Exhibit N
Need

Boardman to Hemingway Transmission Line Project

1221 West Idaho Street
Boise, Idaho 83702

Todd Adams, Project Leader
(208) 388-2740
tadams@idahopower.com

Zach Funkhouser, Permitting
(208) 388-5375
zfunkhouser@idahopower.com

Preliminary Application for Site Certificate

February 2013.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF ATTACHMENTS

ACRONYMS AND ABBREVIATIONS

Note: Not all acronyms and abbreviations listed will appear in this Exhibit.

°C	degrees Celsius
4WD	4-wheel-drive
A	ampere
A/ph	amperes/phase
AC	alternating current
ACDP	Air Contaminant Discharge Permit
ACEC	Area of Critical Environmental Concern
ACSR	aluminum conductor steel reinforced
AIMP	Agricultural Impact Mitigation Plan
AMS	Analysis of the Management Situation
aMW	average megawatt
ANSI	American National Standards Institute
APE	Area of Potential Effect
APLIC	Avian Power Line Interaction Committee
ARPA	Archaeological Resource Protection Act
ASC	Application for Site Certificate
ASCE	American Society of Civil Engineers
ASP	Archaeological Survey Plan
AST	aboveground storage tank
ASTM	American Society of Testing and Materials
ATC	available transmission capacity
ATV	all-terrain vehicle
AUM	animal unit month
B2H	Boardman to Hemingway Transmission Line Project
BCCP	Baker County Comprehensive Plan
BCZSO	Baker County Zoning and Subdivision Ordinance
BLM	Bureau of Land Management
BMP	best management practice
BPA	Bonneville Power Administration
BOR	Bureau of Reclamation
C and D	construction and demolition
CAA	Clean Air Act
CadnaA	Computer-Aided Noise Abatement
CAFE	Corona and Field Effects
CAP	Community Advisory Process
CBM	capacity benefit margin
CFR	Code of Federal Regulations
CH	critical habitat
CIP	critical infrastructure protection
CL	centerline
cm	centimeter
cmil	circular mil
COA	Conservation Opportunity Area
CO_2e	carbon dioxide equivalent

COM Plan	Construction, Operations, and Maintenance Plan
CPCN	Certificate of Public Convenience and Necessity
cps	cycle per second
CRP	Conservation Reserve Program
CRT	cathode-ray tube
CRUP	Cultural Resource Use Permit
CSZ	Cascadia Subduction Zone
CTUIR	Confederated Tribes of the Umatilla Indian Reservation
CWA	*Clean Water Act of 1972*
CWR	Critical Winter Range
dB	decibel
dBA	A-weighted decibel
DC	direct current
DoD	Department of Defense
DOE	U.S. Department of Energy
DOGAMI	Oregon Department of Geology and Mineral Industries
DPS	Distinct Population Segment
DSL	Oregon Department of State Lands
EA	environmental assessment
EDRR	Early Detection and Rapid Response
EIS	Environmental Impact Statement (DEIS for Draft and FEIS for Final)
EFSC or Council	Energy Facility Siting Council
EFU	Exclusive Farm Use
EHS	extra high strength
EMF	electric and magnetic fields
EPA	Environmental Protection Agency
EPC	Engineer, Procure, Construct
EPM	environmental protection measure
EPRI	Electric Power Research Institute
ERO	Electric Reliability Organization
ERU	Exclusive Range Use
ESA	Endangered Species Act
ESCP	Erosion and Sediment Control Plan
ESU	Evolutionarily Significant Unit
EU	European Union
FAA	Federal Aviation Administration
FCC	Federal Communication Commission
FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
FFT	find, fix, track, and report
FLPMA	Federal Land Policy and Management Act
Forest Plan	Land and Resource Management Plan
FPA	Forest Practices Act
FSA	Farm Services Agency
FWS	U.S. Fish and Wildlife Service
G	gauss

GeoBOB	Geographic Biotic Observation
GF	Grazing Farm Zone
GHG	greenhouse gas
GHz	gigahertz
GIL	gas insulated transmission line
GIS	geographic information system
GPS	Global Positioning System
GRMW	Grande Ronde Model Watershed
GRP	Grassland Reserve Program
HAC	Historic Archaeological Cultural
HCNRA	Hells Canyon National Recreation Area
HPFF	high pressure fluid-filled
HPMP	Historic Properties Management Plan
HUC	Hydrologic Unit Code
Hz	hertz
I-84	Interstate 84
ICC	International Code Council
ICES	International Committee on Electromagnetic Safety
ICNIRP	International Commission on Non-Ionizing Radiation Protection
IDAPA	Idaho Administrative Procedures Act
IDEQ	Idaho Department of Environmental Quality
IDFG	Idaho Department of Fish and Game
IDWR	Idaho Department of Water Resources
ILS	intensive-level survey
IM	Instructional Memorandum
INHP	Idaho Natural Heritage Program
INRMP	Integrated Natural Resources Management Plan
IPC	Idaho Power Company
IPUC	Idaho Public Utilities Commission
IRP	integrated resource plan
IRPAC	IRP Advisory Council
ISDA	Idaho State Department of Agriculture
JPA	Joint Permit Application
KCM	thousand circular mils
kHz	kilohertz
km	kilometer
KOP	Key Observation Point
kV	kilovolt
kV/m	kilovolt per meter
kWh	kilowatt-hour
L_{dn}	day-night sound level
L_{eq}	equivalent sound level
lb	pound
LCDC	Land Conservation and Development Commission
LDMA	Lost Dutchman's Mining Association
LiDAR	light detection and ranging
LIT	Local Implementation Team

LMP	land management plan
LOLE	Loss of Load Expectation
LRMP	land and resource management plan
LUBA	Land Use Board of Appeals
LWD	large woody debris
m	meter
mA	milliampere
MA	Management Area
MAIFI	Momentary Average Interruption Frequency Index
MCC	Malheur County Code
MCCP	Morrow County Comprehensive Plan
MCE	Maximum Credible Earthquake
MCZO	Morrow County Zoning Ordinance
mG	milligauss
MHz	megahertz
mm	millimeter
MMI	Modified Mercalli Intensity
MP	milepost
MPE	maximum probable earthquake
MRI	magnetic resonance imaging
MVAR	megavolt ampere reactive
Mw	mean magnitude
MW	megawatt
μV/m	microvolt per meter
N_2O	nitrous oxide
NAIP	National Agriculture Imagery Program
NED	National Elevation Dataset
NEMS	National Energy Modeling System
NEPA	*National Environmental Policy Act of 1969*
NERC	North American Electric Reliability Corporation
NESC	National Electrical Safety Code
NF	National Forest
NFPA	National Fire Protection Association
NFS	National Forest System
NGDC	National Geophysical Data Center
NHD	National Hydrography Dataset
NHOTIC	National Historic Oregon Trail Interpretive Center
NHT	National Historic Trail
NIEHS	National Institute of Environmental Health Sciences
NIST	National Institute of Standards and Technology
NOAA	National Oceanic and Atmospheric Administration
NOAA Fisheries	National Oceanic and Atmospheric Administration Fisheries Division
NOI	Notice of Intent to File an Application for Site Certificate
NOV	Notice of Violation
NPDES	National Pollutant Discharge Elimination System
NRCS	Natural Resources Conservation Service

NRHP	National Register of Historic Places
NSR	noise sensitive receptor
NTTG	Northern Tier Transmission Group
NWGAP	Northwest Regional Gap Analysis Landcover Data
NWI	National Wetlands Inventory
NWPP	Northwest Power Pool
NWR	National Wildlife Refuge
NWSRS	National Wild and Scenic Rivers System
NWSTF	Naval Weapons Systems Training Facility
O_3	ozone
O&M	operation and maintenance
OAIN	Oregon Agricultural Information Network
OAR	Oregon Administrative Rules
OATT	Open Access Transmission Tariff
ODA	Oregon Department of Agriculture
ODEQ	Oregon Department of Environmental Quality
ODF	Oregon Department of Forestry
ODFW	Oregon Department of Fish and Wildlife
ODOE	Oregon Department of Energy
ODOT	Oregon Department of Transportation
OHGW	overhead ground wire
OHV	off-highway vehicle
OPGW	optical ground wire
OPRD	Oregon Parks and Recreation Department
OPS	U.S. Department of Transportation, Office of Pipeline Safety
OPUC	Public Utility Commission of Oregon
OR	Oregon (State) Highway
ORBIC	Oregon Biodiversity Information Center
ORS	Oregon Revised Statutes
ORWAP	Oregon Rapid Wetland Assessment Protocol
OS	Open Space
OSDAM	Oregon Streamflow Duration Assessment Methodology
OSHA	Occupational Safety and Health Administration
OSSC	Oregon Structural Specialty Code
OSWB	Oregon State Weed Board
OWC	Oregon Wetland Cover
P	Preservation
PA	Programmatic Agreement
pASC	Preliminary Application for Site Certificate
PAT	Project Advisory Team
PCE	Primary Constituent Element
PEM	palustrine emergent
PFO	palustrine forested
PGA	peak ground acceleration
PGE	Portland General Electric
PGH	Preliminary General Habitats
Pike	Pike Energy Solutions

