B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

BP-20 Rate Proceeding

Final Proposal

Power Rates Study Documentation

BP-20-FS-BPA-01A

July 2019

Power Rates Study Documentation
Table of Contents

COMMONLY USED ACRONYMS AND SHORT FORMS

AAC	Anticipated Accumulation of Cash
ACNR	Accumulated Calibrated Net Revenue
ACS	Ancillary and Control Area Services
AF	Advance Funding
AFUDC	Allowance for Funds Used During Construction
aMW	average megawatt(s)
ANR	Accumulated Net Revenues
ASC	Average System Cost
BAA	Balancing Authority Area
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Bps	basis points
Btu	British thermal unit
CIP	Capital Improvement Plan
CIR	Capital Investment Review
CDQ	Contract Demand Quantity
CGS	Columbia Generating Station
CHWM	Contract High Water Mark
CNR	Calibrated Net Revenue
COB	California-Oregon border
COE	U.S. Army Corps of Engineers
COI	California-Oregon Intertie
Commission	Federal Energy Regulatory Commission
Corps	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power and Conservation Council
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CSP	Customer System Peak
CT	combustion turbine
CWIP	Construction Work in Progress
CY	calendar year (January through December)
DD	Dividend Distribution
DDC	Dividend Distribution Clause
dec	decrease, decrement, or decremental
DERBS	Dispatchable Energy Resource Balancing Service
DFS	Diurnal Flattening Service
DNR	Designated Network Resource
DOE	Department of Energy
DOI	Department of Interior
DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order
EE	Energy Efficiency

EIM	Energy imbalance market
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
ESA	Endangered Species Act
ESS	Energy Shaping Service
e-Tag	electronic interchange transaction information
FBS	Federal base system
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FELCC	firm energy load carrying capability
FERC	Federal Energy Regulatory Commission
FOIA	Freedom Of Information Act
FORS	Forced Outage Reserve Service
FPS	Firm Power and Surplus Products and Services
FPT	Formula Power Transmission
FRP	Financial Reserves Policy
F&W	Fish & Wildlife
FY	fiscal year (October through September)
G&A	general and administrative (costs)
GARD	Generation and Reserves Dispatch (computer model)
GMS	Grandfathered Generation Management Service
GSP	Generation System Peak
GSR	Generation Supplied Reactive
GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	gigawatthour
HLH	Heavy Load Hour(s)
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydrosystem Simulator (computer model)
IE	Eastern Intertie
IM	Montana Intertie
inc	increase, increment, or incremental
IOU	investor-owned utility
IP	Industrial Firm Power
IPR	Integrated Program Review
IR	Integration of Resources
IRD	Irrigation Rate Discount
IRM	Irrigation Rate Mitigation
IRPL	Incremental Rate Pressure Limiter
IS	Southern Intertie
kcfs	thousand cubic feet per second
kW	kilowatt
kWh	kilowatthour
LDD	Low Density Discount
LGIA	Large Generator Interconnection Agreement
LLH	Light Load Hour(s)

LPP	Large Project Program
LTF	Long-term Firm
Maf	million acre-feet
Mid-C	Mid-Columbia
MMBtu	million British thermal units
MNR	Modified Net Revenue
MRNR	Minimum Required Net Revenue
MW	megawatt
MWh	megawatthour
NCP	Non-Coincidental Peak
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFB	**N**ational Marine Fisheries Service (NMFS) **F**ederal Columbia River Power System (FCRPS) **B**iological Opinion (BiOp)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NOB	Nevada-Oregon border
NORM	Non-Operating Risk Model (computer model)
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NP-15	North of Path 15
NPCC	Pacific Northwest Electric Power and Conservation Planning Council
NPV	net present value
NR	New Resource Firm Power
NRFS	NR Resource Flattening Service
NRU	Northwest Requirements Utilities
NT	Network Integration
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operation and maintenance
OATI	Open Access Technology International, Inc.
OS	Oversupply
OY	operating year (August through July)
PDCI	Pacific DC Intertie
PF	Priority Firm Power
PFp	Priority Firm Public
PFx	Priority Firm Exchange
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Point of Interconnection
POR	Point of Receipt

PS	Power Services
PSC	power sales contract
PSW	Pacific Southwest
PTP	Point to Point
PUD	public or people's utility district
PW	WECC and Peak Service
RAM	Rate Analysis Model (computer model)
RCD	Regional Cooperation Debt
RD	Regional Dialogue
RDC	Reserves Distribution Clause
REC	Renewable Energy Certificate
Reclamation	U.S. Bureau of Reclamation
REP	Residential Exchange Program
REPSIA	REP Settlement Implementation Agreement
RevSim	Revenue Simulation Model
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RR	Resource Replacement
RRS	Resource Remarketing Service
RSC	Resource Shaping Charge
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
SCD	Scheduling, System Control, and Dispatch Service
SCS	Secondary Crediting Service
SDD	Short Distance Discount
SILS	Southeast Idaho Load Service
Slice	Slice of the System (product)
T1SFCO	Tier 1 System Firm Critical Output
TCMS	Transmission Curtailment Management Service
TGT	Townsend-Garrison Transmission
TOCA	Tier 1 Cost Allocator
TPP	Treasury Payment Probability
TRAM	Transmission Risk Analysis Model
Transmission System Act	Federal Columbia River Transmission System Act
Treaty	Columbia River Treaty
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	Transmission Services
TSS	Transmission Scheduling Service
UAI	Unauthorized Increase
UFT	Use of Facilities Transmission
UIC	Unauthorized Increase Charge
ULS	Unanticipated Load Service
USACE	U.S. Army Corps of Engineers

USBR	U.S. Bureau of Reclamation
USFWS	U.S. Fish & Wildlife Service
VER	Variable Energy Resource
VERBS	Variable Energy Resource Balancing Service
VOR	Value of Reserves
VR1-2014	First Vintage Rate of the BP-14 rate period (PF Tier 2 rate)
VR1-2016	First Vintage Rate of the BP-16 rate period (PF Tier 2 rate)
WECC	Western Electricity Coordinating Council
WSPP	Western Systems Power Pool

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BP-20 POWER RATES STUDY DOCUMENTATION

INTRODUCTION

The Power Rates Study Documentation shows the details of the calculation of BPA's proposed power rates.

"Section 1: Introduction and Background" contains an overview of the various models used in the rate development process and presents a flow chart showing the rate development process.

"Section 2: Ratemaking Methodology and Process" contains ratemaking tables that are the output of the Rate Analysis Model (RAM2020). RAM2020 is a group of computer applications that perform most of the computations that determine BPA's final power rates. This group includes the RAM Core Excel-based model, a front-end and back-end database service, and separate modules for the computation of (1) TRM billing determinants, (2) Tier 2 rates, and (3) Resource Support Services (RSS) rates and revenues. The output tables of RAM2020 include billing determinants, which are based on power sales forecasts and associated outputs from the RHWM Process, as well as revenue requirements used in the Power Rates Study's cost of service analysis (COSA). A series of tables shows the initial allocation of the revenue requirement over the billing determinants. The final table shows the calculation of the resource cost contributions that appear in GRSP II.Z.

"Section 3: Rate Design" documents the calculations for Tier 1 rate design and the results of the Tier 2 and RSS modules of RAM. The Tier 2 module results include the Tier 2 rates and charges, billing determinants, rate design adjustments and remarketing associated with Tier 2, and non-Federal remarketing. The results of the RSS module include the rate design revenue credits and adjustments associated with RSS and the Resource Shaping Charge, which are fed into RAM Core for ratemaking purposes. Other results include the associated RSS rates and charges, including the Resource Shaping Charge, the Transmission Scheduling Service Charge, and the Grandfathered Generation Management Service Charge.

"Section 4: Power Rate Schedules" includes tables for Load Shaping Rates, Demand Rates, and Tier 2 billing determinant assumptions.

