PROSPECT NO. 3 HYDROELECTRIC PROJECT
FERC PROJECT NO. P-2337

Final License Application
for Major Project—Existing Dam

Volume I
Initial Statement and Exhibits A, B, C, D, F, G, and H

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

December 2016

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Volume I: Initial Statement and Exhibits A, B, C, D, F, G, and H
Volume II: Exhibit E*
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(*Provided under separate cover)

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ACRONYMS AND ABBREVIATIONS

AC—alternating current
BHE—Berkshire Hathaway Energy
CFR—Code of Federal Regulations
cfs—cubic feet per second
COPCO—California Oregon Power Company
DC—direct current
DLC—direct load control
DSM—demand side management
EIM—energy imbalance market
FERC—Federal Energy Regulatory Commission
Forest Service—U.S. Forest Service
FOT—front office transactions
FPC—Federal Power Commission
FWS—U.S. Fish and Wildlife Service
GSU—generator step-up transformer
GW—gigawatt
GWh—gigawatt hour
HCC—Hydro Control Center in Ariel, Washington
HMI—human-machine interface
hp—horsepower
HPU—high pressure hydraulic unit
IRP—Integrated Resource Plan
ISO—independent system operator
kVA—kilovolt amps
kV—kilovolt
kW—kilowatt
LIHI—Low Impact Hydropower Institute
LLC—limited liability corporation
MW—megawatt
MWh—megawatt hour
NERC—North American Electric Reliability Council
PGE—Portland General Electric
OAR—Oregon Administrative Rule
ODFW—Oregon Department of Fish and Wildlife
OPUC—Oregon Public Utility Commission
ORS—Oregon Revised Statue
PLC—programmable logic controller
PLSS—public land survey system
PRV—pressure relief valve
PTO—participating transmission owner
PV—photo voltaic
REC—renewable energy credit
rpm—revolutions per minute

RPS—renewable portfolio standard
RR-SNF—Rogue River-Siskiyou National Forest
SCADA—Supervisory Control and Data Acquisition
SEC—Securities and Exchange Commission
TIV—turbine isolation valve
USC—United States Code
USGS—United States Geological Survey
VDC—volts of direct current
WECC—Western Electricity Coordinating Council

INITIAL STATEMENT (18 CFR § 4.51(A))

BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

Final License Application for Major Project—Existing Dam

(1) PacifiCorp applies to the Federal Energy Regulatory Commission for a new license for the Prospect No. 3 water power project (Project; FERC Project No. P-2337), as described in the attached exhibits.

(2) The location of the Project is:

State or territory: Oregon
County: Jackson
Township or nearby town: Unincorporated community of Prospect
Stream or other body of water: South Fork Rogue River

(3) The exact name and business address of the applicant are:

PacifiCorp
825 NE Multnomah, Suite 1500
Portland, OR 97232

The exact name and business address of each person authorized to act as agent for the applicant in this application are:

Steve Albertelli, Relicensing Program Manager
PacifiCorp
925 South Grape Street, Building 5
Medford, OR 97501
steve.albertelli@pacificorp.com
541-776-6676

(4) The applicant is a domestic corporation and is claiming preference under section 7(a) of the Federal Power Act. See 16 U.S.C. 796.

(5)(i) The statutory or regulatory requirements of the state(s) in which the Project would be located that affect the project as proposed, with respect to bed and banks and to the appropriation, diversion, and use of water for power purposes, and with respect to the right to engage in the business of developing, transmitting, and distributing power and in any other business necessary to accomplish the purposes of the license under the Federal Power Act, are:

(a) Chapter 757 et. seq., Oregon Revised Statutes, defines public utilities and regulates the business of retail distribution of electricity by the Public Utility Commission of Oregon.

(b) Chapter 543 et. seq., Oregon Revised Statutes, governs appropriation, diversion and use of water for hydropower generation and provides for the licensing of hydropower projects as amended by House Bill 2119 (1997 Oregon Legislative Assembly).

(ii) The steps which the applicant has taken or plans to take to comply with each of the laws cited above are:

PacifiCorp holds a water right certificate from the State of Oregon for the purposes of power generation at the Project to divert up to 150 cubic feet per second (cfs) from the South Fork Rogue River (Permit S-7861, Certificate No. 9688). "Project waters" consist of waters within the Project area that have been diverted pursuant to this right. PacifiCorp is not aware of any existing or proposed uses of Project waters for irrigation, domestic water supply, industrial or other purposes that would impose upstream or downstream constraints to Project operations. Other than the Project itself, there are no known in-stream flow uses, existing water rights, or pending water rights in the Project vicinity upstream of Lost Creek Lake that would be affected by continued operation of the Project.

(6) The Project is partially located on lands of the Rogue River-Siskiyou National Forest:

Rogue River-Siskiyou National Forest
Supervisor's Office
3040 Biddle Road
Medford, OR 97504

GENERAL CONTENT (18 CFR § 5.18(A))

(1) As the sole applicant, PacifiCorp has or intends to obtain and will maintain all proprietary rights necessary to construct, operate, or maintain the Project.

(2) Political subdivisions, federal facilities, special purpose organizations, and Indian tribes interested in or affected by the project include:

(i) The project is located within Jackson County, Oregon and is located partially within lands of the Rogue River-Siskiyou National Forest.

Jackson County Planning Department
10 South Oakdale Avenue
Medford, OR 97501

Rogue River-Siskiyou National Forest
3040 Biddle Road
Medford, OR 97504

(ii) The project is located within unincorporated Jackson County, Oregon and is located partially within lands of the Rogue River-Siskiyou National Forest (see (2)(i) above). The project traverses the unincorporated community of Prospect, but there are no cities or towns with populations of 5,000 of more people within 15 miles of the project dam.

(iii) Project facilities are located within lands serviced by the Jackson Soil and Water Conservation District and the Prospect Rural Fire Protection District.

Jackson Soil and Water Conservation District
573 Parsons Drive, Suite 102
Medford, OR 97501

Prospect Rural Fire Protection District
276 Mill Creek Drive
Prospect, OR 97536

The gaging station on the South Fork Rogue River at approximately River Mile 10.25 is used by the project to monitor minimum stream flow compliance and is owned and operated by the U.S. Geological Survey.

U.S. Geological Survey
4890 North Runway Drive
Medford, OR 97502

(iv) There are no other political subdivisions in the general area of the project that there is reason to believe would likely be interested in, or affected by, the application.

(v) Indian tribes that may be affected by the project and were invited to participate in the relicensing process include the Cow Creek Band of Umpqua, Grande Ronde, and Siletz Tribes.

Cow Creek Band of Umpqua Tribe
2371 NE Stevens, Suite 100
Roseburg, OR 97470

Confederated Tribes of the Grande Ronde Community of Oregon
9615 Grande Ronde Road
Grande Ronde, OR 97347

Siletz Tribal Council
PO Box 549
Siletz, OR 97380

(3) This Final License Application for the Prospect No. 3 Hydroelectric Project (FERC Project No. P-2337) is executed in the State of Oregon, County of Jackson, by Steve Albertelli, PacifiCorp Relicensing Program Manager, 925 South Grape Street, Building 5, Medford, OR 97501, who, being duly sworn, deposes and says that the contents of this application are true to the best of his knowledge or belief and that he is authorized to execute this application on behalf of PacifiCorp. The undersigned has signed this application this 27th day of December 2016.

Steve Albertelli, PacifiCorp Relicensing Program Manager

Subscribed and sworn to before me, a Notary Public of the State of Oregon this 27th day of December 2016.

Brian Owens, Notary Public

My Commission Expires 12-6-2019

OFFICIAL STAMP
BRIAN JOEL OWENS
NOTARY PUBLIC-OREGON
COMMISSION NO. 945165
MY COMMISSION EXPIRES DECEMBER 06, 2019

EXHIBIT A–PROJECT DESCRIPTION

A.1 PROJECT FACILITIES

PacifiCorp provides this final license application for a new license to continue operating the Prospect No. 3 Hydroelectric Project (Project), Federal Energy Regulatory Commission (FERC or Commission) Project No. P-2337, on the South Fork Rogue River in Jackson County, Oregon. The Project has a generation capacity of 7,200 kilowatts (kW) and is located on private lands primarily owned by PacifiCorp and federal lands managed by the Rogue River-Siskiyou National Forest (RR-SNF).

Construction of the Project began in 1931, and the Project was placed in service on April 22, 1932. An original minor-part license (Federal Power Commission (FPC) No. 1163) was issued to California Oregon Power Company (COPCO) on July 30, 1931 for a period of 50 years. This minor license covered the upper Project facilities, including the diversion dam and approximately 4,000 linear feet of the flowline, located on lands administered by the federal government. The initial major-part license (FPC No. P-2337) covering the downstream facilities, including the remaining waterway, penstock, and powerhouse, was issued in July 1931 for a period of 30 years. COPCO merged with Pacific Power and Light[1] on June 21, 1961, and the January 25, 1963 license application requested transfer of the license to Pacific Power and surrender of the minor-part license. By order dated July 8, 1964, the Commission issued a new license for the Project, including all Project facilities under one license for a period of 25 years. An application for a new license was submitted on December 24, 1985, and the current license was issued on January 30, 1989 for a period of 30 years beginning on the first day of the month of issuance.

A.1.1 South Fork Diversion Dam

The South Fork Diversion Dam is a 172-foot-long, 24.7-foot-high concrete dam with a 98-foot-long, un-gated ogee spillway at River Mile 10.5 of the South Fork Rogue River. The 18-foot-wide waterway intake structure is located on the north end of the dam on the right bank of the river. The intake structure has a trash rack with bars spaced three inches on-center, which are cleaned via an automated Atlas Polar trash rake. There is a control and communications building above the intake structure. Continuous data provided by a water surface elevation level logger over the upstream impoundment determines the aperture of the waterway intake sluice gates.

[1] Pacific Power and Light Company is a previous business name of the company currently known as PacifiCorp or Pacific Power.

A.1.2 South Fork Impoundment

The South Fork Diversion Dam impounds the South Fork Rogue River at the elevation of the un-gated spillway crest at 3,375.7 feet above sea level. At normal maximum pool, the impoundment has a surface area of approximately one acre. The retention time of impounded water is less than one hour. The impoundment has a gross storage capacity of approximately nineteen acre-feet and useable capacity of less than five acre-feet. Average and maximum depths are approximately five feet and eight feet, respectively.

A.1.3 Fish Passage Facilities

A.1.3.1 Fish Ladder

Existing

The fish ladder is a concrete pool-and-weir-type ladder with 15 pools of varying dimensions and an approximate running length of 86 feet, providing upstream fish passage over the diversion dam. The ladder is located on the north bank of the South Fork Rogue River adjacent to the waterway intake structure. Pools 1 through 6 of the ladder ascend from the river in a westerly direction to the switchback between Pools 6 and 7, after which the ladder ascends in an easterly direction toward the dam. The fish ladder exit is provided by two submerged, sluice-gated 2.5' x 1.3' rectangular orifices at the upstream face of the dam to the south of the intake structure. The ladder was originally constructed in 1931 and was modified in 1973 and again in 1996 to its current form.

Proposed

PacifiCorp proposes to construct an auxiliary bypass flow system from the existing fish ladder exit orifice closest to the spillway to a plunge pool at the base of the fish ladder to reliably provide increased minimum flows to the bypassed reach. The auxiliary bypass system would consist of a concrete isolation wall separating the two exit orifices and running from Pool 15 through Pool 13, creating a 1.5'-wide x 15.4'-long auxiliary bypass channel, at which point bypass flows are routed through the existing river-side wall of the upper fish ladder, and into a 1.5'-wide x 19.5'-long metal trough dropping 0.13' in elevation along the fish ladder deflector wall. Auxiliary bypass flows would discharge from the trough approximately 9' above the existing tailwater level at the fish ladder entrance. Weir walls 13, 14, and 15 would be cut for the auxiliary flow channel, and the weir notches for Weirs 14 and 15 would be relocated to accommodate the channel.

In addition to modifications to Weirs 13, 14, and 15 associated with the auxiliary bypass flow system, modifications would be made to Weirs 2 through 6 to accommodate relocation of the fish bypass return pipe discharge from Pool 6 to Pool 1 (see Section A.1.3.2 below). Weir notches 2 through 6 would be reduced in width from 3' to 1.5', consistent with the upper fish ladder (Weirs 7 through 15), to accommodate the reduced flow through the lower ladder and provide consistent hydraulics throughout the ladder. Weirs 2, 4, and 6 would be reinforced to handle additional loading of the bypass pipe and associated pipe supports built into these weir walls. Construction of these fish ladder improvements, including the auxiliary bypass flow system, is proposed for calendar year 2019.

A.1.3.2 Fish Screen

The fish screen is located within the Project waterway approximately 215' downstream of the dam. The inclined-plane screen is 25' in length, 9' 9" in width, and composed of 0.25" wedge-wire, with a surface area of approximately 193 square feet. Perforated plate baffles were temporarily installed to create a more uniform flow through the screen following hydraulic assessments in 1998. The baffles were redesigned and replaced in 2015. The screen rotates at its mid-point along the horizontal axis from the inclined position to a plane or declined position to facilitate debris removal via backwashing the screen face with canal flows (see E.6.3.2 for additional information on fish screen cleaning cycles). Converging channel walls over the downstream 11' 5" of the screen direct fish to the fish return pipe.

A backwater sluice gate downstream of the fish screen automatically adjusts its aperture to regulate water surface elevations over the fish screen and into the fish return pipe at varying diversion flow rates. Continuous data provided by water surface elevation level loggers on the upstream and downstream sides of the screen are used to initiate rotation of the screen for cleaning cycles.

A.1.3.3 Fish Bypass Return Pipe

Existing

The fish bypass begins at the converging walls of the fish screen with an 18"-wide, 28"-high steel flume with a 5' radius, 180 degree turn. The bypass is designed to accommodate bypass flows of 6 to 15 cubic feet per second (cfs). An approximately 60"-long, 30"-high slide conveys fish from the steel flume to the 18", steel bypass return pipe. The bypass return pipe descends approximately 48" in elevation in a southeasterly direction for approximately 159.5' to the pipe outlet above Pool 6 of the fish ladder. Fish bypass pipe flows increase attraction flows to the fish ladder.

Proposed

PacifiCorp proposes to extend the existing bypass return pipe over Pools 6 through 2 of the fish ladder and locate the discharge immediately downstream of Weir 2 into Pool 1. The existing fish bypass up to the existing elbow would not require any modifications as part of this proposal. The existing elbow would be replaced with a new elbow with a 4 degree increase in bend greater than the existing elbow. The new section of the fish return bypass pipe would maintain the same slope (approximately 2 percent) and diameter (18") as the existing bypass. The bypass exit would discharge parallel to the flow over Weir 2 at an exit invert elevation of 3364.7', approximately 5.1’ above the expected low water level in Pool 1. Relocation of the fish bypass return pipe discharge would provide more consistent flows through the entire fish ladder but still maximize the attraction flow through the fish ladder entrance. Construction of the fish bypass pipe extension is proposed for calendar year 2019.

A.1.4 Conduit System

Existing

The 15,894-foot-long Project waterway, with a primarily southeast-to-northwest alignment, consists of, in order, (a) a 273-foot-long concrete-lined canal section, which contains the fish screen; (b) a 66-inch-diameter, 5,448-foot-long woodstave pipe; (c) a 5,805-foot-long concrete-lined canal section; (d) a 5-foot-wide by 6.5-foot-high, 698-foot-long, concrete-lined, horseshoe type tunnel; (e) a 416-foot-long canal to penstock transition (i.e. forebay) with a 2,486-foot-long side channel spillway that discharges to Daniel Creek; and (f) a 66-inch to 48-inch-diameter[2], 3,254-foot-long, riveted steel penstock with a south-to-north alignment.

Other components appurtenant to the waterway include, in order, a 77-foot-long side channel spillway upstream of the fish screen and adjacent to the fish ladder; a trash rack at the transition structure to the woodstave pipe; a trash rack at the transition to the tunnel; a trash rack at the penstock transition structure with bars spaced three inches on-center, which are cleaned via an automated Atlas Polar trash rake; and a valve house at the top of the penstock that houses the excess velocity valve.

Proposed

PacifiCorp proposes to replace the existing woodstave flowline with a 63-inch-diameter, 5/16-inch-thick, steel flowline in the same alignment as the existing flowline. The steel flowline would be supported by concrete piers spaced at intervals of 40-feet on-center. Construction is proposed for calendar year 2021.

A.1.5 Powerhouse

The powerhouse contains one generating unit with a rated capacity of 7,200 kW operating under a static head of 713.37 feet[3] and producing a 30-year (1986-2015) average annual energy output of 35,050 megawatt hours (MWh). A pressure relief valve (PRV) is automated to respond to forebay water surface elevations and allow penstock flows to bypass the turbine in the event of a generating unit trip or planned outage. The turbine isolation valve (TIV) closes automatically upon a unit trip, and subsequent increases in forebay water surface elevation resulting from the

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[2] Previously reported incorrectly as “66-inch to 68-inch-diameter.” The penstock includes 66”, 60”, 54”, and 48” segments.

[3] Previously reported incorrectly as “static head of 740 feet.” The static head is measured from the hydraulic gradient (3,352.37’) to the centerline of the penstock where it enters the turbine (2,639.0’).

TIV closure will initiate a corresponding response in aperture of the PRV, allowing diverted flows to continue to the tailrace.

A.1.6 Tailrace

The concrete tailrace structure is approximately 20 feet by 20 feet by 5 feet with a 172-foot-long, concrete lined overflow spillway that discharges in an easterly direction to Daniel Creek. The tailrace backwater sluice gate is automated to respond to penstock flows and prevent routine discharge of flows to Daniel Creek.

A.1.7 Inverted Siphon (Sag-Pipe)

Existing

A 66-inch, 887-foot-long, inverted siphon routes flow from the Project tailrace to the Middle Fork Canal of the Prospect Nos. 1, 2, and 4 Hydroelectric Project (FERC Project No. P-2630). The existing siphon is primarily wood-stave construction with the exception of an approximately 250-foot-long section of steel pipe over the Middle Fork Rogue River that was installed following high flow damage to the original woodstave pipe in December 1964.

Proposed

PacifiCorp proposes to replace the existing woodstave sag-pipe with a 63-inch-diameter, 5/16-inch-thick, steel flowline in the same alignment as the existing flowline. The steel flowline would be supported by concrete piers spaced at intervals of 40-feet on-center. The existing approximately 250-foot-long steel segment over the Middle Fork Rogue River would remain in-place. Construction is proposed for calendar year 2021.

A.2 SOUTH FORK IMPOUNDMENT

The South Fork Diversion Dam impounds the South Fork Rogue River at the elevation of the un-gated spillway crest at 3,375.7’ above sea level. At normal maximum pool, the impoundment has a surface area of approximately one acre. The retention time of impounded water is less than one hour. The impoundment has a gross storage capacity of approximately nineteen acre-feet and useable capacity of less than five acre-feet. Average and maximum depths are approximately five feet and eight feet, respectively.

There are no existing license requirements with respect to reservoir operation. There are no signs of shoreline instability as of the date of this application. There is no known recreational use in the impoundment to warrant a boat barrier. Accumulated sediments upstream of the diversion dam near the intake gate are removed as needed pursuant to requirements and conditions of the U.S. Army Corps of Engineers and Oregon Department of State Lands removal-fill permitting programs for jurisdictional Waters of the U.S./State. Removal of sediments from the impoundment was last conducted in 2010. There is currently minimal debris accumulation in the impoundment upstream of the dam and, therefore, minimal impact on Project operations.

A.3 TURBINE AND GENERATOR

The Project powerhouse includes: (1) one 9,000 kilovolt amps (kVA), Allis-Chalmers Company synchronous generator rated at 80% power factor, 720 revolutions per minute (rpm), three phases, 60 cycles, and 6,900 volts; and (2) one 47-inch diameter, 10,700-horse-power (hp), vertical-shaft, Francis-type turbine with single runner reaction and spiral case manufactured by American Hydro Corporation and operating under 693 feet of net head. The turbine can be manually operated to 7,200 kW/150 cfs. During standard operation (automated mode), the minimum hydraulic capacity is approximately 200 kW/3 cfs. The maximum hydraulic capacity is 7,200 kW/150 cfs.

A.4 TRANSMISSION LINE

Electrical power produced by the Project generating unit is conveyed to the electrical grid via a 6.97-mile-long, 69-kilovolt (kV) transmission line that ultimately terminates at Prospect Central substation. There is also a connection to a local distribution sub-station near Red Blanket Road. From the initial substation immediately to the west of the powerhouse, the transmission line alignment crosses the Middle Fork Rogue River and from that point on follows the general alignment of the Prospect Nos. 1, 2, and 4 waterway. Transmission line access roads are shared with Prospect Nos. 1, 2, and 4 waterway operations and maintenance access. The transmission line alignment crosses primary public access roads at Prospect-Butte Falls Highway, Mill Creek Road, and Highway 62, at the Middle Fork Canal crossing near North Fork Reservoir and at the P2 penstock crossing near the transmission line terminus at Prospect Central substation.

A.5 ADDITIONAL EQUIPMENT

The Project includes a variety of computer, mechanical, electrical, and transmission equipment. These systems are summarized in the following sub-sections.

A.5.1 Powerhouse

The reaction turbine is controlled by a high pressure hydraulic unit (HPU) with proportional valve control, wicket gate position feedback, and turbine speed feedback. The turbine speed monitoring system includes both digital, photoelectric proximity switch monitoring and mechanical centrifugal over speed switch protection. The turbine has a lube oil protection system, a mechanical vibration protection system, and a bearing temperature protection system.

The generator voltage is controlled by a static excitation system. The excitation system includes a three-phase, air-cooled excitation transformer, field voltage regulator, field circuit breaker, field flash system, and field protection relays.

The generator connects to the power system line via an oil filled circuit breaker with a solenoid mechanism. The generator voltage is transformed from 6.9 kV to 69 kV by three single-phase, oil-cooled Generator Step-Up Transformers (GSU) phase rated at 3,000 kVA. Switch gear is available to isolate the generator or GSU. The generator and GSU both have redundant protection relay systems, satellite clocks, fused current transformers, fused voltage transformers, watt-hour meters, lightning arrestors, and temperature protection systems. The generator has a neutral-to-ground protection, high-impedance transformer.

Other auxiliary plant systems include the 125-VDC plant battery system, the plant air compression system, the physical security systems, auxiliary transformers, lighting, communication systems, and various instruments.

The powerhouse programmable logic controller (PLC) system may be thought of as a centralized point of control. This PLC is the interface to generator load control, plant monitoring, local human-machine interface (HMI) control, and remote HMI control from the Hydro Control Center supervisory control and data acquisition (SCADA) system.

The turbine penstock includes a multiple path transit time flowmeter for monitoring penstock flow. Penstock flow can be maintained during a turbine shutdown by the automated pressure relief valve (PRV) position control system. Both the penstock TIV and the TIV bypass valve are automated for open/close operation.

A.5.2 Penstock Intake Building

The penstock intake building houses the excess velocity valve, which automatically closes by mechanical counterweight when triggered by indication of abrupt and extreme change of flow within the penstock. Immediately upstream of the intake building is a water stop log system for maintenance.

A.5.3 Forebay Equipment Building

Forebay facilities are powered from the substation located at the powerhouse. A station service, 200-kVA transformer feeds 12-kV service to the forebay via an underground line. The power system is backed up by a 30-kW, automated, propane generator with automatic transfer switch, uninterruptable power supply, and DC/AC inverter.

The water conveyance control system includes ultrasonic level transmitters upstream and downstream of the intake trash rack. The trash rack has an automated hydraulic trash rake. The forebay controls interface with a dedicated PLC, a touchscreen HMI for local control, and the SCADA system for remote control.

A.5.4 Diversion Dam

Diversion dam facilities are powered from the substation located at the powerhouse. A station service, 200-kVA transformer feeds 12-kV service to the dam via an underground line. At the diversion dam control building, there is a pad mount 75-kVA transformer with lightning arrestors and overload protection. There is also a 15-kVA station service transformer with overload protection.

