies of daily or monthly net heads in the *Net Head Exceedance* tab. If a constant net head (i.e., the turbine rated head) is given by the user, a window message appears on the screen and no head duration curve is generated.
6) TurbineTypeSelection – to select the turbine type based on the determined turbine design flow and net head using the matrix in the *Turbine Type* tab.
7) GenerationCalculation – to determine the generating flow and head, calculate the turbine and unit efficiencies, and power and energy generations.
8) PowerExceedance – to rank and calculate the frequencies of daily or monthly powers in the *Power Exceedance* tab.
9) CostEstimate – to estimate the project initial component and total costs based on the empirical cost equations/models.
10) EconomicAnalysis – to estimate energy production revenue, capacity revenue, and other potential benefits from green incentives; to calculate LCOE, BCR, and IRR.

A.3.1 Design Flow and Net Head Determination with Hydrology Data Input

Gross head is the maximum available hydraulic head between headwater and tailwater. Net head refers to the hydraulic head between the inlet and outlet of a turbine, usually measured at the spiral case inlet (or immediately upstream of the turbine) and draft tube outlet (or immediately downstream of the turbine). The rated net head (or design head) of a turbine or a plant, H_n, is defined as the gross head less the maximum hydraulic losses along both upstream and downstream waterways. That is,

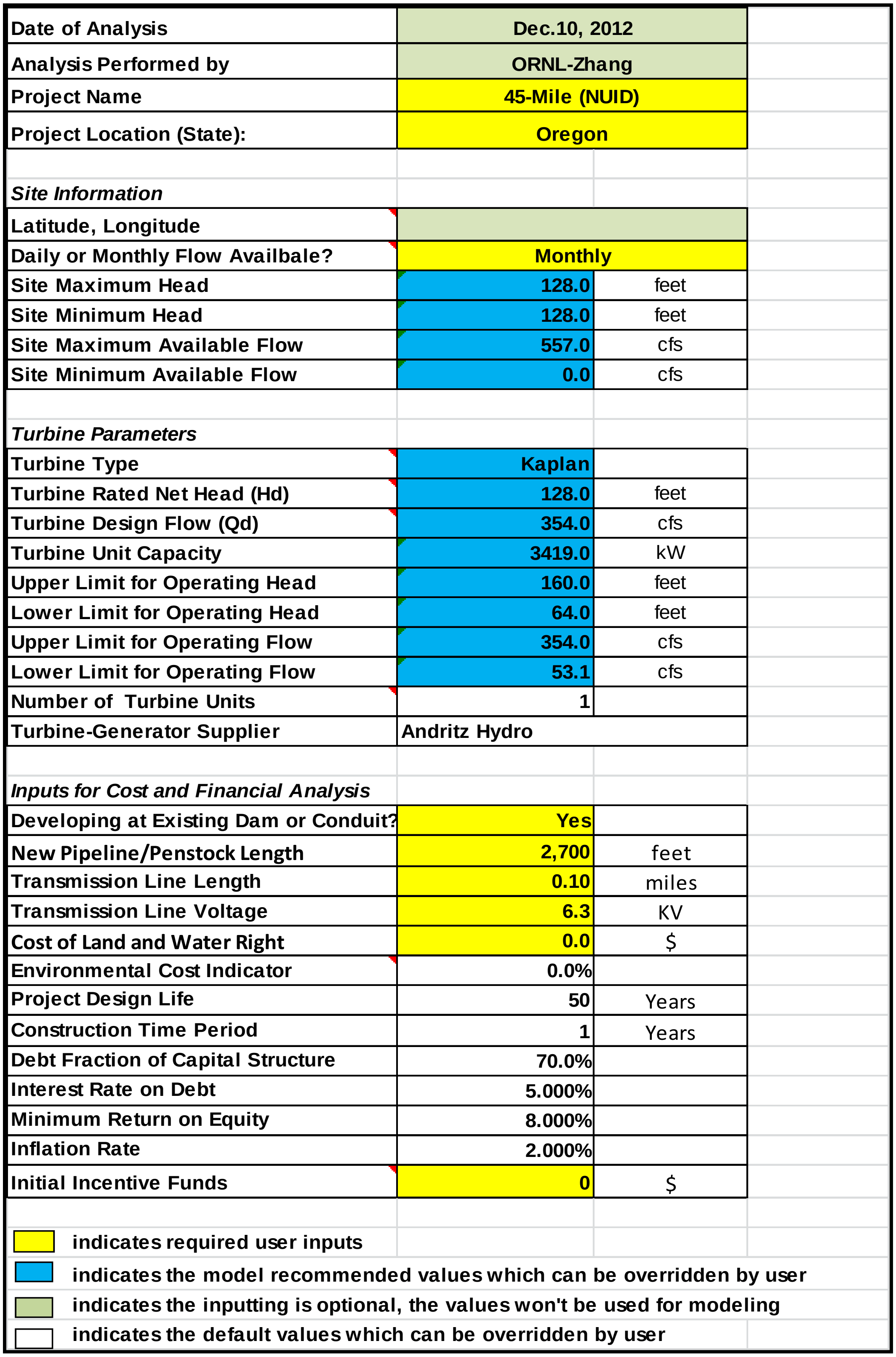
$$H_n = Headwaterlevel - Tailwaterlevel - headlosses \quad \text{(A-1)}$$

For a run-of-river or run-of-reservoir (i.e., NPD) project, both headlosses and tailwater level are associated with the square of discharge flow (Q^2) and increased with the flow Q increase. With the flow Q increase, the headwater level may draw down or remain constant during a certain time period depending on site hydrological condition, intake structures and reservoir scale. So equation (A-1) can be written as:

$$H_n = Headwaterlevel - f(Q^2) \qquad \text{(A-2)}$$

In terms of small hydropower projects, turbine design flow (or rated flow) is defined as the maximum flow passing through the turbine at the rated head and full gate opening; the rated head (net head) is the gross head less the maximum hydraulic losses (i.e., at the design flow condition) (NRC 2004a).

Table A-3. Example of ORNL-HEEA Tool basic site and project information inputs



Date of Analysis	Dec.10, 2012	
Analysis Performed by	ORNL-Zhang	
Project Name	45-Mile (NUID)	
Project Location (State):	Oregon	
Site Information		
Latitude, Longitude		
Daily or Monthly Flow Availbale?	Monthly	
Site Maximum Head	128.0	feet
Site Minimum Head	128.0	feet
Site Maximum Available Flow	557.0	cfs
Site Minimum Available Flow	0.0	cfs
Turbine Parameters		
Turbine Type	Kaplan	
Turbine Rated Net Head (Hd)	128.0	feet
Turbine Design Flow (Qd)	354.0	cfs
Turbine Unit Capacity	3419.0	kW
Upper Limit for Operating Head	160.0	feet
Lower Limit for Operating Head	64.0	feet
Upper Limit for Operating Flow	354.0	cfs
Lower Limit for Operating Flow	53.1	cfs
Number of Turbine Units	1	
Turbine-Generator Supplier	Andritz Hydro	
Inputs for Cost and Financial Analysis		
Developing at Existing Dam or Conduit?	Yes	
New Pipeline/Penstock Length	2,700	feet
Transmission Line Length	0.10	miles
Transmission Line Voltage	6.3	KV
Cost of Land and Water Right	0.0	$
Environmental Cost Indicator	0.0%	
Project Design Life	50	Years
Construction Time Period	1	Years
Debt Fraction of Capital Structure	70.0%	
Interest Rate on Debt	5.000%	
Minimum Return on Equity	8.000%	
Inflation Rate	2.000%	
Initial Incentive Funds	0	$

🟨 indicates required user inputs

🟦 indicates the model recommended values which can be overridden by user

🟩 indicates the inputting is optional, the values won't be used for modeling

⬜ indicates the default values which can be overridden by user

Based on a “rule of thumb” in screening and pre-feasibility studies of run-of-river small hydropower projects, the ORNL-HEEA Tool determines default plant design flow and net head as the 30% exceedance values of the duration curves for available flow and net head for power generation (Reclamation 2011). This indicates that 30% of the time the available flow for power generation at a site will be greater than the design plant flow and excess flow will be spilled bypassing the turbine units, and that 70% of the time the available flow will be fully utilized. This criterion is considered appropriate for a screening stage of energy and economic assessment to ensure that the potential power generation will not be underestimated and the plant capacity factor and investment return will not be too low to warrant further investigation.

Based on the above definition of turbine design flow, the turbine design flow Q_d and rated net head H_n should simultaneously meet equation (A-2) for a single-unit project. However, when both flow and head duration curves are generated using historic data records, it is possible to determine whether the default rated net head (30% exceedance value of head duration curve) always matches the default design flow (30% exceedance value of flow duration curve). If the headwater level is totally correlated to the flow Q or maintained constant (e.g., maintained by intake weir) as most cases of run-of-river projects, they should match with each other if the historic records are sufficiently accurate, just as found for the Deschutes Basin Mile-45 site. Yet, for storage projects, the default design head and flow may not correspond with each other, as was found at Bowman Dam. In this case, the rated net head must be determined by a complexity analysis for storage operation and tailwater effect.

During the simulation, the design flow and rated net head values recommended by the ORNL-HEEA Tool can be overridden by manually inputting user-preferred values. If design flow and net head are provided by manual input after execution of the flow and head duration curves, the model uses the user input values for the turbine type selection, power generation calculation, and project cost estimates. Optimization of turbine design parameters is a complicated decision process, and in future versions of the ORNL-HEEA Tool the alternatives of turbine design parameters could be tracked down for final comparison and determination based on economic analysis results.

To generate a statistically meaningful flow duration curve, the ORNL-HEEA Tool requires the user to input a time series of daily or monthly average flows for 6 complete water years (or calendar years) (Copestake and Young 2008). If both the “Stream Flow” and flow demand for non-power generating purposes (such as the minimum environmental in-stream flows and required irrigation flows) are provided by user input, the net daily or monthly flows that are available for power generation (i.e., “Available Flow”) would be calculated and then used to produce the flow duration curve. The data on minimum environmental in-stream flows are usually provided for different seasons or months in the whole year. However, if the time series data are for “Available Flow” (i.e., the flow data have already been adjusted by subtracting other water demands from raw stream flows), they can be directly inputted. If the length of time series of flow data is <6 years, the Tool provides a warning. However, the Tool can operate with a minimum of 1 year of flow data, assuming the 1-year flows represent the typical or average water year case.

The ORNL-HEEA Tool provides flexibility in adapting to all circumstances of available hydraulic head data. If the time series of daily or monthly average headwater elevation is provided along with variable or a constant tailwater elevation, the Tool calculates gross head and then estimates net head. If the time series of gross head or net head is available, they can be inputted directly. With any type of inputted hydraulic head data, the net head duration curve would is generated to determine the design net head. Otherwise, the Tool would request that design net head be input by the user.

Flow and head data can be input to the ORNL-HEEA Tool by using a pre-processing program, such as the Deschutes Basin-Scale Water Management Model. For a project with water storage beyond the capacity of daily flow adjustment and power generation scheduling, the current version of the ORNL-HEEA Tool requires the user to input flow and water level data from the reservoir operation program for power generation scheduling. As part of the future development of the Tool, reservoir operating rules and power scheduling could be coded in the model, so the flows input by the model could be the raw data of inflows to the reservoir.