"Section 5: Power General Rate Schedule Provisions (GRSPs)" includes tables for the Irrigation Rate Discount and Low Density Discount programs. It also includes customer specific non-Federal resource remarketing credits.

"Section 6: Transfer Service" shows information on the five-year market purchases for Southeast Idaho transfer load service (SILS).

"Section 7: Slice" contains no documentation.

"Section 8: Average System Costs" documents monthly Residential Exchange Program loads and forecast ASCs.

“Section 9: The Revenue Forecast” documents revenue forecasts at both current and proposed rates for the rate period, FY 2020–2021, and at current rates for the fiscal year immediately preceding the two-year rate period, FY 2019.

SECTION 1: BACKGROUND

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RATE PROCESS MODELING

The components listed below, organized by rate proposal study, are the major analyses and computer models used in BPA's rate development process. Included is a brief description of the purpose of each component and how it fits in with the other components. See the flowchart on the page following this section for a picture of how the studies and models work together in the wholesale power rate development process.

POWER LOADS AND RESOURCES STUDY (BP-20-FS-BPA-03):

Federal System Load Obligation Forecasts

The Federal system load obligation forecasts estimate the firm energy load obligations that BPA expects to serve under its firm requirements power sales contracts (PSCs) and BPA's other contractual obligations. BPA's firm requirements PSC load obligation forecasts are used in BPA's rate development process and serve as the primary sources for (1) allocation factors used to apportion costs, and (2) billing determinants used to calculate rates and revenues. BPA's load obligation forecasts are composed of customer forecasts for consumer-owned utilities (COUs), Federal agencies, direct service industrial customers (DSIs), investor-owned utilities (IOUs), and other obligations, such as the U.S. Bureau of Reclamation's irrigation loads. Individual COU and Federal agency loads are forecast by ALF, BPA's Agency Load Forecast model.

BPA also has contract obligations other than those served under firm requirements PSCs. These "other contract" obligations include contract sales to utilities and marketers, and power commitments under the Columbia River Treaty. All of BPA's load obligations are detailed in the Power Loads and Resources Study.

Hydro Regulation Study (HYDSIM)

The Federal system regulated hydro resource estimates are derived by BPA's hydro regulation model (HYDSIM), which estimates project generation for 80 water years (October 1928 through September 2008). BPA uses HYDSIM to estimate the Federal system energy production that can be expected from specific hydroelectric power projects in the PNW Columbia River Basin when operating in a coordinated fashion and meeting power and non-power requirements for the 80 water years of record. The hydro regulation study uses plant operating characteristics and conditions to determine energy production expected from each specific project. Physical characteristics of each project are provided by annual Pacific Northwest Coordination Agreement (PNCA) data submittals from regional utilities and government agencies involved in the coordination and operation of regional hydro projects. The HYDSIM model incorporates these operating characteristics along with power and non-power requirements to provide project by project monthly energy generation estimates for the Federal system's regulated hydro projects for FY 2020-2021.

The HYDSIM studies encompass the power and non-power operating requirements expected to be in effect during the rate period, including those described in applicable biological opinions issued by the National Oceanic and Atmospheric Administration (NOAA) Fisheries and the

U.S. Fish and Wildlife Service (USFWS); relevant operations described in the Northwest Power and Conservation Council's (NPCC) Fish and Wildlife Program published October 2014; and other mitigation measures such as those implemented under Court injunction during the spring of 2018. The HYDSIM studies incorporate spring spill up to applicable water quality standards for Total Dissolved Gas (TDG) and summer spill informed by the results of biological performance standard testing conducted over the last decade to measure dam passage survival for out-migrating juvenile fish ("performances standard spill"). Each hydro regulation study specifies particular hydroelectric project operations for fish, such as seasonal flow objectives, minimum flow levels for fish, spill for juvenile fish passage, reservoir target elevations and drawdown limitations, and turbine operation requirements. The Federal system hydro generation is used in the Federal system load-resource balance and is detailed in the Power Loads and Resources Study.

Federal System Load-Resource Balance

The Federal system load-resource balance provides the complete picture of BPA's loads and resources by comparing Federal system load obligations to Federal system resources. Federal system load obligations include all of BPA's load obligations (firm requirements PSCs and other Federal contracts). Federal system resources include BPA's regulated and independent hydro resources under 1937 water conditions, contract purchases, and other non-hydro generating resources. The result of the Federal system resources less load obligations yields BPA's estimated Federal system monthly firm energy surplus or deficit, in average megawatts. Should the results indicate an energy surplus or deficit in the ratemaking process, firm surplus sales or augmentation purchases must be made to ensure the Federal system is in annual energy load resource balance. The surplus/deficit calculation is performed for each year of the rate period and is detailed in the Power Loads and Resources Study. Results from the Power Loads and Resources Study are used as input into the Power Rates Study, the Power Market Price Study, and the Power and Transmission Risk Study.

POWER REVENUE REQUIREMENT STUDY (BP-20-FS-BPA-02):

The Power Revenue Requirement Study develops BPA's generation revenue requirement for the rate test period. It uses repayment studies for the generation function to determine the schedule of amortization payments and to project annual interest expense for bonds and appropriations that fund the Federal investment in hydro, fish and wildlife recovery, conservation, and related generation assets. Repayment studies are conducted for each year of the rate test period and extend over the 50-year repayment period. The repayment studies establish a schedule of planned amortization payments and resulting interest expense by determining the lowest levelized debt service stream necessary to repay all generation obligations within the required repayment period. Repayment study results are combined with forecasts of program spending to create the revenue requirement. The Power Revenue Requirement Study then determines whether a given set of annual revenues is sufficient to meet projected annual expenses and to cover a given set of long-term obligations when applied in accordance with the requirements of DOE Order RA 6120.2.

POWER MARKET PRICE STUDY (BP-20-FS-BPA-04):

The Power Market Price Study is composed of two different electricity market price runs. These runs are the "market price" run, which is based on hydro generation for 80 water years, and the "critical water price" run, which is based on hydro generation under 1937 streamflow conditions.

"Market Price" Run

The results from the "market price" run are used in the Power Rates Study for the following:

- Prices for secondary energy sales and balancing power purchases
- Prices for firm surplus energy sales
- Load Shaping rates
- Load Shaping True-Up rate
- Resource Shaping rates
- Resource Support Services (RSS) rates
- Priority Firm Power (PF), Industrial Firm Power (IP), and New Resource Firm Power (NR) demand rates
- PF Unused Rate Period High Water Mark (RHWM) Credit
- PF Tier 1 Equivalent rates
- PF Melded rates
- Balancing Augmentation Credit
- IP energy rates
- NR energy rates
- Energy Shaping Service (ESS) for New Large Single Load (NLSL) True-Up rate

"Critical Water Price" Run

The results from the "critical water price" run are used in the Power Rates Study for calculating system augmentation expenses.

Both of these sets of prices are also used for the risk analysis discussed in the Power and Transmission Risk Study, BP-20-FS-BPA-05.

The tool used to calculate electric energy prices is a model of the Western Electricity Coordinating Council (WECC) power system called AURORA©. AURORA© uses a linear program to minimize the cost of meeting load, subject to a number of operating constraints. Given the solution (an output level for all generating resources and a flow level for all interties), the price at any hub is the cost, including wheeling and losses, of delivering a unit of power from the least-cost available resource. This cost approximates the price of electricity by assuming that all resources are centrally dispatched (the equivalent of cost-minimization in production theory) and that the marginal cost of producing electricity approximates the price.

AURORA© produces a single electricity price forecast as a function of its inputs. Thus, to produce a given number of price forecasts requires that AURORA© be run that same number of times using different inputs. Risk models provide inputs to AURORA© and the resulting distribution of electricity price forecasts represents a quantitative measure of electricity price risk. As described in the Power and Transmission Risk Study, BP-20-FS-BPA-05, 3,200 independent games from the joint distribution of the risk models serve as the basis for the 3,200 electricity price forecasts. The monthly Heavy Load Hour (HLH) and Light Load Hour (LLH) electricity prices constitute the electricity price forecast for the "market price" run and the "critical water price" run.