PNSN	Pacific Northwest Seismic Network
POD	Plan of Development
POMU	Permit to Operate, Maintain and Use a State Highway Approach
PPH	Preliminary Priority Habitats
Project	Boardman to Hemingway Transmission Line Project
PSD	Prevention of Significant Deterioration
PSS	palustrine scrub-shrub
R	Retention
R-F	removal-fill
RCM	Reliability Centered Maintenance
RCRA	Resource Conservation and Recovery Act
ReGAP	Regional Gap Analysis Project
RFP	request for proposal
RLS	reconnaissance-level survey
RMP	resource management plan
ROD	Record of Decision
ROE	right of entry
RNA	research natural area
ROW	right-of-way
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SC	Sensitive Critical
SEORMP	Southeastern Oregon Resource Management Plan
SF6	sulfur hexafluoride
Shaw	Shaw Environmental and Infrastructure, Inc.
SHPO	State Historic Preservation Office
SLIDO	Statewide Landslide Inventory Database for Oregon
SMS	Scenery Management System
SMU	Species Management Unit
SPCC	Spill Prevention, Containment, and Countermeasures
SRMA	Special Recreation Management Area
SRSAM	Salmon Resources and Sensitive Area Mapping
SSURGO	Soil Survey Geographic Database
STATSGO	State Soil Geographic Database
SUP	special-use permit
SV	Sensitive Vulnerable
SWPPP	Stormwater Pollution Prevention Plan
T/A/Y	tons/acre/year
TDG	Total Dissolved Gas
TES	threatened, endangered, and sensitive (species)
TG	Timber Grazing
TMIP	Transmission Maintenance and Inspection Plan
TNC	The Nature Conservancy
tpy	tons per year
TSD	treatment, storage, and disposal
TV	television
TVES	Terrestrial Visual Encounter Surveys

TVMP	Transmission Vegetation Management Program
UBAR	Umatilla Basin Aquifer Restoration
UBWC	Umatilla Basin Water Commission
UCDC	Umatilla County Development Code
UCZPSO	Union County Zoning, Partition and Subdivision Ordinance
UDP	Unanticipated Discovery Plan
U.S.	United States
USACE	U.S. Army Corps of Engineers
U.S.C.	United States Code
USDA	U.S. Department of Agriculture
USFS	U.S. Department of Agriculture, Forest Service
USGS	U.S. Geological Survey
UWIN	Utah Wildlife in Need
V/C	volume to capacity
V	volt
VAHP	Visual Assessment of Historic Properties
VMS	Visual Management System
VQO	Visual Quality Objective
VRM	Visual Resource Management
WAGS	Washington ground squirrel
WCU	Wilderness Characteristic Unit
WECC	Western Electricity Coordinating Council
WHO	World Health Organization
WMA	Wildlife Management Area
WOS	waters of the state
WOUS	waters of the United States
WPCF	Water Pollution Control Facility
WR	winter range
WRCC	Western Regional Climate Center
WRD	(Oregon) Water Resources Division
WRP	Wetland Reserve Program
WWE	West-wide Energy
XLPE	cross-linked polyethylene

Exhibit N
Need

1.0 INTRODUCTION

Exhibit N provides Idaho Power Company's (IPC) demonstration of need under Oregon Administrative Rule (OAR) 345-021-0010(1)(n) and OAR Chapter 345, Division 23. These rules require IPC to demonstrate need for the Boardman to Hemingway Transmission Line Project (the Project) under the least-cost plan rule, OAR 860-023-0020, the system reliability rule for transmission lines, OAR 345-023-0030, and/or by demonstrating that the line is proposed to be within a "National Interest Electric Transmission Corridor" designated by the U.S. Department of Energy (DOE) under Section 216 of the Federal Power Act, under OAR 345-023-0005(1).

Exhibit N provides evidence of the need for the Project under both the least-cost plan and system reliability rules; the third rule relating to transmission corridors is inapplicable because the DOE currently has no designated transmission corridors in the Project vicinity.

2.0 APPLICABLE RULES AND STATUTES

Under Oregon Revised Statutes (ORS) 469.501, the Energy Facility Siting Council (EFSC or the Council) is required to adopt standards for the siting, construction, and operation of facilities subject to its jurisdiction. At EFSC's discretion, these standards may, but are not required to, address "the need for proposed nongenerating facilities [such as transmission lines] consistent with the state energy policy."[1] ORS 469.501(1)(L) specifically states that EFSC "may consider least-cost plans when adopting a need standard or in determining whether an applicable need standard has been met."[2]

Pursuant to its statutory discretion, EFSC adopted a need standard for non-generating facilities, which provides as follows:

> *To issue a site certificate for a facility described in sections (1) through (3), the Council must find that the applicant has demonstrated the need for the facility. * * * This division describes the methods the applicant shall use to demonstrate need. * * * The applicant shall demonstrate need:*
>
>> *(1) For electric transmission lines under the least-cost plan rule, OAR 345-023-0020(1), or the system reliability rule for transmission lines, OAR 345-023-0030, or by demonstrating that the transmission line is proposed to be located within a "National Interest Electric Transmission Corridor" designated by the U.S. Department of Energy under Section 216 of the Federal Power Act . . ."[3].*

The following two sections summarize the requirements of both the "least-cost plan rule" and the "system reliability rule" for transmission lines.

[1] ORS 469.501(1) (EFSC "shall adopt standards for the siting, construction, operation and retirement of facilities. These standards may address but need not be limited to the following subjects: . . . (L) The need for the proposed nongenerating facility.").
[2] *Id.*
[3] OAR 345-023-0005.

2.1 Least-Cost Plan Rule

EFSC's least-cost plan rule, OAR 345-023-0020(1), states that EFSC:

> *shall find that the application has demonstrated need for the facility of the capacity of the proposed facility or a facility substantially similar to the proposed facility . . . is identified for acquisition in the short-term plan of action of an energy resource plan or combination of plans adopted, approved or acknowledged by a . . . government body that makes or implements energy policy . . . .*

Under OAR 345-023-0020(2), an Integrated Resource Plan (IRP)--as the least cost plan is currently referred to-- acknowledged by the Public Utility Commission of Oregon (OPUC) that includes the proposed facility or a substantially similar facility satisfies EFSC's need standard. Thus, if the proposed facility or a substantially similar facility is included in the preferred portfolio of an OPUC-acknowledged IRP, EFSC must find that the need standard has been satisfied.

The OPUC's IRP process is "an approach to utility planning which requires consideration of all known resources for meeting the utility's load."[4] These resources include both supply-side resources, such as generation plants, and demand-side resources, such as conservation and load management. The OPUC has adopted guidelines that govern the development and acknowledgement of utility IRPs. These guidelines implement the OPUC's overarching procedural and substantive goals for the IRP process. As relevant here, the IRP process must include significant public involvement in the preparation of the plan.[5] Substantively, the plan must:

- Evaluate all resources on a consistent and comparable basis;
- Consider uncertainty;
- Include as its primary goal the least cost to the utility and ratepayers, consistent with the long-run public interest; and
- Be consistent with Oregon's energy policy.[6]

To meet the OPUC's guidelines and goals, the IRP process requires a utility to identify several portfolios of different combinations of resources that can be used to meet the utility's load over a 20-year planning horizon. Each portfolio is then analyzed in accordance with the OPUC's guidelines to determine which portfolio represents the best combination of costs and risks. The portfolio that represents the best combination of costs and risk is the preferred portfolio. This preferred portfolio is then used to develop the IRP's Action Plan, which describes in more definite terms how the utility will obtain the resources identified in the preferred portfolio.

OPUC acknowledgement of an IRP means that the IRP is "reasonable, based on information available at the time."[7] The OPUC's IRP guidelines recognize that all utility planning encompasses uncertainty and requires only that utilities consider the uncertainties in their planning and that the preferred portfolio represent the best combination of expected costs and associated risks and uncertainties.[8]

[4] Order No. 89-507 at 8.
[5] Order No. 07-002 at 1.
[6] Order No. 07-002 at 2.
[7] Order No. 07-002 at 10.
[8] Order No. 07-002 at 5 ("uncertainty" is a "measure of the quality of information about an event or outcome").