The control system of the South Fork Diversion Dam includes an un-gated concrete spillway, fish ladder, and intake gate to the water conveyance system. There are four automated actuators at the South Fork dam site: a trash rack rake, a canal intake head gate, a fish screen, and a backwater gate. A dedicated PLC system monitors water level gages on the dam reservoir, downstream of the trash rack, upstream of the fish screen, downstream of the fish screen, downstream of the backwater gate, and in the fish ladder. The control system interfaces with a touch screen HMI for local control and the SCADA system for remote control.

A.6 LANDS OF THE UNITED STATES

The Project is located in unincorporated, northeastern Jackson County, Oregon. The existing FERC Project boundary occupies a total of 336.7 acres, of which approximately 38.1 acres[4] are lands of the United States administered by the U.S. Forest Service (Forest Service). PacifiCorp proposes to revise the Project boundary under the next license term to include critical access routes and exclude areas outside of Project influence. The proposed Project boundary would occupy a total of 376.2 acres, of which approximately 52.5 acres are lands of the United States administered by the Forest Service. Project transmission lines are not located on lands of the United States. The locations, identified by Public Land Survey System (PLSS) township, range, and section, of lands of the United States within the proposed Project boundary are presented in Table 1 and depicted in Exhibit G.

Table 1. PLSS location of lands of the United States within the proposed FERC Project (No. P-2337) boundary

PLSS Township and Range, Willamette Meridian	PLSS Section	Subdivision of Section	Acres	Agency Jurisdiction
T33S, R4E	7	Portions of Government Lot 3	9.8	Forest Service
T33S, R4E	7	Portions of the NE 1/4 of the SW 1/4	9.9	Forest Service
T33S, R4E	7	Portions of the SE 1/4 of the SW 1/4	11.6	Forest Service
T33S, R4E	7	Portions of the SW 1/4 of the SE 1/4	11.0	Forest Service

[4] 38.1 acres of federal lands are identified in the prior Exhibit G filing, but the correct amount of federal lands in the existing FERC boundary as plotted and re-calculated in geographic information systems software is 32.4 acres.

T33S, R4E	18	Portions of the NW 1/4 of the NE 1/4	7.5	Forest Service
T33S, R4E	18	Portions of the NE 1/4 of the NE 1/4	2.7	Forest Service
Total Acres (all non-transmission line)			**52.5**	Forest Service

EXHIBIT B–PROJECT OPERATION AND RESOURCE UTILIZATION

B.1 POWERPLANT OPERATION

B.1.1 Plant Supervision

The Project generator is operated automatically by a PLC, and may also be operated manually by an on-site operator, as needed. After normal working hours, plant functions may be monitored remotely over a SCADA network by control operators at PacifiCorp's Hydro Control Center, in Ariel, Washington. Although control operators have the ability to adjust generation through the SCADA network, they generally allow the plant to run in automatic mode, and will call out an on-site operator for any unplanned outages or alarms.

B.1.2 Annual Plant Factor

The current Project license identifies a minimum instream flow of 10 cubic feet per second (cfs) that must be maintained in the South Fork Rogue River below the diversion dam. Prior to the current license, the Project was operated without a minimum flow restriction, and the associated annual generation records during those years do not necessarily represent current operations. PacifiCorp determined that the most accurate estimate of average annual plant factor could be computed from generation records collected between the first full year of the current license, 1990, and 2014. Generation records from this 25-year period provide an average annual plant factor of approximately 55 percent.

B.1.3 Operation during Low, Mean, and High Water Years

The Project is operated in run-of-river mode during low, mean, and high water years, as the small impoundment on the South Fork Rogue River lacks storage. A unit PLC, located in the plant, adjusts the aperture of the wicket gates in order to maintain a constant forebay elevation in response to input from level sensors at the forebay. The adjustments to the wicket gates directly affect the rate of water diversion at the dam, and ultimately result in a near-constant reservoir level for much of the year. When natural inflows exceed the sum of project hydraulic capacity and the minimum flow requirement, spill occurs at the diversion over the un-gated, ogee-style weir.

B.2 CAPACITY AND ENERGY PRODUCTION

The 30-year (1986-2015) average annual energy output of the Project is 35,050 MWh. Production tends to be capacity-limited from February through June, when inflows are sufficient to meet the current minimum instream flow restriction of 10 cfs, as well as the water right and unit capacity of 150 cfs. Between July and January, production is generally flow-limited, as inflows are typically too low to run the unit at capacity after the minimum instream flow has been provided by releases in the bypassed reach below the dam.

Estimated dependable capacity of the Prospect No. 3 generator is 1.11 megawatts (MW). For the purpose of this document, PacifiCorp defines dependable capacity as the average plant output during the critical stream-flow period. The data sources, assumptions, and empirical values used to calculate dependable capacity are described below.

B.2.1 Water Flows

Inflow records from U.S. Geological Survey (USGS) gaging stations within the Project vicinity were referenced to support the selection of the critical stream flow period. Inflows were computed for water years 1934 through 1983[1]. Summary statistics from the period of record include:

- Minimum daily average inflow: 40 cfs
- Mean daily average inflow: 184 cfs
- Maximum daily average inflow: 4500 cfs

The baseflow period, characterized by consistently low, steady flows, occurs during September and October, as illustrated in the flow duration curve provided in Table 2. PacifiCorp identified a critical stream-flow period of September 1, 1934 to September 30, 1934. Average inflows during the critical period were 50 cfs, the lowest monthly average on record. Daily average flows during the critical period, less the minimum flow restriction of 10 cfs, were assumed to be available for diversion and power generation.

Table 2. Duration curves for natural incoming flows to South Fork Diversion Dam (1934-1983)

Month	Flow Recurrence Interval (percent of time flows are equaled or exceeded)														
	95%	90%	85%	80%	75%	70%	60%	50%	40%	30%	25%	20%	15%	10%	5%
Oct	58	60	62	64	66	69	73	78	85	90	93	96	101	106	122
Nov	62	65	68	72	76	80	86	92	102	119	131	146	162	202	274
Dec	65	73	79	85	92	98	114	130	157	193	223	250	282	336	500
Jan	69	81	90	97	105	115	130	149	170	205	223	247	293	362	497
Feb	79	87	102	118	128	134	148	167	190	220	241	258	283	315	447
Mar	86	109	122	131	138	146	161	175	189	207	223	241	266	304	376
Apr	122	144	156	167	179	189	210	236	273	310	336	365	393	430	490
May	138	172	195	218	240	261	296	335	368	407	433	462	502	557	619
Jun	98	124	138	152	161	174	203	238	275	317	344	369	406	448	514
Jul	70	86	93	99	104	109	120	129	139	152	160	170	182	198	227

[1] A mass balance approach was used to calculate inflow from stream gages located in the vicinity of the Project. Inflows between WY 1934 and 1949 were calculated based on USGS gage numbers 14330500 (South Fork Rogue River upstream of diversion) and 14331000 (Imnaha Creek tributary at impoundment). Inflows between WY 1950 and 1983 were calculated at gage number 14332001, which summed diversion flows (power canal gage number 14331500) and releases (South Fork Rogue River bypass gage number 14332000).

Month	Flow Recurrence Interval (percent of time flows are equaled or exceeded)														
	95%	**90%**	**85%**	**80%**	**75%**	**70%**	**60%**	**50%**	**40%**	**30%**	**25%**	**20%**	**15%**	**10%**	**5%**
Aug	61	68	73	76	80	84	90	97	104	111	117	121	127	135	144
Sep	56	62	64	67	69	72	77	83	89	95	98	101	105	109	116
Annual	**64**	**71**	**78**	**84**	**91**	**97**	**115**	**136**	**163**	**200**	**226**	**259**	**301**	**360**	**452**

B.2.2 Impoundment Capacity

The South Fork impoundment has approximately nineteen acre feet of gross storage and five acre feet of active storage. Due to the negligible storage volume, the use of reservoir capacity curves and rule curves are not applicable in the calculation of dependable capacity. Natural inflows provide the only source of water for diversion and generation.

B.2.3 Powerplant Capacity

During standard operation (automated mode), the minimum capacity is approximately 200 kW/3 cfs. The maximum hydraulic capacity is 7,200 kW/150 cfs.

B.2.4 Tailwater Rating Curve

The turbine discharges under minimal pressure into a tailwater box, and then into an inverted siphon. The water surface elevation in the tailwater box is controlled by a backwater sluice gate. Since the turbine does not discharge under the surface of a stream or reservoir, a tailwater rating curve is not applicable in the calculation of dependable capacity.

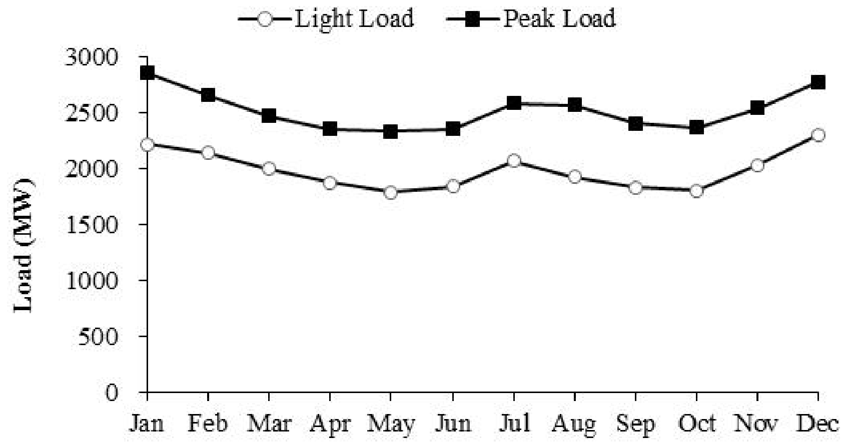
B.2.5 Head

The powerhouse operates under static head of 713.37 feet, measured from the hydraulic gradient at 3,352.57’ to the centerline of the penstock at the turbine at 2,639’; the net head is 693 feet. Virtually all of the Project’s head is provided by topographic relief. Nominal fluctuation in forebay elevation occurs over the course of the year in response to water availability changes. However, water availability, rather than minor head changes at the forebay, dictates dependable capacity. Consequently, a capacity versus head curve is not applicable.

B.3 POWER UTILIZATION

Power generated at the Project is utilized to meet system load, depicted in Figure 1. A nominal, unmetered portion of the output provides station service.

Figure 1. Predicted system load for 2016 in the PacifiCorp West (PACW) balancing area



B.4 FUTURE DEVELOPMENT

PacifiCorp has no current plans to develop any additional generation or expand capacity during the term of a new license. Proposed improvements to the Project include replacement of the existing wood-stave flowline and sag-pipe with steel pipe to ensure reliable, long-term functionality of the water conveyance system. There are no existing data that suggest flowline replacement would appreciably affect generation. Generation capacity would not be affected by future replacement of the turbine runner due to the capacity limitations of the generator.

EXHIBIT C—CONSTRUCTION HISTORY AND PROPOSED CONSTRUCTION SCHEDULE

C.1 CONSTRUCTION HISTORY

The Prospect Hydroelectric Plant (now known as the Prospect No. 1 powerhouse) was constructed on the North Fork Rogue River in 1911 by Condon Water and Power Company. By 1926, Condon Water and Power Company's successor, California Oregon Power Company (COPCO), initiated research and development of an expanded hydroelectric development incorporating multiple forks of the Rogue River, including the original 1911 Prospect facilities. New diversion dams were planned for the South, Middle, and North Forks of the Rogue River and Red Blanket Creek.

Byllesby Engineering and Management Company (Byllesby) of Chicago, Illinois was responsible for the design, engineering, and management of the South Fork development. The South Fork Rogue Riverwas initially surveyed in September 1924. Additional survey and conceptual design work completed in 1926 shows three potential powerhouse and penstock locations for the South Fork development. The eventual layout and alignment for the South Fork development was proposed in July 1929.

The original application for the South Fork development was submitted to the Federal Power Commission (FPC) by Byllesby on April 20, 1931. The application identified the diversion dam site and 0.75 miles of conduit on 40 acres of Crater National Forest (now known as the Rogue River-Siskiyou National Forest), with the balance of lands owned by Rogue River Timber Company. A statement of intent to purchase timber lands within the proposed Project boundary was included with the application. The application identified a planned completion date of June 1, 1932.

Construction of the South Fork development known as Prospect No. 3 was initiated in 1931. The Project was placed in service on April 22, 1932. The current Project is largely unaltered in materials, massing, and/or alignment from its original construction condition with the exception of a section of the sag-pipe over the Middle Fork Rogue River; the forebay canal and associated side channel spillway; the fish passage facilities; and turbine runner. These alterations are discussed below in additional detail.

An original minor-part license (FPC No. 1163) was issued to COPCO on July 30, 1931 for a period of 50 years. This minor license covered the upper Project facilities, including the diversion dam and approximately 4,000 linear feet of the flowline, located on lands administered by the federal government. The initial major-part license (FPC No. P-2337) covering the downstream facilities, including the remaining waterway, penstock, and powerhouse, was issued in 1931 for a period of 30 years. COPCO merged with Pacific Power and Light on June 21, 1961, and the January 25, 1963 license application requested transfer of the license to Pacific

Power and surrender of the minor-part license. By order dated July 8, 1964, the Commission issued a new license for the Project, including all Project facilities under one license for a period of 25 years. An application for new license was submitted on December 24, 1985, and the current license was issued on January 30, 1989 for a period of 30 years beginning on the first day of the month of issuance.

Construction plans dated July 1951 indicate that somewhere in this time frame a short section of the canal near the forebay was realigned, presumably because of observed slope instability. In 1982 a simple vertical and horizontal displacement monitoring system was installed on a head scarp identified immediately adjacent to this lower canal section. In April 1989, accelerated movement of approximately eight inches was measured over a five week period following snowmelt. Four borings were made in the area and equipped with slope inclinometer casings in addition to adjacent groundwater detection borings. It was determined that partial filling of the overflow spillway channel with rock was needed to provide protection for the toe of slope and to stabilize the block of soil immediately down slope from the canal. In September 1989, repairs were initiated, including installation of filter fabric over exposed soil surfaces and placement of 20,000 cubic yards of riprap material to a depth of approximately 25 feet and a distance of approximately 400 feet. Continued post-construction monitoring revealed that, after a period of initial settling, the slope had been stabilized.

A winter storm on December 21 and 22, 1964 resulted in the highest recorded flows during the Project era. High flows and extensive debris mobilization in the Middle Fork Rogue River resulted in damage to the sag-pipe piers and trestles and subsequent loss of the original woodstave sag-pipe crossing. Approximately 250 feet of the sag-pipe were replaced with steel pipeline in early 1965.

Prior to 1989, the Project included five existing wildlife crossings of the open canal and sporadic fencing. In fulfillment of License Article 406, PacifiCorp improved the five existing crossings, installed a new crossing over the open canal, repaired or replaced the fencing around the open canal with 7’-high wildlife fencing, installed two under-crossings of the woodstave flowline, and installed five under-crossings of the penstock.

Original construction of the Project diversion dam and intake canal included a fourteen-pool fish ladder and two eight-foot-wide rotating drum fish screens. Minor modifications were made to the upstream and downstream fish passage facilities in 1976, but significant modifications were made to both facilities in 1996 based on the requirements of License Articles 403, 404, and 405 of the 1989 license and interim design criteria provided by Oregon Department of Fish and Wildlife (ODFW) to PacifiCorp on September 7, 1994. Fish passage facility construction was initiated and completed in 1996. The rotating drum screens, which were located approximately 43’ downstream of the intake, were removed, and the inclined plane screen was installed approximately 215’ downstream of the intake. The fish bypass return pipe was installed from the new fish screen location to its terminus at Pool 6 of the fish ladder. Pool 14 of the existing ladder was bifurcated into two pools and several of the pool walls and weirs were modified to meet the provided design criteria. An access road to the diversion site and a bridge over the flowline were constructed to facilitate the fish passage construction effort. In addition to the backwater sluice gate, screen hoists, and other associated fish screen operation and maintenance infrastructure, a new cinder block control building and the automated Atlas Polar trash rake were installed at the diversion concurrent with the fish passage facilities construction in 1996.

The turbine runner was replaced in 1997. The original turbine was a vertical-shaft, Francis-type hydraulic turbine manufactured by Pelton Water Wheel and rated at 10,000 horsepower (7,460 kW) at a designed head of 693 feet. The new runner was manufactured by American Hydro and fabricated out of 304L stainless steel. In addition to the runner, new wicket gates and associated bushings were installed. Although the turbine capacity increased from 7,460 kW to 7,900 kW, generator capacity limits the installed capacity at 7,200 kW.

Following hydraulic assessments of fish passage facilities in 1998, perforated plate baffles were temporarily installed on the fish screen to create a more uniform flow through the screen. The baffles were redesigned and installed on the downstream side of the screen assembly in 2015.

Automation of the pressure-relief valve and tailrace backwater gate in response to forebay water levels was completed in 2015 and 2016, respectively.

The Project construction history is summarized below in Table 3.

Table 3. Project construction history

Facility	Construction Year
South Fork Diversion Dam	1931-1932
Fish ladder	1931-1932
Rotating drum fish screen	1931-1932
Conduit system	1931-1932
Powerhouse	1931-1932
Tailrace	1931-1932
Sag-pipe	1931-1932
Transmission Line	1931-1932
Forebay realignment	ca. 1951
Steel pipeline segment of sag-pipe	1965
Stabilization of forebay overflow spillway channel	1989
Wildlife crossings and canal fencing	1989
Modifications to fish ladder pool walls and weirs	1996
Inclined plane fish screen	1996
Fish return bypass pipe	1996
Turbine runner replacement	1997
Fish screen baffles	1998, 2015
Pressure-relief valve automation	2015
Tailrace backwater gate automation	2016

C.2 PROPOSED CONSTRUCTION SCHEDULE

PacifiCorp proposes to construct an auxiliary bypass flow system from one of the existing fish ladder exit orifices to a plunge pool at the base of the fish ladder to reliably provide increased minimum flows to the bypassed reach. PacifiCorp proposes to realign and extend the existing fish bypass return pipe discharge from Pool 6 to Pool 1 of the fish ladder. Changes to the fish bypass return pipe discharge location would result in reduced flow through Pools 6 through 2 of the fish ladder, and PacifiCorp proposes to modify the weir notches for Weirs 2 through 6 from 36”-wide to 18”-wide to provide consistent performance throughout the ladder. PacifiCorp proposes to replace the existing woodstave flowline and woodstave sag pipe with steel pipelines in the same alignment. The temporary vehicle-access bridge over the flowline would be rehabilitated to meet current Forest Service engineering standards following flowline replacement. PacifiCorp proposes to construct a road spur from the flowline vehicle-access bridge to the bank of the bypassed reach to facilitate pass-through of materials dredged from the impoundment upstream of the dam to the bypassed reach downstream of the dam. PacifiCorp proposes to upgrade the six existing four-foot-wide wildlife crossings of the canal to twelve feet in width. PacifiCorp also proposes to construct five twelve-foot-wide wildlife crossings of the new steel flowline and eight two-foot-wide wildlife crossings of the canal within the canal fencing. To facilitate compliance with proposed ramp rates, PacifiCorp proposes to install a communications link on the USGS’ South Fork Rogue gage to deliver real-time flow readings to Project instrumentation and controls. The proposed facility construction schedule is identified below in Table 4.

Table 4. Proposed Project facilities and construction schedule

Facility	Proposed Construction Completion
Auxiliary bypass flow system	2019
Fish bypass return pipe extension	2019
Fish ladder weir modifications	2019
Communications link and automation controls	2019
Steel flowline	2021
Steel sag pipe	2021
Wildlife crossing upgrades	2021
Wildlife crossing construction	2021
Vehicle-access bridge over flowline intake	2022
Road spur from flowline bridge to bypassed reach	2022

EXHIBIT D—STATEMENT OF COSTS AND FINANCING

D.1 FEDERAL TAKEOVER COSTS

In accordance with § 16.14 of the Commission's regulations, a federal department or agency may file a recommendation that the United States exercise its right to take over a hydroelectric power project with a license that is subject to sections 14 and 15 of the FPA. In Scoping Document 2 (FERC, 2013), the Commission determined that federal takeover was not a reasonable alternative. Federal takeover of the project would require congressional approval. While that fact alone would not preclude further consideration of this alternative, there is currently no evidence showing that federal takeover should be recommended to Congress. No party has suggested that federal takeover would be appropriate, and no federal agency has expressed interest in operating the project. If the Project was to be taken over by another entity, PacifiCorp would be entitled to its net investment in the Project plus severance damages.

D.1.1 Fair Value

The fair value of the proposed Project was estimated based on the present value of the costs and benefits of the Project assuming a 40-year[1] license that starts in calendar year 2019. The Fair Value of the Project is estimated to be $39,422,924 through the end of 2058.

D.1.2 Net Investment

The net book value of the Project, excluding Intangibles, Transmission, Distribution and Non-utility Assets, as of December 31, 2015, is $3,226,907. This figure is based on an original cost of $10,078,492.

D.1.3 Severance Damages

Under FPA § 14(a), "severance damages" are those "reasonable damages" to protect property not "caused by the severance there from of property taken" (See 16 U.S.C. § 807(a)). PacifiCorp believes that the severance damages inflicted by a takeover of the Project would be significant. Given the inherent difficulties in attempting to quantify such speculative values, PacifiCorp reserves the right to submit additional evidence quantifying such severance damages should FERC consider ordering a takeover of the Project.

[1] A 40-year license term was selected as the median of the range of FERC license terms from 30 to 50 years.

D.2 NEW DEVELOPMENT COSTS

PacifiCorp does not propose any new developments requiring additional land, water rights, or facilities to increase Project generation capacity.

D.3 ESTIMATED AVERAGE ANNUAL PROJECT COSTS

The current FERC license issued on January 30, 1989 expires on December 31, 2018. For estimation of average annual project costs, PacifiCorp analyzed a new license period beginning on January 1, 2019 and expiring in 2058 (i.e., a 40-year license term). The total Project forecast period is 43 years, from 2016 to 2058. The annual inflation rate estimate is 2.33%. Project costs were calculated using rate-based methodology that incorporates existing net investment, routine operations O&M, property and income taxes, depreciation and amortization, deferred taxes, and rate of return. Additional future relicensing Capital and O&M, lost generation, operational capital, and relicensing process costs are covered in section H.3.1.

The estimated annual cost to own and operate the Project's existing assets for 43 years, excluding additional costs for license compliance, implementation, and major capital projects, is $18,282,478. The annual cost per MWh to operate the Project, based on the 30-year average annual generation of 35,050 MWh, is $35.48/MWh.

D.3.1 Cost of Capital

PacifiCorp's discount rate of 6.57% is based on the after-tax, weighted average cost of capital.

D.3.2 Local, State, and Federal Taxes

Property taxes paid on the Project were 0.82% of 2015 net book value, or $26,356, in 2015.

PacifiCorp's corporate tax rate is 37.951%.

D.3.3 Depreciation and Amortization

Book depreciation of the Project's existing assets is 4.44% of original cost annually, or approximately $445,800, in 2015. This is based on a 2013 Depreciation Study approved by FERC. Additional capital expenditures on hydro assets are depreciated over 20 years for tax and 40 years for book analyses. Relicensing process capital is depreciated over 15 years for tax and book analyses, beginning in 2019, the year of the assumed new license.

D.3.4 Operation and Maintenance

Operation and Maintenance estimates can vary significantly from year-to-year. PacifiCorp estimates are based on historical data as well as budget forecast estimates.

Annual routine Operations and Maintenance costs are $609,433 in 2016$, totaling $26.2 million over the 43-year analysis period. This estimate is based on the average of the prior three years of FERC Form 1 costs directly attributable to the Project, inflated to 2016$, and reduced by relicensing implementation expenses.

Non-routine Operations and Maintenance costs (e.g., generator cleaning, impoundment dredging, et al.) are estimated to average $50,744 annually, totaling $2,182,000 over the 43-year analysis period.