POWER AND TRANSMISSION RISK STUDY (BP-20-FS-BPA-05)

The Power and Transmission Risk Study demonstrates that BPA's rates and risk mitigation tools together meet BPA's standard for financial risk tolerance—the Treasury Payment Probability (TPP) standard. The study includes quantitative and qualitative analyses of risks to net revenue and tools for mitigating those risks. It also establishes the adequacy of those tools for meeting BPA's TPP standard.

In addition to the Power operating net revenues used in the calculation of TPP, results from the modeling of various Power operating risks that are components of net revenues are provided for input into the Rate Analysis Model for the BP-20 rate case (RAM2020).

Results Provided for Input into RAM2020 and the Power Services Revenue Forecast

The RevSim model is used to forecast secondary energy revenues, firm surplus energy revenues, balancing power purchase expenses, and augmentation purchase expenses. After accounting for all loads and resources (including augmentation purchases), RevSim computes the monthly HLH and LLH quantities of secondary energy available to sell and power purchases needed to meet firm loads (balancing purchases) using hydro generation available under 80 years of historical streamflow conditions (1929-2008). Inputs used to calculate load and resource balance are forecast loads, non-hydro resources, and hydro generation.

RevSim uses the 80 water year results from the Loads and Resources Study to compute the available HLH and LLH surplus energy and deficits in the Federal hydro system under varying streamflow conditions. RevSim applies HLH and LLH monthly spot market prices supplied by the AURORA© model (see the Power Market Price Study subsection above for a description of the AURORA© model) to the sales and purchase amounts to calculate revenues from surplus energy sales and expenses from balancing power purchases. It also computes augmentation costs based on hydro generation data and AURORA© prices under 1937 hydro conditions. As described in the Power Rates Study below, RAM2020 and the Power Services Revenue Forecast both use the secondary energy revenues, firm surplus energy revenues, and balancing and augmentation power purchase expenses calculated in RevSim.

Results from operating risks modeled external to RevSim that are input into RevSim are the 4(h)(10)(C) credits BPA is allowed to credit against its annual U.S. Treasury payment and Power Services' transmission and ancillary services expenses. The amount of the 4(h)(10)(C) credit is determined by summing the costs of the operational impacts (power purchases) and the direct program expenses and capital costs, and then multiplying the total cost by 0.223 (22.3 percent). The operational portion of the 4(h)(10)(C) credit is computed by taking the same AURORA© prices used for the calculation of secondary energy revenues and applying them to the replacement power purchase amounts. The calculation of the replacement power purchases for 4(h)(10)(C) is described in the Power Loads and Resources Study.

Power Services' transmission and ancillary services expense risk is based on comparisons between monthly firm Point-to-Point (PTP) Network transmission capacity that Power Services has under contract, the amount of existing firm contract sales, and the variability in secondary energy sales estimated by RevSim. Expense risk computations reflect how transmission and ancillary services expenses vary from the cost of the fixed take-or-pay firm PTP Network transmission capacity that Power Services has under contract.

Risk Analysis

RevSim, in conjunction with AURORA© and the Power Non-Operating Risk Model (P-NORM), is used to quantify Power Services' net revenue risk. RevSim estimates net revenue variability associated with various operating risks (load, resource, electricity price, 4(h)(10)(C) credit, and Power Services' transmission and ancillary service expense variations). P-NORM estimates the non-operating risks that are associated with uncertainties in the cost projections in the revenue requirement and revenue uncertainties not captured in RevSim and AURORA©. P-NORM also contains Accrual to Cash adjustments, which translates net revenue into cash flow. The results from RevSim and P-NORM are inputs into the ToolKit, which calculates the probability of Power Services making its portion of scheduled Treasury payments on time and in full.

Risk Mitigation

The ToolKit Model is used to determine Treasury Payment Probability (TPP), which is the probability of Power Services making all its planned Treasury payments during the rate period, given the net revenue risks quantified in RevSim and P-NORM and accounting for the impact of the risk mitigation tools. More specifically, ToolKit is used to assess the effects of various policies and risk mitigation measures, such as the Cost Recovery Adjustment Clause (CRAC) and Revenue Distribution Clause (RDC) on the level of year-end reserves available for risk that are attributable to Power Services.

POWER RATES STUDY (BP-20-FS-BPA-01)

Rate Analysis Model (RAM2020)

RAM2020 is a group of computer applications that perform most of the computations that determine BPA's proposed power rates. RAM Core, a spread sheet-based model, has three main steps that perform the calculations necessary to develop BPA's wholesale power rates: Cost of Service Analysis (COSA), Rate Directives, and Rate Design.

1. Cost of Service Analysis. This step ensures that BPA's proposed rates are consistent with cost of service principles and comply with BPA's statutory rate directives. The COSA Step determines the costs associated with the three resource pools (Federal base system (FBS), residential exchange, and new resources) used to serve sales load and then allocates those costs to the rate pools (Priority Firm Power (PF), Industrial Firm Power

(IP), New Resource Firm Power (NR), and Firm Power Products and Services (FPS)). In addition, the COSA allocates the costs of conservation and other BPA programs to the rate pools.

2. Rate Directives. The Northwest Power Act requires that some rate adjustments be made after the initial allocation of costs to ensure that the rate levels for the individual rate pools (PF Preference, PF Exchange, IP, NR, and FPS) have the proper relationship to each other. The primary rate adjustments are described in sections 7(b) and 7(c) of the Northwest Power Act. The Rate Directives Step of RAM2020 performs these rate adjustments. The amount of PF Public rate protection and the levels of the IP and NR rates are set using the 2012 settlement of legal issues associated with the Residential Exchange Program.

3. Rate Design. In the COSA and Rate Directive steps, costs are allocated to the various rate pools. Upon completion of these steps, a certain amount of costs has been allocated to the PF Preference pool. Section 7(e) affords BPA wide latitude in the design of rates to collect the costs allocated to each rate pool. The Tiered Rate Methodology (TRM) specifies a cost allocation methodology for PF Preference costs allocated in the COSA and Rate Directives steps. RAM accomplishes this separate cost allocation through a process of mapping costs (including net residential exchange costs) and revenue credits (including IP and NR revenues, if any) to the Tier 1 Composite, Non-Slice, Slice, and Tier 2 costs pools. It also demonstrates by "proof" that cost allocations under the TRM and the COSA and Rate Directives steps are equivalent in terms of aggregate costs recovered from the PF Preference, PF Exchange, IP, and NR rates. To provide a crosswalk of the differences between COSA allocations and TRM allocations, the mapping for each is shown in RAM2020 using unique database keys.

RAM2020 develops four rate designs: (1) a tiered rate design for the PFp rate, in which the Tier 1 rates are designed using customer charges and demand and energy rates; (2) a traditional demand and energy design for the PFp Melded rate, the IP rate, and the NR rate; (3) a constant annual energy rate for each PFp Tier 2 rate and the PFx rates; and (4) Resource Support Service rates for customers with new non-Federal Dedicated Resources. RAM2020 designs rates for each rate pool.

Resource Support Services Module of RAM2020

The Resource Support Services (RSS) module of RAM2020, a spreadsheet-based model, calculates the charges and rates applied to resources receiving RSS and related services. These services include Diurnal Flattening Service (DFS), Secondary Crediting Service (SCS), Forced Outage Reserve (FORS), and grandfathered Generation Management Service (GMS). The RSS module of RAM also calculates, as applicable, each customer's Resource Shaping Charge (RSC); Transmission Scheduling Service (TSS) and the Transmission Curtailment Management Service (TCMS) component of TSS (although the TCMS functionality in the RSS module is not currently implemented); the aggregate RSS and RSC revenue credits used in RAM Core (an Excel-based model, one of the computer applications in RAM2020); and the capacity obligations that will inform BPA generation planning and the Slice model. The RSS module is also the source of operating minimums, planned amounts, and FORS energy limits that are defined in the customer contracts. The RSS model calculates the above for non-Federal resources as well as Federal resources used as augmentation and Federal resources used to support the Tier 2 rate.