2.2 System Reliability Rule

EFSC's system reliability rule, OAR 345-023-0030, allows an applicant to demonstrate need for an electric transmission line if EFSC finds the following:

> *(1) The facility is needed to enable the transmission system of which it is to be a part to meet firm capacity demands for electricity or firm annual electricity sales that are reasonably expected to occur within five years of the facility's proposed in-service date based on weather conditions that have at least a 5 percent chance of occurrence in any year in the area to be served by the facility;*
>
> *(2) The facility is consistent with the minimum operating reliability criteria contained in the Western System Coordinating Council Bulk Power Supply Program 1997-2007, dated April 1, 1998, as it applies either internally or externally to a utility system; and*
>
> *(3) Construction and operation of the facility is an economically reasonable method of meeting the requirements of sections (1) and (2) compared to the alternatives evaluated in the application for a site certificate.*

2.3 Requirements of Exhibit N – OAR 345-021-0010(1)(n)

OAR 345-021-0010(1)(n) describes the substantive information that must be included in Exhibit N to satisfy the need standard. The relevant requirements from that rule are as follows:

> (*A) Identification of the rule in Division 23 of this chapter under which the applicant chooses to demonstrate need;*
>
> *(B) If the applicant chooses to demonstrate need for the proposed facility under OAR 345-023-0020(1), the least-cost plan rule:*
>
> > *(i) Identification of the energy resource plan or combination of plans on which the applicant relies to demonstrate need;*
> >
> > *(ii) The name, address and telephone number of the person responsible for preparing each energy resource plan identified in subparagraph (i);*
> >
> > *(iii) For each plan reviewed by a regulatory agency, the agency's findings and final decision, including:*
> >
> > > *(I) For a plan reviewed by the Oregon Public Utility Commission, the acknowledgment order; or*
> > >
> > > *(II) For a plan reviewed by any other regulatory agency, a summary of the public process including evidence to support a finding by the Council that the agency's decision process included a full, fair and open public participation and comment process as required by OAR 345-023-0020(1)(L), and the location of and means by which the Department can obtain a complete copy of the public record;*
> >
> > *(iv) Identification of the section(s) of the short-term action plan(s) that call(s) for the acquisition of the proposed facility or, as defined in OAR 345-001-0010, a facility substantially similar to the proposed facility; and*
> >
> > *(v) The attributes of the proposed facility that qualify it as one called for in the short-term action plan of the energy resource plan or combination of plans identified in subparagraph (i) or a demonstration that, as defined in OAR 345-*

001-0010, a facility substantially similar to the proposed facility is called for in the plan(s);

(C)(D)(E) [Not applicable]

(F) If the applicant chooses to demonstrate need for a proposed electric transmission line under OAR 345-023-0030, the system reliability rule:

(i) Load-resource balance tables for the area to be served by the proposed facility. In the tables, the applicant shall include firm capacity demands and existing and committed firm resources for each of the years from the date of submission of the application to at least five years after the expected in-service date of the facility.

(ii) Within the tables described in subparagraph (i), a forecast of firm capacity demands for electricity and firm annual electricity sales for the area to be served by the proposed facility. The applicant shall separate firm capacity demands and firm annual electricity sales into loads of retail customers, system losses, reserve margins and each wholesale contract for firm sale. In the forecast, the applicant shall include a discussion of how the forecast incorporates reductions in firm capacity demand and firm annual electricity sales resulting from:

(I) Existing federal, state or local building codes, and equipment standards and conservation programs required by law for the area to be served by the proposed facility;

(II) Conservation programs provided by the energy supplier, as defined in OAR 345-001-0010;

(III) Conservation that results from responses to price; and

(IV) Retail customer fuel choice;

(iii) Within the tables described in subparagraph (i), a forecast of existing and committed firm resources used to meet the demands described in subparagraph (ii). The applicant shall include, as existing and committed firm resources, existing generation and transmission facilities, firm contract resources and committed new resources minus expected resource retirements or displacement. In the forecast, the applicant shall list each resource separately;

(iv) A discussion of the reasons each resource is being retired or displaced if the forecast described in subparagraph (iii) includes expected retirements or displacements;

(v) A discussion of the annual capacity factors assumed for any generating facilities listed in the forecast described in subparagraph (iii);

(vi) A discussion of the reliability criteria the applicant uses to demonstrate the proposed facility is needed, considering the load carrying capability of existing transmission system facilities supporting the area to be served by the proposed facility; and

(vii) A discussion of reasons why the proposed facility is economically reasonable compared to the alternatives described below. In the discussion, the applicant shall include a table showing the amounts of firm capacity and firm annual electricity available from the proposed facility and each alternative and the

estimated direct cost, as defined in OAR 345-001-0010, of the proposed facility and each alternative. The applicant shall include documentation of assumptions and calculations supporting the table. The applicant shall evaluate alternatives to construction and operation of the proposed facility that include, but are not limited to:

(I) Implementation of cost-effective conservation, peak load management and voluntary customer interruption as a substitute for the proposed facility;

(II) Construction and operation of electric generating facilities as a substitute for the proposed facility;

(III) Direct use of natural gas, solar or geothermal resources at retail loads as a substitute for use of electricity transmitted by the proposed facility; and

(IV) Adding standard sized smaller or larger transmission line capacity;

(viii) The earliest and latest expected in-service dates of the facility and a discussion of the circumstances of the energy supplier, as defined in OAR 345-001-0010, that determine these dates; and

(G) [Not applicable].

2.4 Project Order Requirements

The Project Order states that all paragraphs of OAR 345-021-0010(1)(n) apply to IPC's Application for Site Certificate, and confirms that "the applicant may provide evidence demonstrating the need for the facility under one or more of the methods described in Division 23."

As documented in Table N-3 (Submittal Requirements Matrix), IPC has drafted Exhibit N to respond to each paragraph of OAR 345-021-0010(1)(n) described above, as well as the additional requirements set forth in the Project Order.

3.0 ANALYSIS

3.1 Identification of the Rule Under Which IPC Will Demonstrate Need

OAR 345-021-0010(1)(n)

(A) Identification of the rule in Division 23 of this chapter under which the applicant chooses to demonstrate need;

Although EFSC's rules require an applicant to demonstrate need under one rule only, the Project meets the requirements of both the least-cost plan and system reliability rules. Based upon the evidence in this exhibit, IPC respectfully requests that EFSC make alternative determinations of need under each of these two rules.

3.2 Demonstration of Need Under the Least-Cost Plan Rule, OAR 345-023-0020

OAR 345-021-0010(1)(n)
(B) If the applicant chooses to demonstrate need for the proposed facility under OAR 345-023-0020(1), the least-cost plan rule:
(i) Identification of the energy resource plan or combination of plans on which the applicant relies to demonstrate need;

IPC's 2009 and 2011 IRPs, both of which the OPUC has acknowledged, demonstrate the need for the Project. The 2009 IRP is Attachment N-1 and the 2011 IRP is Attachment N-2 to this Exhibit. Both IRPs included the Project as a supply-side resource in the IRP's preferred portfolio. The inclusion of the Project in IPC's latest IRPs is a continuation of IPC's review of potential transmission upgrades in every IRP IPC has filed in the last decade.

3.2.1 Identification of Person(s) Responsible for Preparation of IPC's IRPs

OAR 345-021-0010(1)(n)
(B) If the applicant chooses to demonstrate need for the proposed facility under OAR 345-023-0020(1), the least-cost plan rule:
(ii) The name, address and telephone number of the person responsible for preparing each energy resource plan identified in subparagraph (i);

The person responsible for preparation of IPC's IRPs is:

Mark Stokes
Manager Power Supply Planning
1221 West Idaho Street
Boise, Idaho 83702
(208) 388-2483

3.2.2 IPC's Acknowledged IRPs

OAR 345-021-0010(1)(n)
(B) If the applicant chooses to demonstrate need for the proposed facility under OAR 345-023-0020(1), the least-cost plan rule:
(iii) For each plan reviewed by a regulatory agency, the agency's findings and final decision, including:
(I) For a plan reviewed by the Oregon Public Utility Commission, the acknowledgment order;
(iv) Identification of the section(s) of the short-term action plan(s) that call(s) for the acquisition of the proposed facility or, as defined in OAR 345-001-0010, a facility substantially similar to the proposed facility; and
(v) The attributes of the proposed facility that qualify it as one called for in the short-term action plan of the energy resource plan or combination of plans identified in subparagraph (i) or a demonstration that, as defined in OAR 345-001-0010, a facility substantially similar to the proposed facility is called for in the plan(s);

3.2.2.1 IPC's 2009 IRP

IPC filed its 2009 IRP with the OPUC on December 30, 2009, which docketed the filing as LC 50. IPC provided notice of the filing to all parties that had participated in IPC's previous IRP docket, LC 41.

IPC requested that the OPUC acknowledge the preferred portfolios and Action Plan in the 2009 IRP.

In developing the 2009 IRP, IPC engaged in an extensive public process, as required by the OPUC's IRP planning guidelines. This process included the creation of an IRP Advisory Council (IRPAC), which included major stakeholders including representatives of political organizations, environmental groups, and customer representatives, among others. The IRPAC generally met monthly throughout the process of developing the IRP and all meetings were open to the public. These meetings allowed stakeholders to provide input to IPC regarding all aspects of the planning process, including the development of the portfolios that were ultimately included in the 2009 IRP.