The Project has been certified to meet the criteria for low environmental impact as determined by the Low Impact Hydropower Institute (LIHI; LIHI Certificate No. 109). As a result of this certification, the Project is eligible for Renewable Energy Credits, estimated at $1.00 per MWh of net generation based on internal forecast by PacifiCorp's Energy Supply Management department. The average value of the Renewable Energy Credits is $24,719 annually, totaling approximately $1,062,915 and over the 43-year analysis period. For analysis purposes, the value of the Renewable Energy Credits is counted as cash received, which reduces non-routine Operations and Maintenance costs.

The total estimated average annual O&M expense for the proposed Project includes the no action alternative costs in addition to the cost of Protection, Mitigation, and Enhancement Measures (PM&Es). The annual estimated O&M expense for PM&Es (e.g., management plan implementation; in-stream flow release maintenance, monitoring, and reporting; et al.) is $36,093, totaling $1,552,000 over the 43-year period.

Table 5. 43-Year projected average annual operations and maintenance costs

Item	Annual Average (in 2016$)
Routine O&M	$609,433
Non-routine O&M	$50,744
Renewable Energy Credits	$-24,719
Environmental Measures O&M	$36,093
Total Annual O&M	**$671,551**

D.3.5 Estimated Costs of Environmental Measures

The annual estimated operations and maintenance cost of proposed PM&Es is $36,093, totaling $1,552,000 over the 43-year analysis period. The total estimated capital spend on PM&Es is $14,952,026, in 2016$. See Section E.7.2 for additional detail on PM&E costs.

D.4 EQUIVALENT POWER COSTS

The generation output of the Project is primarily consumed by PacifiCorp's retail and wholesale customers within PacifiCorp's service territory. To determine the value of the Project's power benefits, this analysis assumed the dollar value of the Project's annual generation of 35,050 MWh would be the cost of purchasing an equivalent amount of energy from the wholesale power market under average water conditions. The Project's average annual energy value based on market prices would be approximately $43.39 per MWh. The estimated 43-year annual average cost to replace Project generation under current license conditions would be approximately $22,356,486 under average water conditions.

D.5 APPLICANT FINANCING AND ANNUAL REVENUES

All common stock of PacifiCorp is held by its parent company, PPW Holdings LLC, which is a direct, wholly-owned subsidiary of Berkshire Hathaway Energy Company (BHE). PacifiCorp declared and paid dividends to PPW Holdings LLC of $950 million in 2015 and $725 million in 2014. BHE's common stock is owned by Berkshire Hathaway, Mr. Walter Scott, Jr., a member of BHE's Board of Directors (along with family members and related entities), and Mr. Gregory E. Abel, BHE's Chairman, President and Chief Executive Officer, and has not been registered with the Securities and Exchange Commission (SEC) pursuant to the Securities Act of 1933, as amended, listed on a stock exchange, or otherwise publicly held or traded. BHE has not declared or paid any cash dividends to its common shareholders since Berkshire Hathaway acquired an equity ownership interest in BHE in March 2000, and does not presently anticipate that it will declare any dividends on its common stock in the foreseeable future.

Revenues are generated by PacifiCorp through sales of electricity to customers within its service territory. This includes electricity generated from the Project, as well as energy obtained from a variety of other sources to meet the energy needs of customers. Rates for energy sales are set by the Oregon Public Utility Commission in accordance with a rate structure and public utility policies so that, in general, cost of service is covered by revenue.

PacifiCorp's net income for the year ended December 31, 2015 was $695 million on operating revenues of $5.2 billion. PacifiCorp's current five-year (2011-2015), annual average operating revenue is $5.0 billion. Operating revenue and energy costs are the key drivers of PacifiCorp's results of operations as they encompass retail and wholesale electricity revenue and the direct costs associated with providing electricity to customers. Gross margin, representing operating revenue less energy costs, increased $109 million, or 3%, for 2015 compared to 2014 primarily due to lower natural gas costs, lower coal costs, and higher retail rates.

PacifiCorp's revenues are sufficient to meet the costs identified in Exhibit D. Additional financial data is presented in BHE's annual Form 10-K report available on-line at http://www.sec.gov/Archives/edgar/data/71180/000108131616000023/bhe123115form10-kcombined.htm#se17edda4bfae4936a4469a25fcdedad0.

D.6 LICENSE APPLICATION COSTS

The estimated costs to develop the Final License Application are approximately $1,900,000. This includes consultant and applicant costs. Consultant costs pertain to relicensing study planning, study implementation, study reporting, administration, and meetings. PacifiCorp costs include the same cost categories as consultant costs, as well as staff time, overhead, equipment, and services purchased.

D.7 ON-PEAK AND OFF-PEAK POWER VALUES

The Project is only operated in run-of-river mode, and therefore, estimated values of on- and off-peak Project power are not required.

D.8 ESTIMATED AVERAGE ANNUAL CHANGE IN GENERATION AND POWER VALUES

The 30-year (1986-2015) average annual generation of the Project is 35,050 MWh. The proposed Project includes a minimum instream flow of 30 cfs from March 1 through July 31 and 20 cfs from August 1 through February 28 in the South Fork Rogue River bypassed reach. The no action alternative (i.e., current Project license) requires a minimum instream flow of 10 cfs in the bypassed reach. The proposed increased minimum instream flow would result in Project loss of approximately 12 and 24 MWh per day (0.5 MW per 10 cfs) or 4,864 MWh annually. Over a 43-year analysis period, the average annual cost of lost generation is $3,075,179 or $5.97/MWh. Note that lost generation resulting from an increase in minimum flows would begin in 2019, the year the new license was granted.

An additional loss of 4,621 MWh (95% of Project loss) would be incurred by the Prospect Nos. 1, 2, and 4 Hydroelectric Project due to the conveyance of Project waters from the Prospect No. 3 project to the Prospect Nos. 1, 2, and 4 project. Therefore, the total loss of generation incurred by PacifiCorp as a result of the proposed Project would be 9,485 MWh annually. Because the license application is predicated on the impacts of relicensing Prospect No. 3 only, the value of the lost generation on Prospect Nos. 1, 2, and 4 is beyond the scope of this document, and is not included in the financial analysis presented herein.

EXHIBIT E—ENVIRONMENTAL EXHIBIT

(Provided under separate cover as
PROSPECT NO. 3 HYDROELECTRIC PROJECT
FERC PROJECT NO. P-2337
Final License Application
for Major Project—Existing Dam
Volumes II and III)

EXHIBIT F—GENERAL DESIGN DRAWINGS

F.1 GENERAL DESIGN DRAWINGS

Exhibit F consists of general design drawings of the principal Project works, existing and proposed, described in Exhibit A of this application for new license. Also included is the one-line diagram required in Exhibit H, section H.6.3. The Federal Energy Regulatory Commission Rule RM02-40-000, Order No. 630, as amended by RM02-4-001 and PL02-1-001; Order No. 630-A; and Order No. 702, RM06-23-000 require applicants to separate certain information into the following categories: Public, Critical Energy Infrastructure Information (CEII), and Privileged (other non-public).

Drawings of the general design and principal Project works are classified as CEII under Order 630. To comply with this order, each of the Exhibit F drawings is marked as CEII. The drawings are submitted as non-public CEII under separate cover as Volume IV of the license application and will not be available in FERC's Public Reference Room or as a public access image on FERC's eLibrary web location, except as an indexed item. The drawings contained in this Exhibit F are listed in Table 6 below.

Table 6. Prospect No. 3 Hydroelectric Project general design drawings

Drawing Number	Drawing Title
F-1	Dam, Intake, and Fish Facilities
F-2	Powerhouse
F-3	Miscellaneous Project Structures
F-4	Wildlife Crossings – Locations and Details
F-5	Sag Pipe to Middle Fork Canal
F-6	Transmission One-line Diagram

F.2 SUPPORTING DESIGN REPORT

The Supporting Design Report (SDR) for the Project includes separate reports on existing and proposed Project facilities. Reports for these facilities are submitted as non-public CEII under separate cover as Volume IV of the license application.

F.2.1 Existing Features

The SDR describing existing facilities follows the format provided in Appendix I of Chapter 14 (Dam Safety Performance Monitoring Program) of FERC's Engineering Guidelines for the Evaluation of Hydropower Projects.

F.2.2 Proposed Facilities

PacifiCorp proposes to replace the existing woodstave flowline and woodstave sag-pipe as part of the proposed Project. A report evaluating replacement of these features is provided in Volume IV (Exhibit F, Appendix C) of the license application.

While the alignment and general engineering parameters would be installed as described, the specific material types, foundation supports, and installation methods would be selected prior to construction based on the most economical alternative. The engineering details for the final selected features would be provided for review and acceptance by the FERC in accordance with customary engineering review requirements.

PacifiCorp also proposes to modify existing fish passage facilities to improve performance and reliably supply the bypassed reach with increased minimum flows. Modifications include an auxiliary bypass supply system from the left fish ladder exit orifice to the fish ladder entrance; cutting weir walls, repairing weirs, and relocating weir notches at Weirs 13, 14, and 15 to accommodate the auxiliary bypass supply system; extension of the fish return bypass pipe and relocation of the discharge to Pool 1 of the fish ladder; and modifications to Weirs 2 through 6 to accommodate relocation of the fish bypass pipe discharge. Conceptual drawings of these features are provided in Volume IV (Exhibit F, Appendix E) of the license application and described in greater detail in Volume II (Exhibit E, Section E.6.3.3).

EXHIBIT G—PROJECT MAPS

The Prospect No. 3 Hydroelectric Project is located in Jackson County in the state of Oregon. The existing Exhibit G contains five drawings listed below in Table 7.

Table 7. Existing Exhibit G drawings

Exhibit Sheet	FERC Drawing No.	Title/Showing	Approval order date
1	2337-14	Principal Features and Project Boundary/Diversion and Flowline	1/30/1989
2	2337-15	Principal Features and Project Boundary/Penstock and Powerhouse	1/30/1989
3	2337-16	Principal Features and Project Boundary/Transmission Line	1/30/1989
4	2337-17	Principal Features and Project Boundary/Transmission Line	1/30/1989
5	2337-18	Principal Features and Project Boundary/Transmission Line	1/30/1989

The revised Exhibit G replaces the five current drawings with six newly-created sheets that consist of a series of five overlapping maps depicting the proposed Project boundary location and principal features of the Project and a sixth sheet with coordinates, distances, and descriptions for the boundary shown on the maps. These maps also delineate the land ownership and property interests within that boundary.

The existing FERC Project boundary occupies a total of 336.7 acres, of which approximately 38.1[1] acres are lands of the United States administered by the U.S. Forest Service. PacifiCorp proposes to revise the Project boundary under the next license term to include critical access routes and exclude areas outside of Project influence. The proposed Project boundary would occupy a total of 376.2 acres, of which approximately 52.5 acres are lands of the United States administered by the U.S. Forest Service. There are no transmission lines on lands of the United States in either the existing or revised Project boundaries.

There are two proposed changes to the Project boundary on National Forest lands (see sheet G-1). The first includes reducing the Project boundary to follow a 10-ft offset from the normal maximum pool elevation (3375.7 feet MSL) of the South Fork Impoundment to eliminate the surrounding uplands that are not needed for Project operation. The second includes widening the boundary on the north side of the flowline (currently 100-ft wide) to include the strip of land

[1] On the approved Exhibit G (FERC drawing 2337-14), the sum of acreages listed on the drawing for federal lands is 38.1 acres, but the actual area is 32.41 acres when re-plotted from the description and calculated in GIS.

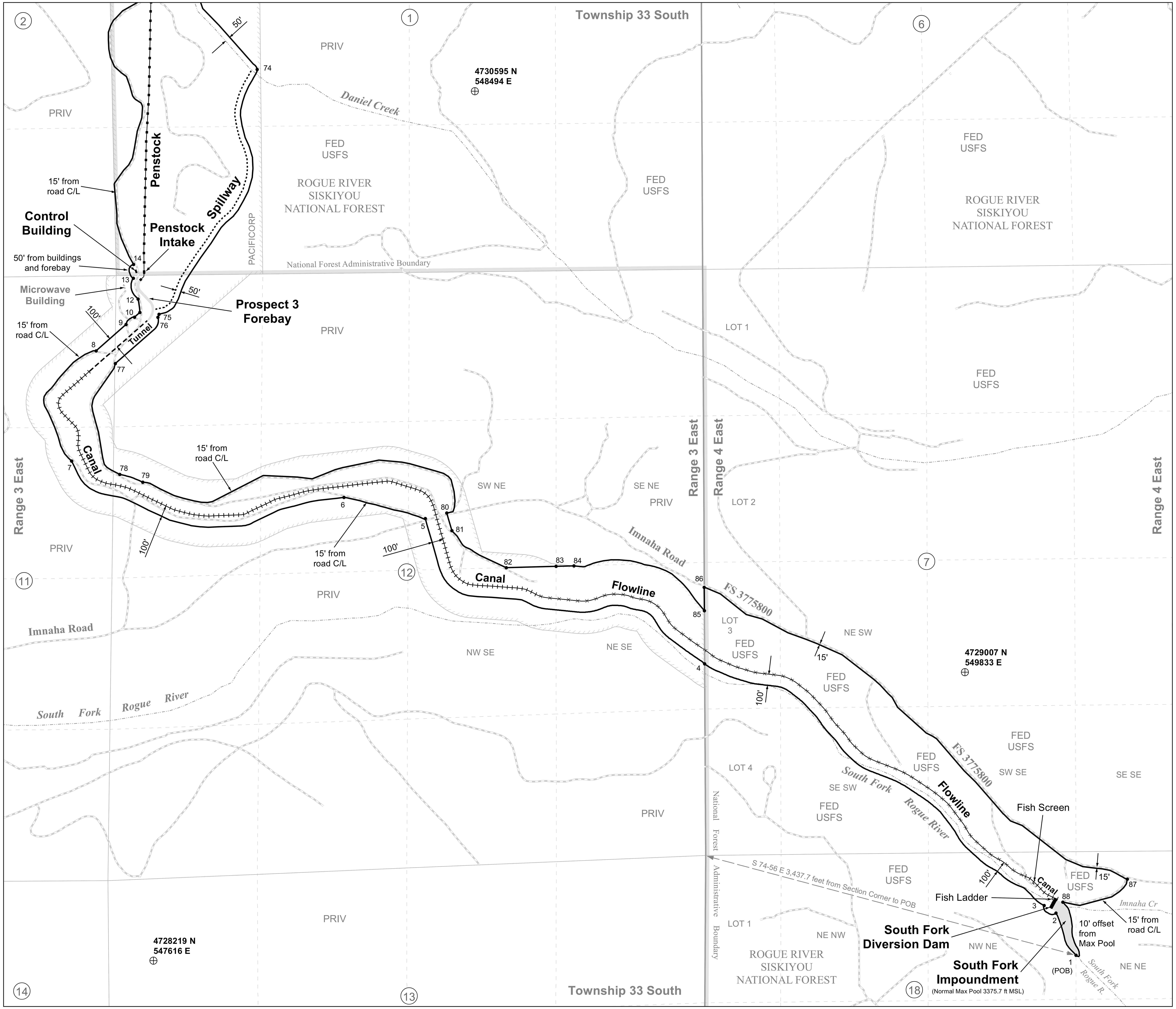
between the flowline and the south shoulder of the FS 3775-800 road. This addition incorporates the Project access roads and the underground power and communication lines and would provide access to the upslope side of the flowline for flowline replacement construction and potential erosion remediation access.

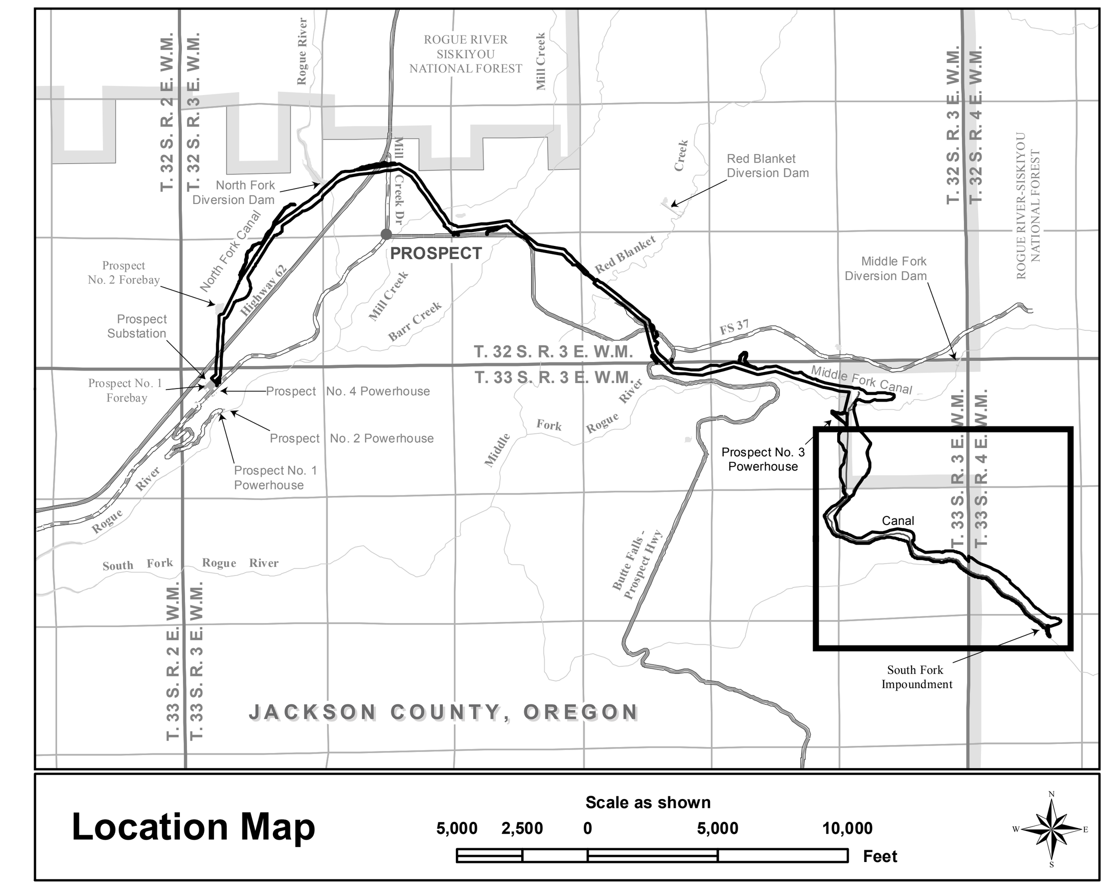
West of the National Forest boundary (beginning on the section line between Section 12 T33S R3E WM and Section 7 T33S R4E WM), the proposed boundary generally maintains the current 100-ft buffer width on each side of the water conveyance system but is widened in places to incorporate the access roads and maintenance areas along the water conveyance system (see sheet G-1). North of the penstock intake, the boundary is reduced to follow a 50-ft east offset of the center line of the spillway and Daniel Creek or a 15-ft west offset from the center line of an access road, to exclude excess lands (see sheet G-1).

The Sag Pipe to the Middle Fork Canal has been added to the proposed boundary (see sheet G-2). This feature is also in the Prospect Nos. 1, 2 & 4 Project boundary.

The proposed boundary generally incorporates a 100-ft wide buffer along each side of the 69kV transmission line as shown in the existing Exhibit G but has been realigned to match pole locations and expanded in places to add transmission line access roads (sheets G-2 through G5). The access roads are shared with the Prospect Nos. 1, 2 & 4 Project. The boundary has also been adjusted in a few locations to follow property lines.

A Public Land Survey System (PLSS) description of lands of the United States located within the current and proposed Project boundary and identified on these maps can be found in Section A.4 of this application for a new license.





Flowline
Canal
Canal Tunnel
Penstock
Spillway, Sag Pipe
Transmission Tower
Transmission Line
Project Facility
Non-Project Facility
Highway
Road
Boundary Point *
Reference Point **
City
Stream
PacifiCorp Land
FERC Boundary
Water Body
USFS Administrative Boundary
Township/Range
Section
Qtr Qtr Section

* *Boundary Point numbers correspond to boundary description table.*
** *Reference Point coordinates are in meters.*

Map Projection: UTM Zone 10, NAD 83, meters

MAP TEXT ABBREVIATIONS:
- SEC 24 = Section 24 Reservation under Federal Power Act
- FED = Federally Owned Land
- E# = Easement Reference Number
- PAC = PacifiCorp Owned Lands
- POB = Point of Beginning
- PRIV = Private Land
- USFS = USDA Forest Service

PROJECT BOUNDARY ACREAGE		
PacifiCorp Project Boundary:	376.2	ACRES
Federal Lands included within the project boundary (all non-transmission line):	52.5	ACRES

I hearby state that the project boundary represented on this drawing is developed with reasonable accuracy in accordance with FERC requirements. Data has been developed by PacifiCorp's GIS department from a variety of sources including Federal, State, County, and PacifiCorp GIS sources including orthophotos. No field surveys were conducted. All reasonable efforts have been made to ensure that positional accuracy conforms to National Map Accuracy Standards for maps at 1:24000 scale. Public Land Survey data are approximately located. Property lines are approximately located.

REGISTERED PROFESSIONAL LAND SURVEYOR
OREGON
MARK R. HEIDECKE
2132
Expires 6/30/2017

PACIFICORP

PacifiCorp has reviewed the Project boundary shown herein. PacifiCorp either owns in fee simple or possesses the flowage easements or property rights* for all lands drawn on this map that are inside the boundary.

* Property rights to be updated for areas shown as PacifiCorp Interest Lands.