Tier 2 Module of RAM2020

The Tier 2 module of RAM2020, a spreadsheet-based model, calculates Tier 2 rates and the applicable Tier 2 revenue credits and adjustments used in RAM Core that are not already accounted for in the RSS module of RAM2020. This module also calculates customer remarketing credits for amounts of Tier 2 service, non-Federal resource DFS, and Resource Remarketing Service. It produces the aggregate revenue and cost data associated with remarketing between the Tier 2 cost pools used in the RAM Core calculation.

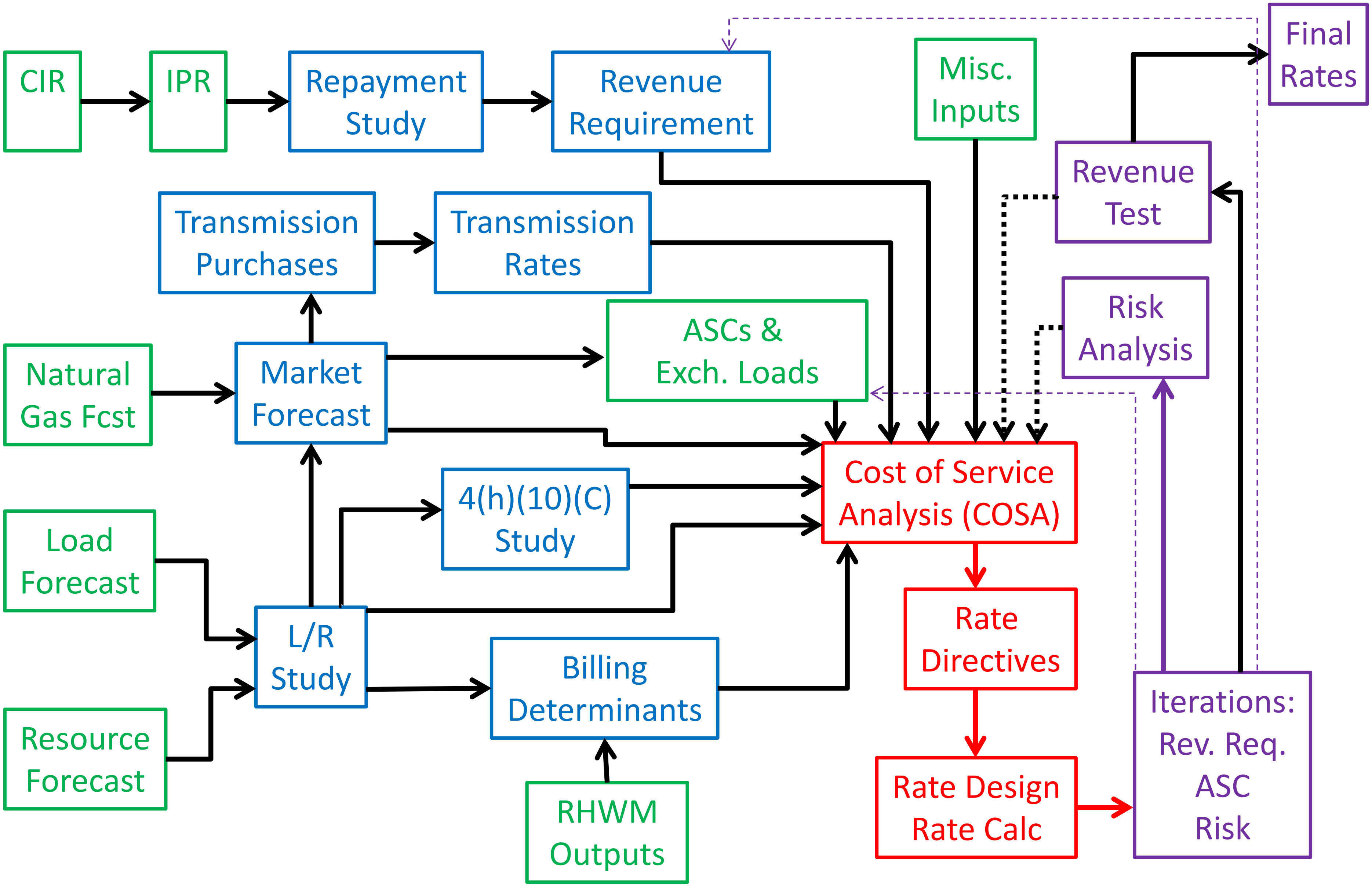
FY 2020-2021 Average System Cost (ASC) Forecasts

ASCs are used in determining the forecast of Residential Exchange Program (REP) benefits that exchanging utilities are entitled to during the rate period. For purposes of the BP-20 rates, BPA is using the ASC Reports published by BPA on July 25, 2019.

Revenue and Power Purchase Expense Forecast

The Revenue Forecast presents BPA's expected level of revenue and power purchase expense for FY 2019-2021. FY 2019 revenues are forecast to estimate the level of reserves at the beginning of the rate period. Selected power purchase expenses that affect the sales of surplus energy are also included. The revenue forecast documents the revenues at both current and proposed rates by applying rates (PF, IP, and NR, if applicable) to projected billing determinants. These two revenue forecasts, one with current rates and the other with proposed rates, are used to demonstrate whether current rates will recover BPA's revenue requirement and, if not, whether proposed rates will recover the revenue requirement. The revenue test is described in the Power Revenue Requirement Study. The Revenue Forecast uses outputs from a number of sources to determine total revenues expected, and to obtain short-term marketing revenues, firm surplus energy revenues, balancing power purchase expenses, augmentation power purchase expenses, 4(h)(10)(C) credits, and Power Services' transmission and ancillary service expenses.

Power Rate Development Process



SECTION 2: RATEMAKING METHODOLOGY AND PROCESS

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Description of Ratemaking Tables

Table 2.1.1
Disaggregated Load Input Data (RDI 01)
The "Loads" worksheet is the input site where disaggregated load data enters the model. The worksheet load data is displayed in average annual form as well as monthly diurnal form. Table 2.1.1 load data is displayed in average annual form. Energy values are in MWh.

Table 2.1.2
Disaggregated Resource Input Data (RDI 02)
The "Resources" worksheet is the input site where disaggregated resource data enters the model. The worksheet resource data is displayed in average annual form as well as monthly diurnal form. Table 2.1.2 resource data is displayed in average annual form. Energy values are in MWh.

Table 2.1.3
Exchange ASCs, Loads, and Gross Costs (RDI 03)
Worksheet displays the utilities that are forecast to be active in the REP with their average system costs and loads. Worksheet calculates the gross cost of exchange resources.

Table 2.2.1
Power Sales and Resources (EAF 01)
Worksheet aggregates the disaggregated sales and resource data from their input worksheets.

Table 2.2.2
Aggregated Loads and Resources (EAF 02)
Worksheet adds transmission losses to power sales from the previous worksheet and performs an annual energy loads and resource balance.

Table 2.2.3
Calculation of Energy Allocation Factors (EAF 03)
Worksheet displays the energy loads and resource balance from the previous worksheet and also calculates several sets of Energy Allocation Factors (EAFs). The EAFs measure the relative use of the different types of resources to serve the different types of loads in the COSA ratemaking step. In addition, EAFs are used to reallocate costs among load types to comport with specific Rate Directive steps.