The 2009 IRP divided the 20-year planning period into two 10-year periods. IPC then developed different portfolios for each of those 10-year periods. These portfolios each represented the resources that IPC plans to obtain during each of the 10-year periods. For the first period, 2010 to 2019, IPC developed four different resources portfolios. For the second period, 2019 to 2029, IPC developed five different resource portfolios.

To analyze the resource portfolios, IPC uses an electric market model as the primary tool. This tool enables IPC to model resource operations and determine operating costs for the entire 20-year planning horizon. This analysis is based on the application of economic principles and dispatch simulation to model the relationships between generation, transmission, and demand to forecast market prices. The operation of existing and future resources is based on forecasts of key fundamental elements, such as demand, fuel prices, hydroelectric conditions, and operating characteristics of new resources. The modeling simulates the regional electrical system to determine how utility generation and transmission resources operate to serve load. This analysis includes multiple electricity markets, zones, and hubs. IPC models the entire Western Electricity Coordinating Council (WECC) system when evaluating the various resource portfolios for the IRP.

IPC's analysis also includes detailed assessment of risk, both quantitative and qualitative. This analysis identifies portfolios that perform well in a variety of possible future scenarios. This risk analysis identified six risk variables that were then included in IPC's modeling—carbon risk, natural gas price risk, capital cost risk, risk associated with demand side management variability, risk caused by load variability, and risk associated with renewable energy certificate price changes. This stochastic modeling was used to estimate the distribution of the incremental portfolio costs. Based on its modeling and analysis, IPC selected a preferred portfolio for each 10-year period.

The 2009 IRP's preferred portfolio for the first 10-year period included the Project as a supply-side resource. IPC's analysis demonstrated that this preferred portfolio represented the best combination of cost and risk for IPC and its ratepayers. The IRP also included IPC's Action Plan, which describes the specific actions IPC intends to take to implement its preferred portfolio. That Action Plan included the construction of the Project. Chapter 10 of the 2009 IRP describes the modeling and risk analysis of each of the identified portfolios and identifies the selection of the portfolio including the Project as the preferred portfolio.

The OPUC's analysis and public process on the 2009 IRP was both extensive and thorough. The IRP was the subject of discussion at two separate OPUC public meetings. In addition, there was a public hearing held in Ontario, Oregon. This hearing allowed members of the public to submit both oral and written comments for the OPUC's consideration. The OPUC's process also allowed parties that formally intervened in the docket to submit written comments on two separate occasions. Over 25 individuals and organizations submitted written comments that were considered by the OPUC in the IRP process.

In addition to public comment, the staff of the OPUC undertook a comprehensive and independent review of the 2009 IRP. As part of that process, the staff issued 69 data requests to which IPC responded with additional analysis and explanation. OPUC staff ultimately concluded that IPC's preferred portfolio, which included the Project, represented the "best combination of expected costs and associated risks and uncertainties for IPC and its customers."[9] OPUC staff concluded that IPC's analysis demonstrated the "robustness of the Preferred Portfolio." As OPUC staff noted, for the next best portfolio to break even with the preferred portfolio (meaning only that the two portfolios' cost assumptions become comparable) the Project's capital costs would have to increase by 40 percent and the subscription rates would have to decrease by 15 percent.[10] This demonstrated that not only was the preferred portfolio the most cost effective and lowest risk, the preferred portfolio also tolerated a great deal of uncertainty before the next best alternative became competitive.

On October 11, 2010, the OPUC issued Order No. 10-392, which acknowledged IPC's 2009 IRP. The OPUC concluded that it is "reasonable to proceed with [the Project] based on the information available now and acknowledge it as part of [IPC's] 2009 IRP."[11] Order No. 10-392 is included as Attachment N-3 to this Exhibit.

3.2.2.2 IPC's 2011 IRP

On June 30, 2011, IPC filed its 2011 IRP with the OPUC, which docketed the filing as LC 53. IPC provided notice of the filing to all parties that had participated in IPC's previous IRP docket, LC 50.

Like the 2009 IRP, IPC's 2011 IRP also included extensive public participation through the IRPAC. This process allowed for significant input into the portfolios included for analysis in the 2011 IRP. The IRPAC held nine monthly meetings, all of which were open to the public. In addition, IPC hosted a field trip covering wind, hydroelectric, and natural gas resources and held two resource portfolio-design workshops. Several of the portfolios included in the 2011 IRP were developed during these workshops.

The 2011 IRP again utilized two 10-year planning periods to develop its resource portfolios. For the first 10-year period, 2011 to 2020, IPC developed and analyzed nine different portfolios. These portfolios included eight different types of supply-side resources—solar, single-cycle combustion turbine, combined-cycle combustion turbine, geothermal, pumped storage, distributed generation, combined heat and power, and the Project. For the second 10-year period, 2020 to 2030, IPC developed and analyzed 10 different resource portfolios.

IPC's analysis in the 2011 IRP was largely the same as that used in the 2009 IRP, although the 2011 IRP included significantly more resource portfolios. As a result, the analysis in the 2011

[9] *See* Final Comments and Recommendations at 6 and Appendix A at 1 (Comments); Order No. 07-002 at 5 ("The primary goal [of the IRP process] must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.").
[10] LC 50 Staff Proposed Order at 6.
[11] Order No. 10-392 at 9.

IRP was more robust and compared the Project as a supply-side resource to a greater range of potential alternatives.

Based on the analysis and modeling in the 2011 IRP, IPC selected the Project portfolio as the preferred portfolio for the first 10-year period. This selection was based on the expected low costs and the limited risk spread provided by this portfolio. Because the Project was included in the preferred portfolio it was also included in the 2011 IRP's Action Plan, which is described in Chapter 10 of the 2011 IRP.

The OPUC's analysis and public process for the 2011 IRP was as extensive and thorough as that described for the 2009 IRP. On September 20, 2011, IPC presented its IRP to the Commission at a public meeting. Thereafter, the OPUC held a technical workshop for parties in the docket. Staff and intervenors filed initial comments on October 18, 2011, followed by several additional rounds of comments from IPC and other parties. Staff filed its report and proposed order on January 24, 2012, recommending acknowledgement of the Project. Staff noted its general agreement "regarding the benefits [the Project] brings," and the fact that the Project was "proposed and justified as the primary resource in a portfolio representing the best combination of cost and risk for Idaho Power and its ratepayers."[12]

At the OPUC's February 14, 2012, public meeting, the OPUC reviewed and acknowledged IPC's 2011 IRP. On May 21, 2012, the OPUC confirmed its acknowledgement of IPC's 2011 IRP in a written order (Order No. 12-177). Order No. 12-177 is included as Attachment N-4 to this Exhibit.

3.3 Demonstration of Need Under the System Reliability Rule, OAR 345-023-0030

The system reliability rule requires a showing that the Project is needed to allow IPC to meet its projected firm capacity demands or firm annual sales, is required for IPC to meet its minimum operating criteria, and is an economically reasonable method of meeting these requirements as compared to other alternatives. The following analysis provides this showing.

First, the Project is required to meet projected loads. Without additional resources, IPC projects a resource deficiency (unmet load) of 250 megawatts (MW) in 2016 , 350 MW in 2018, and up to 450 MW by 2020. Moreover, additional transmission capacity is also needed to meet IPC's minimum operating criteria for reliability and to provide transmission service to wholesale customers.

Without the Project, the alternate portfolio identified in the 2011 IRP (shown on page 121) includes the addition of a 170 MW simple-cycle combustion turbine every 2 years beginning in 2015. This portfolio represents the next best option when considering cost and risk. IPC's acknowledged 2011 IRP analysis demonstrates that the Project is the most economic alternative to meet IPC's need to serve its native load, satisfy minimum reliability standards, and provide service to wholesale transmission customers.

[12] LC 53 Staff Proposed Order at 9-10.

3.3.1 Load-Resource Balance Tables, OAR 345-021-0010(1)(n)(F)(i)

> **OAR 345-021-0010(1)(n)**
>
> (F) If the applicant chooses to demonstrate need for a proposed electric transmission line under OAR 345-023-0030, the system reliability rule:
>
> (i) Load-resource balance tables for the area to be served by the proposed facility. In the tables, the applicant shall include firm capacity demands and existing and committed firm resources for each of the years from the date of submission of the application to at least five years after the expected in-service date of the facility.

The load-resource balance tables for the area to be served by the Project are included in Attachment N-2, the IPC 2011 IRP, Appendix C – Technical Appendix, pages 22 through 65. The monthly average energy load-resource balance values are reported on pages 22 through 43, and the monthly peak hour load-resource balance values are reported on pages 44 through 65. These tables include annual firm capacity demands and existing and committed firm resources for a 20-year period beginning in 2011.