Exhibit G - 1 **Rev. 0a**

Prospect 3 Hydroelectric Project FERC No. P-2337
Draft License Application August 3, 2016

Project Boundary

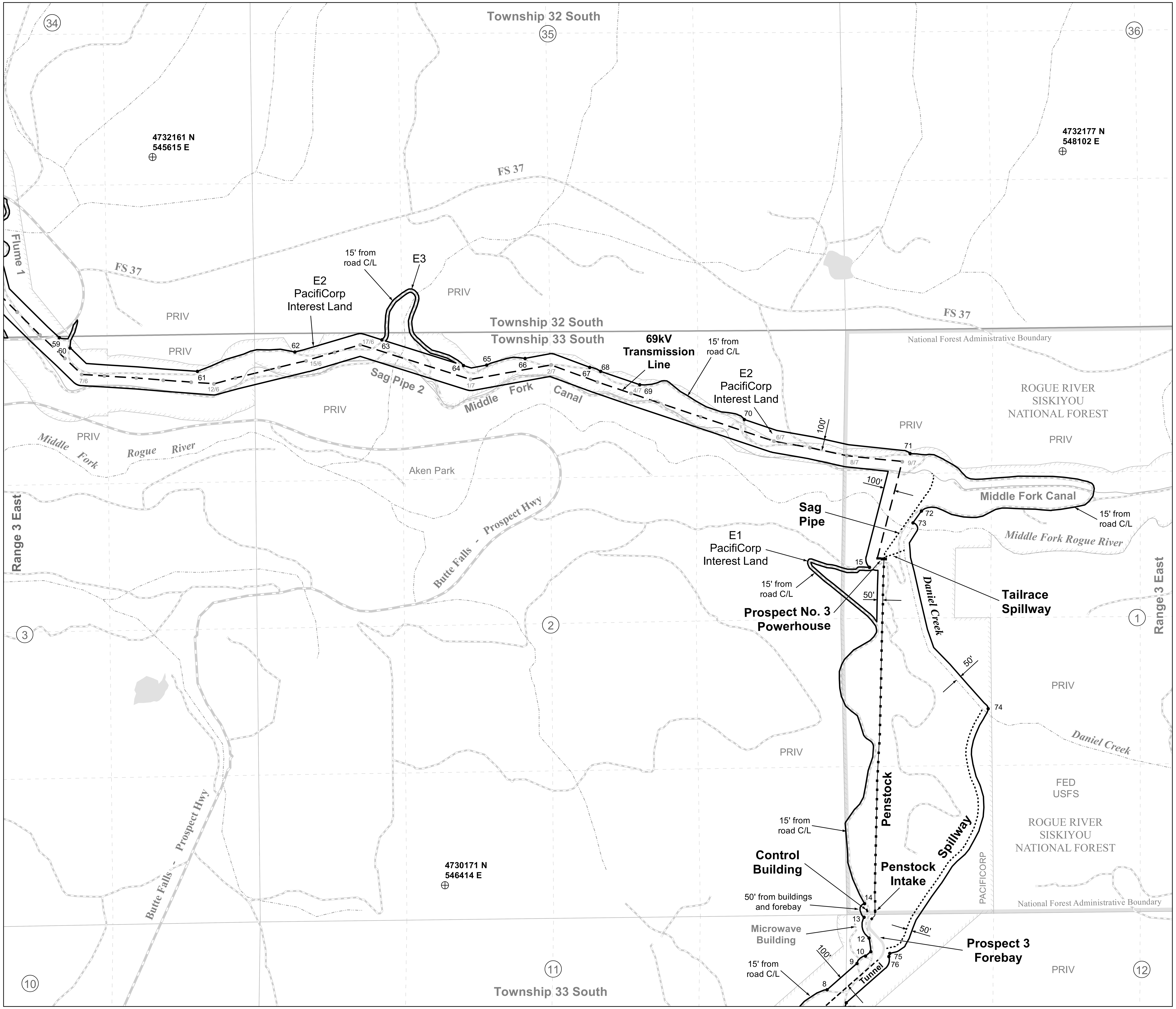
Original Drawing Dated July 2016

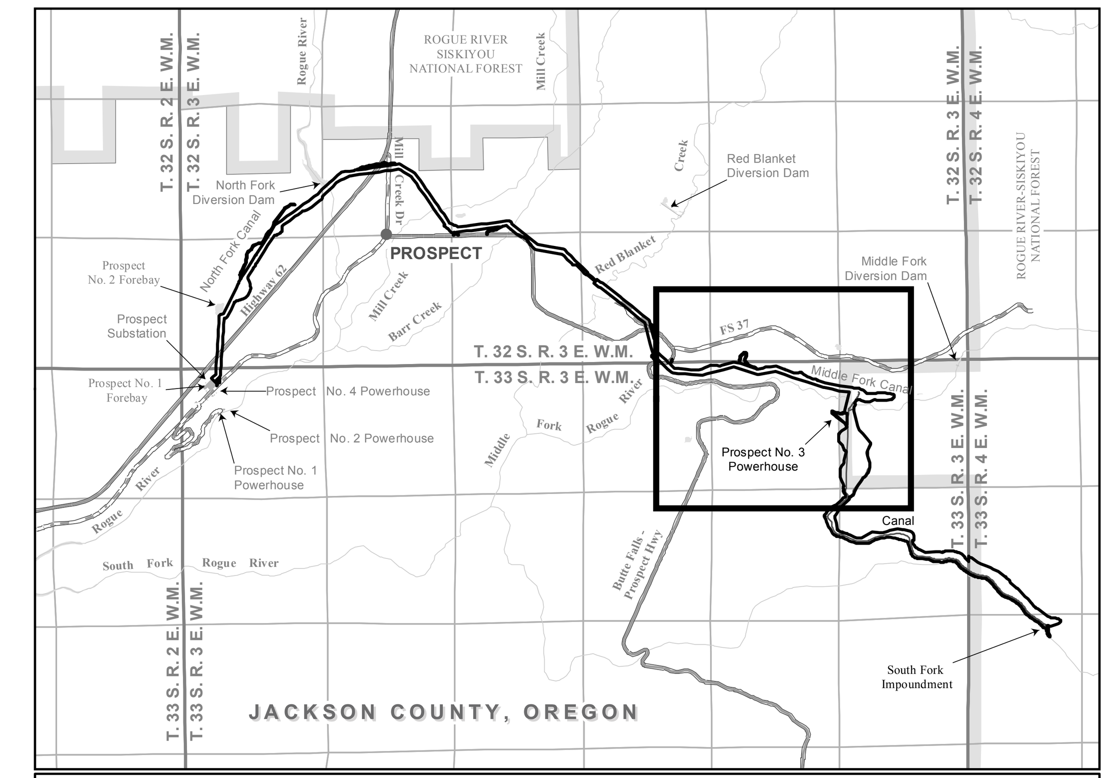
Scale as shown
500 250 0 500 1,000 Feet

N

Rev. No.	Date	Old FERC No.	Description
0a	8/3/16		Draft Application for License for Major Project-Existing Dam

FERC Drawing No. P-2337-____





Location Map

Scale as shown

5,000 2,500 0 5,000 10,000 Feet

	Flowline		Boundary Point *
	Canal		Reference Point **
	Canal Tunnel		City
	Penstock		Stream
	Spillway, Sag Pipe		PacifiCorp Land
	Transmission Tower		FERC Boundary
	Transmission Line		Water Body
	Project Facility		USFS Administrative Boundary
	Non-Project Facility		Township/Range
	Highway		Section
	Road		Qtr Qtr Section

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Rev. No.	Date	Old FERC No.	Description
0a	8/3/16		Draft Application for License for Major Project-Existing Dam

Exhibit G - 2 Rev. 0a

Prospect 3 Hydroelectric Project FERC No. P-2337
Draft License Application August 3, 2016

Project Boundary

Original Drawing Dated July 2016

Scale as shown

500 250 0 500 1,000 Feet

N

FERC Drawing No. P-2337-____

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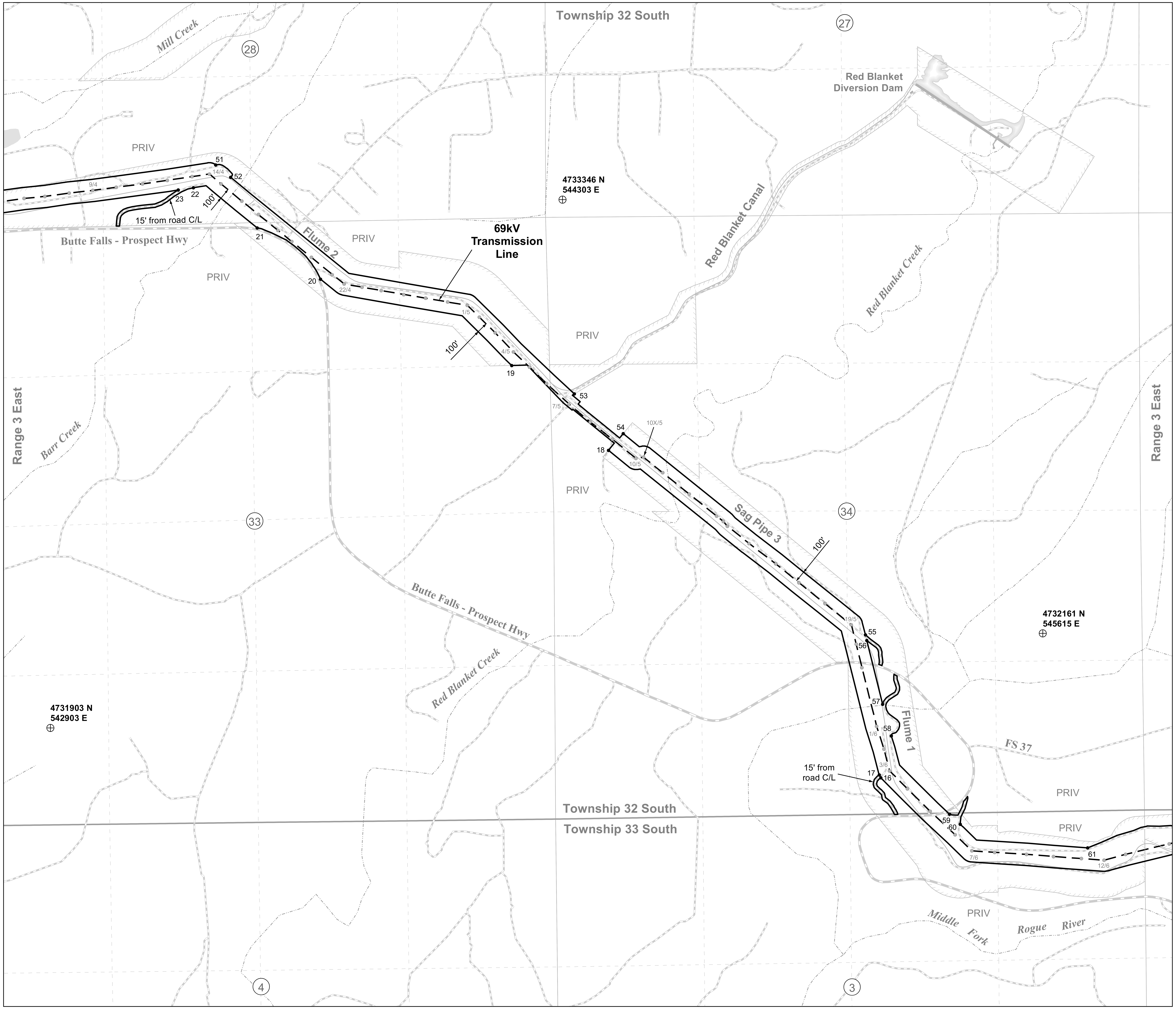

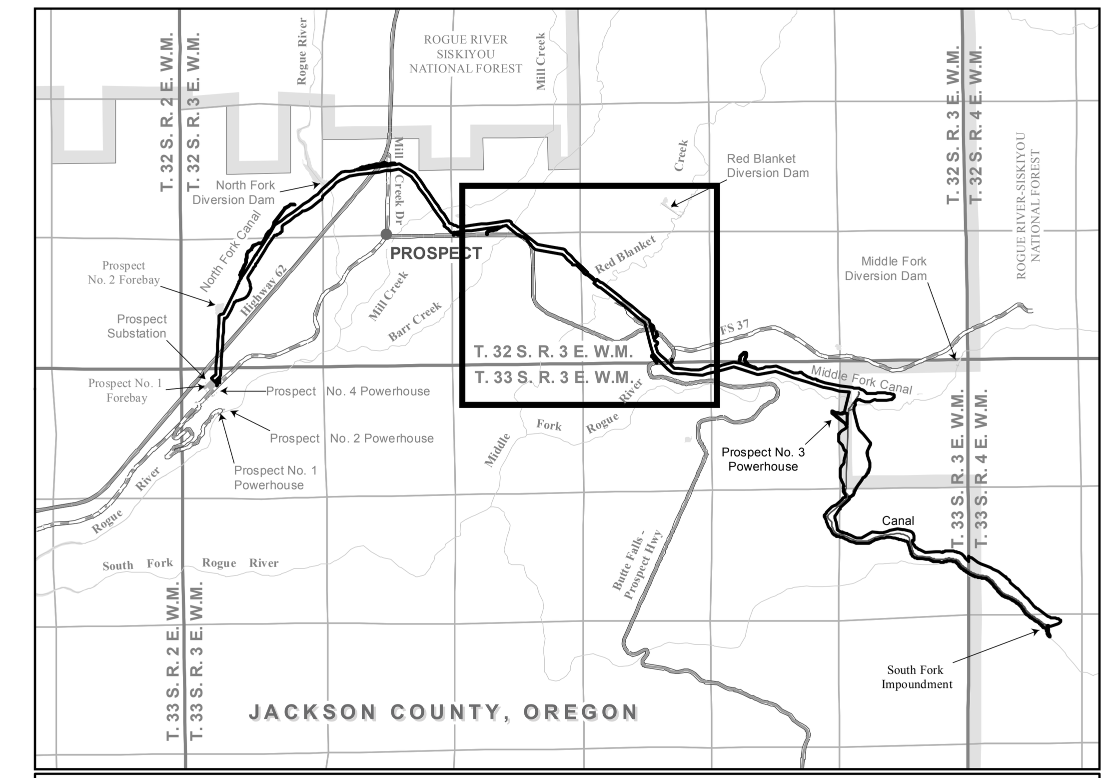

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Scale as shown
5,000 2,500 0 5,000 10,000 Feet

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	Canal		Reference Point **
	Canal Tunnel		City
	Penstock		Stream
	Spillway, Sag Pipe		PacifiCorp Land
	Transmission Tower		FERC Boundary
	Transmission Line		Water Body
	Project Facility		USFS Administrative Boundary
	Non-Project Facility		Township/Range
	Highway		Section
	Road		Qtr Qtr Section

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Exhibit G - 3 **Rev. 0a**

Prospect 3 Hydroelectric Project FERC No. P-2337
Draft License Application August 3, 2016

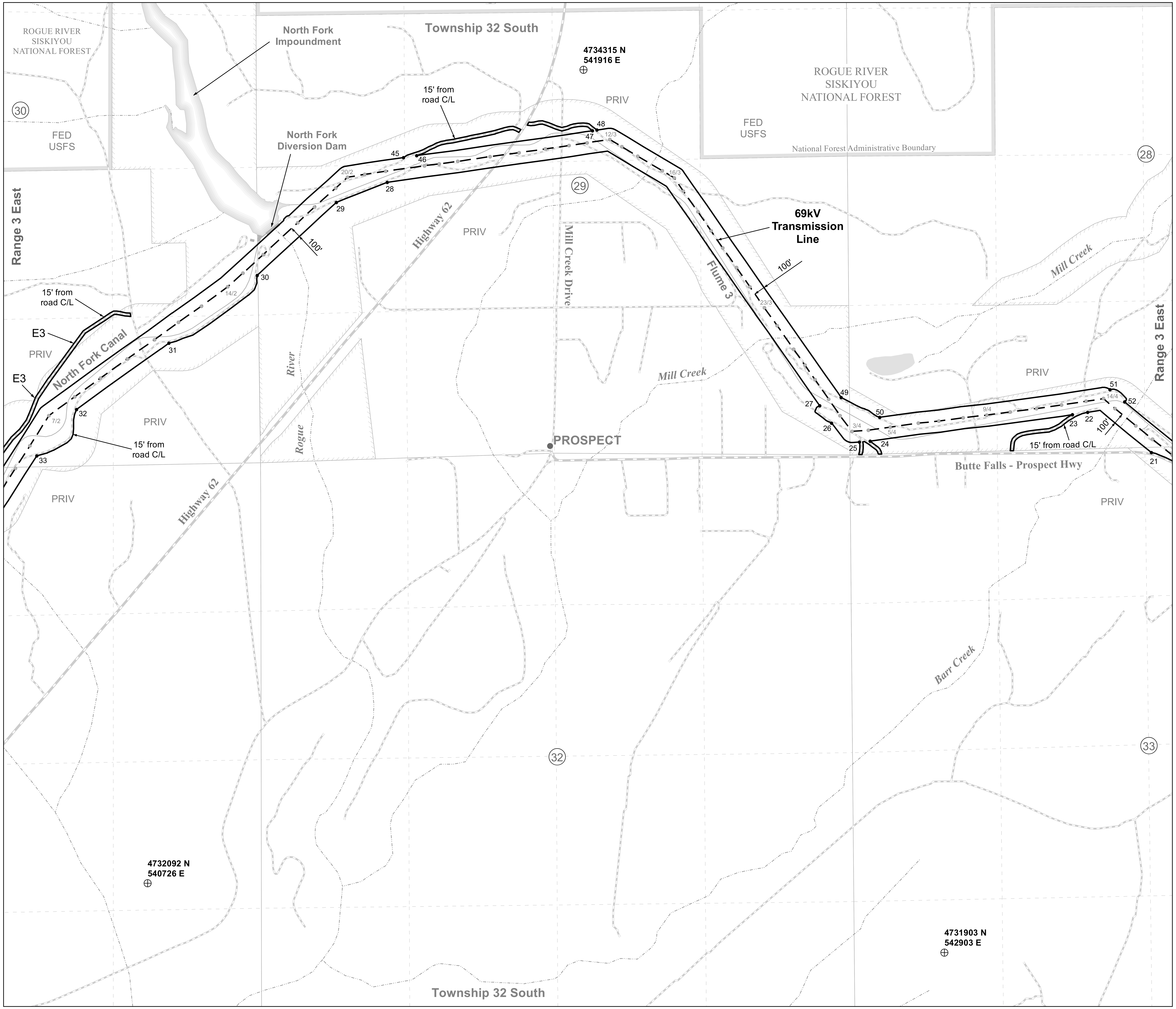
Project Boundary

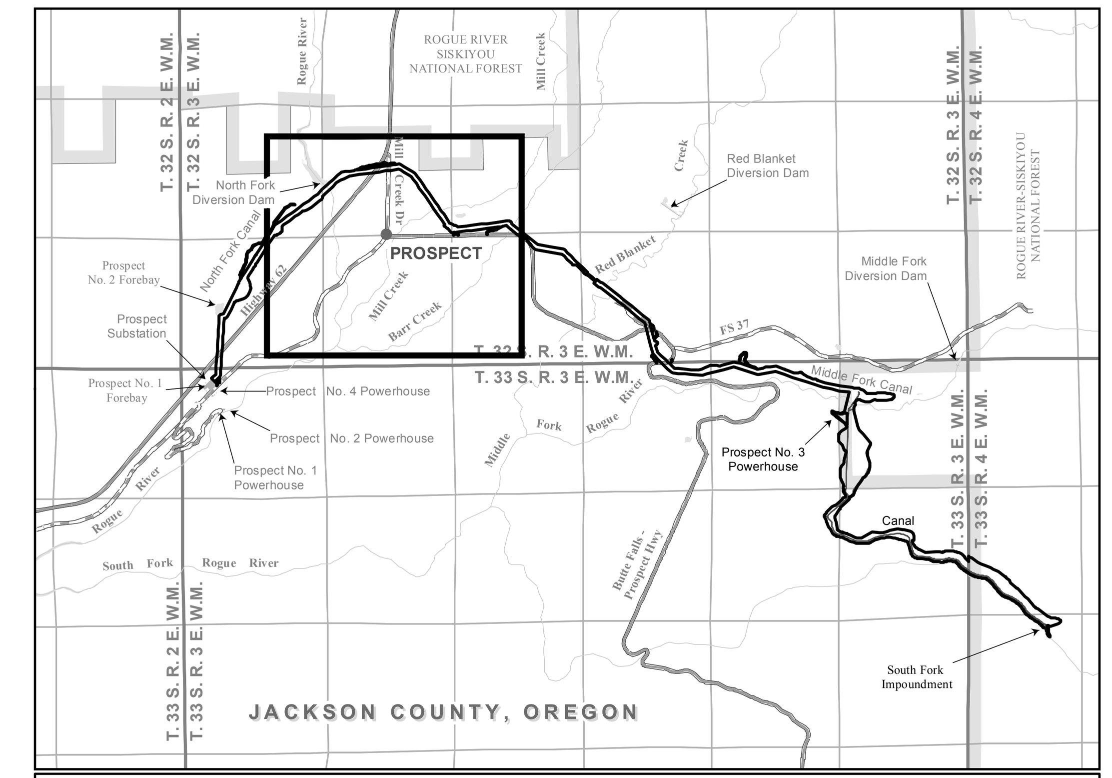
Original Drawing Dated July 2016

Scale as shown
500 250 0 500 1,000 Feet

Rev. No.	Date	Old FERC No.	Description
0a	8/3/16		Draft Application for License for Major Project-Existing Dam

FERC Drawing No. P-2337-____





Location Map

Scale as shown
5,000 2,500 0 5,000 10,000 Feet

- Flowline
- Canal
- Canal Tunnel
- Penstock
- Spillway, Sag Pipe
- Transmission Tower
- Transmission Line
- Project Facility
- Non-Project Facility
- Highway
- Road
- Boundary Point *
- Reference Point **
- City
- Stream
- PacifiCorp Land
- FERC Boundary
- Water Body
- USFS Administrative Boundary
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Exhibit G - 4 Rev. 0a

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Draft License Application August 3, 2016

Project Boundary

Original Drawing Dated July 2016

Scale as shown
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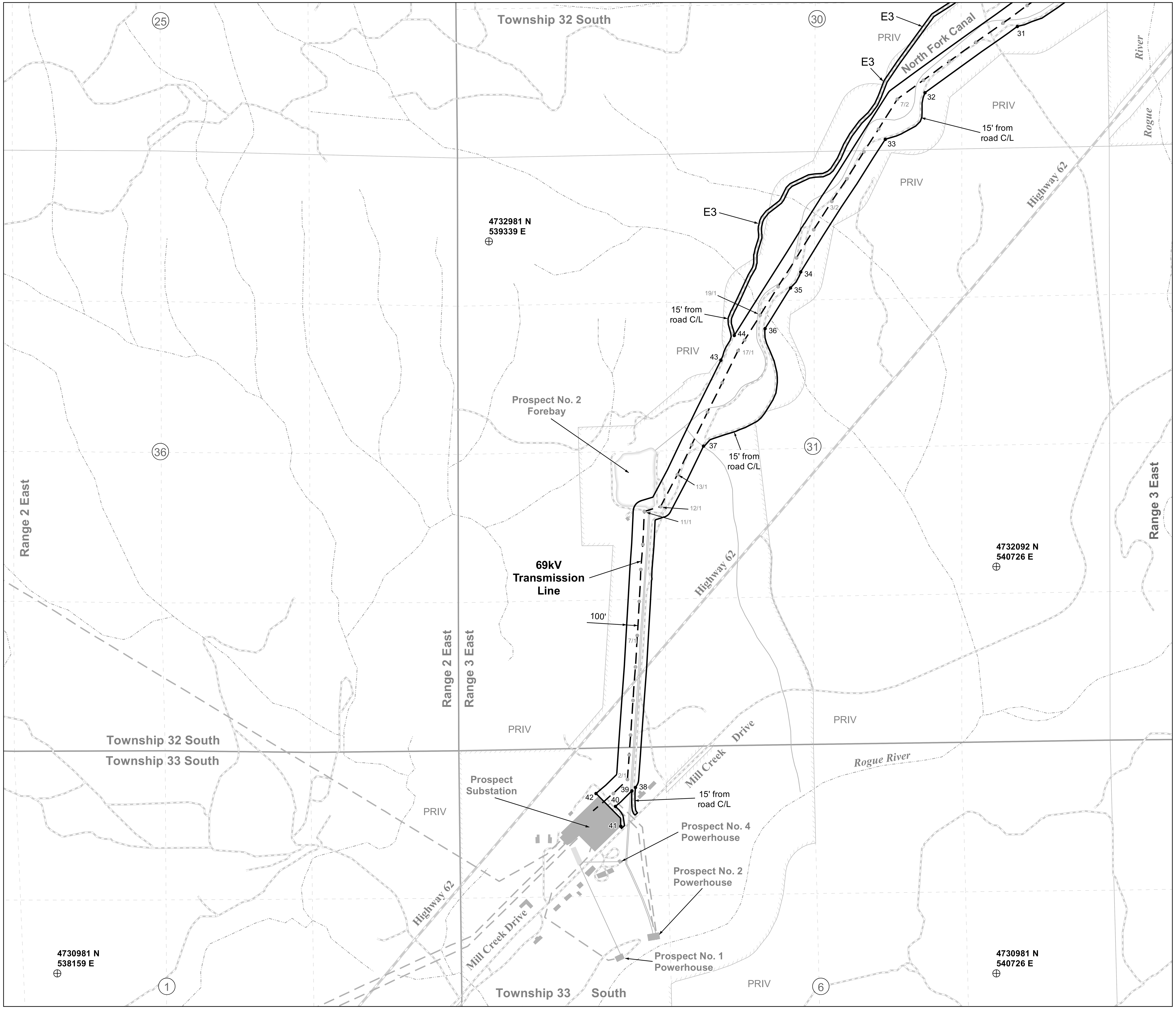
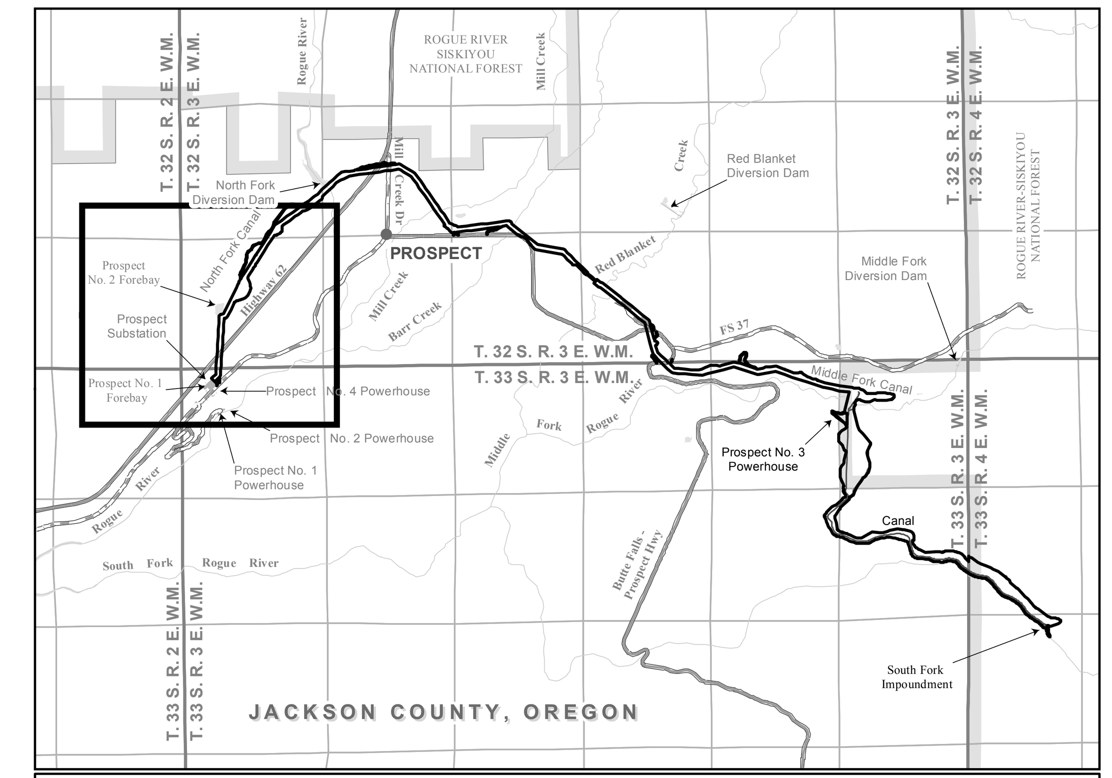
FERC Drawing No. P-2337-____