A.3.2 Hydro Turbine Technology and Selection

The ORNL-HEEA Tool develops a matrix of turbine types, including the Francis, Kaplan, Propeller, Pelton, and Cross-Flow turbines and their corresponding design flow and net head intervals, by referencing several existing charts (ESHA 2004; ASME-HPTC 1996). In the matrix, flow ranges from 0.7 cfs to 2500 cfs and net head ranges from 6.6 ft to 3000 ft, which encompass micro- to medium-scale hydro turbines.

The Pelton type is suitable for high-head cases, the Francis and Cross-Flow types are suitable for medium head and flow conditions, and the Kaplan and Propeller types are suitable for relatively lower heads and higher flows.

The propeller turbine has a fixed wicket-gate and fixed runner blades and is suitable for relatively constant head and flow conditions, while the Kaplan (double-regulated, i.e., both wicket gates and blades are adjustable) features high efficiency over wide ranges of variable flow and head (Fig. A-2), and thus the higher cost of a Kaplan may be worth the benefits from increased energy generation. Semi-Kaplan is a variant of the Kaplan type, and lies between the double-regulated Kaplan and the Propeller, which is called a single-regulated Kaplan (i.e., with adjustable wicket gates and fixed blades, or fixed wicket gates and adjustable blades). The efficiency curves for variants of Kaplan turbines are illustrated in Fig. A-2.

Kaplan turbines include Conventional and Axial-Flow types. In Conventional Kaplan turbines, water enters the runner in a radial direction through the wicket gates (or fixed guide vanes), and then runs down and strikes the blades along the axial direction. A Conventional Kaplan is vertically shafted and used for relatively higher head and larger power applications, while an Axial-Flow Kaplan (Double-regulated or Single-regulated) is typically used for low-head and low-power cases and may have three configurations for water passage (i.e., for the inlet-outlet bending) and multiple modifications based on these three basic configurations:

a) Hnet = 6.6 ft – 33 ft, Bulb or Pit or Tubular = Horizontal axis or main shaft = 0°- 0° inlet - outlet;
b) Hnet = 26 ft –50 ft, S-type Axial Flow turbine = inclined main shaft = 45°- 45° inlet - outlet bending (Standard Draft Tube);
c) Hnet = 33 ft – 83 ft, Z-type or Saxophone = Axial Flow vertical main shaft = 90 °- 90 ° inlet - outlet.

In addition, an Axial Flow Kaplan turbine usually has 3-6 blades, the lower the head the fewer the blades.

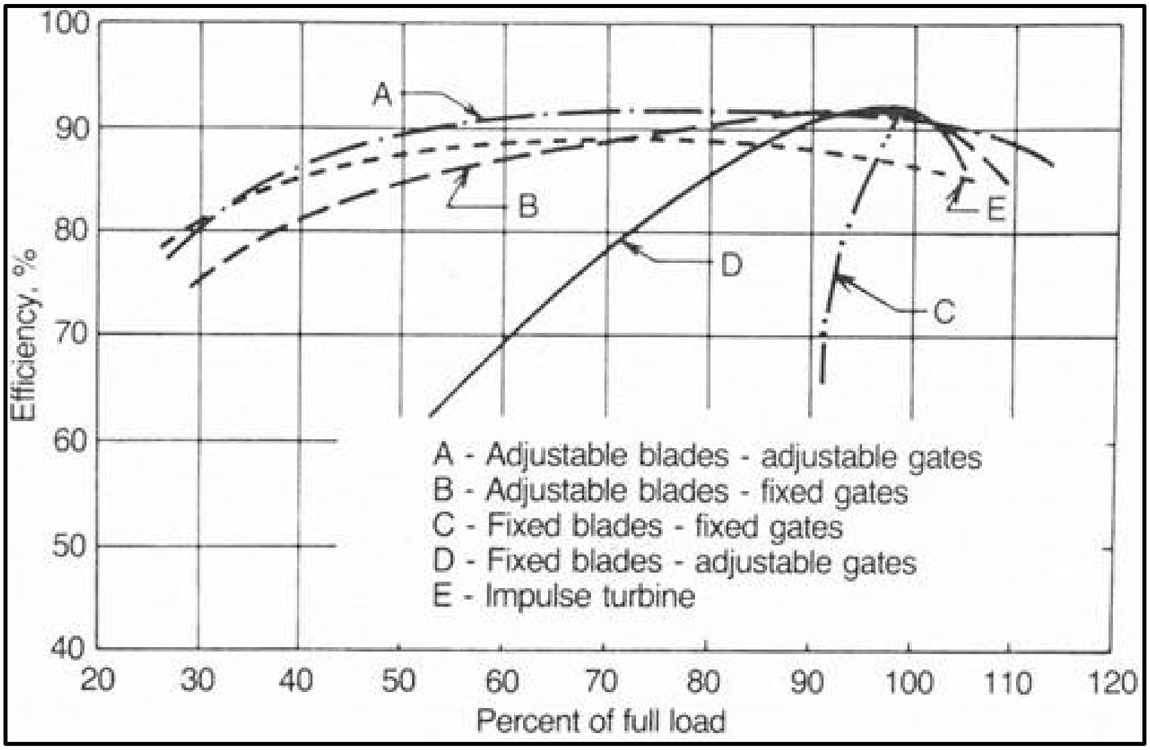


Fig. A-2. Kaplan-type Turbine Efficiency Curve Comparison
(*Source*: Renewables First Ltd., 2012)

To reduce the cost of micro-scale hydropower projects (i.e., power capacity ≤100 kW), the turbine matrix developed for the current version of the ORNL-HEEA Tool assumes a Propeller turbine rather than a Kaplan turbine if net head is <10 ft, and assumes a Cross-Flow turbine rather than a Francis turbine if net head is <100 ft.

The Tool automatically selects turbine type based on the ranges of rated net head and turbine unit design flow. However, the user can override the Tool-recommended turbine type by manually inputting a preferred type, which is then used to calculate efficiency and generation and estimate project costs. In addition to turbine type, the user can specify the name of the turbine supplier to account for the significant cost differences among domestic, Canadian, and Chinese turbine suppliers.

In the boundary areas within the turbine selection matrix, where multiple turbine types could be well-suited for a site (e.g., Kaplan or Francis for medium head and medium flow), the current version of the ORNL-HEEA Tool selects only one turbine type. In future versions of the Tool, a more complicated turbine selection matrix could be developed, and the turbine type alternatives could be incorporated as different design options for project costing and economic analysis. The final turbine type then could be determined by a cost-benefit comparison of different design options.

The Tool-recommended turbine type can be overridden by manually inputting a user-preferred type, which is then used for efficiency and generation estimates and project costing. The user can choose Turgo, Natel, and Turbinator technologies in addition to Francis, Kaplan, Propeller, Pelton, and Cross-Flow turbines. Turgo turbines are applied at relative higher heads, having a similar application range as the Pelton but with less efficiency and lower cost. The current Natel technology can only be applied at very low-head sites with net head between 5 ft to 20 ft and capacity below 500 kW (Natel

2012). The Turbinator, developed by CleanPower of Norway, is an axial flow (AF) semi-Kaplan turbine with adjustable wicket gates and fixed runner blades, integrated with a permanent magnet (PM) generator. Currently, there are six standard sizes (500 - 1500 mm in runner diameter) designed for heads ranging from 5 m to 55 m and power ranging from 75 kW to 3300 kW. Each standard-sized Turbinator system is suitable for relatively narrow variable flow conditions (40-50% of maximum design flow) due to the fixed blades (Hadjerioua and Stewart 2013).

A.3.3 Turbine and Generator Efficiency

The ORNL-HEEA Tool determines turbine efficiency based on several empirical efficiency curves (NRC 2004; Gordon 2001; Manness and Doering 2005). Turbine peak efficiency (η_p) is determined based on the selected turbine type, turbine design flow, and rated net head. The Tool assumes that turbine operating efficiency varies with the turbine operating flow (i.e., η_T *vs.* Q) at the rated head. Taking the example of a Francis turbine, the turbine diameter (d) and specific speed (n_q) are first estimated using an empirical formula based on the design flow (Q_d) and net head (H_d). Then, the peaking efficiency (η_p) and corresponding peak efficiency flow (Q_p) can be determined according to the specific speed and turbine size. Finally, the turbine efficiencies at the operating flows below and above the peak efficiency flow (Q_p) are calculated, respectively, by the following equations (NRC 2004a):

$$\eta_Q = \left\{1 - [1.25(1 - \frac{Q}{Q_P})^{(3.94 - 0.0195 n_q)}]\right\}\eta_P, \qquad Q<Q_P \qquad \text{(A-3)}$$

$$\eta_Q = \eta_P - \left(\frac{Q - Q_P}{Q_d - Q_P}\right)^2 [1 - (1 - 0.0072 {n_q}^{0.4})]\eta_P, \qquad Q>Q_P \qquad \text{(A-4)}$$

The remaining question is how turbine efficiency varies with operating head. For a Kaplan or Francis turbine, with constant flow, the change in turbine efficiency is minor when the turbine is operating under hydraulic heads different than the rated one, and the efficiency change vs. operating head can be expressed by (Gordon 2001):

$$\Delta\eta = -0.5(\frac{H - H_d}{H_d})^2 \qquad \text{(A-5)}$$

As shown in Fig. A-2 and Table A-4, a Propeller turbine should not be applied for cases with significant changes in hydraulic head (the maximum operating range is 80-110% of the rated head). Also, for impulse turbines no significant change in hydraulic head is allowed (the maximum operating range is 75-110% of rated head). Thus, there is no significant efficiency change for these types of turbines arising from the allowable variations of operating head.

The turbine efficiency formulas for the Francis, Kaplan, Propeller, Pelton, Turgo, and Cross-Flow turbines are essentially taken from Appendix A of *RETScreen Engineering & Cases Textbook* (NRC 2004a) with a few minor modifications. The efficiency curve for Natel technology is obtained from the “Part Flow Efficiency Chart” on Natel Energy’s website (Natel 2012). The Turbinator turbine’s efficiency curve is obtained from CleanPower (Hadjerioua and Stewart 2013).

The ORNL-HEEA Tool displays the resulting chart for turbine efficiency vs. relative flow for the selected and sized turbine in the Generation tab. The turbine efficiency curves have been verified with example projects using different types of turbines. Figures A-3 through A-9 show typical turbine efficiency curves that have been reproduced using the ORNL-HEEA Tool with data generated for the projects assessed in the Deschutes Basin.

Table A-4. Turbine operating range of flow and net head for power generation

Turbine Type	*Hmax* (%H_d) (upper limit operating head)	*Hmin* (%H_d) (lower limit operating head)	*Qmax* (%Q_d) (upper limit operating flow)	*Qmin* (%Q_d) (lower limit operating flow)
Kaplan	125	50	100	15
Francis	125	65	100	20
Propeller	110	80	100	35
Pelton	110	75	100	10
Turgo	110	75	100	10
Cross-Flow	110	75	100	8
Turbinator	110	75	100	40
Natel	110	75	100	20

(Sources: ESHA 2004; Natel Energy 2012; Hadjerioua and Stewart 2013.)