Table 2.3.1
Disaggregated Costs and Credits (COSA 01)
Worksheet is the input site where disaggregated revenue requirement cost data as well as revenue credit data enters the model. Each line item in the worksheet is associated with aggregation keys that are used in the model to build the COSA and TRM cost tables used in the subsequent ratemaking calculations.

Table 2.3.2
Cost Pool Aggregation (COSA 02)
Worksheet aggregates the revenue requirement data from the previous worksheet into the COSA cost categories: FBS costs, New Resource costs, Residential Exchange Program costs, Conservation costs, BPA Program costs, and Power Transmission costs. Balancing power purchase cost and system augmentation purchase cost are calculated in the model, as are the Residential Exchange Program costs.

Table 2.3.3
Computation of Low Density and Irrigation Rate Discount Costs (COSA 03)
Worksheet calculates the forgone revenue due to the Low Density Discount and the Irrigation Rate Discount. The forgone revenue must be added to the power revenue requirement as a cost to be recovered from PF rates. A macro is used to iterate the costs of the LDD/IRD with the TRM rates so that the LDD/IRD costs are calculated with the current power rates.

Table 2.3.4.1
Allocation of Costs: FBS and LDD/IRD (COSA 04-1)
Worksheet allocates FBS costs as directed by section 7(b) of the Northwest Power Act. Worksheet allocates LDD/IRD costs due to the forgone revenue associated with the LDD and IRD rate discounts, which are allocated to PF load.

Table 2.3.4.2
Allocation of Costs: New Resources and Exchange Resources (COSA 04-2)
Worksheet allocates New Resource costs as directed by sections 7(b) and 7(f) of the Northwest Power Act. Worksheet functionalizes Exchange resource costs between power and transmission before allocating the power portion as directed by sections 7(b) and 7(f) of the Northwest Power Act.

Table 2.3.4.3
Allocation of Costs: Conservation, BPA Programs and Transmission (COSA 04-3)
Worksheet allocates Conservation costs, BPA Program costs and Transmission costs as directed by section 7(g) of the Northwest Power Act.

Table 2.3.5
Allocation of Costs Summary (COSA 05)
Worksheet displays the dollar amounts in the seven COSA cost categories or cost pools and the initial allocation of those costs to the four COSA rate pools.

Table 2.3.6
General Revenue Credits (COSA 06)
Worksheet displays and aggregates the revenue credits from the disaggregated cost worksheet above.

Table 2.3.7.1
Allocation of Revenue Credits: FBS (COSA 07-1)
Worksheet allocates FBS-related revenue credits as directed by section 7(b) of the Northwest Power Act.

Table 2.3.7.2
Allocation of Revenue Credits: Transmission (COSA 07-2)
Worksheet allocates revenue credits associated with transmission costs as directed by section 7(g) of the Northwest Power Act.

Table 2.3.7.3
Allocation of Revenue Credits: New Resources(COSA 07-3)
Worksheet allocates New Resource-related revenue credits as directed by sections 7(b) and 7(f) of the Northwest Power Act.

Table 2.3.7.4
Allocation of Revenue Credits: Conservation(COSA 07-4)
Worksheet allocates revenue credits associated with Conservation costs as directed by section 7(g) of the Northwest Power Act.

Table 2.3.7.5
Allocation of Revenue Credits: Generals (COSA 07-5)
Worksheet allocates revenue credits associated with providing generation inputs as directed by section 7(g) of the Northwest Power Act, and other revenues that are allocated pro rata to all loads.

Table 2.3.7.6
Allocation of Revenue Credits: Non-Federal RSS/RCS (COSA 07-6)
Worksheet allocates revenue credits associated with non-Federal RSS/RCS as directed by section 7(g) of the Northwest Power Act.

Table 2.3.8
Calculation and Allocation of Secondary Revenue Credit (COSA 08)
Worksheet calculates the secondary revenue credit for the rate test period. The secondary revenue credit is allocated to loads that recover FBS and New Resource costs.

Table 2.3.9
Calculation and Allocation of FPS Revenue Deficiency Delta (COSA 09)
Worksheet calculates the firm surplus sale revenue (surplus)/shortfall. The generation revenue requirement costs allocated to FPS sales are reduced by the excess revenue credit allocated to FPS sales in the previous worksheet. The resulting costs are compared with the revenues recovered from FPS sales, resulting in a revenue deficit. This revenue deficit is allocated based on the service provided by the FBS and NR resources to these rate pools.

Table 2.3.10
Calculation of Initial Allocation Power Rates (COSA 10)
Worksheet uses the cost and revenue credit allocations at this point in the rate modeling, when the COSA allocations have been completed and before the Rate Directive steps, to calculate initial rates.

Table 2.4.1
Calculation of the DSI Value of Reserves and Net Industrial Margin (RDS 01)
Worksheet is the input site where data used to calculate the Direct Service Industry (DSI) value of reserves (VOR), Industrial Margin and Net Industrial Margin are input into the model. Worksheet also calculates the Net Industrial Margin to be used in the calculation of the IP rates.

Table 2.4.2
Calculate Energy Rate Scalars First IP-PF Link Calculation (RDS 02)
Worksheet calculates the annual scalar adjustments needed to scale the market price monthly diurnal energy rates such that the resulting energy rates recover the PF rate and IP rate revenue requirements at this point in the ratemaking.

Table 2.4.3
Calculate Monthly Energy Rates Used in First IP-PF Link Calculation (RDS 03)
Worksheet uses the annual energy rate scalars calculated in the previous worksheet to produce monthly diurnal energy rates for PF and IP rates. The annual scalars for both PF and IP rates are then applied to the monthly market price curve to produce a monthly shape for the PF energy rates (at the PF load shape) and the IP energy rate (at the IP load shape).

Table 2.4.4
Calculation of First IP-PF Link Delta (RDS 04)
Worksheet uses shaped energy rates from the previous worksheet to calculate the first IP-PF link delta. The IP-PF Link 7(c)(2) adjustment is necessary to account for the difference between the revenues expected to be recovered from the DSIs at the IP rate and the costs allocated to the DSIs at this point in the ratemaking. This difference, known as the 7(c)(2) Delta, is allocated to non-DSI rates, primarily the PF rate. The IP rate is a formula rate based on the "applicable wholesale rate"—the load-weighted PF and NR rates. The interaction between the applicable wholesale rate and the IP rate has been reduced to an algebraic formula to approximate a solution, and then the RAM uses an intrinsic Excel function, "Goal Seek," to converge to a solution for each year of the rate test period.

Table 2.4.5
Allocation of First IP-PF Link Delta and Recalculation of Rates (RDS 05)
Worksheet reallocates the first IP-PF link delta from the previous worksheet. The delta amount is reallocated from IP to all other loads (7(b) and 7(f) loads associated with PF Preference, PF Exchange, and NR).

Table 2.4.6
Calculation of the DSI Floor Rate (RDS 06)
The IP-83 rates are applied to the current DSI test period billing determinants to determine an average rate. Adjustments are made for Transmission, Exchange Cost, and Deferral to yield the DSI floor rate.

Table 2.4.7
DSI Floor Rate Test 1 (RDS 07)
A test is conducted comparing the IP rate at this stage in the ratemaking process to the floor rate established above.

Table 2.4.8
Calculation of IOU and COU Base Exchange Rates (RDS 08)
Worksheet calculates the Base Exchange rates for IOU and COU exchanging utilities. The IOU Base Exchange rate is the unbifurcated PF rate with transmission costs added. The COU Base Exchange rate differs in that it is calculated without Tier 2 costs and loads.

Table 2.4.9
Calculation of IOU REP Benefits in Rates (RDS 09)
Worksheet calculates the annual IOU REP Benefits to be recovered in power rates.

Table 2.4.10
Calculation of REP Base Exchange Benefits (RDS 10)
Worksheet calculates the REP benefits assuming no PF Public rate protection. The IOU and COU Base PF Exchange rates are subtracted from each IOU and COU individual utility average system cost and that difference is multiplied by the utility's exchangeable load to yield its Unconstrained Benefit.