Location Map

Scale as shown

5,000 2,500 0 5,000 10,000 Feet

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Canal	Reference Point **
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Exhibit G - 5 **Rev. 0a**

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Draft License Application August 3, 2016

Project Boundary

Original Drawing Dated July 2016

Scale as shown

500 250 0 500 1,000 Feet

Rev. No.	Date	Old FERC No.	Description
0a	8/3/16		Draft Application for License for Major Project-Existing Dam

FERC Drawing No. P-2337-____

Project Boundary Table

Point	Northing (Meters)	Easting (Meters)	Bearing	Distance (feet)	Remarks
1	4728234	550136			BEGINNING FROM THE NW CORNER OF SEC 18 T33S R4E AND BEARING S74-56E 3,437.7 FEET (GIS CALCULATED) TO THE EAST LINE OF
					NW NE 1/4 1/4 SECTION 18, THE, POB IS AN UNMARKED POINT THAT IS ALONG A 10-FOOT BUFFER (OFFSET LINE) THAT IS PARALLEL TO THE
					WATER LINE OF THE SOUTH FORK IMPOUNDMENT AT NORMAL MAXIMUM POOL ELEVATION (3375.7 FT MSL).
				421	ALONG SOUTH FORK IMPOUNDMENT BUFFER (10' OFFSET FROM NORMAL MAX POOL WATER LINE)
2	4728349	550082			INTX W/ SOUTH FORK DIVERSION DAM BUFFER (50' FROM FACILITY)
				161.9	ALONG SOUTH FORK DIVERSION DAM BUFFER (50' FROM FACILITY)
3	4728369	550049			INTX W/ CANAL AND FLOWLINE BUFFER (100' FROM CANAL C.L.)
				3843.2	ALONG CANAL AND FLOWLINE BUFFER (100' FROM C.L.)
4	4729030	549122			INTX W/ PACIFICORP PROPERTY LINE (WEST LINE OF SECTION 7)
				3175	ALONG CANAL AND FLOWLINE BUFFER (100' FROM C.L.)
5	4729426	548358			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				756.4	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
6	4729484	548136			INTX W/ CANAL BUFFER (100' FROM CANAL C.L.)
				2687	ALONG CANAL BUFFER (100' FROM C.L.)
7	4729583	547392			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				1279	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
8	4729885	547459			INTX W/ WATERWAY TUNNEL BUFFER (100' FROM TUNNEL C.L.)
			N48-46-44E	358.1	ALONG WATERWAY TUNNEL BUFFER (100')
9	4729957	547541			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				108.7	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
10	4729977	547563			INTX W/ WATERWAY TUNNEL BUFFER (100' FROM TUNNEL C.L.)
			N48-46-42E	62.8	ALONG WATERWAY TUNNEL BUFFER (100')
11	4729990	547578			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				121.7	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
12	4730026	547573			INTX W/ FOREBAY BUFFER (50' FROM C.L.)
				207.2	ALONG FOREBAY BUFFER (50' FROM C.L.)
13	4730083	547560			INTX W/ CONTROL BUILDING BUFFER (50' FROM FACILITY)
				151.8	ALONG CONTROL BUILDING BUFFER (50' FROM FACILITY)
14	4730121	547561			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				4288.1	ALONG ACCESS ROAD BUFFER (15' FROM C.L.) EXCEPTING LAND BETWEEN ROAD AND PENSTOCK BUFFER
15	4731040	547574			INTX W/ TRANSMISSION LINE BUFFER (100' FROM C.L.)
				9478.7	ALONG TRANSMISSION LINE BUFFER (100' FROM C.L.)
16	4731766	545173			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				888.9	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
17	4731774	545168			INTX W/ TRANSMISSION LINE BUFFER (100' FROM C.L.)
				3995	ALONG TRANSMISSION LINE BUFFER (100' FROM C.L.)
18	4732661	544428			INTX W/ PACIFICORP PROPERTY LINE
				1283.2	ALONG PACIFICORP PROPERTY LINE
19	4732893	544164			INTX W/ TRANSMISSION LINE BUFFER (100' FROM C.L.)
				1961.3	ALONG TRANSMISSION LINE BUFFER (100' FROM C.L.)
20	4733128	543642			INTX W/ NORTH SHOULDER OF BUTTE FALLS - PROSPECT HIGHWAY (15' FROM C.L.)
				757.2	ALONG NORTH SHOULDER OF BUTTE FALLS - PROSPECT HIGHWAY (15' FROM C.L.)
21	4733269	543468			INTX W/ TRANSMISSION LINE BUFFER (100' FROM C.L.)
				708.4	ALONG TRANSMISSION LINE BUFFER (100' FROM C.L.)
22	4733379	543294			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				1539.6	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
23	4733372	543253			INTX W/ TRANSMISSION LINE BUFFER (100' FROM C.L.)
				1828	ALONG TRANSMISSION LINE BUFFER (100' FROM C.L.)
24	4733300	542700			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				637.8	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
25	4733297	542671			INTX W/ TRANSMISSION LINE BUFFER (100' FROM C.L.)
				329.1	ALONG TRANSMISSION LINE BUFFER (100' FROM C.L.)
26	4733350	542595			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				253.9	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
27	4733397	542562			INTX W/ TRANSMISSION LINE BUFFER (100' FROM C.L.)
				5009.6	ALONG TRANSMISSION LINE BUFFER (100' FROM C.L.)
28	4734007	541381			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				489.9	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
29	4733952	541242			INTX W/ TRANSMISSION LINE BUFFER (100' FROM C.L.)
				966.7	ALONG TRANSMISSION LINE BUFFER (100' FROM C.L.)
30	4733753	541025			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				1048.5	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
31	4733568	540783			INTX W/ TRANSMISSION LINE BUFFER (100' FROM C.L.)
				1018.3	ALONG TRANSMISSION LINE BUFFER (100' FROM C.L.)
32	4733387	540531			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				620.9	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
33	4733260	540422			INTX W/ TRANSMISSION LINE BUFFER (100' FROM C.L.)
				1411	ALONG TRANSMISSION LINE BUFFER (100' FROM C.L.)
34	4732897	540191			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				172.1	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
35	4732854	540163			INTX W/ TRANSMISSION LINE BUFFER (100' FROM C.L.)
				429.7	ALONG TRANSMISSION LINE BUFFER (100' FROM C.L.)
36	4732743	540094			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				1444.2	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
37	4732421	539926			INTX W/ TRANSMISSION LINE BUFFER (100' FROM C.L.)
				3227.1	ALONG TRANSMISSION LINE BUFFER (100' FROM C.L.)
38	4731489	539740			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				490.8	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
39	4731479	539730			INTX W/ TRANSMISSION LINE BUFFER (100' FROM C.L.)
				202.6	ALONG TRANSMISSION LINE BUFFER (100' FROM C.L.)
40	4731437	539685			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				255.5	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
41	4731383	539699			INTX W/ PROSPECT SUBSTATION FENCE
				383.8	ALONG PROSPECT SUBSTATION FENCE
42	4731472	539632			INTX W/ TRANSMISSION LINE BUFFER (100' FROM C.L.)
				4222.7	ALONG TRANSMISSION LINE BUFFER (100' FROM C.L.)
43	4732656	539973			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				8358.9	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
44	4732724	540010			INTX W/ TRANSMISSION LINE BUFFER (100' FROM C.L.)
				6618.4	ALONG TRANSMISSION LINE BUFFER (100' FROM C.L.)
45	4734075	541425			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				2090.9	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
46	4734080	541461			INTX W/ TRANSMISSION LINE BUFFER (100' FROM C.L.)
				1591.5	ALONG TRANSMISSION LINE BUFFER (100' FROM C.L.)
47	4734148	541941			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				1292.5	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
48	4734150	541953			INTX W/ TRANSMISSION LINE BUFFER (100' FROM C.L.)
				3356.5	ALONG TRANSMISSION LINE BUFFER (100' FROM C.L.)
49	4733419	542621			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				390.9	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
50	4733365	542726			INTX W/ TRANSMISSION LINE BUFFER (100' FROM C.L.)
				2085.6	ALONG TRANSMISSION LINE BUFFER (100' FROM C.L.)
51	4733441	543355			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				214.8	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
52	4733407	543396			INTX W/ TRANSMISSION LINE BUFFER (100' FROM C.L.)
				3763.4	ALONG TRANSMISSION LINE BUFFER (100' FROM C.L.)
53	4732815	544335			INTX W/ PACIFICORP PROPERTY LINE
				674.9	ALONG PACIFICORP PROPERTY LINE
54	4732707	544469			INTX W/ TRANSMISSION LINE BUFFER (100' FROM C.L.)
				2868.7	ALONG TRANSMISSION LINE BUFFER (100' FROM C.L.)
55	4732157	545130			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				636.1	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
56	4732142	545134			INTX W/ TRANSMISSION LINE BUFFER (100' FROM C.L.)
			S14-2-26E	588.8	ALONG TRANSMISSION LINE BUFFER (100' FROM C.L.)
57	4731967	545178			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				1036.4	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
58	4731881	545202			INTX W/ TRANSMISSION LINE BUFFER (100' FROM C.L.)
				901.2	ALONG TRANSMISSION LINE BUFFER (100' FROM C.L.)
59	4731667	545360			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				529	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
60	4731639	545390			INTX W/ TRANSMISSION LINE BUFFER (100' FROM C.L.)
				1200	ALONG TRANSMISSION LINE BUFFER (100' FROM C.L.)
61	4731575	545738			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				912.4	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
62	4731628	546004			INTX W/ TRANSMISSION LINE BUFFER (100' FROM C.L.)
				811.9	ALONG TRANSMISSION LINE BUFFER (100' FROM C.L.)
63	4731661	546242			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				1563.3	ALONG ACCESS ROAD BUFFER (15' FROM C.L.) EXCEPTING LAND BETWEEN ROAD AND TRANSMISSION LINE BUFFER
64	4731591	546465			INTX W/ TRANSMISSION LINE BUFFER (100' FROM C.L.)
				215.2	ALONG TRANSMISSION LINE BUFFER (100' FROM C.L.)
65	4731592	546529			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				353.9	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
66	4731611	546633			INTX W/ TRANSMISSION LINE BUFFER (100' FROM C.L.)
				605.7	ALONG TRANSMISSION LINE BUFFER (100' FROM C.L.)
67	4731586	546810			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				105.9	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
68	4731575	546840			INTX W/ TRANSMISSION LINE BUFFER (100' FROM C.L.)
				370.2	ALONG TRANSMISSION LINE BUFFER (100' FROM C.L.)
69	4731539	546947			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				1040	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
70	4731443	547232			INTX W/ TRANSMISSION LINE BUFFER (100' FROM C.L.)
				1524.2	ALONG TRANSMISSION LINE BUFFER (100' FROM C.L.)
71	4731350	547685			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				3450.7	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
72	4731194	547717			INTX W/ SAG PIPE BUFFER (50' FROM C.L.)
			S35-17-14W	131.9	ALONG SAG PIPE BUFFER (50' FROM C.L.)
73	4731161	547693			INTX W/ DANIEL CREEK BUFFER (50' FROM C.L.)
				1922.5	ALONG DANIEL CREEK BUFFER (50' FROM C.L.)
74	4730654	547899			INTX W/ SPILLWAY BUFFER (50' FROM C.L.)
				2541.8	ALONG SPILLWAY BUFFER (50' FROM C.L.)
75	4729985	547630			INTX W/ FOREBAY BUFFER (50' FROM C.L.)
				29.2	ALONG FOREBAY BUFFER (50' FROM C.L.)
76	4729976	547627			INTX W/ WATERWAY TUNNEL BUFFER (100' FROM TUNNEL C.L.)
				584.6	ALONG WATERWAY TUNNEL BUFFER (100')
77	4729850	547511			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				1143.3	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
78	4729547	547523			INTX W/ CANAL BUFFER (100' FROM CANAL C.L.)
				217.7	ALONG CANAL BUFFER (100' FROM CANAL C.L.)
79	4729526	547586			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				3267.7	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
80	4729442	548417			INTX W/ CANAL BUFFER (100' FROM CANAL C.L.)
				165.6	ALONG CANAL BUFFER (100' FROM CANAL C.L.)
81	4729393	548431			INTX W/ ACCESS ROAD BUFFER (15' FROM ROAD C.L.)
				603.8	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
82	4729292	548580			INTX W/ N'LY LINE OF THE NW 1/4 SE 1/4 T33S R3E SEC 1
			N88-28-20E	445.9	ALONG N'LY LINE OF THE NW 1/4 SE 1/4 T33S R3E SEC 1
83	4729296	548716			INTX W/ N'LY LINE OF THE NE 1/4 SE 1/4 T33S R3E SEC 1
			N88-28-8E	159.8	ALONG N'LY LINE OF THE NE 1/4 SE 1/4 T33S R3E SEC 1
84	4729297	548764			INTX W/ PACIFICORP PROPERTY LINE
				1350.5	ALONG PACIFICORP PROPERTY LINE
85	4729175	549121			INTX W/ USFS PROPERTY LINE (WEST LINE OF SECTION 7)
			N0-18-30W	210.7	ALONG USFS PROPERTY LINE (WEST LINE OF SECTION 7)
86	4729239	549121			INTX W/ SOUTH SHOULDER OF FS ROAD 3775800 (15' FROM C.L.)
				4717.2	ALONG SOUTH SHOULDER OF FS ROAD 3775800 (15' FROM C.L.)
87	4728441	550277			INTX W/ EAST SIDE OF ACCESS ROAD BUFFER (15' FROM C.L.)
				672.2	ALONG ACCESS ROAD BUFFER (15' FROM C.L.)
88	4728379	550101			INTX W/ SOUTH FORK IMPOUNDMENT BUFFER (10' OFFSET FROM NORMAL MAX POOL WATER LINE)
				559.5	ALONG SOUTH FORK IMPOUNDMENT BUFFER (10' OFFSET FROM NORMAL MAX POOL WATER LINE) TO POB

Transmission Line Center Line Table

Point	Northing (Meters)	Easting (Meters)	Bearing	Distance (feet)	Description
SUB STATION	4731425	539624			PROSPECT SUBSTATION
			N47-44-39E	417.2	
2/1	4731510	539718			TRANSMISSION TOWER
			N3-52-36E	1293.5	
7/1	4731904	539745			TRANSMISSION TOWER
			N3-17-2E	1113.8	
11/1	4732243	539764			TRANSMISSION TOWER
			N72-48-36E	151.7	
12/1	4732256	539808			TRANSMISSION TOWER
			N27-53-4E	323.7	
13/1	4732343	539854			TRANSMISSION TOWER
			N26-3-40E	1236.1	
17/1	4732682	540020			TRANSMISSION TOWER
			N32-1-0E	375.9	
19/1	4732779	540081			TRANSMISSION TOWER
			N32-10-12E	1205.2	
3/2	4733090	540276			TRANSMISSION TOWER
			N32-41-13E	1089.2	
7/2	4733369	540456			TRANSMISSION TOWER
			N54-13-59E	1977	
14/2	4733722	540945			TRANSMISSION TOWER
			N47-32-6E	1454.4	
20/2	4734021	541272			TRANSMISSION TOWER
			N81-48-6E	2377.1	
12/3	4734124	541989			TRANSMISSION TOWER
			S59-7-53E	672.5	
16/3	4734019	542165			TRANSMISSION TOWER
			S34-46-41E	1417	
23/3	4733664	542411			TRANSMISSION TOWER
			S35-20-27E	1358.1	
3/4	4733327	542650			TRANSMISSION TOWER
			N83-47-52E	344	
5/4	4733338	542755			TRANSMISSION TOWER
			N82-52-50E	873.7	
9/4	4733371	543019			TRANSMISSION TOWER
			N81-57-39E	1055.7	
14/4	4733416	543338			TRANSMISSION TOWER
			S50-47-4E	1559.4	
22/4	4733115	543706			TRANSMISSION TOWER
			S80-8-49E	1121.6	
1/5	4733057	544043			TRANSMISSION TOWER
			S44-47-9E	587.1	
4/5	4732930	544169			TRANSMISSION TOWER
			S46-45-15E	682.4	
7/5	4732787	544320			TRANSMISSION TOWER
			S50-59-21E	774	
10/5	4732639	544504			TRANSMISSION TOWER
			N82-1-17E	68.7	
10X/5	4732642	544524			TRANSMISSION TOWER
			S51-8-29E	2391.9	
19/5	4732185	545092			TRANSMISSION TOWER
			S14-3-43E	938.8	
1/6	4731907	545161			TRANSMISSION TOWER
			S16-6-49E	416.4	
3/6	4731785	545197			TRANSMISSION TOWER
			S45-47-7E	1027.9	
7/6	4731567	545421			TRANSMISSION TOWER
			S85-58-4E	1189.7	
12/6	4731541	545783			TRANSMISSION TOWER
			N75-57-47E	852.1	
15/6	4731604	546035			TRANSMISSION TOWER
			N73-32-8E	506.6	
17/6	4731648	546183			TRANSMISSION TOWER
			S72-32-35E	1037.4	
1/7	4731553	546485			TRANSMISSION TOWER
			N79-46-5E	733	
2/7	4731593	546705			TRANSMISSION TOWER
			S70-19-43E	761.2	
4/7	4731514	546923			TRANSMISSION TOWER
			S71-31-12E	1350.6	
6/7	4731384	547313			TRANSMISSION TOWER
			S78-45-20E	664.6	
8/7	4731345	547512			TRANSMISSION TOWER
			S83-58-49E	500.8	
9/7	4731328	547664			TRANSMISSION TOWER
			S14-25-13W	902.9	
TRANS FORMER	4731062	547595			TRANSFORMER AT POWERHOUSE

Easement Reference Table

Easement/ Property Rights No.	Interest Type	Jackson County Recorder No.
E1	Road use agreement (amendment or new agreement needed)	
E2	Easement for Transmission structure and road use (new easement needed)	
E3	Right-of-way (reserved in deed to Elk Creek Timber, 1/4/1962)	546140 (Vol 531 pg 204)

Notes:
1) Information in the table is based on GIS derived coordinates and measurements, and is not intended to represent station points or measurements established by ground surveys.
2) Coordinates and Bearings are in UTM Zone 10, NAD 83, meters.
3) Distances are in U.S. survey feet.
3) Project is located in the state of Oregon, Willamette Meridian.

I hearby state that the project boundary represented on this drawing is developed with reasonable accuracy in accordance with FERC requirements. Data has been developed by PacifiCorp's GIS department from a variety of sources including Federal, State, County, and PacifiCorp GIS sources including orthophotos. No field surveys were conducted. All reasonable efforts have been made to ensure that positional accuracy conforms to National Map Accuracy Standards for maps at 1:24000 scale. Public Land Survey data are approximately located. Property lines are approximately located.

REGISTERED PROFESSIONAL LAND SURVEYOR
OREGON
MARK R. HEIDECKE
2132

Expires 6/30/2017

PACIFICORP

PacifiCorp has reviewed the Project boundary shown herein. PacifiCorp either owns in fee simple or possesses the flowage easements or property rights* for all lands drawn on this map that are inside the boundary.

* Property rights to be updated for areas shown as PacifiCorp Interest Lands.

Exhibit G - 6 Rev. 0a

Prospect 3 Hydroelectric Project FERC No. P-2337
Draft License Application August 3, 2016

Project Boundary Description

Original Drawing Dated July 2016

Rev. No.	Date	Old FERC No.	Description
0a	8/3/16		Draft Application for License for Major Project-Existing Dam

FERC Drawing No. P-2337-____

 U:\Projects\Exhibit_G\Prospect\2016-04 P3 Revision\Prospect 3 Exhibit G_6.mxd 07/01/2016

EXHIBIT H—MARKET INTEGRATION AND COSTS; PROJECT OPERATIONS AND MAINTENANCE

H.1 APPLICANT PLANS AND ABILITIES

PacifiCorp, an indirect wholly-owned subsidiary of Berkshire Hathaway Energy Company (BHE), is a United States-regulated electric utility company headquartered in Oregon that serves 1.8 million retail electric customers in portions of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp is principally engaged in the business of generating, transmitting, distributing and selling electricity. PacifiCorp's combined service territory covers approximately 143,000 square miles and includes diverse regional economies across six states. No single segment of the economy dominates the service territory, which helps mitigate PacifiCorp's exposure to economic fluctuations. In the western portion of the service territory, consisting of Oregon, southern Washington and northern California, the principal industries are agriculture, manufacturing, forest products, food processing, technology, government and primary metals. In addition to retail sales, PacifiCorp buys and sells electricity on the wholesale market with other utilities, energy marketing companies, financial institutions and other market participants to balance and optimize the economic benefits of electricity generation, retail customer loads and existing wholesale transactions.

PacifiCorp's operations are conducted under numerous franchise agreements, certificates, permits and licenses obtained from federal, state and local authorities. The average term of the franchise agreements is approximately 27 years, although their terms range from five years to indefinite. Several of these franchise agreements allow the municipality the right to seek amendment to the franchise agreement at a specified time during the term. PacifiCorp generally has an exclusive right to serve electric customers within its service territories and, in turn, has an obligation to provide electric service to those customers. In return, the state utility commissions have established rates on a cost-of-service basis, which are designed to allow PacifiCorp an opportunity to recover its costs of providing services and to earn a reasonable return on its investments.

PacifiCorp was initially incorporated in 1910 under the laws of the state of Maine under the name Pacific Power & Light Company. In 1984, Pacific Power & Light Company changed its name to PacifiCorp. In 1989, it merged with Utah Power and Light Company, a Utah corporation, in a transaction wherein both corporations merged into a newly formed Oregon corporation. The resulting Oregon corporation was re-named PacifiCorp, which is the operating entity today. PacifiCorp delivers electricity to customers in Utah, Wyoming and Idaho under the trade name Rocky Mountain Power and to customers in Oregon, Washington and California under the trade name Pacific Power.