3.3.2 Detail on Firm Capacity Load-Resource Balance Tables, OAR 345-021-0010(1)(n)(F)(ii)

> **OAR 345-021-0010(1)(n)(F)**
>
> (ii) Within the tables described in subparagraph (i), a forecast of firm capacity demands for electricity and firm annual electricity sales for the area to be served by the proposed facility. The applicant shall separate firm capacity demands and firm annual electricity sales into loads of retail customers, system losses, reserve margins and each wholesale contract for firm sale.

The load-resource balance tables in Attachment N-2, IPC's 2011 IRP, are based on a forecast of firm capacity demands for electricity and firm annual electricity sales for the area to be served by the Project. As explained below, (1) the firm capacity demands for electricity or firm annual electricity sales are those reasonably expected to occur within 5 years of the facility's proposed in-service date based on weather conditions that have at least a 5 percent chance of occurrence in any year; and (2) IPC has separated firm capacity demands and firm annual electricity sales into loads of retail customers, system losses, reserve margins, and each wholesale contract for firm sales.

The sales and load forecast values are reported in Attachment N-2, IPC's 2011 IRP, at Appendix C – Technical Appendix, pages 3 through 21. The expected-case load forecast is shown on pages 4 through 12 of the Technical Appendix. The expected-case load forecast is based on median forecast data. The planning period load forecast values are shown on pages 13 through 21 of the Technical Appendix. The planning period load forecast is based on 70th percentile forecast data. IPC has separated firm capacity demands and firm annual electricity sales into loads of retail customers, system losses, and each wholesale power purchase agreement. Reserve margins deserve special discussion. IPC does not explicitly calculate reserve margins in its IRP; instead, IPC uses 70th percentile planning criteria as discussed on page 85 of the IPC's 2011 IRP:

> *The planning criteria for monthly average load planning are 70th percentile water and 70th percentile average load conditions. For peak hour load conditions, the planning criteria used are 90th percentile water and 95th percentile peak hour load. The peak hour analysis is coupled with Idaho Power's ability to import additional energy on its transmission system. Peak hour load planning criteria are more stringent than average*

load planning criteria because Idaho Power's ability to import additional energy is typically limited during peak load periods. The median forecast is no longer used for resource planning but it is used to set retail rates and avoided-cost rates during regulatory proceedings.

Idaho Power has adopted the practice of assuming drier than median water conditions and higher than median load conditions in its resource planning process. Targeting a balanced position between load and resources, while using the conservative water and load conditions, is considered comparable to requiring capacity margin in excess of load while using median load and water conditions. Both approaches are designed to result in a system having generating capacity in reserve for meeting day to day operating reserve requirements.

The 95th percentile means that 95 percent of the time, the peak load is expected to be less than the peak load value used for planning, and five percent of the time the peak load is expected to be greater than the peak load value used in the planning analysis. The 95th percentile peak load distribution is based on observations of the IPC peak load and the historical probability distribution of the peak load. The 95th percentile calculations for peak load mean that the peak load has approximately a 5 percent probability of occurrence.

IPC has calculated the capacity planning margin resulting from the resource planning process. The capacity planning margin calculations are for the month of July, the month of IPC's peak load. The capacity planning margin calculations are shown on pages 117 and 118 of IPC 2011 IRP.

The load forecast used in the 2011 IRP uses statistically adjusted end-use (SAE) methodology. The SAE model is designed to capture impacts of codes, standards, and utility-based conservation. This approach is the preferred method for residential forecasting methodology.

3.3.3 Detail Regarding Forecast Inputs, OAR 345-021-0010(1)(n)(F)(ii)(I)-(IV)

OAR 345-021-0010(1)(n)(F)(ii)

In the forecast, the applicant shall include a discussion of how the forecast incorporates reductions in firm capacity demand and firm annual electricity sales resulting from:

(I) Existing federal, state or local building codes, and equipment standards and conservation programs required by law for the area to be served by the proposed facility;

(II) Conservation programs provided by the energy supplier, as defined in OAR 345-001-0010;

(III) Conservation that results from responses to price; and

(IV) Retail customer fuel choice;

The forecast incorporates reductions in firm capacity demand and firm annual electricity sales resulting from the factors set forth in OAR 345-021-0010(1)(n)(F)(ii)(I)-(IV).

First, IPC's forecast reflects "Existing federal, state or local building codes, and equipment standards and conservation programs required by law for the area to be served by the proposed facility," as discussed in OAR 345-021-0010(1)(n)(F)(ii)(I). IPC's forecasting process integrates conservation through the SAE methodology. This approach incorporates the most recent codes and standards in the DOE National Energy Modeling System (NEMS). The regionally-based data are conformed to the IPC service territory data, including building characteristics and equipment installation shares. The intensity of the conservation is developed through appliance shipment data from manufacturers and suppliers.

In addition, large industrial and irrigation customer code-related conservation is often tied to large process/operational improvements that are part of IPC-sponsored programs. The reductions recognized by virtue of integrating the results from the measurement and validation process for codifying energy savings (both code-impacted and utility-incentivized installations), are discussed in the following paragraphs responding to OAR 345-021-0010(1)(n)(F)(ii)(II).

Second, IPC's forecast reflects "Conservation programs provided by the energy supplier, as defined in OAR 345-001-0010," as discussed in OAR 345-021-0010(1)(n)(F)(ii)(II). Conservation programs provided by energy suppliers are integrated into the SAE conservation curve via data from the DOE annual reporting process. IPC monitors its energy-supplier conservation history to ensure that utility-program conservation acquisition comports with the DOE model treatment. IPC adjusts the primary model output for significant deviations of IPC program savings from the model treatment.

Large industrial and irrigation customer conservation is modeled by utilizing survey data from individual customers and directly subtracted from the forecast output. For aggregated sector forecasts, IPC analyzes historical conservation data for marginal impact (rate of change) and compares this to future conservation to establish trend reductions of forecast model output. Implied trends of improvement in industrial and irrigation equipment are integrated into the utility conservation forecasts applied to the total energy forecasts. As part of the improvement process, IPC is developing analytical methods for code impacts to explicitly segregate the code and program conservation associated with the forecast for the applicable models for these sectors.

Third, IPC's forecast reflects "Conservation that results from responses to price" as discussed in OAR 345-021-0010(1)(n)(F)(ii)(III). Price elasticity for each forecast model sector is developed and integrated into the forecast models. IPC applies elasticity variables to IPC's internally developed energy price forecast using the most recent IRP preferred-portfolio rate impact.

Fourth, IPC's forecast reflects "Retail customer fuel choice" as discussed in OAR 345-021-0010(1)(n)(F)(ii)(IV). For SAE-based models, fuel switching is integrated via the consumption and equipment stock manufacturer shipments data from DOE. For example, these data capture usage of electric versus gas space heating appliances and fuel price differentials to capture the impacts of fuel choice dynamics on the forecast.

3.3.4 Detail Regarding Resources in Forecast, OAR 345-021-0010(1)(n)(F)(iii)

OAR 345-021-0010(1)(n)(F)

(iii) Within the tables described in subparagraph (i), a forecast of existing and committed firm resources used to meet the demands described in subparagraph (ii). The applicant shall include, as existing and committed firm resources, existing generation and transmission facilities, firm contract resources and committed new resources minus expected resource retirements or displacement. In the forecast, the applicant shall list each resource separately;

As discussed in Section 3.3.1, the load-resource balance tables for the area to be served by the Project are included in Attachment N-2, IPC's 2011 IRP, Appendix C – Technical Appendix, pages 22 through 65. The monthly average energy load-resource balance values are reported on pages 22 through 43, and the monthly peak hour load-resource balance values are reported on pages 44 through 65. The load-resource balance tables provide a forecast of IPC's existing and committed firm resources used to meet its forecast demands. Idaho Power has included its existing generation and transmission facilities, firm contract resources and committed new resources minus expected resource retirements or displacement. IPC has listed each resource separately.

3.3.5 Retirement or Displacement of Resources in Forecast, OAR 345-021-0010(1)(n)(F)(iv)

> **OAR 345-021-0010(1)(n)(F)**
>
> (iv) A discussion of the reasons each resource is being retired or displaced if the forecast described in subparagraph (iii) includes expected retirements or displacements;

Of the IPC resources included in the load-resource tables in Attachment N-2, IPC's 2011 IRP, only one reflects an expected early retirement or displacement. IPC is a 10 percent owner of the Boardman coal plant, which typically provides IPC with 55 average megawatt (aMW)[13] of generation per year. This facility is expected to be decommissioned in 2020 in compliance with an Oregon Environmental Quality Commission plan approved in December 2010.