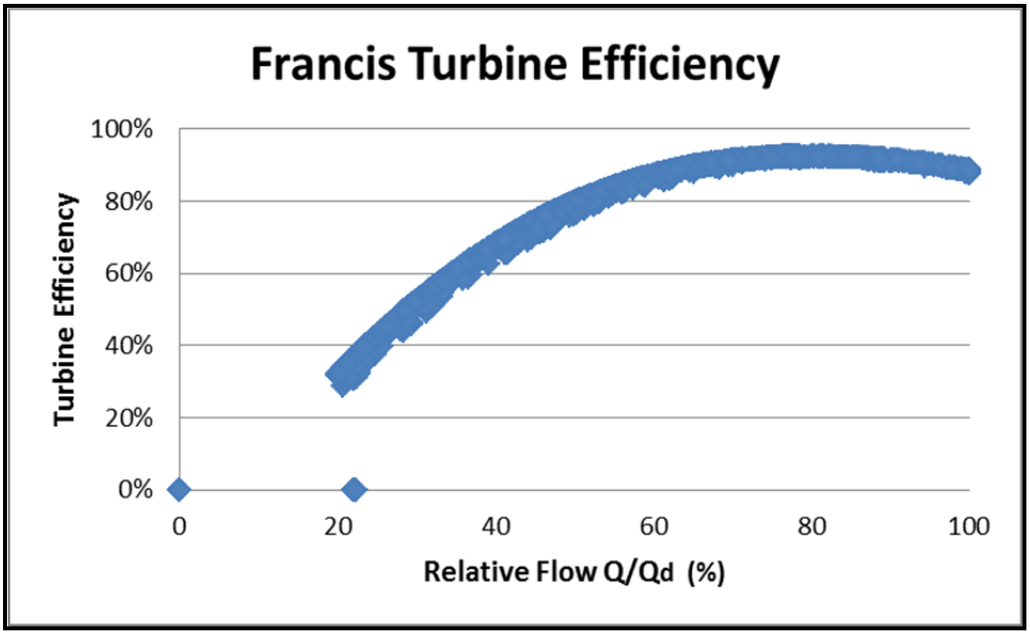


Fig. A-3. Francis turbine efficiency curve

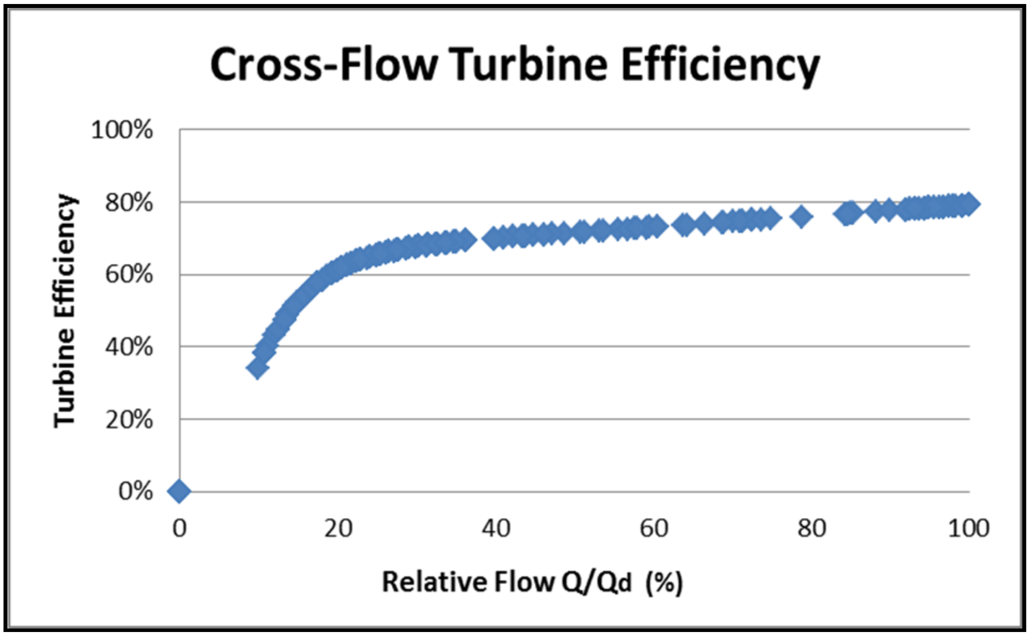


Fig. A-4. Cross-Flow turbine efficiency curve

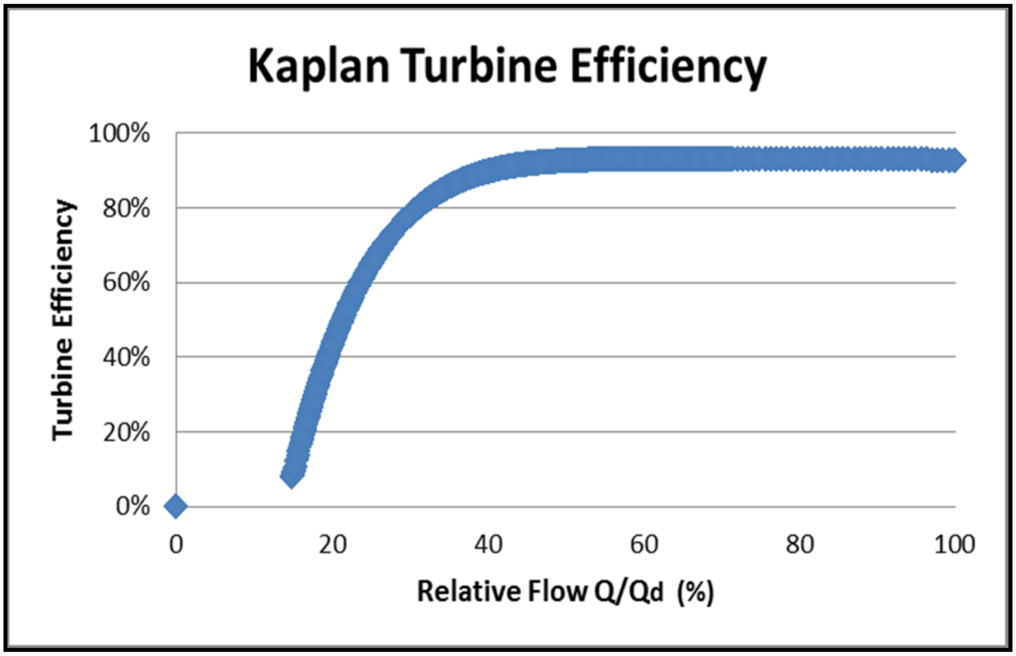


Fig. A-5. Kaplan turbine efficiency curve

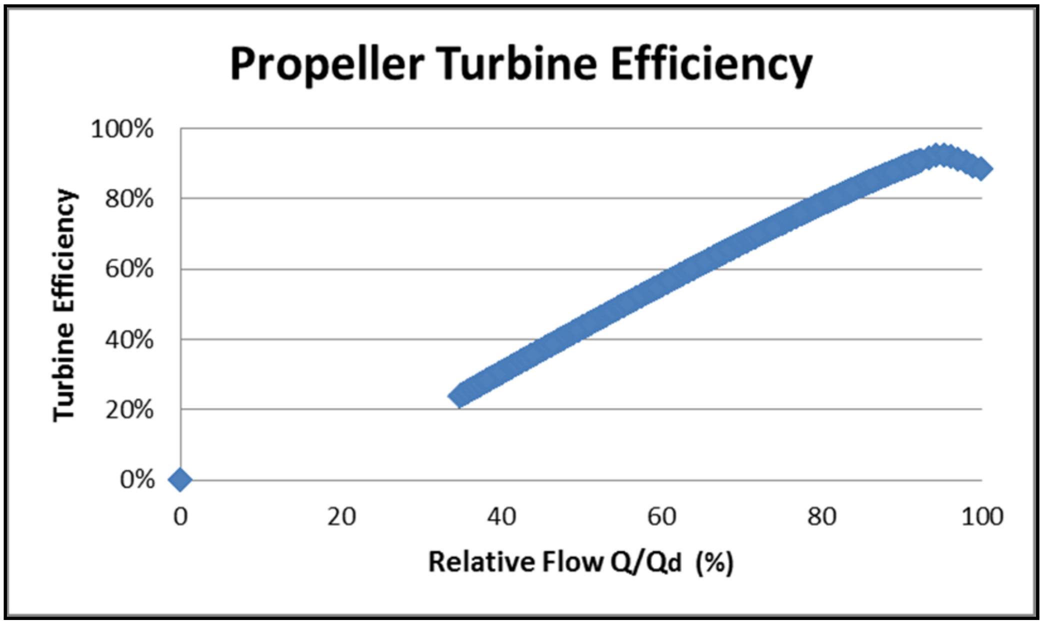


Fig. A-6. Propeller turbine efficiency curve

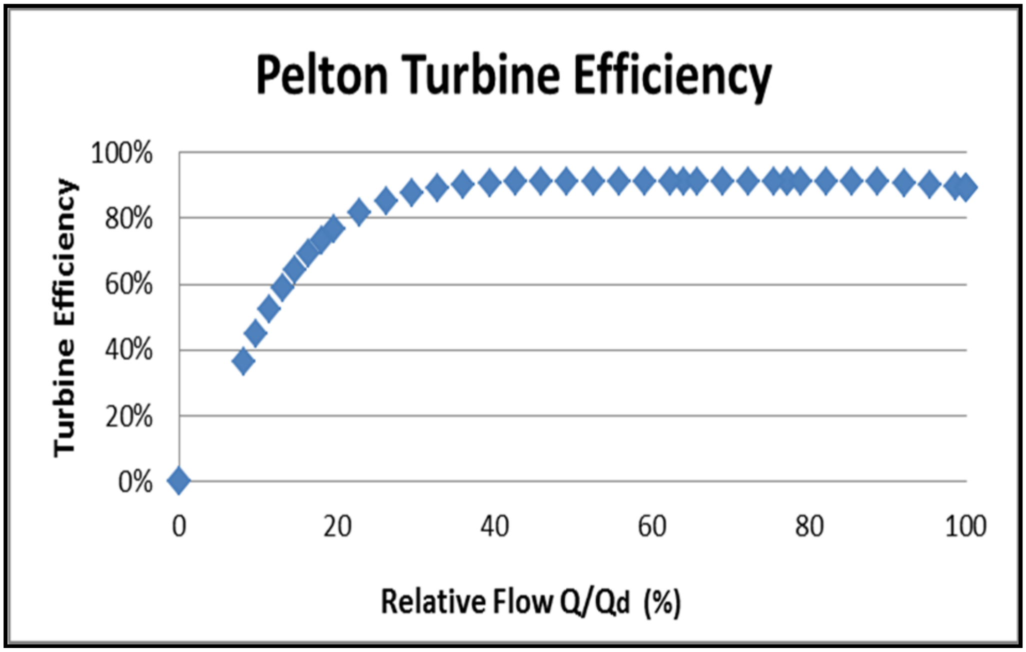


Fig. A-7. Pelton turbine efficiency curve

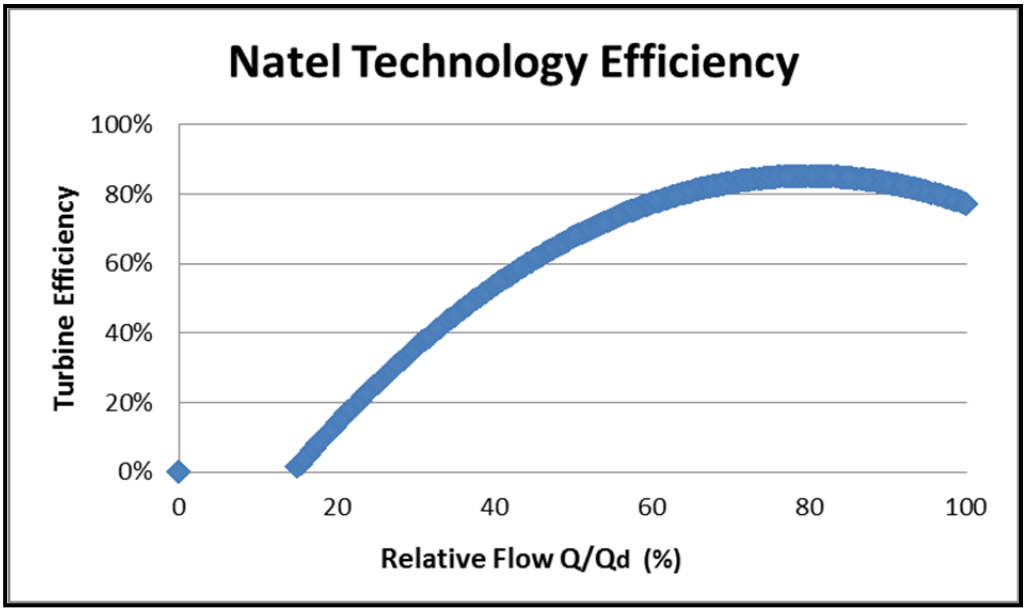


Fig. A-8. Natel turbine efficiency curve

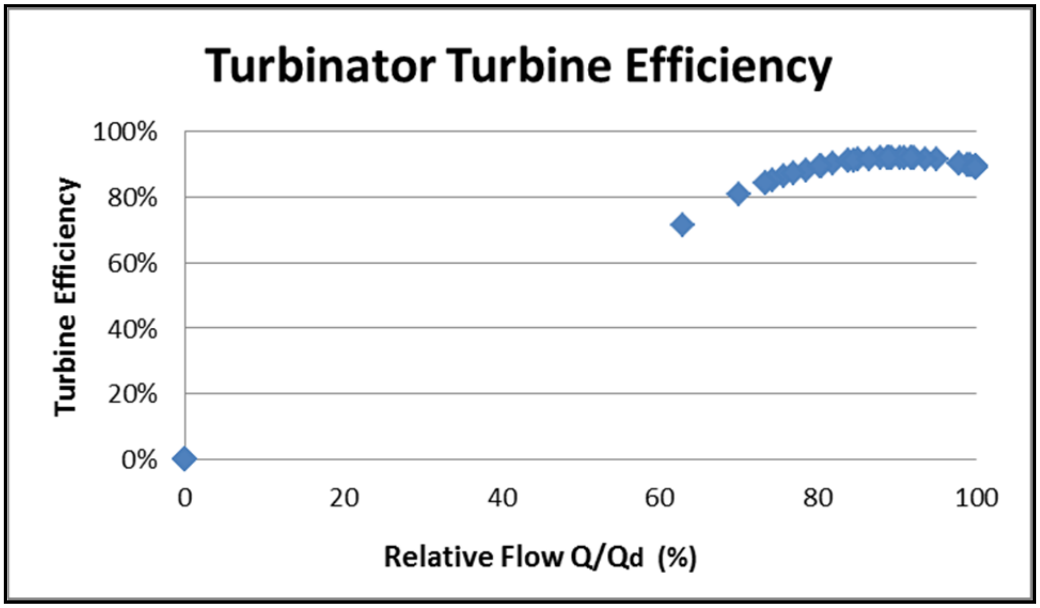


Fig. A-9. Turbinator turbine efficiency curve

The ORNL-HEEA Tool calculates generator efficiencies during partial load operations using a generic efficiency curve that corresponds to the selected best efficiency value (Fig. A-10) (Haglind and Elmegaard 2009). The best generator efficiency depends upon the rated speed and rated power capacity of the generator.

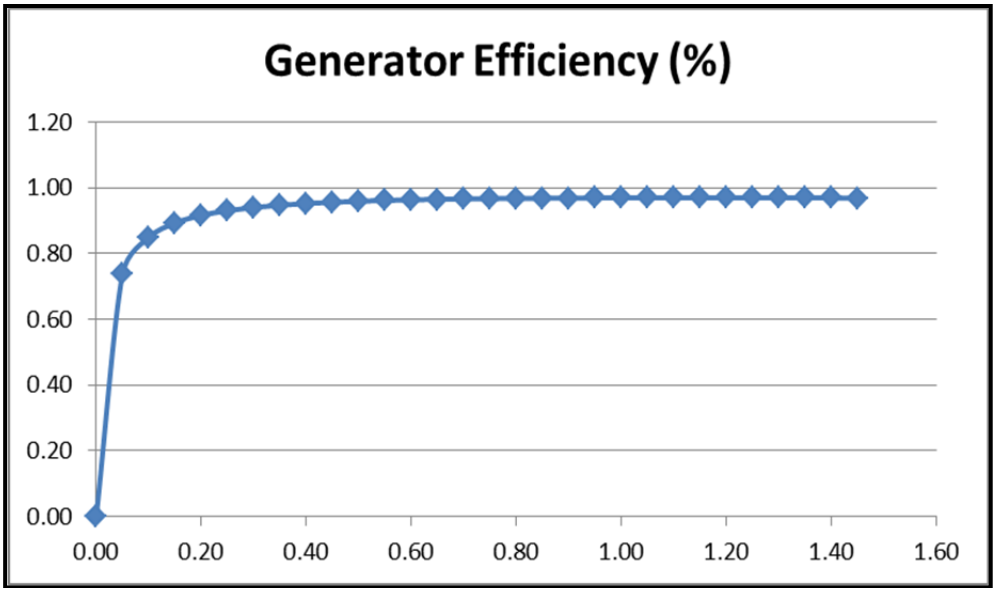


Fig. A-10. Generator efficiency curve

Because the current version of the ORNL-HEEA Tool assumes one single unit for each site development, the turbine-generator unit efficiency (i.e., turbine efficiency multiplied by generator efficiency) is the plant efficiency. As part of the future development of the Tool, the user will be allowed to select multiple units and plant efficiency will be optimized based on the best load allocation among different units.

A.3.4 Power Generation and Energy Calculations

Once the ORNL-HEEA Tool has determined turbine type, design flow, and rated net head, it sets the upper and lower limits of operating head and flow for power generation. Table A-4 above provides the suggested ranges of operating flow and net head for different turbine types in terms of the percentages of turbine design flow and rated net head.

The Tool's energy calculation module checks the time series of available flows for power generation. If the available flow exceeds the upper limit (*Qmax*) of turbine operating flow, the Tool sets the generating flow as the upper limit flow (*Qmax*). If the available flow is below the lower limit of turbine operating flow (*Qmin*), the Tool sets the generating flow as zero, which implies that the turbine unit will not take any power load. If the net head is beyond the range of allowable turbine operating heads, the Tool sets the generating head at zero, which implies that the turbine unit will be turned off.

Once the Tool has determined the allowable generating flow and head in time series, it calculates the turbine and generator efficiencies (in time series) based on the selected turbine type and generating flows and heads. Finally, the Tool calculates daily or monthly power and energy values, which are used for producing power duration curves and statistics of average monthly and annual power and energy generation.

The design power capacity for a unit or plant is the power output under the design flow and rated net head with corresponding efficiencies. The plant capacity factor is the ratio of average annual energy generation over the potential output if the plant had operated at the design capacity and entire time of one year.

A.3.5 Initial Investment Cost Estimate

To develop a reasonably accurate estimate of the initial investment for hydropower project development and construction, the ORNL-HEEA Tool requires the following user inputs:

- Type of potential site: would the project be developed at an existing dam or conduit/canal? Licensing and civil works costs can be significantly reduced for existing dam or conduit/canal projects.
- New Pipeline/Penstock Length: the cost of a long pipeline for an in-canal site without steep hydraulic drop could render a potential site economically infeasible.
- New Transmission Line Length and Voltage: the cost of obtaining a new transmission line right-of-way (ROW) and constructing a new transmission line could render a potential site economically infeasible.
- Environmental Cost Indicator: the additional project cost due to the site's environmental features and any corresponding mitigations required.
- Cost of Land and Water Right: the initial lump-sum cost of purchasing or leasing the property and facilities for project development.

Based on these user inputs, the ORNL-HEEA Tool estimates the initial project cost as the "overnight development cost," which does not include any financing costs or cost escalation during the construction period. Financing costs vary significantly among projects depending, among other things, on the developer type. For that reason, the Tool does not include financing costs when comparing the installation costs ($/kW) for a group of potential sites.

The overnight development cost is calculated considering the following elements:

A) *Direct construction costs*

1) turbine-generator package (including the turbine, governor, generator, and switchgear)
2) plant balance systems (including mechanical, electrical, controls, and communications equipment)
3) installation of powerhouse equipment and balance systems
4) transformer and switchyard
5) transformer and switchyard installation
6) penstock and pipeline
7) other civil works and structures
8) transmission line (estimated based on the length and voltage of the line)
9) transmission line ROW (user input)
10) land and water rights (user input)
11) state sales tax (based on the sales tax rate of the state in which the project would be located)
12) contingency (estimated as 8-12% of the sum of the above elements, depending on the scale of projects)

B) *Soft or indirect costs*

13) environmental mitigations
14) licensing and permitting
15) engineering and construction management.

The above component costs are estimated by reference to the cost equations in Appendix B of the RETScreen Textbook (NRC 2004a), Appendix C of Reclamation 2011, and ORNL's previous and current costing studies for small hydropower projects (Zhang et al. 2012). The cost of Turbinator technology is estimated by reference to the project budgetary costs from the manufacturer (CleanPower) and project developer (Hadjerioua et al. 2012). The cost of Natel technology is estimated based on the equipment quotations in previous investigations (Black Rock 2009; COID and ODE 2011).

The generating equipment is one major contributor to the initial investment. The cost of turbine and governor is related to the turbine type, design head, power capacity, and number of units. To reduce project cost, the ORNL-HEEA Tool assumes a horizontal axis turbine when gross head is <83 ft. The cost of the generator and switchgear is related to power capacity, the number of units, and gross head. An induction generator is assumed for units with a capacity <10 MW to reduce the cost. The cost of the transformer and switchyard is related to power capacity, voltage, and the number of units. The detailed costing formulas used in the ORNL-HEEA Tool make reference to Appendix B of the RETScreen Textbook (NRC 2004a).