Table 2.4.11
Calculation of Utility-Specific PF Exchange Rates and REP Benefits (RDS 11)
Worksheet calculates utility-specific PF Exchange rates by adding a utility-specific REP Settlement Charge to the Base Exchange rate. The IOU REP Settlement Charges are sized to collect the difference between the Unconstrained Benefits for the IOUs and the REP Settlement Benefit for the IOUs. This amount is the PF Public rate protection provided by the IOU Exchangers. The IOU Settlement Charges are computed for each utility by allocating this rate protection amount among the IOUs according to the relative size of their share of the Unconstrained Benefits. COUs' Settlement Charges are computed by imputing an amount of "protection" equivalent to the IOU Settlement.

Table 2.4.12
IOU Reallocation Balances (RDS 12)
Worksheet performs a reallocation of benefits between the IOUs to account for differential outstanding Lookback balances at the time of the REP Settlement. The procedure for the reallocation is included in section 6.2 of the Settlement Agreement. This table shows the outstanding balance each IOU is obligated to repay to other IOUs, if any, for the full term of the Regional Dialogue contracts. Provided that each utility has sufficient benefit amounts prior to

reallocation, these amounts (and scheduled future amounts) will not change. However, if a particular utility has insufficient benefits in any one rate period to pay down its reallocation obligation, the scheduled payment amounts will be recalculated.

Table 2.4.13
Allocation of the Increased PF Exchange Costs Due to Settlement (RDS 13)
The difference between the Unconstrained Benefits and the REP Settlement benefits is allocated to the Priority Firm Exchange loads and away from the PF Preference loads. Average power rates are calculated after this reallocation of costs.

Table 2.4.14
Calculation of PF, IP and NR Contribution to Net REP Benefit Costs (RDS 14)
At this point in the REP Settlement rate modeling, the cost of providing IOU and COU Net REP Benefits is assumed to be spread pro rata by load to all PF Public, IP, and NR load. A reallocation adjustment is performed to make the REP Benefit cost contribution of the various rate pools comport with the Net REP Exchange cost contribution present in the WP-10 rate proceeding. The ratio of BP-12 to WP-10 net benefits is used as a factor applied to scale down (or up) the supplemental surcharge from its WP-10 level, and apply this surcharge to IP and NR loads to determine the amount of net REP dollars which should be applied to IP and NR loads.

Table 2.4.15
Reallocate Rate Protection Provided by IP and NR Rates (RDS 15)
Worksheet reallocates the rate protection amount provided by the IP and NR rates from the previous worksheet to the PF Public rate pool. Rates are then computed.

Table 2.4.16
Annual PF and IP scalar under Settlement (RDS 16)
Worksheet calculates the annual scalar adjustments needed to scale the market price monthly diurnal energy rates such that the resulting energy rates recover the PF rate and IP rate revenue requirements at this point in the ratemaking.

Table 2.4.17
Monthly PF and IP rates under Settlement (RDS 17)
Worksheet uses the annual energy rate scalars calculated in the previous worksheet to produce monthly diurnal energy rates for PF and IP rates. The annual scalars for both PF and IP rates are then applied to the monthly market price curve to produce a monthly shape to the PF energy rates (at the PF load shape) and the IP energy rate (at the IP load shape).

Table 2.4.18
IP-PF Link (RDS 18)
Worksheet uses shaped energy rates from previous worksheet to calculate the IP-PF link delta. The IP-PF Link 7(c)(2) adjustment is necessary to account for the difference between the revenues expected to be recovered from the DSIs at the IP rate and the costs allocated to the DSIs at this point in the ratemaking. This difference, known as the 7(c)(2) Delta, is allocated to non-DSI rates, primarily the PF rate. The IP rate is a formula rate based on the "applicable wholesale rate"—the load-weighted PF and NR rates. The interaction between the applicable

wholesale rate and the IP rate has been reduced to an algebraic formula to approximate a solution, and then the RAM uses an intrinsic Excel function, "Goal Seek," to converge to a solution for each year of the rate test period.

Table 2.4.19
Reallocation of IP-PF Link Delta (RDS 19)
Worksheet reallocates IP-PF Link Delta dollars from IP to PF preference and NR loads and recalculates average power rates.

Table 2.4.20
REP Benefit Reconciliation (RDS 20)
Worksheet compares calculated REP benefits to the cost/revenue allocations from the COSA step.

Table 2.5.1
Allocated Costs and Unit Costs, Priority Firm Power Rates
Table provides a summary of the various COSA cost allocations and Rate Design Adjustments associated with Priority Firm Public Power and Priority Firm Exchange Power. A percentage contribution to the final Priority Firm Preference Power rate and Priority Firm Exchange Power rate for each COSA cost allocation and Rate Design Adjustment is calculated.

Table 2.5.2
Allocated Costs and Unit Costs, Industrial Firm Power
Table provides a summary of the various COSA cost allocations and Rate Design Adjustments associated with Industrial Firm Power. A percentage contribution to the final Industrial Firm Power rate for each COSA cost allocation and Rate Design Adjustment is calculated.

Table 2.5.3
Allocated Costs and Unit Costs, New Resource Firm Power
Table provides a summary of the various COSA cost allocations and Rate Design Adjustments associated with New Resource Firm Power. A percentage contribution to the final New Resource Firm Power rate for each COSA cost allocation and Rate Design Adjustment is calculated.

Table 2.5.4
Resource Cost Percent Contribution to Rate Pools
Table provides a summary of the percentages of each resource pool--FBS, Residential Exchange, and New Resources--used in ratemaking to serve each of the rate pools: PF, IP, NR, and FPS.

Rate Data Input
Disaggregated Loads
Test Period October 2019 - September 2021
(MWh)

	A	B	C	E	F
4				2020	2021
5	Preference			58,757,234	59,035,753
6		Block		5,042,139	5,009,642
7		Slice Block		11,260,751	11,559,704
8		Slice		13,856,575	13,702,740
9		Load Following		28,121,738	28,207,433
10		Tier 2		476,031	556,234
11	Industrial			105,420	105,108
12		Smelter		0	0
13		Other Industrial		105,420	105,108
14	New Resource			10	10
15	Firm Power and Services			5,812,380	5,751,973
16		Intraregional Transfer		98,675	98,426
17			WNP#3 Settlement	0	0
18			Dittmer Station Service	82,895	82,668
19			Transfer Gen Losses	15,781	15,758
27		FBS Obligation		5,658,472	5,646,953
28			Canadian Entitlement	3,990,571	3,979,668
29			USBR Pump Load	1,562,315	1,561,924
30			Hungry Horse	0	0
31			Upper Baker	11,340	11,116
32			Non-Treaty Storage	94,246	94,246
33			Libby Coordination	0	0
38		Seasonal or Capacity Exchange		55,233	6,593
39			Riverside Capacity	0	0
40			Riverside Seasonal	0	0
41			Pasadena Capacity	0	0
42			Pasadena Seasonal	0	0
43			PG&E	0	0
44			Intertie Losses	16,932	3,314
45			PacifiCorp	38,301	3,280
49	Firm Surplus Sale			1,381,840	300,550
50	Presale of Secondary			0	0
51	Conservation			0	0
52					
53					
54	Loss Percentage			3.061%	3.061%

Table 2.1.2

Rate Data Input
Disaggregated Resources
Test Period October 2019 - September 2021
(MWh)