3.3.6 Assumed Annual Capacity Factors in Forecast, OAR 345-021-0010(1)(n)(F)(v)

> **OAR 345-021-0010(1)(n)(F)**
>
> (v) A discussion of the annual capacity factors assumed for any generating facilities listed in the forecast described in subparagraph (iii);

The assumed annual capacity factors for IPC generation resources by resource type are set forth in the tables in Attachment N-5. The annual capacity factor calculations are based on the average annual forecasted MW for hydro, coal, and gas facilities in IPC's 2011 IRP (Attachment N-2, Appendix C – Technical Appendix, Monthly Average Energy Load and Resource Balance, pages 22 through 41, and Hydro Modeling Results [PDR580], pages 96 through 125). For informational purposes, the capacity factors of IPC's hydroelectric resources are presented under 50th percentile, 70th percentile, and 90th percentile water assumptions. IPC's 2011 IRP assumes a 70th percentile water condition for energy-based resource adequacy assessments, and 90th percentile water condition for peak-hour resource adequacy assessments.

3.3.7 Reliability Criteria Demonstrating Need for the Project, OAR 345-021-0010(1)(n)(F)(vi)

> **OAR 345-021-0010(1)(n)(F)**
>
> (vi) A discussion of the reliability criteria the applicant uses to demonstrate the proposed facility is needed, considering the load carrying capability of existing transmission system facilities supporting the area to be served by the proposed facility;

The Project is critical to IPC satisfying its minimum operating reliability criteria, including those contained in the Western System Coordinating Council Bulk Power Supply Program 1997-2007, dated April 1, 1998.

The Project is needed for IPC to satisfy North American Electric Reliability Corporation (NERC) reliability standards. These standards require IPC to (a) regulate load; (b) maintain contingency reserves (operate the system such that the most severe single contingency does not result in loss of load or instability); (c) operate the system within facility limits, and (d) maintain voltage through reactive power control.

[13] One megawatt of capacity produced continuously over a period of one year. 1 aMW = 1 MW x 8760 hours/year = 8,760 MWh = 8,760,000 kWh.

The Project will allow IPC to regulate load by providing access to critical markets to import necessary power and offset generation. It will also allow IPC access to necessary contingency reserves that are currently limited by transmission constraints the Project will relieve.

The Project will be within facility limits and IPC has procedures in place to ensure the operation of its system within all applicable compliance standards. The Project's design also ensures voltage control through reactive power control—both series and shunt capacitor devices will be installed along the line along with switchable shunt reactors. Finally, the Project provides the additional capacity that will allow IPC to maintain system reliability for the most severe contingency.

Currently, IPC's intertie lines are constrained with little or no available transmission capacity (ATC). The Project will add ATC to the IPC bulk transmission system and will allow IPC to maintain some margin between actual flow and facility limits. Historically, IPC has had to cut schedules or curtail generation in order to maintain flow under the facility limits.

IPC maintains contingency reserves on existing Idaho – Northwest 230-kilovolt (kV) intertie transmission lines. In the past, IPC has needed to utilize nearly 100 percent of available transmission capacity to purchase resources from the Northwest in order to serve load. Without ATC, serving load with transmission reserves could put IPC's native load at risk if the most severe single contingency were to occur. IPC has also had to cut schedules across the Idaho – Northwest path (WECC Path 14) in order to maintain the path under WECC-accepted facility limits. The Project will increase the capability of the Idaho – Northwest path, effectively increasing contingency reserve capability, reducing load risk for the most severe single contingency, and establishing additional margin between where the system is operated and the system's facility limits.

Credible N-2 contingencies on the IPC system have historically driven reactive margin limits at critical IPC system busses to their minimums. Additionally, heavily loaded transmission lines consume large amounts of reactive power. The Project's transmission connectivity to the Northwest will reduce previously heavily loaded transmission lines and greatly increase the reactive margin across the IPC system, making it even more unlikely that a system event could lead to voltage collapse. The Project has also been shown to increase the reactive performance of the Northwest system around the California-Oregon Intertie.

For N-1 outages, IPC's reactive margin requirements are 250 megavolt ampere reactive (MVAR) for 345- and 230-kV IPC busses. For N-2 outages, the requirements are 200 MVAR for 345- and 230-kV IPC busses. The Project adds about 400 MVAR of reactive margin to the Treasure Valley (Boise) 230-kV system, greatly increasing voltage stability for IPC's largest load center.

The addition of variable resources, e.g., wind power generation, on the IPC system has increased the need for both up and down generation regulating margin. The Project will provide access to the Pacific Northwest generation market, which will allow IPC to augment the existing resource regulating reserves with Pacific Northwest generation.

IPC's 2011 IRP analysis also supports the need for the Project for reliability purposes, demonstrating that the concerns addressed above will persist without the Project. IPC maintains 330 MW of transmission import capacity above the forecast peak load to cover the worst single planning contingency. The worst single planning contingency is defined as an unexpected loss equal to IPC's share of two of four units at the Jim Bridger coal generation facility. The reserve level of 330 MW translates into a reserve margin of approximately 10 percent. The reserved transmission capacity allows IPC to import energy during an emergency via the Northwest

Power Pool (NWPP). A 330-MW reserve margin is also roughly equivalent to a Loss of Load Expectation (LOLE) of 1 day in 10 years, a standard industry measurement.

IPC used a spreadsheet model to calculate the LOLE for the preferred and alternate portfolios identified in the 2011 IRP. The assessment assumes critical water conditions at the existing hydroelectric facilities and the planned additions for the preferred and alternate portfolios. IPC uses a capacity benefit margin (CBM) of 330 MW in transmission planning to provide the necessary reserves for unit contingencies. The CBM capacity is reserved in the transmission system and is sold on a non-firm basis until forced unit outages require use of the transmission capacity. The analysis assumes CBM transmission capacity is available to meet deficits due to forced outages.

The model uses the IRP-forecasted hourly load profile, generator/purchase outage rates, and generation and transmission capacities to compute an LOLE for each hour of the 20-year planning period. Demand response programs were modeled as a reduction in the hourly load during the mid-week peak hours rather than as a dispatchable resource due to the limited energy of the demand response programs. The LOLE analysis is performed on a monthly basis to permit capacity de-rates for maintenance or lack of fuel (water).

The typical metric used in the utility industry to assess probability-based resource reliability is a LOLE of 1 day in 10 years. IPC has chosen to calculate LOLE on an hourly basis to evaluate the reliability at a more granular level. The 1-day-in-10-years metric is roughly equivalent to 0.5–1.0 hour per year. The results of the loss of load probability analysis are shown in Figures N-1 and N-2.