To help calibrate the cost model in the ORNL-HEEA Tool, ORNL staff made inquiries of two domestic equipment suppliers for one project with 67 ft of net head and 3.4 MW of capacity. The budget price for turbine, generator, hydraulic power units, and controls/switchgear in United States dollars is $2.9 million from Andritz Hydro and $5.5 million from Voith Hydro. By comparison, the ORNL-HEEA Tool estimated the cost to be $3.8 million (not including installation cost). Additional cost model calibrations were performed, and will be discussed in the full documentation for the ORNL-HEEA Tool.

In addition, the ORNL-HEEA Tool accounts for equipment cost differences for the following turbine-generator supplier:

- Domestic suppliers including Voith Hydro, Andritz Hydro, Alstom, Listostroj, American Hydro, and Canyon Hydro.
- Canadian small hydro suppliers including Canadian Hydro Components (CHC).
- Chinese suppliers

The 2010 ETO report (ETO 2010) states that:

> "Pricing from the Chinese manufacturer was significantly less than Domestic manufacturers. For one installation, the pricing ranged from $800,000 for the Chinese equipment to $2,025,000 for Domestic."

Thus, in the current version of the ORNL-HEEA Tool, if a Chinese supplier is selected, the cost of the turbine-generator is only 40% of the cost from a domestic supplier. If a Canadian supplier is selected, the cost of turbine-generator is only 80% of the cost from a domestic supplier, a percentage based on previous studies on small hydropower cost modeling (Zhang et al. 2012).

Mitigation costs include any additional initial costs for fish passage, water quality, fish and wildlife species, recreation, and culture resources, excluding items included in direct construction costs. In the

ORNL-HEEA Tool, mitigation costs are estimated based on input to the Environmental Cost Indicator (a percentage of cost increase for site-specific environmental features and required mitigations).

The pipeline cost equation (Fig. A-11) is regressed based on data taken from 21 in-canal projects assessed by ETO (ETO 2010). The regression analysis shows that pipeline cost does not explicitly relate to the design head and flow, but to pipeline diameter. The pipe diameter is estimated based on the design head and flow.

All the cost values are assumed as 2012 US$. As discussed earlier, neither interest during the construction period nor other financing costs are included in the initial project cost. However, the interest paid during construction, the escalation/inflation factor and discount rate [weighted average cost of capital (WACC)] are all accounted for in the LCOE and economic analysis module.

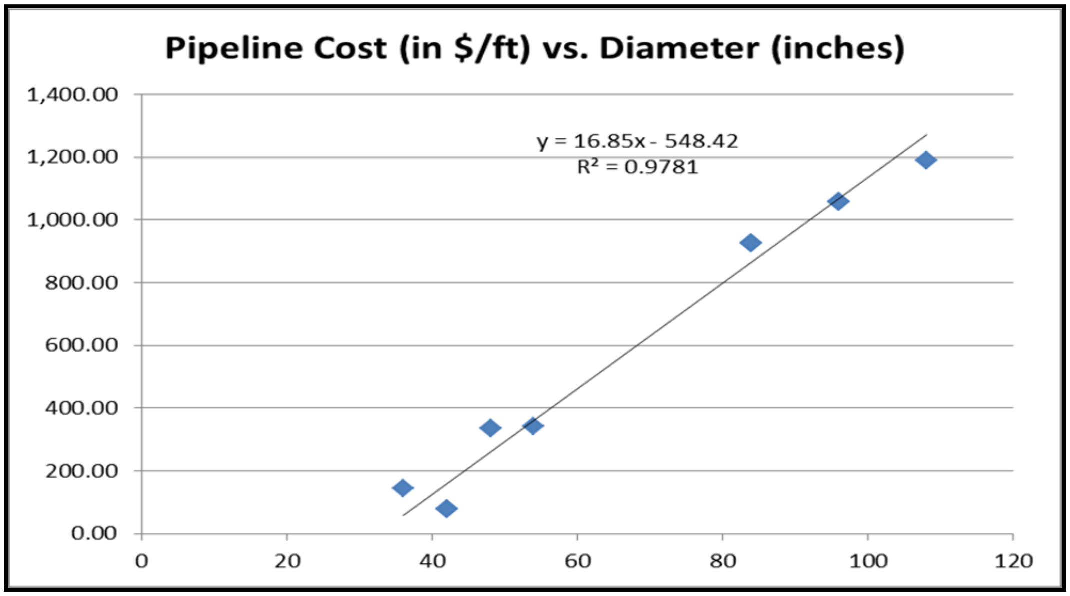


Fig. A-11. Pipeline cost modeling

A.3.6 Annual Operation and Maintenance and Periodic Replacement Cost Estimates

Annual operation and maintenance (O&M) costs at a hydropower project include the costs of labor, supplies, taxes (such as property taxes and income-based taxes) and duties, insurance, regulatory compliance (relative to environmental issues and power production) and rents. Annual O&M costs also include the costs of interim project overhauls and repairs (occurring every 3-5 years). Because there is no accurate model for estimating annual O&M cost, the ORNL-HEEA Tool calculates annual O&M cost as a percentage of the project’s overnight development cost based on the size of the plant’s design capacity (MW) (Table A-5).

Table A-5. Annual O&M cost

Annual O&M Cost Percentage	Range of Plant Design Capacity (P)
3.0%	if P <5MW
2.5%	if 5MW ≤P ≤10MW
2.0%	if P >10MW

The recurring expenditures included in the O&M category are not enough to maximize the life and optimize the performance of a small hydropower project. Periodic replacement of key components extends project life, maintains or improves efficiency, and minimizes unplanned outages. Therefore, periodic replacement expenditures need to be included in lifecycle cost calculations. The ORNL-HEEA Tool assumes replacements over pre-specified periods ranging from 10 to 50 years for the turbine, generator, auxiliary mechanical and electrical components, transformer and switchyard equipment, and civil works/structures. Table A-6 shows a simplified replacement cost model referenced to information from the Western Area Power Administration and Reclamation (DOE/WAPA and DOI/Reclamation 2006).

Table A-6. Periodic replacement cost

Replacement Cost Items	Cost as Percentage of Original Component Cost	Cost Intervals (years)
Turbine-Generator	50%	25
Balance of Plant Mechanical	40%	25
Balance of Plant Electrical	50%	10
Transformer & Switchyard Equipment	50%	35
Penstock and Pipeline	100%	>50
Civil Works/Structures	100%	>50

Source: DOE/WAPA and DOI/Reclamation 2006

In subsequent sections of this Appendix, the combination of recurring O&M costs and periodic replacement costs is referred to as operation and maintenance and replacement (O&M&R) costs.

A.3.7 Levelized Cost of Energy

Levelized cost of energy (LCOE) can be interpreted as the minimum price at which a project owner must sell the electricity generated by a project to make the project economically feasible. To develop an estimate of a project's LCOE, the ORNL-HEEA Tool requires the following inputs:

- Project design life
- Construction time period
- Debt fraction of capital structure
- Interest rate on debt
- Minimum return on equity
- Inflation rate
- Initial incentive funds

With the exception of initial incentive funds, the ORNL-HEEA Tools sets these inputs as default values, but the user can override the defaults and input site-specific data. The methodology used to compute LCOE in the ORNL-HEEA Tool is based on the methodology outlined in *Electricity Utility Planning and Regulation* (Kahn 1991).

LCOE can be calculated by dividing both the fixed and variable components of the levelized cost by the average annual energy production:

$$LCOE = \frac{(FCR * Initial\ Project\ Cost) + LevelizedO\&M\&R\ Costs}{Annual\ average\ production}$$

where *FCR* = fixed charge rate

The fixed charge rate (FCR) corresponds to the sum of annual requirements for return, taxes, depreciation and, sometimes, other fixed overhead costs, while capital recovery factor (CRF) does not consider taxes.

$$FCR = Return\ (\%) + Depreciation\ (\%) + Tax\ (\%)$$

$$CRF = Return\ (\%) + Depreciation\ (\%)$$

The return (*r*) is the discount rate which, typically, is assumed to also equal the weighted average cost of capital (WACC) of the project. The WACC is calculated as a weighted average of the interest rate on debt and the return on equity where the weights are the fractions of debt and equity used to finance the project.

Depreciation is based on the concept that by the end of a project's operating life, enough funds should have been accrued to replace it with a new one. The depreciation rate can be calculated given information about the return rate (*r*) and project life (*n*):

$$Depreciation = \frac{r}{(1+r)^n - 1}$$

$$Tax = \left(CRF - \frac{1}{n}\right) * \left(1 - \frac{di}{WACC}\right) * \left(\frac{t}{1-t}\right)$$

where

d = debt fraction of capital structure

i = interest on debt

t = income tax rate (state + federal)

Conversely, the levelization of variable costs involves finding a constant value such that the sum of its discounted value during each year of the project life is equal to the present value of the stream of varying $O\&M\&R_i$ costs:

$$\sum_{i=1}^{n} \frac{Levelized\ O\&M\&R\ Costs}{(1+r)^i} = \sum_{i=1}^{n} \frac{O\&M\&R_i}{(1+r)^i}$$

$$Levelized\ O\&M\&R\ Costs = \frac{\sum_{i=1}^{n} \frac{O\&M\&R_i}{(1+r)^i}}{\sum_{i=1}^{n} \frac{1}{(1+r)^i}}$$

A.3.8 Benefit Evaluation

If a project's LCOE is higher than the forecasted electricity price, it does not automatically mean that the project would not be economically feasible because revenue from the sale of electricity is not the only revenue stream a project might generate. For example, the project's provision of capacity, in addition to energy generation, has an economic value. In addition, for renewable technologies like hydropower, green-based financial incentives are often available from federal, state, or municipal agencies. The following subsections briefly describe how the ORNL-HEEA Tool calculates benefits for potential hydropower sites.

A.3.8.1 Energy and capacity benefits

Most of the potential small hydropower projects in the Deschutes Basin would be owned by independent developers or irrigation districts. Neither of these types of entities has the authority to sell electricity directly to commercial, residential, or industrial consumers. Therefore, they would likely sell the electricity generated by their projects to a utility through a long-term power purchase agreement (PPA). PPAs typically offer a fixed price for energy and/or capacity over 15-20 years.

The energy component in a PPA reflects the cost that the purchasing utility would have to pay for electricity in the spot market. The capacity component acknowledges the cost avoided by the utility by buying electricity through the PPA rather than building an alternative power plant. A conventional combustion turbine is typically considered as the alternative peaking technology. This is the rationale used, for instance, in PacifiCorp Schedule 37 for Oregon, which determines the price that this utility is willing to pay for electricity produced by small (<10MW) qualifying facilities.[2]

PacifiCorp tariffs can be considered representative of the energy and capacity revenues that new hydropower production in Oregon would receive. However, the specific terms of a PPA might depend on multiple project-specific factors such as seasonality or dispatchability. Also, in some cases, power could be sold on the spot market or through a contractual arrangement that links the payment per kWh to a market price index (e.g., ICE's Mid Columbia price index).