	A	B	C	E	F
5				2020	2021
6	Hydro			57,957,196	57,835,789
7		Regulated		53,713,750	53,598,333
8		Independent		3,055,739	3,052,662
9			Cowlitz Falls	232,671	232,343
10			Idaho Falls	0	0
11			PreAct	2,823,068	2,820,320
19		Hydro Other		1,187,707	1,184,794
20			Canadian Entitlement	1,187,707	1,184,794
21			Libby Coordination	0	0
22			Other	0	0
30	Non Hydro			10,231,144	9,097,304
31		Water		23,102	23,039
32			Dworshak/Clearwater Small Hydropower	23,102	23,039
33			Elwha Hydro	0	0
34			Glines Canyon Hydro	0	0
42		Thermal		9,802,944	8,704,656
43			Columbia Generating Station	9,802,944	8,704,656
53		Wind		405,079	369,609
54			Foote Creek 1	31,657	31,593
55			Foote Creek 2	0	0
56			Foote Creek 4	34,720	0
57			Stateline Wind Project	186,184	185,808
58			Condon Wind Project	102,918	102,710
59			Klondike I	49,600	49,499
64		Renewable		20	0
67			Ashland Solar Project	20	0
75	Contracts			1,216,938	970,083
76		Imports		1,178,645	970,083
77			Riverside Exchange Energy	0	0
78			Pasadena Exchange Energy	0	0
79			BC Hydro Power Purchase	8,784	8,760
80			Slice Return of Losses	264,661	261,722
81			Southeast Idaho Load Service	905,200	699,600
87		Seasonal or Capacity Exchange		38,293	0
88			Riverside Capacity	0	0
89			Riverside Seasonal	0	0
90			Pasadena Capacity	0	0
91			Pasadena Seasonal	0	0
92			PG&E Shaping	0	0
93			PacifiCorp Shaping	38,293	0
109	Augmentation and Balancing			105,714	105,505
110		Tier 1 Resources		105,714	105,505
111			Klondike III	103,511	103,302
112			Rocky Brook	2,203	2,203
113					
114	Transmission Losses			(2,053,373)	(2,014,838)

Table 2.1.3

Rate Data Input
Exchange ASCs, Loads, and Gross Costs
Test Period October 2019 - September 2021

	B	D	E
7	**Exchange ASCs ($/MWh)**	**2020**	**2021**
8			
9	Avista Corporation	$ 67.60	$ 67.60
10	Idaho Power Company	$ 64.41	$ 64.41
11	NorthWestern Energy, LLC	$ 82.91	$ 82.91
12	PacifiCorp	$ 79.43	$ 79.43
13	Portland General Electric Company	$ 77.53	$ 77.53
14	Puget Sound Energy, Inc.	$ 75.72	$ 75.72
15	Clark Public Utilities	$ 55.17	$ 55.17
17	Snohomish PUD	$ 54.68	$ 54.68
18			
19	**Exchange Loads (GWh)**	**2020**	**2021**
20			
21	Avista Corporation	3,936	3,936
22	Idaho Power Company	6,760	6,760
23	NorthWestern Energy, LLC	702	702
24	PacifiCorp	9,172	9,172
25	Portland General Electric Company	8,168	8,168
26	Puget Sound Energy, Inc.	11,869	11,869
27	Clark Public Utilities	2,541	2,543
29	Snohomish PUD	3,600	3,567
30		46,748	46,718
31			
32	**Exchange Resource Cost ($000)**	**2020**	**2021**
33			
34	Avista Corporation	$ 266,049	$ 266,049
35	Idaho Power Company	$ 435,418	$ 435,419
36	NorthWestern Energy, LLC	$ 58,217	$ 58,217
37	PacifiCorp	$ 728,530	$ 728,531
38	Portland General Electric Company	$ 633,272	$ 633,272
39	Puget Sound Energy, Inc.	$ 898,755	$ 898,755
40	Clark Public Utilities	$ 140,160	$ 140,305
42	Snohomish PUD	$ 196,831	$ 195,043
43		$ 3,357,234	$ 3,355,590

Table 2.2.1.1

Energy Allocation Factor
Power Sales and Resources
Test Period October 2019 - September 2021
(aMW)

	B	C	E	F
4			**2020**	**2021**
5	**Sales**			
6	Public			
7		Load Following	3,201	3,220
8		Tier 2 (block net of remarketing)	54	63
9		Slice (output energy)	1,577	1,564
10		Block	1,856	1,891
12	Exports			
13		BC Hydro (Cdn Entitlement)	454	454
14		Non-Treaty Storage	11	11
15		Libby Coordination	0	0
16		Pasadena Capacity	0	0
17		Pasadena Seasonal	0	0
18		Riverside Capacity	0	0
19		Riverside Seasonal	0	0
20		PacifiCorp	4	0
21		PG&E	0	0
22		Federal Generation Transmission Losses	2	2
23		Intertie Losses	2	0
24	Intra-regional Transfers			
25		Firm Surplus Sale	157	34
26		Dittmer/Substration Sale	9	9
27	Other Loads			
28		USBR Pump Load	178	178
29		Hungry Horse	0	0
30		Upper Baker	1	1
31		Direct Service Industries	12	12
32		New Resource	0	0
33	Total Firm Obligations		**7,520**	**7,442**
34				
35	**Resources**			
36	Hydro			
37		Regulated	6,115	6,119
38		Independent		
39		Cowlitz Falls	26	27
40		Idaho Falls	0	0
41		PreAct	321	322
42		Non-Fed CER (Canada)	135	135
43		Libby Coordination	0	0
44	Other Hydro Resources			
45				

Energy Allocation Factor
Power Sales and Resources
Test Period October 2019 - September 2021
(aMW)

	B	C	E	F
4			**2020**	**2021**
46	Combustion Turbines			
47	Renewables			
48		Foote Creek 1	4	4
49		Foote Creek 2	0	0
50		Foote Creek 4	4	0
51		Stateline Wind Project	21	21
52		Condon Wind Project	12	12
53		Klondike I	6	6
54		Georgia-Pacific Paper (Wauna)	0	0
55		Klondike III	12	12
56		Fourmile Hill Geothermal	0	0
57		Ashland Solar Project	0	0
58		White Bluffs Solar	0	0
59	Cogeneration			
60	Imports			
61		Riverside Exchange Energy	0	0
62		Pasadena Exchange Energy	0	0
63		BC Hydro Power Purchase	1	1
64		Riverside Capacity	0	0
65		Riverside Seasonal	0	0
66		Pasadena Capacity	0	0
67		Pasadena Seasonal	0	0
68		Slice Losses Return	30	30
69	Regional Transfers (In)			
70		Southeast Idaho Load Purchase	103	80
71		PacifiCorp	4	0
72	Large Thermal		1,116	994
73	Non-Utility Generation			
74		Dworshak/Clearwater Small Hydropower	3	3
75		Elwha Hydro	0	0
76		Glines Canyon Hydro	0	0
77		Rocky Brook	0.25	0.25
78	Tier 2 Purchases		54	63
79	Federal Trans. Losses		(235)	(231)
80	Total Net Resources		**7,733**	**7,596**
81				
82	Total Firm Surplus/Deficit		**212**	**154**

Table 2.2.2.1

Energy Allocation Factor
Aggregated Loads and Resources
Test Period October 2019 - September 2021
(aMW)

	B	C	D	E
4			**2020**	**2021**
7	**Loads**			
8	Priority Firm - 7(b) Loads			
9		Block	1,913	1,949
10		Load Following	3,299	3,319
11		Slice (output energy)	1,626	1,612
12		Tier 2	56	65
14		5(c) Exchange	5,485	5,496
15	Industrial Firm - 7(c) Loads			
16		Direct Service Industries	12	12
17	New Resources - 7(f) Loads			
18		NR	0.001	0.001
19	Surplus Firm - SP Loads			
20		Firm Surplus Sale	162	35
21		Dittmer/Substation Sale	10	10
22	Total Loads		**12,563**	**12,499**
23				
24	**Resources**			
25	Federal Base System			
26		Hydro	6,572	6,576
27		Other Resources		
28		Small Thermal & Misc.		
29		Combustion Turbines		
30		Renewables	0	0
31		Cogeneration		
32		Imports	1	1
33		Regional Transfers (In)	107	80
34		Large Thermal	1,116	994
35		Non-Utility Generation	0	0
36		Slice Loss Return	30	30
37		Augmentation Purchases	0	0
38		Tier 2 Purchases	56	65