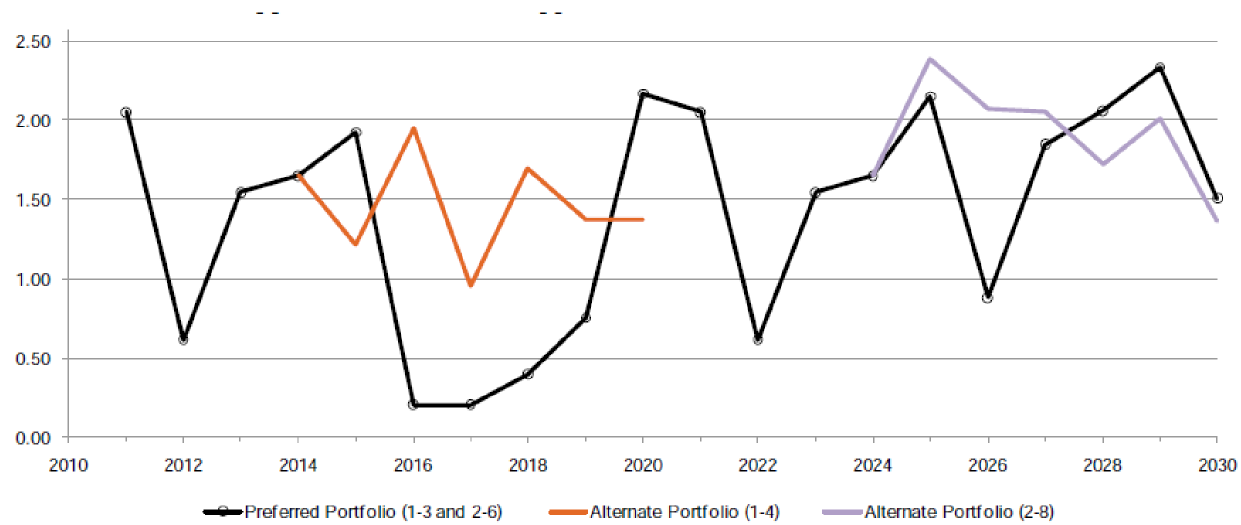

Figure N-1. Loss of Load Expectation

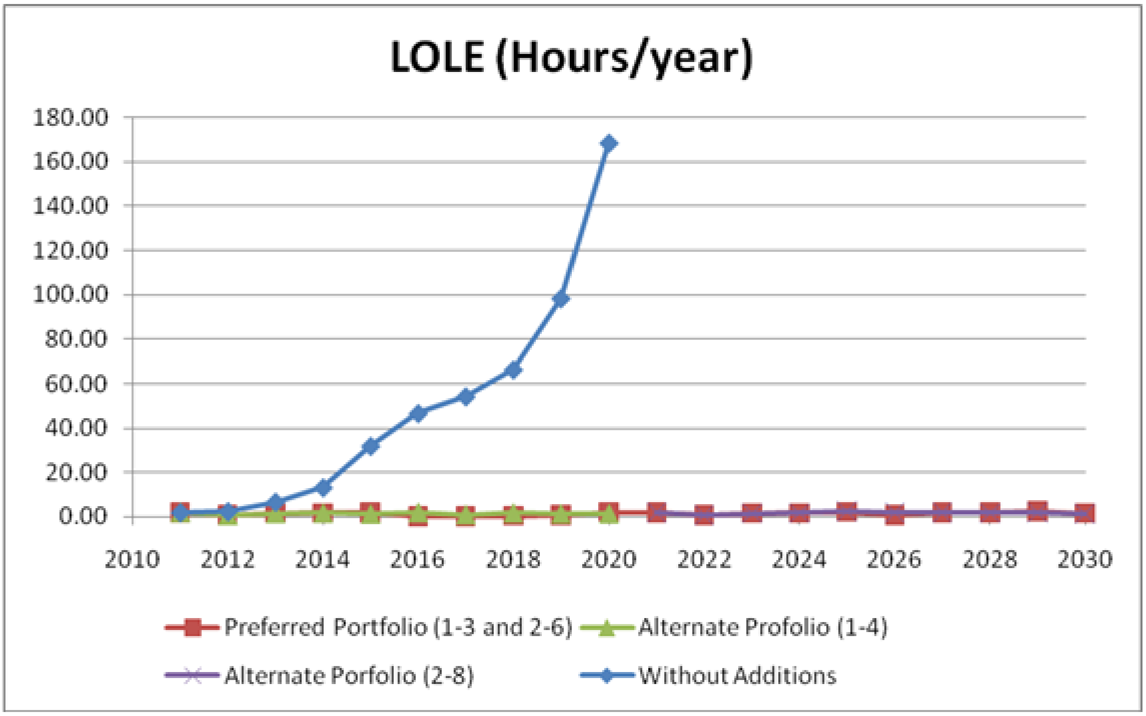

Figure N-2. Loss of Load Expectation (Hours/year)

3.3.8 The Project is an Economically Reasonable Alternative, OAR 345-021-0010(1)(n)(F)(vii)

OAR 345-021-0010(1)(n)(F)(vii)
(vii) A discussion of reasons why the proposed facility is economically reasonable compared to the alternatives described below. In the discussion, the applicant shall include a table showing the amounts of firm capacity and firm annual electricity available from the proposed facility and each alternative and the estimated direct cost, as defined in OAR 345-001-0010, of the proposed facility and each alternative. The applicant shall include documentation of assumptions and calculations supporting the table.

The Project represents the lowest-cost resource that will ensure that IPC is able to meet growing load and maintain its system in a safe, reliable, and economic manner. The Project is the key component of the preferred portfolio acknowledged in IPC's 2009 and 2011 IRPs. The Project portfolio was selected on the basis of extensive cost analysis performed as part of the IRP process. The cost analysis considers the discounted sum of all monetary costs as described in OAR 345-001-0010(16) (providing the definition of "direct cost").

Focusing on the most recent 2011 IRP analysis, the nine portfolios considered are provided in Chapter 8 of the 2011 IRP, included as Attachment N-2. The total costs for the nine portfolios are in Chapter 9 and Table N-1. Financial assumptions for the 2011 IRP portfolio cost analysis are provided in table form in Chapter 9. An overview of the IRP Methodology for evaluating resource portfolios is provided in Chapter 1.

Table N-1. Expected-Case Total Portfolio Cost (2011-2020)

Base Case	NPV Portfolio Costs (2011 dollars, 000's)				
	Variable (AURORA)	Capital	Transmission	RECs	Total
1-1 Sun & Steam	$3,041,735	$552,164	$17,925	($24,396)	**$3,587,428**
1-2 Solar	$2,924,308	$683,497	$20,865	($32,033)	**$3,596,637**
1-3 Boardman to Hemingway	$3,088,318	$0	$98,929	($9,940)	**$3,177,308**
1-4 SCCT	$3,099,029	$108,835	$22,748	($9,940)	**$3,220,672**
1-5 CCCT	$3,115,384	$188,415	$19,546	($9,940)	**$3,313,406**
1-6 CHP	$3,162,397	$190,436	$15,798	($9,940)	**$3,358,691**
1-7 Balanced	$3,085,533	$293,344	$16,349	($15,384)	**$3,379,843**
1-8 Pumped Storage	$3,093,051	$416,887	$23,099	($15,206)	**$3,517,831**
1-9 Distributed Generation	$3,099,323	$114,153	$22,748	($9,940)	**$3,226,284**

Portfolio 1-3 Boardman to Hemingway capital cost is included in the transmission column
Source: IPC 2011 IRP

3.3.9 Required Alternatives Evaluated, OAR 345-021-0010(1)(n)(F)(vii)(I)-(IV)

OAR 345-021-0010(1)(n)(F)(vii) (I)-(IV)

The applicant shall evaluate alternatives to construction and operation of the proposed facility that include, but are not limited to:

(I) Implementation of cost-effective conservation, peak load management and voluntary customer interruption as a substitute for the proposed facility;

(II) Construction and operation of electric generating facilities as a substitute for the proposed facility;

(III) Direct use of natural gas, solar or geothermal resources at retail loads as a substitute for use of electricity transmitted by the proposed facility; and

(IV) Adding standard sized smaller or larger transmission line capacity;

First, IPC's economic analysis of alternatives included evaluation of "Implementation of cost-effective conservation, peak load management and voluntary customer interruption as a substitute for the proposed facility," as required by OAR 345-021-0010(1)(n)(F)(vii)(I). In the IRP process, IPC has committed to implementing all cost-effective, demand-side management measures prior to considering supply-side alternatives, including the Project. Further description of the analyses and assumptions associated with demand-side measures is included in Chapter 4 of the 2011 IRP and Appendix B - Demand-Side Management 2010 Annual Report.

Second, IPC evaluated "Construction and operation of electric generating facilities as a substitute for the proposed facility," as required by OAR 345-021-0010(1)(n)(F)(vii)(II). The portfolios considered in the 2011 IRP include a variety of generation resources. Based on the IRP analysis, portfolios containing these resources were expected to result in higher direct costs (as defined by OAR 345-001-0010(16)) than the Project preferred portfolio.

Third, IPC evaluated "Direct use of natural gas, solar or geothermal resources at retail loads as a substitute for use of electricity transmitted by the proposed facility," as required by OAR 345-021-0010(1)(n)(F)(vii)(III). Natural gas, solar, and geothermal resources were included in the alternative portfolios considered for the 2011 IRP. As an example, the 1-2 Solar portfolio contains 530 MW of solar resources (photovoltaic and thermal). The IRP cost analysis indicated that the costs associated with these alternative portfolios were expected to be greater than those for the Project preferred portfolio.

Fourth, IPC evaluated "Adding standard sized smaller or larger transmission line capacity," as required by OAR 345-021-0010(1)(n)(F)(vii)(IV). A number of factors impact the transfer capability of transmission lines, including distance, source/sink capabilities, relative location in the bulk electric system, etc. IPC's analysis assumed a 300-mile line between a substation in the Northwest and Hemingway, Idaho. Table N-2 contains a summary of relative capacities, anticipated ratings, and losses. Only the scenarios including 500-kV line capacity or greater are capable of providing the service capacity needed, including existing Transmission Service Requests. The 2011 IRP analysis demonstrates the cost-effectiveness of the 500-kV single circuit design, as opposed to those with greater capacity.

Table N-2. Comparison of Transmission Line Capacity Scenarios

Scenario	Line Capacity[1]	Potential Rating[2]	Losses[3]
a. 230-kV single circuit	956 MW	538 MW	3.7 %
b. 230-kV double circuit	2,199 MW	866 MW	2.4 %
c. 500-kV single circuit	3,585 MW	1,300 MW	1.3 %
d. 500-kV–two separate lines	7,170 MW	2,600 MW	1.3 %
e. 500-kV double circuit	7,170 MW	1,300 MW	1.3 %
f. 765-kV single circuit	4,770 MW	1,300 MW	0.5 %

[1] Line Capacity is the thermal rating of the assumed conductors and does not account for system limitations of voltage, stability, or reliability requirements.
[2] Potential Rating is based upon study results to date to meet reliability design requirements for the WECC ratings processes, not including simultaneous interaction studies which were to be initiated in 2009.
[3] Estimated Losses are percent losses at the Potential Rating loading level. Annual energy losses are dependent on total system loss reductions. All of the scenarios would likely yield a total system loss reduction for the flow levels above.