To estimate the potential revenue from electricity sales for a small hydropower project, a long-time price forecast matching the life of the project is needed. The ORNL-HEEA Tool uses two sources to develop the price forecast displayed in Fig. A-12:

- the base price projection used by the Northwest Power Planning Council (NPPC) for the Sixth Power Plan (NPPC 2010); and

- state-level, monthly retail electricity prices from the Energy Information Administration (EIA) (EIA 2012).

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[2] Small hydropower is among the technologies classified as qualifying facilities in PacifiCorp's Schedule 37.

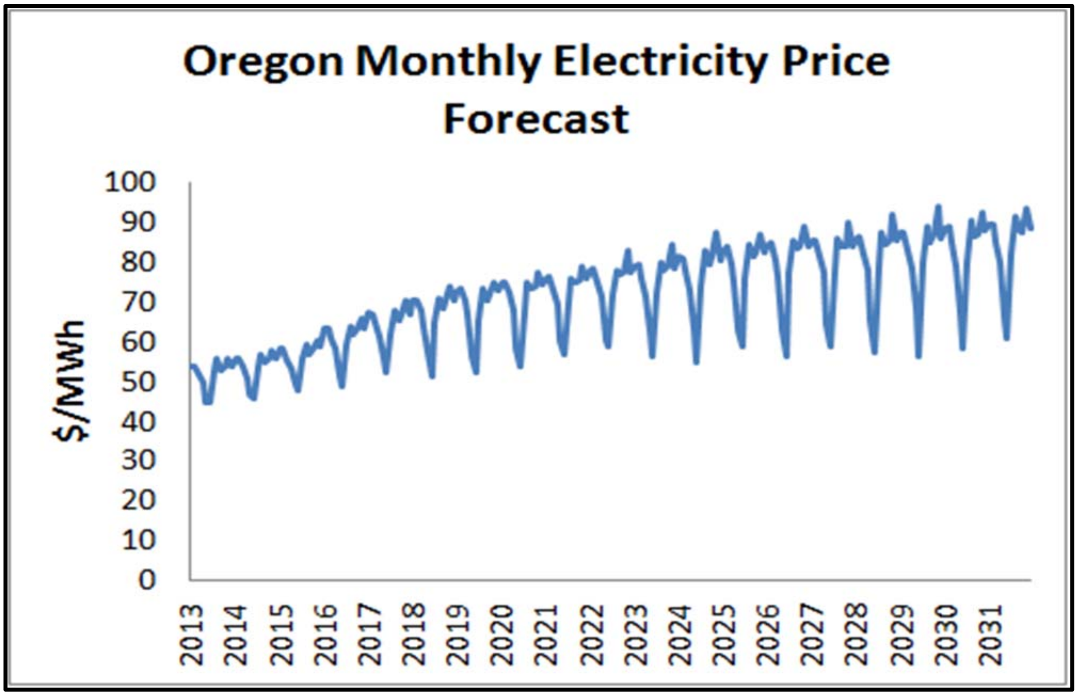

Fig. A-12. Oregon monthly electricity price forecast
(*Sources*: Based on NPPC 2010 and EIA 2012)

The NPPC Sixth Power Plan provides an annual forecast value for the state of Oregon from 2013 to 2031. The EIA report provides monthly, historical data. Both sources were combined to develop a monthly price forecast for the Deschutes Basin projects assessed using the ORNL-HEEA Tool. The EIA report was used to compute seasonal adjustment coefficients. Then, those coefficients were applied to the annual price forecasts obtained from the NPPC Power Plan. Two assumptions were made:

- the seasonal profile of electricity prices observed in the last 2 years will be constant for the next 50 years
- the annual price forecast was kept constant after 2031.

Figure A-12 depicts a moderate upward trend in electricity prices for Oregon over the next 20 years. The average annual growth rate is 4% for the first half of the forecast period and 2% for the second half. Some of the key factors that could alter the overall electricity price trend for Oregon over the next few decades are the evolution of natural gas prices and possible changes in regulation that would result in the introduction of a carbon tax or cap-and-trade system for CO_2 permits.[3] The seasonal pattern is displayed more clearly, for one sample year, in Fig. A-13.

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[3] The price forecast used in this report assumes that natural gas prices will be in the $5-$7/MM Btu range, considerable higher from currently observed prices. No carbon tax is assumed.

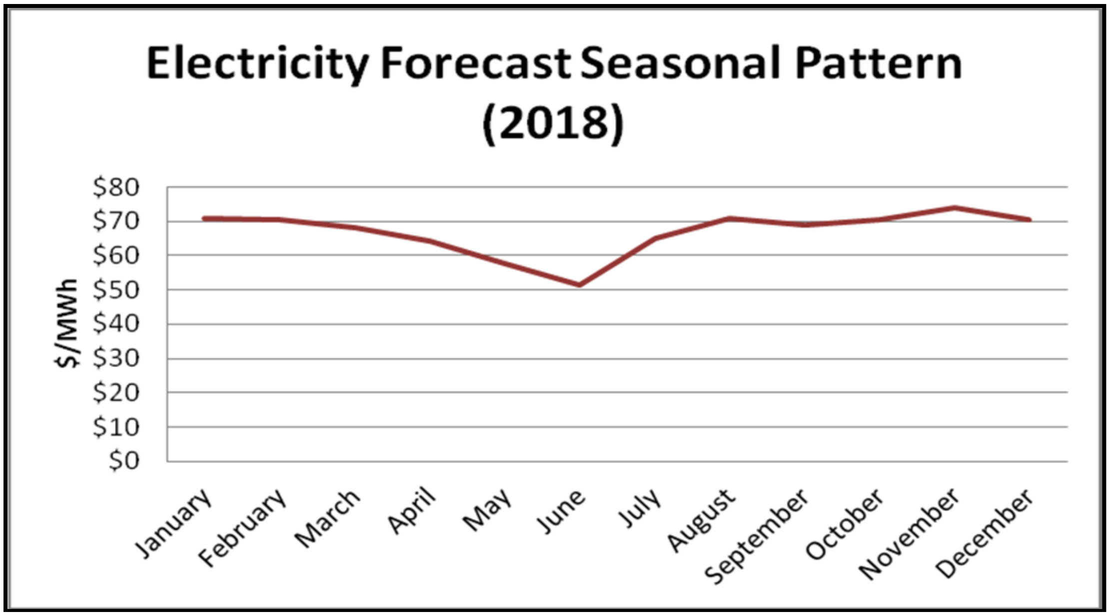

Fig. A-13. Electricity forecast seasonal pattern

The lowest price is assumed to occur in June and the price peak corresponds to the winter months. The closer a power plant can match its production to the seasonal price pattern, the higher its energy revenue will be. However, the Deschutes Basin sites evaluated in this report typically would not have much flexibility to optimize the timing of their production because the seasonal distribution of flow typically would be far from optimal because energy production would coincide with the irrigation season (April to October) rather than the winter months.

The capacity revenue for each potential project in the Deschutes Basin was computed as follows:

> Capacity revenue ($) = [Dependable capacity (%) * Levelized capital cost of combustion turbine ($/MWh)]*Energy production (MWh)

For the levelized capital cost of combustion turbines, the ORNL-HEEA Tool used the EIA estimate (EIA 2012) converted to 2012 dollars, producing a value of $50.92/MWh. However, a combustion turbine is dispatchable while a run-of-river hydropower project is not, so the levelized capital cost was adjusted by a factor that reflects the percentage of a small hydropower project’s capacity that can be considered firm capacity. The production corresponding to the level of flow that is exceeded 95% of the time was taken to compute the dependable capacity for each project. The product of dependable capacity times levelized capital cost of combustion turbine reflects the avoided costs brought about by the hydropower project relative to the case in which a combustion turbine would have to be built to provide the same amount of energy.

A.3.8.2 Green incentive benefits

Federal, state, or municipal-level incentives could play a crucial role in enabling some of the small hydropower projects in the Deschutes Basin. Some of the incentives (e.g., grants and low-interest loans) are focused on reducing the net initial cost of the project and are independent of its utilization factor. Other incentives, however, are performance-based (e.g., Renewable Energy Certificates, Production Tax Credit).

At the federal level, private developers have a choice between claiming the Renewable Electricity Production Tax Credit (PTC) or the Business Energy Investment Tax Credit (ITC). The PTC is currently set to expire in December 2013, but for this assessment the ORNL-HEEA Tool assumes that it would be renewed for another 5 years. For hydropower projects, the PTC provides a tax credit of $0.011/kWh during the first 10 years of operation. The ITC is available for eligible systems placed in service through 2016. For the purposes of this assessment, it is represented as a credit equal to 30% of the total initial project cost which is claimed in five equal installments in years 1 through 5 of the plant's operation.[4]

In this Deschutes assessment, for projects that can opt for either the PTC or the ITC, the value of both incentives is calculated and the one that generates the maximum value is chosen. The Oregon Department of Energy (ODE) formerly played a role in helping small hydropower developers fully realize the benefit of the federal ITC by enabling them to pass on credits to a private entity with a tax burden. In this way, the developer received the credit as a grant. However, in 2012 ODE replaced that program with the Renewable Energy Development Grant Program. This new program has a budget of $3M/year and covers up to $250,000 or 35% of total project costs. It is administered as a competitive grant program in which projects that apply are ranked and highest-ranked projects are funded.

Other state-level programs that can help in small hydropower development in Oregon are the Community Renewable Energy Feasibility Fund Program (which provides up to $50,000 per project for conducting feasibility studies for eligible facilities ranging between 25 kW and 10 MW) and the Small-Scale Energy Loan Program (5-15 year-term low-interest loans).

Because Oregon has a Renewable Portfolio Standard (RPS), eligible facilities can register and produce Renewable Energy Certificates (REC) (one REC per MWh produced), which then can be sold, bundled with electricity or unbundled, to the obligated parties under RPS legislation. There are two main outlets for RECs produced in Oregon: sales to obligated parties under Oregon's RPS and sales to obligated parties under California's RPS.

If the RECs are sold in Oregon, their value would likely be close to zero over the next decade. The RPS objectives for the large utilities in Oregon (Portland General Electric, PacifiCorp, and Eugene Water and Electric Board) are 5% of renewable electricity sales by 2011, 15% by 2015, and 25% by 2025. The 2011 compliance reports filed by PacifiCorp and Portland General Electric show that they used almost exclusively banked RECs from their own renewable generation facilities to comply with their requirements. This indicates that, until now, the utilities have produced more RECs than they needed and are banking them for compliance in future periods. Therefore, expected demand for additional RECs in Oregon should be low and REC prices in the state are expected to stay close to zero in the short and medium term.

Projects in the Deschutes Basin could also sell RECs in California as unbundled tradable RECs (TRECs), but there are limits on how many of these can count towards meeting the California RPS requirement. Unbundled TRECs in the California market have sold for approximately $2/MWh until now. Table A-7 displays estimates of the maximum demand for unbundled TRECs that could originate in California in the next 10 years. These estimates result from combining information about the limits on unbundled RECs utilization for each compliance period in the California RPS and

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[4] Issues related to finding a partner with a sufficient "tax appetite" to make use of the full tax credit are not considered here. Instead, the assumption is that the small hydropower developer would find a way to benefit from the entire tax credit.