PacifiCorp and its antecedent business entities have furnished electric service within Southern Oregon and Northern California for over 100 years. Since the development of the greater

Prospect hydroelectric development, including the Prospect Nos. 1, 2, and 4 Hydroelectric Project (FERC Project No. P-2630) and the Prospect No. 3 Hydroelectric Project (FERC Project No. P-2337), in the early 1930s, PacifiCorp has modified and upgraded Project facilities and control equipment to provide reliable, efficient electricity supply for their customers.

PacifiCorp does not propose any upgrades for increased capacity during the proposed license term. The turbine runner was replaced in 1997, and PacifiCorp may replace the current runner during the proposed license term. Although turbine capacity may increase with turbine replacement, generator capacity limits the installed capacity at 7,200 kW.

As a result of the relicensing process studies and development of protection, mitigation, and enhancement measures, proposed minimum in-stream flow releases of 30 cfs from March 1 through July 31 and 20 cfs from August 1 through February 28 in the Project bypassed reach would decrease current annual generation by 4,864 MWh/year to 30,186 MWh/year, based on the current 30-year average generation of 35,050 MWh/year.

There are no upstream or downstream water resource projects that require coordination with Project operations, which are run-of-river. Flows immediately downstream of the confluence of the South and North Fork Rogue Rivers are regulated by U.S. Army Corps of Engineers operations at the William L. Jess Dam.

PacifiCorp operates and maintains the Project in accordance with guidelines established by both the Western Electricity Coordinating Council (WECC) and the North American Electric Reliability Council (NERC). The Project resides within the PacifiCorp West Balancing Authority Area. PacifiCorp is required under NERC standards to maintain a 5 percent operating reserve requirement for the amount of online generation the Project produces each hour.

PacifiCorp and the California Independent System Operator (ISO) launched the Energy Imbalance Market (EIM) on November 1, 2014. The EIM is a voluntary market and the first western energy market outside of California, including six states upon launch: California, Idaho, Oregon, Utah, Washington, and Wyoming. The EIM uses California ISO's advanced market systems that automatically balance supply and demand for electricity every 15 minutes, dispatching the least-cost resources every five minutes. Since the launch of the EIM, NV Energy joined the market December 1, 2015, adding Nevada to the EIM footprint. Puget Sound Energy and Arizona Public Service are scheduled to join on October 1, 2016. Portland General Electric is expected to join the EIM on October 1, 2017, and other balancing authorities in the west have indicated interest. PacifiCorp continues to work with the California ISO, existing and prospective EIM entities, and stakeholders to enhance market functionality and support market growth with the addition of new EIM entities.

The California ISO is exploring expanding into a regional ISO. PacifiCorp is exploring joining the regional ISO and becoming a full participating transmission owner (PTO). This effort is aimed at reducing costs for consumers, enhancing coordination and reliability of western electric networks, facilitating the integration of renewable resources, reducing emissions, and enhancing regional transmission planning and expansion.

H.2 APPLICANT NEED FOR PROJECT GENERATION

PacifiCorp serves 740,000 retail customers, including residential, commercial, and industrial sectors, in Washington, Oregon, and California as Pacific Power. Their load requirements were 17.7 million MWhs in calendar year 2015 and are forecasted to more than 17.8 million MWhs in calendar year 2016.

PacifiCorp is required to have resources available to continuously meet its customer needs. The percentage of PacifiCorp's energy supplied by energy source varies from year to year and is subject to numerous operational and economic factors such as planned and unplanned outages, fuel commodity prices, fuel transportation costs, weather, environmental considerations, transmission constraints, and wholesale market prices of electricity. PacifiCorp evaluates these factors continuously in order to facilitate economical dispatch of its generating facilities. When factors for one energy source are less favorable, PacifiCorp must place more reliance on other energy sources. For example, PacifiCorp can generate more electricity using its low cost hydroelectric and wind-powered generating facilities when factors associated with these facilities are favorable. When factors associated with hydroelectric and wind resources are less favorable, PacifiCorp increases its reliance on coal- and natural gas-fueled generation or purchased electricity.

In addition to meeting its customers' energy needs, PacifiCorp is required to maintain operating reserves on its system to mitigate the impacts of unplanned outages or other disruption in supply, and to meet intra-hour changes in load and resource balance. This operating reserve requirement is dispersed across PacifiCorp's generation portfolio on a least-cost basis based on the operating characteristics of the portfolio. Operating reserves may be held on hydroelectric, coal-fueled or natural gas-fueled resources. PacifiCorp manages certain risks relating to its supply of electricity and fuel requirements by entering into various contracts, which may be accounted for as derivatives and may include forwards, options, swaps and other agreements.

The 30-year (1986-2015) average annual generation of the Project is 35,050 MWh. All of the power produced by the Project is taken into PacifiCorp’s electric system for consumption by the utility’s customers. The Project’s estimated historical annual cost to produce power is based on the BusBar cost of the Project. BusBar costs include annual depreciation, capital project financing based on the weighted average cost of capital, income and real estate taxes, and annual operations and maintenance costs. The average historical annual cost of power produced by the Project has been approximately $1.6 million, or approximately $43.45 per MWh, for the period 2011 to 2015. Based on an average annual consumption of 12,000 kWhs per household, the average power production from the Project is enough to satisfy the needs of approximately 2,920 homes.

H.2.1 Alternative Sources of Power

PacifiCorp purchases and sells power in the short-term energy markets to balance the seasonal and daily variations in its customer loads and PacifiCorp's owned and contracted resources. PacifiCorp has also engaged in progressive conservation efforts to encourage its customers to be as efficient as possible with their electric consumption. If load growth cannot be met through cost-effective conservation, then new resource acquisitions, wholesale market purchases, or power supply contracts must be sought. If a new license is not granted for the Project, PacifiCorp would purchase an equivalent amount of replacement power from the wholesale power market.

H.2.2 Costs of Alternative Sources of Power

At a discount rate of 6.57% and based on the October 2016 Mid-Columbia flat-price official forward price curve[1], the net present value of replacement power from 2019 through 2058 is $20.7 million (i.e., $57.1 million in 2016 dollars). Relying on the wholesale power market to replace the Project's generation exposes PacifiCorp to increased financial and supply risks.

H.2.3 Effects of Alternative Sources of Power

Any viable new generating resource equal in output and comparable in operating characteristics to the Project would likely be more expensive in the long-term than continued operation of the existing Project. Therefore, under current laws and regulations, replacing the Project with a different generating resource and decommissioning the Project could increase the retail power costs in PacifiCorp's service territory.

The Project is certified by the Low Impact Hydropower Institute (LIHI) through December 31, 2019. PacifiCorp will have the option to undergo re-certification once the current certification expires. LIHI is a non-profit organization dedicated to reducing the impacts of hydropower generation through the certification of hydro projects that have avoided or reduced their environmental impacts. The certification requirements include the use of a stringent set of mitigation measures and environmental impact standards. As a project with LIHI certification, Prospect No. 3 is an eligible resource under Oregon's Renewable Portfolio Standard (RPS) program. Oregon's RPS requires large investor-owned utilities to ensure that 50 percent of their retails sales come from renewable generation by 2040 with interim targets in years 2020, 2025, and 2035. PacifiCorp demonstrates compliance with the RPS by retiring renewable energy certificates (RECs) which represent the environmental and non-power attributes associated with one megawatt-hour of generation from an eligible renewable resource. RECs from low-impact hydro projects are low cost and represent reliable and cost-effective way for PacifiCorp meet its RPS compliance requirements. The Project contributes significant value for PacifiCorp in meeting RPS requirements--without its LIHI resources, PacifiCorp would potentially be required

[1] The last year of the March 2016 official forward price curve is 2045. Projected costs for years beyond 2045 were held flat to 2045 costs (i.e., not inflated).

to acquire or purchase replacement energy and RECs, likely at a higher cost. This value will only increase as the RPS requirements increase in future years.

Because the Project is a small contributor to PacifiCorp's overall power supply portfolio, there would be minimal impact to the region's overall load characteristics. However, the loss of any base load generation, such as the Project, could increase the number of transmission curtailments PacifiCorp may expect under certain system conditions.

If the license were transferred to a different licensee, the Project's operating costs and power benefits would be transferred to the new licensee. This would result in a reallocation of the Project's net benefits from PacifiCorp's customers to the customers of the new licensee.

H.3 COSTS AND AVAILABILITY OF ALTERNATIVE SOURCES OF POWER

H.3.1 Average Annual Cost of Project Generation

The estimated Average Annual Cost of Project Generation is based on the present value of future Project costs, including net investment, depreciation and amortization, taxes, operations and license implementation capital and O&M, routine and non-routine O&M, lost generation, and relicensing process costs.

The estimated present value of the additional investment required to relicense the project, including capital and maintenance necessary to continue generation of the existing Project for 43 years, including FERC fees, is $21,140,446. The annual additional cost per MWh to relicense and operate the Project, based on 35,050 MWh of generation, is $41.03 per MWh.

The present value of the proposed Project costs for 43 years, including routine and additional O&M, depreciation, lost generation, interest and taxes of the existing assets is $39,422,924. The annual total cost per MWh to operate the Project, based on 35,050 MWh of generation, is $76.51 per MWh.

Table 8. Present value costs of Project (in thousands of dollars)

Item	Present Value Cost ($000)
Existing Project Cost	$18,283
Additional Investment	$21,140
Total Project Costs	**$39,423**

H.3.2 Resources Required to Meet Capacity and Energy Requirements

An integrated resource plan (IRP) is a comprehensive decision support tool and road map for meeting a utility's objective of providing reliable and least-cost electric service to customers while addressing the substantial risks and uncertainties inherent in the electric utility business. PacifiCorp prepares its integrated resource plan on a biennial schedule, filing its plan with state utility commissions during each odd numbered year. The IRP is developed with considerable public involvement from state utility commission staff, state agencies, customer and industry advocacy groups, project developers, and other stakeholders. The key elements of the IRP include: a finding of resource need, focusing on the first 10 years of a 20-year planning period; the preferred portfolio of supply-side and demand-side resources to meet this need; and an action plan that identifies the steps we will take during the next two to four years to implement the plan.

The IRP uses system modeling tools as part of its analytical framework to determine the long-run economic and operational performance of alternative resource portfolios. These models simulate the integration of new resource alternatives with our existing assets, thereby informing the selection of a preferred portfolio judged to be the most cost-effective resource mix after considering risk, supply reliability, uncertainty, and government energy resource policies.

PacifiCorp's 2015 IRP, filed March 31, 2015, and 2015 IRP Update, filed March 31, 2016, provide much of the information for Section H.3.2. Additional detail can be found in the IRP, available on-line at www.pacificorp.com/es/irp.

H.3.2.1 Energy and Capacity Resources

Development of the 2015 IRP involved a balanced consideration of cost, risk, uncertainty, supply reliability/deliverability, and public policy goals. PacifiCorp's resource needs can be met with demand side management (DSM) and low cost short-term firm market purchases, labeled as front office transactions (FOTs), through 2027. The first deferrable thermal resource in the 2015 IRP preferred portfolio is added in 2028. By the end of the 20-year planning horizon, PacifiCorp's 2015 IRP preferred portfolio reflects an assumed reduction of 2,775 MW in existing owned capacity. By 2034, it is assumed that approximately 2,800 MW of existing coal generation will either be retired or converted to operate as natural gas-fired generation.

Various resources are considered in the IRP for meeting future capacity and energy needs. Organized by major category, these resources consist of utility-scale supply-side generation, DSM programs, transmission resources and market purchases.

Supply-side Resources

Capital costs, in general, have remained stable due to recessionary economic conditions in 2008-2009 and a very gradual recovery experienced in 2010-2014. As with the 2013 IRP, natural gas-fueled plants are expected to fulfill future base-load obligations for meeting customer needs, therefore, they have received a significant level of attention. A variety of gas-fueled generating resources were selected after consultation with major suppliers, large engineering-consulting firms, and primary stakeholders. New coal-fueled resources received minimal focus during this planning cycle due to ongoing environmental, permitting and sociopolitical obstacles for siting new coal-fueled generation. The capital and operating costs of simple and combined-cycle gas turbine plants have remained relatively flat to slightly increasing since the previous IRP. Certain alternative (i.e. non-fossil-fuel) energy resources such as wind and solar received even greater emphasis during this review cycle compared to prior reviews. Solar resource options include utility-size photovoltaic systems with both fixed and single axis tracking. Energy storage options of at least one megawatt continue to be of interest among the stakeholders, with options analyzed for large pumped-storage projects, as well as advanced battery, fly wheel and compressed air energy storage projects.

Demand-side Management

As with supply-side resources, the development of demand-side resource supply curves requires specification of quantity, availability, and cost attributes. Three classes of DSM supply curves were utilized in the IRP modelling environment. Class 1 DSM products include direct load control of residential and small commercial central air conditioning and water heating, irrigation load curtailment, and commercial/industrial curtailment. Class 2 DSM products include known changes in building codes, advancing equipment efficiency standards, market transformation, resource cost changes, changes in building characteristics and state-specific resource evaluation considerations (e.g., cost-effectiveness criteria). Class 2 DSM resource potential was assessed by state to the individual measure and facility levels; e.g., specific appliances, motors, lighting configurations for residential buildings, small offices, etc. Class 3 DSM resources are customer opt-in products including time-of-use rates, critical peak pricing, real-time pricing, and demand buyback.

Transmission Resources

For the 2015 IRP, PacifiCorp selects generation resource portfolios with a pre-determined transmission topology based on transmission rights that are owned by PacifiCorp and contracted with third parties. Potential transmission resource additions are examined prior to generation resource selection. Sensitivities are also developed to test various transmission build-out scenarios. Additionally, in order to determine the appropriate placement and timing of generation resources, generic assumptions on transmission integration costs are included in the costs of potential resources. These costs are associated with improvements needed to transfer the generation to load centers and/or markets and maintain the reliability and stability of the transmission system.

Market Purchases

PacifiCorp and other utilities engage in purchases and sales of electricity on an ongoing basis to balance the system and maximize the economic efficiency of power system operations. In addition to reflecting spot market purchase activity and existing long-term purchase contracts in the IRP portfolio analysis, PacifiCorp modeled front office transactions (FOT). FOTs are proxy resources, assumed to be firm, that represent procurement activity made on an on-going, forward basis to help PacifiCorp cover short positions.

As proxy resources, FOTs represent a range of purchase transaction types. They are usually standard products, such as heavy load hour, light load hour, and super peak (hours ending 13 through 20) and typically rely on standard enabling agreements as a contracting vehicle. FOT prices are determined at the time of the transaction, usually via an exchange or third party broker, and are based on the then-current forward market price for power. An optimal mix of these purchases would include a range of volumes and terms for these transactions.

Solicitations for FOTs can be made years, quarters or months in advance, however, most transactions made to balance PacifiCorp's system are made on a balance of month, day-ahead, hour-ahead, or intra-hour basis. Annual transactions can be available three or more years in advance. Seasonal transactions are typically delivered during quarters and can be available from one to three years or more in advance. The terms, points of delivery, and products will all vary by individual market point.

H.3.2.2 Resource Analysis

PacifiCorp's need for new resources is determined by developing a capacity load and resource balance that considers the coincident system peak load hour capacity contribution of existing resources, forecasted loads and sales, and reserve requirements. For capacity expansion planning, the Company uses a 13% planning reserve margin, which is applied to PacifiCorp's obligation net of offsetting "load resources" such as dispatchable load control capacity.

On a system coincident basis, PacifiCorp is a summer-peaking utility. The forecasted system coincidental peak load prior to energy efficiency and distributed generation reductions is 10,368 MW in 2015. For the forecasted 2015 summer coincident peak, PacifiCorp owns, or has interest in, resources with an expected system peak capacity of 11,810 MW. PacifiCorp's system coincident peak load is forecasted to grow at a compounded average annual growth rate of 0.89% over the period 2015 through 2024. On an energy basis, PacifiCorp expects system-wide average load growth of 0.85% per year from 2015 through 2024.

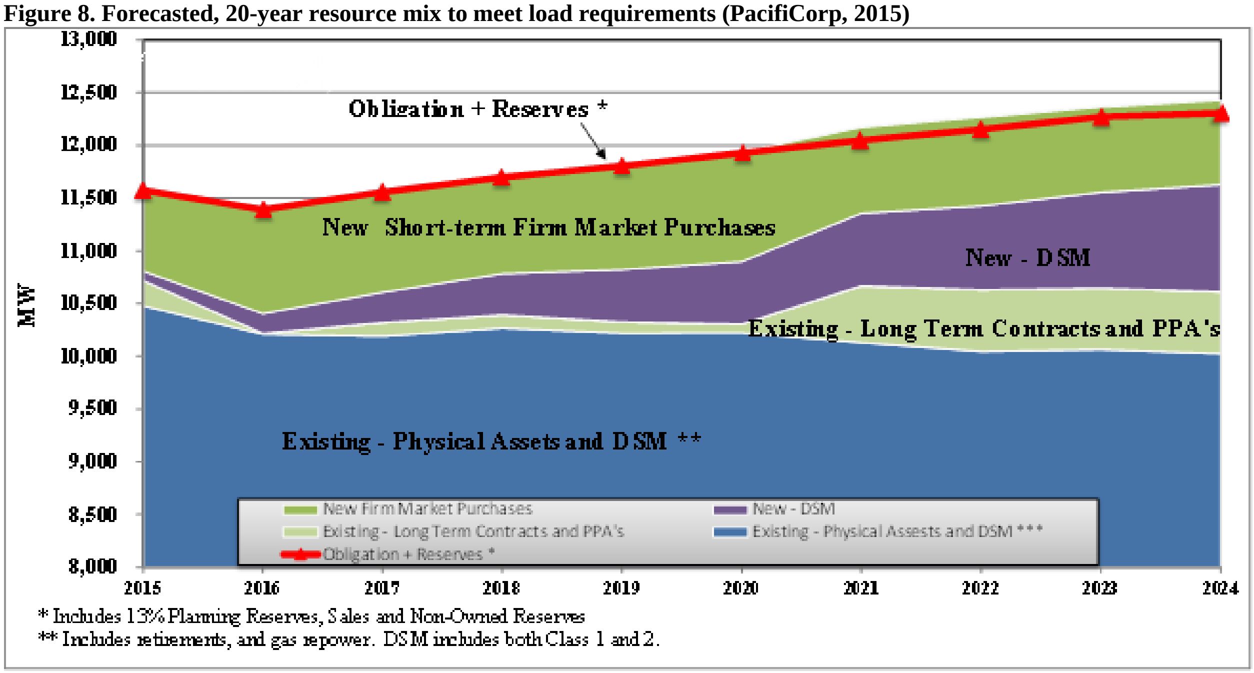
Accounting for available FOTs, PacifiCorp exceeds its 13% target planning reserve margin through 2019 and falls just short of its target planning reserve margin in 2020. With the expiration of a legacy exchange contract, available system capacity is increased in the summer of 2021, and PacifiCorp's system once again exceeds its 13% target planning reserve margin through 2022. With continued load growth, PacifiCorp falls 82 MW and 165 MW below its target planning reserve margin in 2023 and 2024, respectively.

The capacity position shows how existing resources and loads balance during the coincident peak load hour of the year inclusive of a planning reserve margin. Outside of the peak hour, PacifiCorp economically dispatches its resources to meet changing load conditions taking into consideration prevailing market conditions. In those periods when system resource costs are less than the prevailing market price for power, PacifiCorp can dispatch resources that in aggregate exceed then-current load obligations, facilitating off system sales that reduce customer costs. Conversely, at times when system resource costs are greater than prevailing market prices, system balancing market purchases can be used to meet then-current system load obligations to reduce customer costs. The economic dispatch of system resources is critical to how the Company manages net power costs.

At times, system resources are economically dispatched above load levels facilitating net system balancing sales. This occurs more often in off-peak periods than in on-peak periods. At other times, economic conditions result in net system balancing purchases, which occur more often during on-peak periods. Those periods where all available resource energy falls below forecasted loads are indicative of short energy positions absent the addition of any new demand side or supply side resources to the portfolio. During on-peak periods, the first energy shortfall appears in July 2020, totaling 5 GWh. In July 2024, available system energy falls short of monthly loads by 189 GWh. During off-peak periods, there are no energy shortfalls through the 2024 timeframe.

PacifiCorp's 2015 IRP preferred portfolio includes 816 MW of executed qualifying facility power purchase agreements from new wind and solar projects expected to come on-line in 2015 and 2016. Through the front ten years of the planning horizon, PacifiCorp's incremental resource needs can be met with DSM and FOTs. The first deferrable thermal resource in the 2015 IRP preferred portfolio is added in 2028, four years later relative to the 2013 IRP preferred portfolio. By 2034, it is assumed that approximately 2,800 MW of existing coal generation will either be retired or converted to operate as natural gas-fired generation. To mitigate the cost of state renewable portfolio standard compliance, analyses in the 2015 IRP continue to support the use of unbundled renewable energy credits to meet projected compliance needs through the planning horizon.

Figure 8. Forecasted, 20-year resource mix to meet load requirements (PacifiCorp, 2015)



H.3.2.3 Load Management Measures

Changes to PacifiCorp's load forecast are driven by reduced residential class load forecast due to increased energy efficiency, including continued phase in of the Energy Independence and Security Act federal lighting standards. In addition, lower energy response to economic growth has lowered system load and coincident peak growth.

PacifiCorp continues to evaluate DSM as a resource that competes with traditional supply-side resource alternatives when developing resource portfolios that are compared under a range of cost and risk metrics. In preparing its 2015 IRP, PacifiCorp used updated estimates of reasonably achievable DSM resource potential in each year of the planning horizon. Driven by increased cost-effective lighting opportunities followed by cost-effective opportunities in heating, cooling, water heating, appliances and industrial process end-uses, Class 2 DSM, or energy efficiency, savings in the 2015 IRP preferred portfolio exceed energy efficiency savings from the 2013 IRP preferred portfolio by 59 percent by 2024. Over this front ten years of the planning horizon, accumulated acquisition of incremental energy efficiency resources meets 86 percent of forecast load growth from 2015 through 2024.

H.3.2.4 Replacement Sources of Power

As PacifiCorp acquires new resources, it will need to determine whether it is better to own a resource or purchase power from another party. While the ultimate decision will be made at the time resources are acquired, and will primarily be based on cost, there are other considerations that may be relevant.

With owned resources, PacifiCorp is in a better position to control costs, make life extension improvements, use the site for additional resources in the future, change fueling strategies or sources, efficiently address plant modifications that may be required as a result of changes in environmental or other laws and regulations, and utilize the plant at cost as long as it remains economic. In addition, by owning a plant, PacifiCorp can hedge itself from the uncertainty of the ability to perform consistent with the terms and conditions outlined in a power purchase agreement over time.

Depending on contract terms, purchasing power from a third party in a long term contract may help mitigate and may avoid liabilities associated with closure of a plant. A long-term power purchase agreement relinquishes control of construction cost, schedule, ongoing costs and compliance to a third party, and exposes the buyer to default events and contract remedies that will not likely cover the potential negative impacts. Finally, credit rating agencies impute debt associated with long-term resource contracts that may result from a competitive procurement process, and such imputation may affect PacifiCorp's credit ratios and credit rating.

PacifiCorp's IRP considers an integrated portfolio analysis to value new resources. If an alternative to the Project's power and capacity is required, no single replacement resource would be assumed. Instead, integrated portfolio planning implies that all existing resources and loads would be evaluated together to find the best mix of resources based on least cost and lowest risk. To match the Project's average annual generation and capacity, the alternative cost estimate is based on the Project's projected annual output as if wholesale market purchases were utilized to replace Project MWhs.

H.4 APPLICANT USES OF PROJECT GENERATION

PacifiCorp does not use Project generation for PacifiCorp-owned industrial facilities and related operations.