3.3.10 Earliest and Latest Expected In-Service Dates, OAR 345-021-0010(1)(n)(F)(viii)

OAR 345-021-0010(1)(n)(F)

(viii) The earliest and latest expected in-service dates of the facility and a discussion of the circumstances of the energy supplier, as defined in OAR 345-001-0010, that determine these dates; and

Based on Idaho Power's assessment of siting, permitting, regulatory approvals, in-service date requirements of the parties electing to construct the line, the terms of any resulting joint construction agreements, and other conditions and factors, a project in-service date prior to 2018 is unlikely.

4.0 CONCLUSION

Based on the information in this Exhibit N, there is substantial evidence upon which EFSC can find that IPC has demonstrated the need for the Project under both the least-cost plan rule, OAR 345-023-0020, and the system reliability rule for transmission lines, OAR 345-023-0030.

5.0 SUBMITTAL AND APPROVAL REQUIREMENTS MATRIX

Table N-3 provides cross-references between the exhibit submittal requirements of OAR 345-021-0010 and the requirements of the Project Order and where discussion can be found in this Exhibit.

Table N-3. Submittal Requirements Matrix

Requirement	Location
OAR 345-021-0010(1)(n)	
(n) **Exhibit N.** If the proposed facility is a non-generating facility for which the applicant must demonstrate need under OAR 345-023-0005, information about the need for the facility, providing evidence to support a finding by the Council as required by OAR 345-023-0005, including:	
(A) Identification of the rule in Division 23 of this chapter under which the applicant chooses to demonstrate need;	Section 3.1
(B) If the applicant chooses to demonstrate need for the proposed facility under OAR 345-023-0020(1), the least-cost plan rule:	Section 3.2
(i) Identification of the energy resource plan or combination of plans on which the applicant relies to demonstrate need;	Section 3.2, Attachment N-1, Attachment N-2
(ii) The name, address and telephone number of the person responsible for preparing each energy resource plan identified in subparagraph (i);	Section 3.2.1
(iii) For each plan reviewed by a regulatory agency, the agency's findings and final decision, including:	Section 3.2.2
(I) For a plan reviewed by the Oregon Public Utility Commission, the acknowledgment order; or	Section 3.2.2, Attachment N-3, Attachment N-4
(II) For a plan reviewed by any other regulatory agency, a summary of the public process including evidence to support a finding by the Council that the agency's decision process included a full, fair and open public participation and comment process as required by OAR 345-023-0020(1)(L), and the location of and means by which the Department can obtain a complete copy of the public record;	Not Applicable
(iv) Identification of the section(s) of the short-term action plan(s) that call(s) for the acquisition of the proposed facility or, as defined in OAR 345-001-0010, a facility substantially similar to the proposed facility; and	Section 3.2.2
(v) The attributes of the proposed facility that qualify it as one called for in the short-term action plan of the energy resource plan or combination of plans identified in subparagraph (i) or a demonstration that, as defined in OAR 345-001-0010, a facility substantially similar to the proposed facility is called for in the plan(s);	Section 3.2.2
(C) In addition to the information described in paragraph (B), if the applicant chooses to demonstrate need for the proposed facility under OAR 345-023-0020(1), the least-cost plan rule, and relies on an energy resource plan not acknowledged by the Public Utility Commission of Oregon * * * *	Not Applicable
(D) In addition to the information described in paragraphs (B) and (C), if the applicant chooses to demonstrate need for a proposed natural gas pipeline or storage facility for liquefied natural gas under OAR 345-023-0020(1), the least-cost plan rule, and relies on an energy resource plan not acknowledged by the Public Utility Commission of Oregon, the applicant shall include the information described in paragraph (G) of this subsection if the energy resource plan or combination of plans does not contain that information. If the energy resource plan or combination of plans contains the information described in paragraph (G), the applicant shall provide a list of citations to the sections of the energy resource plan(s) that contain the information;	Not Applicable

Table N-3. Submittal Requirements Matrix (continued)

Requirement	Location
(E) In addition to the information described in paragraphs (B) and (C), if the applicant chooses to demonstrate need for a proposed electric transmission line under OAR 345-023-0020(1), the least-cost plan rule and relies on an energy resource plan not acknowledged by the Public Utility Commission of Oregon, the applicant shall include the information described in paragraph (F) of this subsection if the energy resource plan or combination of plans does not contain that information. If the energy resource plan or combination of plans contains the information described in paragraph (F), the applicant shall provide a list of citations to the sections of the energy resource plan(s) that contain the information;	Not Applicable
(F) If the applicant chooses to demonstrate need for a proposed electric transmission line under OAR 345-023-0030, the system reliability rule:	Section 3.3
(i) Load-resource balance tables for the area to be served by the proposed facility. In the tables, the applicant shall include firm capacity demands and existing and committed firm resources for each of the years from the date of submission of the application to at least five years after the expected in-service date of the facility.	Section 3.3.1, Attachment N-2
(ii) Within the tables described in subparagraph (i), a forecast of firm capacity demands for electricity and firm annual electricity sales for the area to be served by the proposed facility. The applicant shall separate firm capacity demands and firm annual electricity sales into loads of retail customers, system losses, reserve margins and each wholesale contract for firm sale. In the forecast, the applicant shall include a discussion of how the forecast incorporates reductions in firm capacity demand and firm annual electricity sales resulting from:	Section 3.3.2, Attachment N-2
(I) Existing federal, state or local building codes, and equipment standards and conservation programs required by law for the area to be served by the proposed facility;	Section 3.3.3
(II) Conservation programs provided by the energy supplier, as defined in OAR 345-001-0010;	Section 3.3.3
(III) Conservation that results from responses to price; and	Section 3.3.3
(IV) Retail customer fuel choice;	Section 3.3.3
(iii) Within the tables described in subparagraph (i), a forecast of existing and committed firm resources used to meet the demands described in subparagraph (ii). The applicant shall include, as existing and committed firm resources, existing generation and transmission facilities, firm contract resources and committed new resources minus expected resource retirements or displacement. In the forecast, the applicant shall list each resource separately;	Section 3.3.4, Attachment N-2
(iv) A discussion of the reasons each resource is being retired or displaced if the forecast described in subparagraph (iii) includes expected retirements or displacements;	Section 3.3.5
(v) A discussion of the annual capacity factors assumed for any generating facilities listed in the forecast described in subparagraph (iii);	Section 3.3.6, Attachment N-5
(vi) A discussion of the reliability criteria the applicant uses to demonstrate the proposed facility is needed, considering the load carrying capability of existing transmission system facilities supporting the area to be served by the proposed facility; and	Section 3.3.7, Figures N-1 and N-2

Table N-3. Submittal Requirements Matrix (continued)

Requirement	Location
(vii) A discussion of reasons why the proposed facility is economically reasonable compared to the alternatives described below. In the discussion, the applicant shall include a table showing the amounts of firm capacity and firm annual electricity available from the proposed facility and each alternative and the estimated direct cost, as defined in OAR 345-001-0010, of the proposed facility and each alternative. The applicant shall include documentation of assumptions and calculations supporting the table. The applicant shall evaluate alternatives to construction and operation of the proposed facility that include, but are not limited to:	Section 3.3.8, Table N-1
(I) Implementation of cost-effective conservation, peak load management and voluntary customer interruption as a substitute for the proposed facility;	Section 3.3.9
(II) Construction and operation of electric generating facilities as a substitute for the proposed facility;	Section 3.3.9
(III) Direct use of natural gas, solar or geothermal resources at retail loads as a substitute for use of electricity transmitted by the proposed facility; and	Section 3.3.9
(IV) Adding standard sized smaller or larger transmission line capacity;	Section 3.3.9, Table N-2
(viii) The earliest and latest expected in-service dates of the facility and a discussion of the circumstances of the energy supplier, as defined in OAR 345-001-0010, that determine these dates; and	Section 3.3.10
(G) If the applicant chooses to demonstrate need for a proposed natural gas pipeline or a proposed facility for storing liquefied natural gas under OAR 345-023-0040, the economically reasonable rule: * * * *	Not Applicable
Project Order Section VI(n) Comments	
The Council requires applicants to demonstrate public need for an electric transmission line facility under the least-cost plan rule (OAR 345-023-0020), the system reliability rule for transmission lines (OAR 345-023-0030), or by demonstrating that the transmission line is proposed to be within a “National Interest Electric Transmission Corridor” designated by the US Department of Energy under Section 216 of the Federal Power Act. The applicant may provide evidence demonstrating the need for the facility under one or more of the methods described in Division 23.	All sections

6.0 RESPONSE TO COMMENTS FROM REVIEWING AGENCIES AND THE PUBLIC

There were no comments from reviewing agencies and the public regarding Exhibit N.

7.0 REFERENCES

None.