Table A-7. Maximum unbundled tradable RECs demand in California

			Maximum Unbundled TREC Demand (Millions)		
	Percentage of Compliance that can be Achieved with TRECs	**Percentage of Total Sales that must be Renewable**	**High Electricity Demand Scenario**	**Mid Electricity Demand Scenario**	**Low Electricity Demand Scenario**
2013	0.15	0.2125	7.53	7.45	7.33
2014	0.15	0.225	8.10	7.99	7.84
2015	0.15	0.2375	8.70	8.55	8.36
2016	0.15	0.25	9.31	9.11	8.92
2017	0.1	0.27	6.81	6.64	6.52
2018	0.1	0.29	7.44	7.23	7.09
2019	0.1	0.31	8.08	7.82	7.69
2020	0.1	0.33	8.74	8.42	8.30
2021	0.1	0.33	8.91	8.54	8.40
2022	0.1	0.33	9.07	8.65	8.50

(Source: DOE 2012; Kavalec et al. 2011)

electricity consumption forecasts from the three big electric utilities in California (Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric).

According to this forecast, California's demand for TRECs could be up to 9 million in 2016. However, renewable generation projects within the entire Western Electricity Coordinating Council (WECC) footprint can qualify as unbundled TRECs under the California RPS program. Depending on how much REC supply is generated in California and throughout WECC, the range of California unbundled TRECs prices is wide and uncertain.

Because of their low expected value in Oregon and uncertainty about their value in California, RECs are not included as a source of revenue in this Deschutes Basin assessment. The uncertainty associated with REC revenues suggests that they should not play a large role in assessing a potential project’s economic viability.

A.3.8.3 Greenhouse gas emissions benefit

Avoided greenhouse gas (GHG) emissions are one of the positive attributes of hydropower generation. Previous research shows that hydropower is generally competitive, from the standpoint of life-cycle GHG emissions, with other renewable energy technologies such as wind and solar power generation (Zhang et. al. 2007).

Typically, GHG emissions are reported in units of carbon dioxide equivalent (CO_2e). Gases (CH_4 and N_2O) are converted to CO_2e by multiplying emission volumes by the global warming potential (GWP) of the gas; the GWP for CH_4 is 21 and for N_2O is 310 over the time horizon of 100 years. Based on the Environmental Protection Agency Electricity Emission Factors in different subregions, the averaged GHG Emission Factor from mixed fuel is around 0.59 tonne CO_2e/MWh (EPA 2011), while the GHG Emission Factor from run-of-river small hydropower is around 0.2 tonne CO_2e/MWh (Hydro Quebec 2001). Therefore, the annual reduction of GHG emissions in the United States power system due to consuming hydroelectricity can be estimated based on the annual average energy generation from the studied hydropower project.

Because there is no carbon market in North America, the ORNL-HEEA Tool does not assign a dollar value to a project's carbon reduction potential. If the Clean Development Mechanism or other carbon market would become active in the United States power market, the additional revenue to hydropower projects would be based on these avoided GHG estimates.

A.3.9 Benefit-Cost Ratio and Internal Rate of Return

Benefit-cost ratio (BCR) and internal rate of return (IRR) are two standard metrics for evaluating the economic feasibility of a project. BCR is calculated as the ratio of the net present value of lifecycle benefits to the net present value of lifecycle costs. This means that the timing of revenues versus expenditures, as well as the amount of revenues versus expenditures, is important for determining the feasibility of the project.

$$BCR = \frac{\sum_{i=1}^{n} \frac{Benefits_i}{(1+r)^i}}{\sum_{i=1}^{n} \frac{Costs_i}{(1+r)^i}}$$

Lifecycle benefits and costs are compared to develop BCRs and pre-tax IRRs for a potential project. IRR is the annual rate of return for which the net present value of lifecycle net benefits (i.e., benefits minus costs in each period) equals zero. Investors compare the IRR to their hurdle rate to assess the attractiveness of each project.

$$\sum_{i=1}^{n} \frac{Benefits_i - Costs_i}{(1+IRR)^i} = 0$$

The project IRR is independent of the financing structure of the project. To the extent that the owner/developer would put some equity into the project, the equity IRR is also be an important metric to consider (Yescombe 2002). The formula for equity IRR is similar to that of project IRR except that:

- during the construction period, the numerator is construction cost minus debt release
- during the operation period, the net benefit is computed *after* debt service repayments (i.e., payments to cover the principal of the loan and interest expenses).

The ORNL-HEEA Tool uses the following criteria to define an economically viable site:

1. BCR $\geq$1.00; and
2. IRR > WACC (weighted average cost of capital).

The ORNL-HEEA Tool also requires an extra input (the debt repayment term) for computing equity IRR. Equity IRR depends on the fractions of debt and equity being used to finance the project. When the interest rate on debt is lower than the project IRR, equity IRR gets larger as the fraction of debt increases. Conversely, if the interest rate on debt is larger than the project IRR, the equity IRR will improve as the fraction of debt utilized for financing the project decreases.

A.3.10 ORNL-HEEA Tool Results and Outputs

Once the ORNL-HEEA Tool simulation for a given hydropower site is complete, the *Results* tab summarizes basic project information, turbine unit parameters, energy generation, project cost, and economic analysis results. Table A-8 shows an example of the output list from the *Results* tab for the Bowman Dam site in the Deschutes Basin.

Additional example results for the Bowman Dam site include the Flow Duration Curve (Fig. A-14), Net Head Duration Curve (Fig. A-15), Power Duration Curve (Fig. A-16), Turbine Efficiency Curve (Fig. A-17), and Project Costs (Table A-9).

A.3.11 Assumptions, Limitations, and Future Improvements for the ORNL-HEEA Tool

The following list summarizes the assumptions made in developing the ORNL-HEEA Tool, as well as some of the limitations of Version 1.0:

1) For storage projects, the input time series of flow and head must be the regulated flows and heads resulting from the reservoir operation.
2) Only one single unit would be installed at each potential site.

3) It is assumed that the generating unit would be connected to the central grid system, so all the available power can be absorbed by the power grid system. That is, the available power on the site is the power output of turbine unit.

Table A-8. Example of ORNL-HEEA Tool output

Date of Assessment	**Dec. 10, 2012**
Analysis Performed by	**ORNL-Zhang**
Project Name	**Bowman Dam**
Project Location (State)	**Oregon**
Latitude/Longitude	**44°04' 57"N /121°17'14'' W**

Summary of Results

Length of Flow Data	**29**	**Years**
Site Maximum Head	**180.6**	**Feet**
Site Minimum Head	**104.2**	**Feet**
Site Maximum Available Flow	**3280.0**	**Cfs**
Site Minimum Available Flow	**7.1**	**Cfs**

Turbine Selection Analysis

Turbine-Generator Supplier	**Andritz Hydro**	
Selected Turbine Type	**Francis**	
Turbine Runner Diameter	**3.91**	**Ft**
Turbine Rated Net Head (Hd)	**163.9**	**Ft**
Turbine Unit Design Flow (Qd)	**264.0**	**Cfs**
Turbine Unit Capacity	**3,271.4**	**kW**
Upper Limit for Operating Head	**204.9**	**Ft**
Lower Limit for Operating Head	**106.6**	**Ft**
Upper Limit for Operating Flow	**264.0**	**Cfs**
Lower Limit for Operating Flow	**52.8**	**Cfs**
Number of Turbine Unit	**1**	

Power Generation Analysis

Plant Installed Capacity	**3,271**	**kW**
Plant Capacity Factor	**0.61**	

Projected Monthly Production:

January	**789.1**	**MWH**
February*	**1,002.9**	**MWH**
March	**1,321.3**	**MWH**
April	**1,868.0**	**MWH**
May	**2,209.8**	**MWH**
June	**2,134.7**	**MWH**
July	**2,125.4**	**MWH**
August	**2,032.6**	**MWH**
September	**1,639.8**	**MWH**
October	**1,055.2**	**MWH**
November	**507.6**	**MWH**
December	**706.6**	**MWH**
Annual production*	**17,392.7**	**MWH**

* For non-leap year

Projected Expenditure to Implement Project

Over Night Development Cost	**5,755,403**	**US$**
Installation Cost	**1,759**	**US$/KW**
Initial Incentive Funds	**0**	**US$**
Net Initial Cost	**5,755,403**	**US$**
Annual O&M Cost	**172,662**	**US$**

Levelized Cost of Energy

LCOE with Financial Assistance	**40.06**	**US$/MWh**
LCOE without Financial Assistance	**40.06**	**US$/MWh**

Benefit/Cost Analysis

Benefit/Cost Ratio (with Green incentives)	**2.25**
Benefit/Cost Ratio (w/o Green incentives)	**2.03**
Internal Rate of Return (with Green incentives)	**20.8%**
Internal Rate of Return (w/o Green incentives)	**16.7%**

Greenhouse Gas (GHG) Emission Reduction

Annual GHG Reduction	**6,444**	**t CO2 eqv.**
Project Lifetime GHG Reduction	**322,201**	**t CO2 eqv.**