H.5 IMPACTS ON APPLICANT'S TRANSMISSION SYSTEM

H.5.1.1 Effects of Redistribution of Power Flows

The Project is connected to the PacifiCorp transmission system via a radial 69 kV transmission line from Prospect Central Substation. Also served from the radial 69 kV line is a 69-4.16 kV distribution substation, Red Blanket Substation. In addition to connecting the Project, Prospect Central Substation provides radial interconnections to the Prospect Nos. 1, 2, and 4 Hydropower Project generating facilities.

Two 115 kV lines and one 69 kV line provide looped transmission connections to Prospect Central to integrate the generation resources with the PacifiCorp transmission system. The looped transmission system is connected between the Roseburg, Oregon and Medford, Oregon areas and provides one element out ("N-1") contingency capability for Prospect Central. If an outage occurs on one of the looped 115 kV or 69 kV lines connecting to Prospect Central, the Project will remain operational.

Reducing generation levels at the Project would reroute the power flow through this transmission loop, but would not affect the utility's ability to serve its customer load in the vicinity of the Project.

H.5.1.2 Advantages of Applicant's Transmission System

The Project connects with the PacifiCorp 115 kV and 69 kV looped transmission system at Prospect Central Substation via a radial 69 kV transmission line (Line 22). The existing line is located on PacifiCorp property that is bounded by numerous private property owners, which would make alternate transmission right-of-way authorizations difficult to obtain. The remote Project connects exclusively to PacifiCorp's larger transmission system via the Prospect Central Substation. Alternate transmission systems would require significant engineering, permitting, and infrastructure investments.

H.5.1.3 Single-line Diagrams

See Exhibit F (Volume IV, Appendix A) for a detailed single-line diagram of the existing transmission facilities associated with the Project.

H.6 MODIFICATIONS OF EXISTING PROJECT FACILITIES AND OPERATIONS

PacifiCorp does not propose any modifications of existing Project facilities that would alter the capacity or efficiency of the Project. PacifiCorp proposes to construct an auxiliary bypass flow system from one of the existing fish ladder exit orifices to a plunge pool at the base of the fish ladder to reliably provide increased minimum flows to the bypassed reach. PacifiCorp proposes to realign and extend the existing fish bypass return pipe discharge from Pool 6 to Pool 1 of the fish ladder. Changes to the fish bypass return pipe discharge location would result in reduced flow through Pools 6 through 2 of the fish ladder, and PacifiCorp proposes to modify the weir notches for Weirs 2 through 6 from 36”-wide to 18”-wide to provide consistent performance throughout the ladder. PacifiCorp proposes to replace the existing woodstave flowline and woodstave sag-pipe. The temporary vehicle-access bridge over the flowline would be rehabilitated to meet current Forest Service engineering standards following flowline replacement. PacifiCorp proposes to construct a road spur from the flowline vehicle-access bridge to the bank of the bypassed reach to facilitate pass-through of materials dredged from the impoundment upstream of the dam to the bypassed reach downstream of the dam. PacifiCorp proposes to upgrade the six existing four-foot-wide wildlife crossings of the canal to twelve feet in width. PacifiCorp also proposes to construct five twelve-foot-wide wildlife crossings of the new steel flowline and eight two-foot-wide wildlife crossings of the canal within the canal fencing. To facilitate compliance with proposed ramp rates, PacifiCorp proposes to install a communications link on the USGS’ South Fork Rogue gage to deliver real-time flow readings to Project instrumentation and controls.

PacifiCorp proposes to modify Project operations to incorporate the protection, mitigation and enhancement (PM&E) measures developed during the relicensing study process and subsequent discussions with the agencies and relicensing stakeholders. These modifications include an increase in the minimum instream flow and ramping rate limits.

H.7 APPLICANT’S FINANCIAL AND PERSONNEL RESOURCES

PacifiCorp has adequate financial resources to meet its obligations under a new license for the Project. PacifiCorp’s financial information is available in the annual Securities and Exchange Commission Form 10-K report which can be accessed on-line at http://www.sec.gov/cgi-bin/browse-edgar?action=getcompany&CIK=0000075594&type=10-K&dateb=&owner=exclude&count=40.

As of December 31, 2015, PacifiCorp had approximately 5,700 employees, of which approximately 3,300 were covered by union contracts, principally with the International Brotherhood of Electrical Workers, the Utility Workers Union of America and the International Brotherhood of Boilermakers. Currently PacifiCorp has four full-time, on-site employees dedicated to support of the Project in varying capacities as well as support staff in Medford and Portland, Oregon. They are adequate in number and training to operate the Project in accordance with the provisions of the license.

H.8 PROJECT EXPANSION

PacifiCorp is proposing to expand the Project to encompass additional lands necessary for operation and maintenance of the Project. On National Forest lands (see Exhibit G sheet G-1), PacifiCorp is proposing to widen the boundary on the north side of the flowline (currently 100-ft wide) to include the strip of land between the flowline and the south shoulder of the FS 3775-800 road. This addition would incorporate the Project access roads, the underground power and communication lines, and would provide access to the upslope side of the flowline.

West of the National Forest boundary (beginning on the section line between Section 12 T33S R3E WM and Section 7 T33S R4E WM), the proposed boundary generally maintains the current 100-ft buffer width on each side of the water conveyance system but is widened in places to incorporate the access roads and maintenance areas along the water conveyance system (see Exhibit G sheet G-1) and to add the sag-pipe alignment to the Middle Fork Canal (see Exhibit G sheet G-2).

The proposed boundary is expanded beyond the existing 100-ft center line buffer width along the 69kV transmission line to add transmission line access roads (Exhibit G sheets G-2 through G5).

The addition of the sag-pipe and the access roads would add 39.5 acres to the project boundary (25.1 acres of non-federal lands and 14.4 acres of federal lands).

H.9 ELECTRICITY CONSUMPTION EFFICIENCY IMPROVEMENT PROGRAM

PacifiCorp has provided a comprehensive set of DSM programs to its customers since the 1970s. The programs are designed to reduce energy consumption and more effectively manage when energy is used, including management of seasonal peak loads. PacifiCorp offers services to customers such as energy engineering audits and information on how to improve the efficiency of their homes and businesses. To assist customers in investing in energy efficiency, PacifiCorp offers rebates or incentives encouraging the purchase and installation of high-efficiency equipment such as lighting, heating and cooling equipment, weatherization, motors, process equipment and systems, as well as incentives for energy project management, efficient building operations and efficient construction. Incentives are also paid to solicit participation in load management programs by residential, business and agricultural customers through programs such as PacifiCorp's residential and small commercial air conditioner load control program and irrigation equipment load control programs. Although subject to prudence reviews, state regulations allow for contemporaneous recovery of costs incurred for the DSM programs through state-specific energy efficiency surcharges to retail customers or for recovery of costs through rates.

During 2015, PacifiCorp spent $134 million on these DSM programs, resulting in an estimated 641,486 MWh of first-year energy savings and an estimated 269 MW of peak load management. In addition to these DSM programs, PacifiCorp has load curtailment contracts with a number of large industrial customers that deliver up to 305 MW of load reduction when needed, depending on the customers' actual loads. Recovery of the costs associated with the large industrial load management program are captured in the retail rate agreements with those customers approved by their respective state commissions or through PacifiCorp's general rate case process.

H.9.1.1 Customer Conservation

Customer conservation is encouraged through Pacific Power’s “wattsmart” energy efficiency programs, which include cash incentives for home energy upgrades. The wattsmart program includes tools and information to help customers save energy and money through the following methods, available on-line at https://www.pacificpower.net/res/sem/eeti.html:

- Efficiency Video Clips—Customers can follow the "high-bill detective" through six areas of the home where they can make improvements to save money.
- Calculate Energy Use—Customers choose from common appliances and equipment for the home to gain a better understanding of electricity use.
- Usage Data & Green Button—Customers can download monthly electricity usage information via the Green Button on Pacific Power’s website and use the data with tools such as ENERGY STAR’s Home Energy Yardstick to see how a customer’s home measures up.
- Energy Trust of Oregon—Pacific Power customers in Oregon can take advantage of Energy Trust services and cash incentives to upgrade the energy efficiency of a home or business.
- Oregon Online Home Analysis—Customers can fill out this online survey and get customized recommendations for savings in a home.
- Enhabit—Customers can improve a home’s comfort, reduce energy waste and access no-money-down financing through Enhabit services.
- Department of Energy Online Home Audit—Customers can complete this online survey about a home to find out how they use energy and get detailed instructions on how to reduce consumption.

H.9.1.2 Compliance with Regulatory Requirements

PacifiCorp's energy conservation programs comply with applicable energy efficiency and conservation requirements of Oregon Revised Statues (ORS) Chapters 469, 756, and 757 and Oregon Administrative Rules (OAR) Chapter 860, Division 30.

In 1999, Oregon lawmakers established stable, consistent funding to help Oregonians invest in energy efficiency and renewable resources. Energy Trust of Oregon was created as the non-profit organization to manage these funds. Energy Trust began operation in March 2002, charged by the Oregon Public Utility Council (OPUC) with investing in cost-effective energy efficiency, helping to pay the above-market costs of renewable energy resources, delivering services with low administrative and program support costs and maintaining high levels of customer satisfaction. Through state legislation, tariffs and other requirements, Energy Trust is funded by customers of Portland General Electric (PGE), Pacific Power, NW Natural and Cascade Natural Gas. Customers of all four utilities pay a dedicated percentage of their utility bills to support a variety of energy-efficiency and renewable energy services and programs.

As a result of a 1999 energy restructuring law, Oregon's two largest electric investor-owned utilities (PGE and Pacific Power) are required to collect a 3 percent "public purpose charge" from their customers. The funds support:

- energy conservation in K-12 schools delivered through school districts;
- low-income housing energy assistance delivered through Oregon Housing and Community Services; and
- energy efficiency and renewable energy programs for residential and business customers delivered through Energy Trust, an independent, third party approved by the OPUC in 2001.

The last piece of Energy Trust funding is separate legislation passed in 2007 that allows PGE and Pacific Power to work with Energy Trust on capturing more low-cost electric efficiency for their customers, thereby avoiding the need to purchase more expensive electricity.

H.10 AFFECTED INDIAN TRIBES

The existing and proposed Project is not located on or otherwise affecting the land of any Indian tribes.

H.11 SAFETY MEASURES

H.11.1 Operation During Flood Conditions

The Project is operated exclusively in run-of-river mode. During flood conditions, high flows proceed over the un-gated, ogee spillway into the bypassed reach of the South Fork Rogue River.

H.11.2 Warning Devices

The Project does not include any warning devices used to ensure downstream public safety. There is no appreciable storage in the Project impoundment, and the Project is operated in run-of-river mode.

H.11.3 Proposed Changes Affecting the Emergency Action Plan

The Project is exempt from Commission requirements for an Emergency Action Plan (EAP) due to the absence of reasonably foreseeable emergency situations that would endanger life, health, or property. Pursuant to FERC Engineering Guidelines, Chapter 6: "Emergency Action Plans," Section 6-2.2.7, PacifiCorp conducts annual reconnaissance of the Project for conditions that may change the EAP-exempted status and requests continuance of exemption annually by December 31 if conditions still support that designation. There are no proposed changes to the Project that would affect any future EAP.

H.11.4 Monitoring Devices

Four slope inclinometer casings were installed in sub-surface borings on the slope between the forebay and the side-channel spillway in 1989 for the purpose of monitoring slide movements at depth. There are no other monitoring devices to detect structural movement, stress, seepage, or uplift of Project facilities.

Powerhouse equipment failure is monitored by various general control systems (e.g., lube oil level sensors) and alarms in the PLC and SCADA systems.

Potential water conduit failure is monitored via the ultrasonic water level logger at the Project forebay and the penstock flow meter. Loss of diverted flows from the conduit upstream of the forebay would result in low forebay water levels that, when compared with diversion intake gate levels, trigger associated alarms in the SCADA system. Catastrophic loss (i.e., rupture) of the penstock would be indicated by the penstock flow meter and trigger closure of the excess velocity valve immediately downstream of the penstock intake.

Potential sag-pipe failure is monitored via flow meters at Sag-pipe No. 3 of the Prospect Nos. 1, 2, and 4 Hydroelectric Project, which indicate the combined Prospect No. 3 penstock flow measurements with calculated diversions from Middle Fork Rogue via Middle Fork Canal ratings (Combined Flow). Differences of greater than 30 cfs between the Combined Flow and the measured flow at Sag-pipe No. 3 trigger an alarm in the SCADA system. On-site operators are dispatched to investigate and respond to alarms as needed.

H.11.5 Employee and Public Safety Record

PacifiCorp employees attend monthly safety meetings. All mandated safety training is tracked along with other core competency training. In addition to regular, monthly safety training, staff members meet daily to review the day's assignments and raise awareness about the potential hazards and practices to be followed.

PacifiCorp maintains an electronic database of safety incidents. The database was reviewed from 2005 through June 2016 for any incidents at the Project; no OSHA-reportable, restricted duty, or lost time incidents were incurred by Project staff.

There are no known records of injury or death to the public within the Project boundary. The most recent Public Safety Plan was filed with the Commission on March 7, 2012.

H.12 PROJECT OPERATIONS

The Project generator is operated automatically by a PLC, and may also be operated manually by an on-site operator, as needed. After normal working hours, plant functions may be monitored remotely over the SCADA network by control operators at PacifiCorp's Hydro Control Center, in Ariel, Washington. Although control operators have the ability to adjust generation through the SCADA network, they generally allow the plant to run in automatic mode, and will call out an on-site operator for any unplanned outages or alarms.

The current Project license identifies a minimum instream flow of 10 cubic feet per second (cfs) that must be maintained in the South Fork Rogue River below the diversion dam. PacifiCorp proposes to increase the minimum in-stream flow in the South Fork Rogue River below the diversion dam to 30 cfs from March 1 through July 31 and 20 cfs from August 1 through February 28 to maximize incremental gains in fish habitat from proportionate increases in flow.

The Project is operated in run-of-river mode during low, mean, and high water years, as the small impoundment on the South Fork Rogue River lacks storage. A unit PLC, located in the plant, adjusts the aperture of the wicket gates in order to maintain a constant forebay elevation in response to input from level sensors at the forebay. The adjustments to the wicket gates directly affect the rate of water diversion at the dam, and ultimately result in a near-constant reservoir level for much of the year. When natural inflows exceed the sum of project hydraulic capacity and the minimum flow requirement, spill occurs at the diversion over the un-gated, ogee-style weir.

H.13 PROJECT HISTORY AND OPERATIONS AND MAINTENANCE UPGRADES

The Prospect Hydroelectric Plant (now known as the Prospect No. 1 powerhouse) was constructed on the North Fork Rogue River in 1911 by Condon Water and Power Company. By

1926, Condon Water and Power Company's successor, California Oregon Power Company (COPCO), initiated research and development of an expanded hydroelectric development incorporating multiple forks of the Rogue River, including the original 1911 Prospect facilities. New diversion dams were planned for the South, Middle, and North Forks of the Rogue River and Red Blanket Creek.

Byllesby Engineering and Management Company (Byllesby) of Chicago, Illinois was responsible for the design, engineering, and management of the South Fork development. The South Fork Rogue was initially surveyed in September 1924. Additional survey and conceptual design work completed in 1926 shows three potential powerhouse and penstock locations for the South Fork development. The eventual layout and alignment for the South Fork development was proposed in July 1929.

The original application for the South Fork development was submitted to the Federal Power Commission (FPC) by Byllesby on April 20, 1931. The application identified the diversion dam site and 0.75 miles of conduit on 40 acres of Crater National Forest (now known as the Rogue River-Siskiyou National Forest), with the balance of lands owned by Rogue River Timber Company. A statement of intent to purchase timber lands within the proposed Project boundary was included with the application. The application identified a planned completion date of June 1, 1932.

Construction of the South Fork development known as Prospect No. 3 was initiated in 1931. The Project was placed in service on April 22, 1932. The current Project is largely unaltered in materials, massing, and/or alignment from its original construction condition with the exception of a section of the sag-pipe over the Middle Fork Rogue River; the forebay canal and associated side channel spillway; the fish passage facilities; and turbine runner. These alterations are discussed below in additional detail.

An original minor-part license (FPC No. 1163) was issued to COPCO on July 30, 1931 for a period of 50 years. This minor license covered the upper Project facilities, including the diversion dam and approximately 4,000 linear feet of the flowline, located on lands administered by the federal government. The initial major-part license (FPC No. P- 2337) covering the downstream facilities, including the remaining waterway, penstock, and powerhouse, was issued in 1931 for a period of thirty years. COPCO merged with Pacific Power and Light on June 21, 1961, and the January 25, 1963 license application requested transfer of the license to Pacific Power and surrender of the minor-part license. By order dated July 8, 1964, the Commission issued a new license for the Project, including all Project facilities under one license for a period of twenty-five years. An application for new license was submitted on December 24, 1985, and the current license was issued on January 30, 1989 for a period of thirty years beginning on the first day of the month of issuance.

A winter storm on December 21 and 22, 1964 resulted in the highest recorded flows during the Project era. High flows and extensive debris mobilization in the Middle Fork Rogue resulted in damage to the sag-pipe piers and trestles and subsequent loss of the original woodstave sag-pipe crossing. Approximately 250 feet of the sag-pipe were replaced with steel pipeline in early 1965.

Construction plans dated July 1951 indicate that somewhere in this time frame a short section of the canal near the forebay was realigned, presumably because of observed slope instability. In 1982 a simple vertical and horizontal displacement monitoring system was installed on a headscarp identified immediately adjacent to this lower canal section. In April 1989, accelerated movement of approximately eight inches was measured over a five week period following snowmelt. Four borings were made in the area and equipped with slope inclinometer casings in addition to adjacent groundwater detection borings. It was determined that partial filling of the overflow spillway channel with rock was needed to provide protection for the toe of slope and to stabilize the block of soil immediately down slope from the canal. In September 1989 repairs were initiated, including installation of filter fabric over exposed soil surfaces and placement of 20,000 cubic yards of riprap material to a depth of approximately 25 feet and a distance of approximately 400 feet. Continued post-construction monitoring revealed that, after a period of initial settling, the slope had been stabilized.

Prior to 1989 the Project included five existing wildlife crossings of the open canal and sporadic fencing. In fulfillment of License Article 406, PacifiCorp improved the five existing crossings, installed a new crossing over the open canal, repaired or replaced the fencing around the open canal with 7’-high wildlife fencing, installed two under-crossings of the woodstave flowline, and installed five under-crossings of the penstock.

Original construction of the Project diversion dam and intake canal included a fourteen-pool fish ladder and two eight-foot-wide rotating drum fish screens. Minor modifications were made to the upstream and downstream fish passage facilities in 1976, but significant modifications were made to both facilities in 1996 based on the requirements of License Articles 403, 404, and 405 of the 1989 license and interim design criteria provided by ODFW to PacifiCorp on September 7, 1994. Fish passage facility construction was initiated and completed in 1996. The rotating drum screens, which were located approximately 43’ downstream of the intake, were removed, and the inclined plane screen was installed approximately 215’ downstream of the intake. The fish bypass return pipe was installed from the new fish screen location to its terminus at Pool 6 of the fish ladder. Pool 14 of the existing ladder was bifurcated into two pools and several of the pool walls and weirs were modified to meet the provided design criteria. An access road to the diversion site and a bridge over the flowline were constructed to facilitate the fish passage construction effort. In addition to the backwater sluice gate, screen hoists, and other associated fish screen operation and maintenance infrastructure, a new cinder block control building and the automated Atlas Polar trash rake were installed at the diversion concurrent with the fish passage facilities construction in 1996.

The turbine runner was replaced in 1997. The original turbine was a vertical-shaft, Francis-type hydraulic turbine manufactured by Pelton Water Wheel and rated at 10,000 horsepower (7,460 kW) at a designed head of 693 feet. The new runner was manufactured by American Hydro and fabricated out of 304L stainless steel. In addition to the runner, new wicket gates and associated bushings were installed. Although the turbine capacity increased from 7,460 kW to 7,900 kW, generator capacity limits the installed capacity at 7,200 kW.

Following hydraulic assessments of the fish passage facilities in 1998, perforated plate baffles were temporarily installed on the fish screen to create a more uniform flow through the screen. The baffles were redesigned and replaced in 2015.

Automation of the pressure-relief valve and tailrace backwater gate in response to forebay water levels was completed in 2015 and 2016, respectively.

H.14 UNSCHEDULED OUTAGES

A summary of unscheduled outages over the last five calendar years (2010-2015) is provided below in Table 9. Forty-eight unscheduled outages occurred during the five-year period for total unscheduled outage duration of 1,075.5 hours and average unscheduled outage duration of 22.0 hours. A total of seven unscheduled outages lasted over 24 hours, with an average duration of 96.4 hours, during the five-year period. Potential generation output is dependent upon available diversion flows, but assuming full diversion of 150 cfs, a maximum of 7,743 MWh of potential Project generation were lost during the five-year period. The actual Project generation lost during the five year period is expected to be much less than the potential maximum loss.

Table 9. Unscheduled generating unit outages (2010-2015)

Outage Start (Date/Time)	Outage End (Date/Time)	Duration (Hours)	Cause	Corrective Action
1/1/2010 14:01	1/1/2010 17:03	3.03	86N lockout tripped. No cause found by operator.	Operator reset relay and restarted unit.
1/2/2010 19:33	1/2/2010 21:30	1.95	86N lockout tripped. No cause found by operator.	Operator reset relay and restarted unit.
3/7/2010 18:22	3/7/2010 19:58	1.60	PLC comm failure caused unit to trip offline.	Comms were reset and unit was restarted.
3/18/2010 18:40	3/18/2010 20:30	1.83	No cause found by operator.	Operator reset relay and restarted unit.
3/29/2010 07:12	3/29/2010 08:17	1.08	Trash rack differential alarm caused unit to trip offline.	Operator reset alarm and restarted unit.
4/3/2010 06:31	4/3/2010 07:45	1.23	86N lockout tripped. No cause found by operator.	Operator reset relay and restarted unit.
4/12/2010 14:00	4/18/2010 17:14	147.23	Woodstave flowline had excessive leakage caused by a landslide along the pipe.	Damage was repaired.
5/29/2010 11:48	5/29/2010 18:15	6.45	64F relay tripped unit offline.	Collector rings were cleaned and unit was returned to service.
5/29/2010 19:27	5/30/2010 03:18	7.85	Low voltage alarm tripped 86N relay.	All GSU fuses were replaced, unit returned to service.
6/1/2010 06:04	6/1/2010 07:55	1.85	System disturbance caused unit to trip offline.	Operator reset relay and restarted unit.