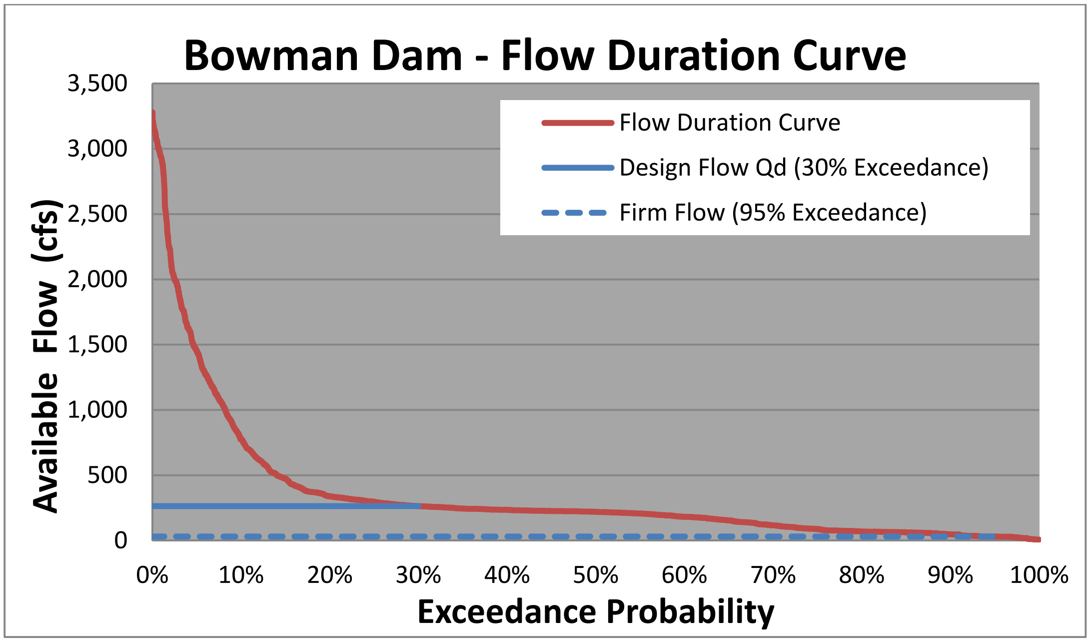

Fig. A-14. Example flow duration curve for Bowman Dam

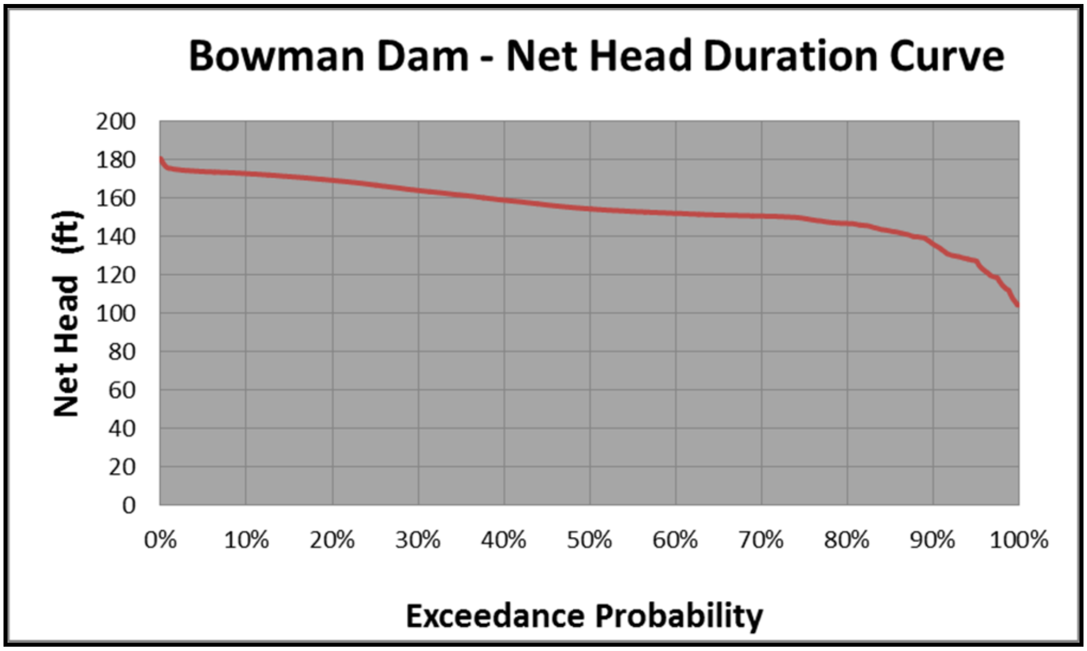

Fig. A-15. Example net head duration curve for Bowman Dam

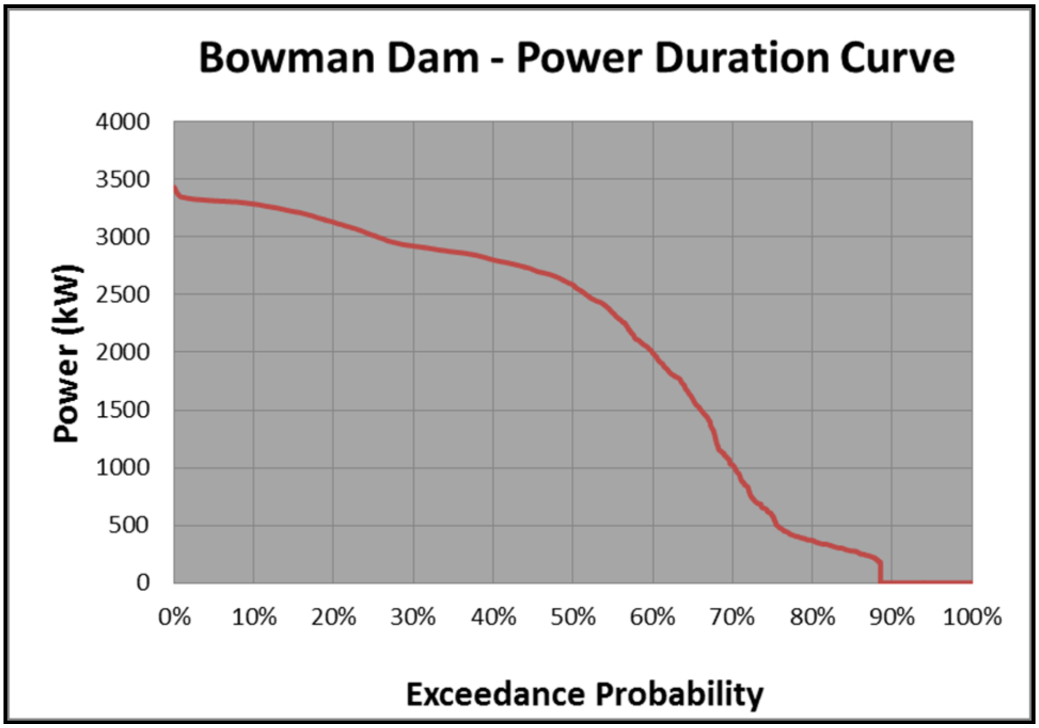

Fig A-16. Example power duration curve for Bowman Dam

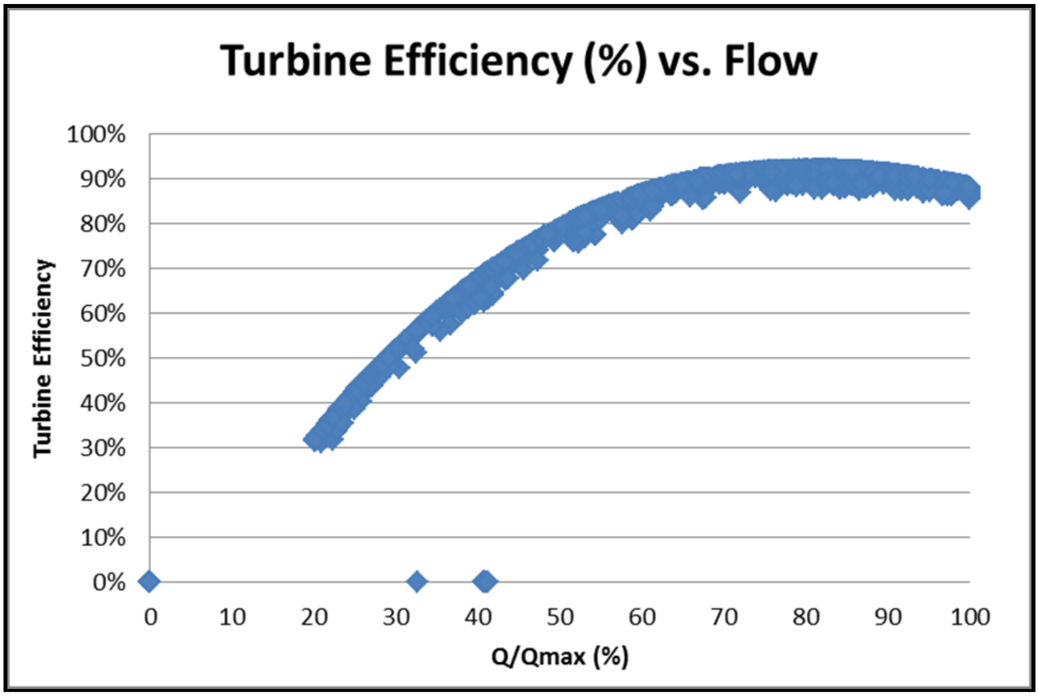

Fig. A-17. Example turbine efficiency curve (under variable heads) for Bowman Dam

Table A-9. Example project costs

Initial Cost Items	
Turbine & Governor*	1,603,143
Generator & Switchgear*	635,398
Turbine-Generator (T-G) Package	2,238,541
Plant Balance Systems	543,018
Installation of T-G and Balance Systems	417,234
Transformer & Switchyard*	29,566
Transformer & Switchyard Installation	4,435
Penstock and Pipeline	2,207,206
Other Civil Works & Structures in Total	671,562
Transmission Line (T-L) Construction	10,000
Transmission Line (T-L) Right-of-Way	3,636
Land and Water Right	0
State Sales Tax	0
Contingency for Construction Cost	539,018
Direct Construction Cost	**6,664,217**

Environmental Mitigations **	0
Licensing and Permitting	795,506
Engineering & Construction Management)	466,495
Total Overnight Development Cost	**7,926,218**
Installation Cost per KW ($/kW)	**2,863**

Annual O&M Cost ($ per year):	**$237,787**

Periodic Replacement Costs (at 2012 US$ price level)

Cost Category	**Replacement Cost**	**Replacement Timing (Years)**
Turbine-Generator	$ 1,119,271	25
Balance of Plant	$ 271,509	10
Transformer and Switchyard Equipment	$ 14,783	35
Penstock and Pipeline	$ 2,207,206	>50
Other Civil Works/Structures	$ 671,562	>50
Every 10 years Cost	***$ 271,509***	
Every 25 years Cost	***$ 1,119,271***	
Every 35 years Cost	***$ 14,783***	

4) Given the currently available empirical formulas for project initial cost, annual O&M cost, and periodic replacement cost estimation, the accuracy of costing and economic analysis is limited.

5) Avoided GHG emissions are estimated based on average annual generation and referenced emission factors for mixed fuel and run-of-river hydropower.

Future improvements to the ORNL-HEEA Tool for expanding its application scope as an independent software package would include:

1) Coding reservoir operating rules and water scheduling in the model so that the Tool can be applied to assessments of large reservoir projects. The RiverWare Power Reservoir Program will be investigated for possible combination with the ORNL-HEEA Tool.

2) Incorporating the results from the Hydropower Cost Model Development Project and updating the cost models embedded in the Tool, to include different types of projects (NPDs, canal/conduit projects, new sites) and also for different ranges of installed capacity and design heads. Also, it may include alternative methods for cost estimation, such as regression-based formula costing or engineering-based detailed costing.

3) Improving embedded benefit data (energy prices, incentives, etc.) for all 50 states and validating with more projects located in different states.

4) Allowing multiple units at each potential site and optimizing the plant efficiency based on the optimized load allocation among different units.

5) Creating a "portal" to access USGS or other GIS databases to download and pre-process hydrological, topographic, and geotechnical data for a specific site.

6) Improvements to the turbine selection matrix to allow for larger turbines units.

7) Tracking and comparing life-cycle costs and benefits (generating performances) for different options of project layouts, technology selections, and component sizing for all major mechanical, electrical, and civil components. The design options would include the number of units, turbine types, and settings and sizes. For example, in the overlap areas where either a Kaplan or a Francis (and a Francis or a Pelton) can be selected, only one type is provided in the current Tool. In future versions of the Tool, a more complicated turbine selection matrix would be available and the turbine type alternatives would be tracked as different design options for project costing and benefits and economic evaluations, and the final selection of turbine type would be determined according to the economic indicators.

8) Adding a *Design* module to integrate and visualize the project components in AutoCAD and SolidWorks drawings based on different design options for project components and combinations. This module would include sub-modules for civil, mechanical, and electrical components design. The feasibility-level design function would allow the user to select or combine the empirical costing method or the detailed costing method based on the design drawings and civil work volume estimates.

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