Outage Start (Date/Time)	Outage End (Date/Time)	Duration (Hours)	Cause	Corrective Action
8/12/2010 11:30	8/12/2010 12:45	1.25	System disturbance caused unit to trip offline.	Operator reset relay and restarted unit.
9/19/2010 16:17	9/20/2010 00:08	7.85	Lightning caused unit to trip offline.	Operator reset relay and restarted unit.
9/28/2010 13:29	9/28/2010 14:47	1.30	Calibration and testing of forebay levels caused trip.	Unit was returned to service.
10/24/2010 10:00	10/24/2010 18:00	8.00	A downed line caused the protective relay to trip.	When service was returned, operator reset relay and restarted unit.
10/28/2010 21:36	10/29/2010 19:48	22.20	System disturbance when Prospect Central 69/115KV transformer bus cleared due to bad suspension insulators. The unit remained out due to reduced line capacity.	When service was returned, operator reset relay and restarted unit.
11/23/2010 09:33	11/23/2010 11:56	2.38	PRV malfunction caused low forebay level, resulting in an 86N lockout.	Malfunction was cleared, relay reset, and unit was returned to service.
1/14/2011 03:03	1/14/2011 15:15	12.20	115/69 kv transformer 86T lockout T3069, 70, 71 caused trip of all units.	Operator reset relay and restarted unit.
1/17/2011 09:57	1/19/2011 14:20	52.38	High in-flows clogged screens with debris.	Screens were cleaned after flows subsided.
1/19/2011 15:08	1/19/2011 16:48	1.67	System disturbance caused unit to trip offline.	Operator reset relay and restarted unit.
3/13/2011 14:55	3/14/2011 10:38	19.72	System disturbance caused unit to trip offline.	Operator reset relay and restarted unit.
8/14/2011 13:50	8/16/2011 17:40	51.83	Leaks on transition ends deteriorated, creating potential for erosion near footings.	Leaks plugged and unit returned to service.
10/2/2011 11:34	10/2/2011 16:00	4.43	Low forebay level resulted in 86N trip.	Operator reset relay and restarted unit.
10/5/2011 10:55	10/5/2011 18:54	7.98	PRV malfunction caused low forebay level, resulting in an 86N lockout.	Malfunction was cleared, relay reset, and unit was returned to service.
10/6/2011 00:03	10/6/2011 13:27	13.40	PRV malfunction caused low forebay level, resulting in an 86N lockout.	Malfunction was cleared, relay reset, and unit was returned to service.
1/8/2012 12:47	1/8/2012 14:48	2.02	PRV malfunction caused low forebay level, resulting in an 86N lockout.	Malfunction was cleared, relay reset, and unit was returned to service.
1/23/2012 11:21	1/23/2012 12:58	1.62	86E and 86N lockouts tripped.	Operator reset relays and restarted unit.
1/23/2012 13:40	1/23/2012 15:43	2.05	Trip from surge from power source (125VDC battery) to PLC.	Operator reset relays and restarted unit.
2/28/2012 06:49	3/1/2012 13:45	54.93	86N relay breaker coil malfunction.	Breaker coil was replaced and unit returned to service.
3/9/2012 13:21	3/9/2012 14:41	1.33	Unit was taken offline to rectify PLC issues.	Updated PLC.

Outage Start (Date/Time)	Outage End (Date/Time)	Duration (Hours)	Cause	Corrective Action
3/10/2012 08:30	3/13/2012 12:10	75.67	Unit was taken offline to rectify PLC issues.	Updated PLC.
3/16/2012 10:10	3/19/2012 13:10	75.00	Unit was taken offline to dewater woodstave sagpipe due to leaks.	Hole in woodstave sagpipe was repaired.
4/23/2012 17:50	4/24/2012 09:30	15.67	Lightning strike in the area caused unit to trip offline.	Unit was reset and operator attempted to return to service. TIV bypass valve would not open, continued in Outage #11961.
4/23/2012 19:46	4/24/2012 09:00	13.23	TIV bypass valve would not open.	Opening mechanism repaired and unit was returned to service.
6/1/2012 15:21	6/1/2012 17:02	1.68	System disturbance caused unit to trip offline.	Operator reset relay and restarted unit.
9/4/2012 20:00	9/5/2012 11:40	15.67	Unit was taken offline to rectify PLC issues.	Updated PLC.
9/4/2012 21:00	9/5/2012 11:40	14.67	Unit was taken offline to rectify PLC issues.	Updated PLC.
3/28/2013 22:32	3/29/2013 12:07	13.58	Wicket gate not responding alarm caused unit to trip offline. Governor operating erratically.	Governor erratic operation was diagnosed and unit returned to service.
6/3/2013 18:21	6/4/2013 10:10	15.82	Loss of PT sensing, exciter supply undervoltage, and exciter phase unbalance alarms would not clear.	Operator cleared alarms and returned unit to service.
12/8/2013 04:40	12/8/2013 13:13	8.55	Freezing weather conditions caused blockages, causing unit to trip.	Blockages were cleared and unit was put back in service
2/14/2014 13:59	2/16/2014 10:00	44.02	High in-flows clogged screens with debris.	Screens were cleaned after flows subsided.
4/11/2014 13:55	4/11/2014 18:05	4.17	Line disturbance at Prospect Central Substation caused unit to trip offline.	Operator reset relay and restarted unit.
4/14/2014 17:19	4/14/2014 18:35	1.27	115kV system disturbance tripped unit offline.	Operator reset relay and restarted unit.
8/12/2014 16:22	8/12/2014 18:01	1.65	System disturbance caused unit to trip offline.	Operator reset relay and restarted unit.
12/21/2014 10:05	12/23/2014 13:14	51.15	High in-flows clogged screens with debris.	Screens were cleaned after flows subsided.
2/6/2015 07:00	2/16/2015 15:25	248.42	A storm in the area downed several trees on the main transmission line out of P3.	Trees were cleared and line was repaired before the unit could be put back into service.
4/14/2015 01:03	4/14/2015 10:50	9.78	Stator RTD comm failure.	Comms were reset and unit was restarted.
7/1/2015 15:35	7/1/2015 17:25	1.83	Unit tripped offline due to lack of water.	Unit was put back into service when adequate water was available.
12/3/2015 10:43	12/3/2015 11:59	1.27	High winds caused disturbance.	Operator reset relays and restarted unit.

H.15 LICENSE COMPLIANCE RECORD

PacifiCorp has not been cited for a license violation during the current license term, and has never received a Notice of Violation from the Commission related to the Project. A brief history of compliance with current License articles and conditions is provided below.

License Article 101 required, within six months following the date of license issuance, PacifiCorp to file with the Commission a special-use authorization approved and enforceable by the Forest Service. The Forest Service Rogue River-Siskiyou National Forest issued a special-use permit to Pacific Power and Light Company on September 25, 1989 authorizing the Prospect No. 3 Hydroelectric Project to occupy Rogue River-Siskiyou National Forest lands. Per License Article 101 the special-use permit was filed with the Commission on September 26, 1989. The terms of the 1989 special-use permit are concurrent with the license and are void on December 31, 2018.

License Article 102 requires PacifiCorp to consult annually with the Forest Service with regard to measures needed to ensure protection and development of natural resource values. Because of the low maintenance required and the lack of new project facilities during the license term, annual coordination is generally limited to a brief phone call or electronic mail communication. PacifiCorp annually files a report with the Commission documenting the required consultation within two months of the meeting.

License Articles 103 through 106 and License Article 109 required PacifiCorp to submit various mitigation and control plans. The required plans addressed fish and wildlife habitat mitigation (Article 103); erosion, stream sedimentation, dust and soil mass movement (Article 104); solid waste and wastewater (Article 105); oil and hazardous substances (Article 106); and pesticide and herbicide use (Article 109). License Article 401 included similar requirements as Article 104, and the resulting erosion control plan satisfied both license articles. The plans were submitted to the Commission on January 30, 1990 and accepted by Commission order on February 23, 1990.

PacifiCorp has complied with License Article 107 and no previously unrecorded archeological or historical sites were discovered during the course of construction or development of the Project during the current license period. Similarly, PacifiCorp has complied with License Article 108 because there were not any changes in the location of any existing or proposed Project features or facilities or any changes in the uses of Project lands during the current license period.
License Article 402 requires that PacifiCorp maintain a continuous minimum flow of 10 cfs or the natural inflow to the impoundment, whichever is less, in the bypassed reach of the South Fork Rogue River, as measured at the U.S. Geological Survey gaging station 0.25 miles downstream from the dam (USGS Gage 14332000). Minimum flow is maintained by means of flow through the fish ladder and downstream fish return pipe, which discharges into Pool 6 of the fish ladder. Minimum stream flow variances during the current license term are discussed below in Section H.15.1

License Articles 403, 404, and 405 required PacifiCorp to submit a downstream fish passage plan, an upstream fish passage plan, and a fish passage monitoring plan, respectively, developed in consultation with ODFW and U.S. Fish and Wildlife Service (FWS). These three fish passage plans were initially required within six months of license issuance (i.e. July 30, 1989). However, prior to and following license issuance, ODFW was in the process of developing new, statewide fish protection facility criteria. PacifiCorp, ODFW, and FWS agreed that fisheries resources associated with the Project would be better served by waiting to design fish protection facilities until the new criteria were finalized. Therefore, with the support of the consulting agencies, PacifiCorp requested and was granted a series of extensions to the time required for compliance with these license articles. Commission orders on February 7, 1990, October 9, 1991, and January 25, 1993 progressively granted an extension to December 31, 1993. Although the statewide criteria were still in development, on December 9, 1993 ODFW requested that PacifiCorp proceed with design of the facility utilizing interim design criteria to be provided by ODFW at a future date. PacifiCorp requested an additional extension of time to December 31, 1994, which was granted by Commission order on February 1, 1994. ODFW provided a "Fish Screen Policy" with interim design standards to PacifiCorp on September 7, 1994, and PacifiCorp requested a final extension of time with support of the consulting agencies on December 21, 1994. The February 14, 1995 Commission order and the subsequent July 3, 1995 order granting rehearing extended the date for submittal of the required plans to December 31, 1995. PacifiCorp filed the final upstream and downstream fish passage designs along with the monitoring plan on December 28, 1995. The plans and designs were accepted by Commission order on May 21, 1996.

Construction of the upstream and downstream fish passage facilities was completed in November 1996, and the final construction report was filed with the Commission on February 17, 1997. Testing of the downstream fish screen facilities in February 1997 revealed that approach velocities exceeded the criteria of 0.75 feet per second (fps) but could be ameliorated by modifying the baffles. Baffle testing was delayed by an extended Project outage for overhaul and controls upgrades from March 1997 through March 1998, during which time the system was dewatered. On March 20, 1998 with the support of the consulting agencies, PacifiCorp requested an extension of time to file the final monitoring report from April 1, 1998 to April 1, 2000. The Commission granted the requested extension in an order dated April 16, 1998. Initial evaluations in November 1999 revealed that fish were passing through the screen and into the waterway via seals in need of replacement, repair, and/or redesign. On March 16, 2000, PacifiCorp requested a final extension of time to remedy the faulty seals and obtain fish of adequate size for the monitoring studies. The date for submittal of the monitoring report was extended to September 2000 by order of the Commission on June 6, 2000. PacifiCorp submitted the final monitoring report to the Commission on August 31, 2000, and the report was accepted by the Commission on August 20, 2002.

License Article 406 required PacifiCorp to install wildlife crossings and fencing and file as-built drawings of these facilities within one year of license issuance. Additionally, PacifiCorp was required to submit an annual maintenance program for the wildlife crossings and canal fencing to the Commission within six months of license issuance. PacifiCorp filed the annual maintenance program with the Commission on July 6, 1989, and the program was approved by Commission order on September 7, 1989. The canal fencing and wildlife crossings, including six canal crossings and seven underpasses, were constructed in the fall of 1989. ODFW inspected the facilities on December 13, 1989 and provided written approval in a letter dated December 22, 1989. ODFW's approval letter and a figure detailing the as-built locations were included in Appendix C of the Fish and Wildlife Habitat Mitigation Plan filed with the Commission on January 30, 1990 pursuant to License Article 103. Annual monitoring and maintenance reports are filed with the Commission by January 30 of each year.

PacifiCorp has complied with License Article 407 because there have not been any land-clearing or land-disturbing activities within the Project boundaries, other than those specifically authorized in the license, during the current license term.

License Article 408 required PacifiCorp to monitor recreation activity in the Project area for a period of five years and file a recreation report, prepared in consultation with the Oregon Parks and Recreation Division (OPRD) and Forest Service, with the Commission within six years of license issuance. The initial recreation monitoring report was filed with the Commission on January 23, 1995 and approved by Commission order on March 6, 1995. This order required PacifiCorp to continue recreation monitoring and to file a recreation monitoring report no later than January 31 of every sixth year. A second recreation monitoring report was filed with the Commission on January 31, 2001. Both recreation monitoring reports identified less than 200 total visitors over each five-year period. With the support and concurrence of OPRD and Forest Service, PacifiCorp requested to be relieved from future monitoring given the limited recreational use and demand in the area. The Commission concurred with PacifiCorp's request, approved the 2001 report, and deleted Article 408 from the license by Commission order on April 3, 2001.

H.15.1 Minimum Stream Flow Variances

During the first year of the current license term, minimum stream flow variances appear frequently in the historic flow record (USGS, 2013). These variances occurred prior to the development of (a) a flow rating for minimum flow releases through the South Fork dam fish ladder; and (b) a comprehensive compliance plan for use by operations personnel. By March 1990, a minimum flow compliance plan had been developed and implemented. In the years that followed, a limited number of stream flow variances occurred. Each of these variances was limited in duration and the result of maintenance activities and/or equipment malfunctions. A brief summary of each event is provided below.

A minimum stream flow variance occurred on October 27, 1996. During the week of October 20, 1996, PacifiCorp was completing installation of fish screens and modifications to the fish ladder, as per the Fish Passage and Evaluation Plans approved by FERC order on May 21, 1996. On October 24, 1996, the area around the fish ladder was dewatered in order to install a sump pump for the fish screen cleaning system, and at that time, approximately 30 cfs was spilling over the dam. Six inches of snow on October 25, 1996 resulted in increased flows in the river, but when the Project operator arrived on site on October 27, 1996 inflow to the Project had naturally decreased and no water was flowing over the dam. The operator immediately closed the canal headgate and re-established the required minimum flow. Flow monitoring and operation control equipment that may have prevented an incident of this nature were being installed in conjunction with the fishway modifications. A written report was submitted to the Commission on November 26, 1996, and the Commission determined in a letter dated May 6, 1997 that the infrequent occurrence was minimal, of short duration, and did not constitute a violation of License Article 402.

A minimum flow variance occurred on July 13, 2000. On July 11, 2000, a heavy rainstorm caused high flows and high impoundment elevations. The head gate was opened to pass the high flows, but when the flows naturally attenuated, the gate failed to close automatically due to a failed motor operator shaft. As the impoundment elevation dropped, water in the fish ladder was reduced to approximately 8.7 cfs. In addition to the failure of the gate, the mechanism designed to alarm the control operator failed due to an incorrect setting. The problem was identified and corrected during a routine inspection on July 13, 2000. The motor shaft and alarm setting were repaired by September 22, 2000. A written report was submitted to the Commission on September 18, 2000, and the Commission determined in a letter dated July 17, 2001 that the causes of the incident were beyond PacifiCorp’s control, appropriate actions were taken to prevent future occurrences, and the incident was not considered a violation of License Article 402.

A minimum flow variance occurred on December 18, 2000 for approximately six hours from 5:00 a.m. to 11:00 a.m. PacifiCorp’s investigation of the event included testing of the diversion control systems. Test results indicated that the pressure transducer located upstream of the fish screen failed, causing a continuous “high level” signal input to the control system. It was believed that moisture contaminated and froze in the vent tube within the pressure transducer. The failed transducer simulated a pressure differential across the fish screen, which caused the control system to initiate a screen washing sequence, maintain the present headgate position, and allow the backwater gate to open. When the screen pressure differential persisted after the screen washing sequence, the headgate remained open and the fish screen remained in the plane position, sending an alarm to the Project plant and warehouse. The plant and warehouse are not staffed at night, so the alarm was discovered when the operator checked the alarm screen that morning. The operator placed the system in manual operational mode, and flows increased to the proper level. Examination of the gage data indicated that the stream flows dropped from 14 cfs at 4:30 a.m. to approximately 5 cfs at 10:30 a.m. and increased to about 18 cfs by 11:00 a.m. A written report of the variance was submitted to the Commission on January 17, 2001, and the Commission determined in a letter, dated June 11, 2002, that the failed pressure transducer was beyond PacifiCorp’s control, appropriate actions were taken to prevent future occurrences, and the incident was not considered a violation of License Article 402. On June 19, 2002, PacifiCorp notified the Commission that the three remedial actions had been completed to prevent future incidents of this type. The remedial actions included establishing a communications link with PacifiCorp’s Hydro Control Center (HCC) in Ariel, Washington to allow alarms at the Project to be continuously monitored, replacement of the failed transducer, and calibration and testing of the fish screen in both stream-flow and spill conditions.

A minimum flow variance occurred on October 11, 2001 at approximately 11:00 p.m. and lasted for nine and a half hours. An equipment malfunction caused the fish screen to be held in the position used to flush the screen, which caused the water level passing through the fish ladder to be reduced below the minimum flow. The malfunction was the result of newly installed cables on the fish screen that added two to three inches in length and prevented the limit switch from making the necessary contact to indicate that the back flush cycle was complete. In addition, the low flow alarm that should have been received at the HCC was disconnected during the fish screen maintenance. The operator took corrective action upon arrival for the morning shift and restored the minimum flow. The limit switch was recalibrated and tested to operate properly with the longer cables, and the alarm was returned to automatic operation and tested to ensure proper operation. A written report was submitted to the Commission on November 9, 2001, and the Commission determined in a letter dated September 12, 2002 that the flow variance was the result of required maintenance work and would not be considered a violation of License Article 402.

Hourly average flows dropped below 10 cfs on October 25, 2010 for four hours from 8:00 a.m. to a low of 6 cfs at 12:00 p.m. Prospect 3 tripped offline on the morning of October 24, 2010 due to a storm-related, transmission line outage, and the Project was brought back online on the evening of October 25, 2010. The minimum flow variance occurred when the Project was offline, and there is no known operational cause of the limited duration variance in the middle of an extended outage. The perceived variance may have been the result of environmental noise (e.g., debris) around the gage resulting in inaccurate flow data.

On August 6, 12, and 16, 2015, the South Fork Rogue River bypassed reach experienced minimum flow variances below an hourly average of 10 cfs. The diurnal flows within the South Fork Rogue River caused consistent minimum flow events to occur around the 10:00 hour. Low seasonal flows coupled with reduced operational control resulting from loss of a flash board at the dam crest contributed to variances of a limited volume and duration. During these events, PacifiCorp operated with both fish ladder gates, which supply upstream water to the fish ladder, in their full open positions and a full fish return pipe to maximize the amount of water distributed to the bypass reach in an effort to achieve the 10 cfs minimum flow. On August 18, 2015, PacifiCorp responded through additional adjustments to the Water Management System (WMS), which automatically controls water diversions and the level of the impoundment immediately upstream of the South Fork Diversion Dam, and were able to provide an additional buffer through reduced diversions to ensure that minimum flows were met. PacifiCorp had received three gage rating shifts from USGS in July 2015, and as a result PacifiCorp staff questioned the validity of the current rating since the fish gates and return pipe at full open positions and flow capacities had been able to provide minimum flows in the past. PacifiCorp requested that USGS reassess their river flow rating curve information, and USGS field measured and adjusted the rating on August 19, 2015. PacifiCorp replaced the flash board on the dam crest on September 9, 2015. Since that time, PacifiCorp has returned the WMS to previous set points, and confirmed that the minimum flow of 10 cfs has been maintained in the bypass reach. A report was submitted to FERC on September 9, 2015, but a response was not received.

The South Fork gage registered a brief low of approximately 5 cfs on the evening of October 13, 2016. The sharp dip in the flow record was experienced in the middle of a sharply rising hydrograph resulting from a significant precipitation event. No low-water alarms were received for the fish ladder (i.e., the minimum flow supply) during the event in question, and on-site operators did not observe any blockages during an after-hours call out to clean debris from the fish screen. The perceived variance was apparently the result of environmental noise at the gage and was not the result of PacifiCorp operations. The rain storm mobilized a significant amount of debris, including large wood as observed at the dam, and the assumption is that debris was temporarily in front of the gage sensors.

H.15.2 Unexpected Operational Events

Three significant, unexpected operational events have occurred during the current license term. A brief summary of each event is provided below.

In March and April of 1989, significant horizontal movement of an existing landslide adjacent to the forebay required remediation and additional monitoring of the slide area. The landslide, which dates back to the late 1940s or early 1950s, is located on the downstream, northeast side of the forebay entrance to the penstock. In 1951, the forebay and adjoining canal segment were realigned to repair or prevent damage to the canal because of landslide action. Formal monitoring of the slide, consisting of manual measurements of displacement, began in 1982. The significant movement in early 1989 amounted to seven to eight inches of horizontal movement. At this time, it was determined that erosion within the forebay spillway was contributing to movement of the slide. Repair activities in 1990 consisted of filling the spillway ravine with 20,000 cubic yards of rock fill to a depth of approximately 25 feet and a distance of approximately 400 feet in an effort to control erosion in the spillway and buttress the slide area. Post-construction monitoring revealed that additional horizontal movement had been reduced, and a report of the incident, including remediation and monitoring, was provided to the Commission on July 30, 1990.

On the afternoon of March 15, 2006, a rockslide occurred uphill of the woodstave flowline. A large boulder fell and punched a hole in the flowline, which caused the unit to trip offline and the flowline to spill approximately 130 cfs of water into the bypass reach. Following consultation with the Commission, ODFW, and Forest Service, the Commission granted authorization to conduct emergency repairs on March 17, 2006. PacifiCorp submitted a construction plan to Forest Service for approval on March 21, 2006, and Forest Service approved the submitted construction plan on March 22, 2006. Repairs commenced on March 23, 2006 with slope stabilization and flowline footing replacement. Woodstave replacement work was completed on March 31, 2006, and the unit was returned to service on April 3, 2006. A report with photos of the incident was submitted to the Commission on May 5, 2006. Adan Archuleta provided Commission acknowledgement and approval of the report via e-mail on June 5, 2006.

The flowline incurred additional damage from a large boulder in late 2012. The boulder, which broke from an exposed scarp approximately 1,200 feet from the head works, was discovered during water-up inspections on November 28, 2012 following an annual maintenance outage. Due to the proximity of the damage to the intake and the timing of the water-up inspection, a minimal amount of water was released from the waterway to the river. A plan for flowline repair and rockfall remediation was submitted to Forest Service on December 3, 2012, and Forest Service approved the plan on December 6, 2012. Scaling removed loose rock and debris from the scarp, and cable lashings, nets, and rock dowels were installed to preserve the current position of the lower breccia rock and upper massive basalt block assemblages. Following stabilization of the scarp, damaged flowline sections were replaced. Repairs were completed on January 17, 2013.

H.16 PUBLIC IMPACTS

The Project provides low-cost, renewable energy that is primarily consumed by local customers. The Project has been certified to meet the criteria for low environmental impact as determined by the Low Impact Hydropower Institute (LIHI; LIHI Certificate No. 109). The Project is staffed by four on-site operators with support from additional crews from PacifiCorp's Medford Hydro Operations staff. The Project has a minor influence on the local labor market.

H.17 PROJECT TRANSFER EXPENSES

Annual ownership and operating expenses are provided in Exhibit D. PacifiCorp estimates that all operations and maintenance costs for the proposed Project would average $671,551 per year for the next 43 years, totaling $28.9 million. This is based on estimates of historical and budget forecasts, which can have a high degree of variability from year to year. Routine operations and maintenance costs over the 43-year analysis period would average an estimated $609,433 annually, totaling $26.2 million. Non-routine operations and maintenance costs, net of Renewable Energy Credits, would average an estimated $26,025 annually, totaling $1.1 million. Implementation operations and maintenance costs would average an estimated $36,093 annually, totaling $1.6 million. These costs would be avoided if the Project license were to be transferred to another entity. See Section D.3.4 for a full description.

H.18 ANNUAL FEES FOR FEDERAL OR TRIBAL LANDS

The existing Project occupies 38.1 acres[2] of federal lands administered by the Forest Service. These federal lands are subject to federal land use charges pursuant to Section 24 of the Federal Power Act. In 2015, PacifiCorp paid $8,334.04 in annual fees for the use of federal lands within the Project boundary.

[2] On the approved Exhibit G (FERC drawing 2337-14), the sum of acreages listed on the drawing for federal lands is 38.1 acres, but the actual area is 32.41 acres when re-plotted from the description and calculated in GIS.

Table 10. Itemized charges for the use of government lands (including lands subject to the provisions of Section 24 FPA, excluding Indian lands) listed on the FERC Statement of Annual Charges for U.S. Lands (statement date 02/12/2015)

Fee Category	Acres	Rate	Amount
Exclusive of Transmission Lines	38.10	115.59	$4,403.98
Transmission Lines	34.0	115.59	$3,930.06
Total Charges			**$8,334.04**

The annual fees were based on occupancy of 38.1 acres of federal lands exclusive of transmission line and 34.0 acres of federal lands with transmission lines. However, Project transmission lines do not occupy federally-owned lands or Section 24 FPA reserved lands so the fee assessment appears to be based on incorrect information.

The Project does not occupy any Indian Tribal lands.