Table 2.2.2.2

Energy Allocation Factor
Aggregated Loads and Resources
Test Period October 2019 - September 2021
(aMW)

	B	C	D	E
4			**2020**	**2021**
39	less: FBS Obligations			
40		BC Hydro (Cdn Entitlement)	(468)	(468)
41		Non-Treaty Storage	(11)	(11)
42		Libby Coordination	0	0
43		Hungry Horse	0	0
44		Upper Baker	(1)	(1)
45		USBR Pump Load	(183)	(184)
46	less: FBS Uses			
47		Pasadena	0	0
48		Riverside	0	0
49		PacifiCorp	(4)	(0)
50		PG&E	0	0
51		Federal Generation Transmission Losses	(2)	(2)
52		Intertie Losses	(2)	(0)
53	Exchange Resources			
54		5(c) Exchange	5,485	5,496
55	New Resources			
56		Cowlitz Falls	26	27
57		Idaho Falls	0	0
58		Foote Creek 1	4	4
59		Foote Creek 2	0	0
60		Foote Creek 4	4	0
61		Stateline Wind Project	21	21
62		Condon Wind Project	12	12
63		Klondike I	6	6
64		Klondike III	12	12
65		Georgia-Pacific Paper (Wauna)	0	0
66		Fourmile Hill Geothermal	0	0
67		Ashland Solar Project	0	0
68		White Bluffs Solar	0	0
69		Dworshak/Clearwater Small Hydropower	3	3
70		Elwha Hydro	0	0
71		Glines Canyon Hydro	0	0
72		Rocky Brook	0	0
73	Total Resources		**12,782**	**12,658**

Table 2.2.3.1

Energy Allocation Factor
Calculation of Energy Allocation Factors
Test Period October 2019 - September 2021
(aMW)

	B	C	D
4		**2020**	**2021**
5			
6	**Loads (after adjustments)**		
7	Public	6,894	6,946
8	Exchange	5,485	5,496
9	DSI	12	12
10	NR	0.001	0.001
11	FPS	391	204
12			
13	Load Pools -- Program Case		
14	Priority Firm - 7(b) Loads	12,379	12,442
15	Industrial Firm - 7(c) Loads	12	12
16	New Resources - 7(f) Loads	0.001	0.001
17	Surplus Firm - SP Loads	391	204
18	Total Firm Loads	12,782	12,658
19	Secondary	2,382	2,322
20	Surplus Firm - SP Loads (for rate protection)	391	204
21			
22	**Resources (after adjustments)**		
23	Federal Base System	7,210	7,079
24	Exchange Resources	5,485	5,496
25	New Resources	87	83
26	Total Firm Resources	12,782	12,658
27			
28	Allocators -- Program Case		
29	Federal Base System		
30	Priority Firm - 7(b) Loads	7,210	7,079
31	Industrial Firm - 7(c) Loads	0	0
32	New Resources - 7(f) Loads	0	0
33	Surplus Firm - SP Loads	0	0
34	Exchange Resources		
35	Priority Firm - 7(b) Loads	5,169	5,363
36	Industrial Firm - 7(c) Loads	10	8
37	New Resources - 7(f) Loads	0.0009	0.0007
38	Surplus Firm - SP Loads	306	126
39	New Resources		
40	Priority Firm - 7(b) Loads	0	0
41	Industrial Firm - 7(c) Loads	3	5
42	New Resources - 7(f) Loads	0	0
43	Surplus Firm - SP Loads	85	79

Table 2.2.3.2

Energy Allocation Factor
Calculation of Energy Allocation Factors
Test Period October 2019 - September 2021

	B	C	D
4		**2020**	**2021**
44			
45	**Allocation Factors -- Program Case with Exchange**		
46	Federal Base System + NR		
47	Priority Firm - 7(b) Loads	0.9880	0.9884
48	Industrial Firm - 7(c) Loads	0.0004	0.0007
49	New Resources - 7(f) Loads	0.0000	0.0000
50	Surplus Firm - SP Loads	0.0116	0.0110
51	Federal Base System		
52	Priority Firm - 7(b) Loads	1.0000	1.0000
53	Industrial Firm - 7(c) Loads	0.0000	0.0000
54	New Resources - 7(f) Loads	0.0000	0.0000
55	Surplus Firm - SP Loads	0.0000	0.0000
56	Exchange Resources		
57	Priority Firm - 7(b) Loads	0.9424	0.9758
58	Industrial Firm - 7(c) Loads	0.0018	0.0014
59	New Resources - 7(f) Loads	0.0000	0.0000
60	Surplus Firm - SP Loads	0.0558	0.0228
61	New Resources		
62	Priority Firm - 7(b) Loads	0.0000	0.0000
63	Industrial Firm - 7(c) Loads	0.0307	0.0571
64	New Resources - 7(f) Loads	0.0000	0.0000
65	Surplus Firm - SP Loads	0.9693	0.9429
66	Conservation & General		
67	Priority Firm - 7(b) Loads	0.9685	0.9829
68	Industrial Firm - 7(c) Loads	0.0010	0.0010
69	New Resources - 7(f) Loads	0.0000	0.0000
70	Surplus Firm - SP Loads	0.0306	0.0161
81	Surplus Deficit		
82	Priority Firm - 7(b) Loads	0.9990	0.9990
83	Industrial Firm - 7(c) Loads	0.0010	0.0010
84	New Resources - 7(f) Loads	0.0000	0.0000
85	Surplus Firm - SP Loads	-1.0000	-1.0000
89	Rate Protection		
90	PF Exchange	0.6632	0.6840
91	Industrial Firm - 7(c) Loads	0.0015	0.0015
92	New Resources - 7(f) Loads	0.0000	0.0000
93	Secondary Sales	0.3353	0.3144

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2019 - September 2021
($ 000)

	B	D	E
4		**2020**	**2021**
5	**Power System Generation Resources**		
6	**Operating Generation**		
7	Columbia Generating Station (WNP-2)	262,471	319,462
8	Bureau of Reclamation	153,609	151,623
9	Corps of Engineers	252,557	252,557
10	Billing Credits Generation	5,300	5,300
11	Cowlitz Falls O&M	5,448	5,948
12	Idaho Falls Bulb Turbine	-	-
13	Clearwater Hatchery Generation	1,332	1,370
14	New Resources Integration Wheeling	629	632
15			
16	**Operating Generation Settlement Payment**		
17	Operating Generation Settlement Payment (Colville)	22,997	22,997
18			
19	**Non-Operating Generation**		
20	Trojan Decomissioning	1,200	1,200
21	WNP-1&3 Decomissioning	431	331
22			
23	**Contracted and Augmentation Power Purchases**		
24	Augmentation Power Purchases	-	-
25	Balancing Purchases	31,137	24,393
26	PNCA Headwater Benefits	3,100	3,100
27	Tier 1 Augmentation Resources (Klondike III)	10,048	10,158
28	Hedging/Mitigation	38,555	29,380
29	Other Committed Purchase (excl. Hedging)	250	250
30	Bookout Adj to Contracted Power Purchases	-	-
31			
32	**Exchanges and Settlements**		
33	Residential Exchange (IOU)	245,200	245,200
34	Residential Exchange (COU)	4,566	4,546
35	Residential Exchange (Refund)	-	-
36	Residential Exchange Program Support	803	624
37	Residential Exchange Interest Accrual	-	-
38			
39	**Renewable and Conservation Generation**		
40	Renewables R&D	-	-
41	Renewable Generation	26,475	24,711
42	Conservation Infrastructure	27,296	27,296
43	Generation Conservation R&D	1,654	1,657
44	DR & Smart Grid	855	855
45	Conservation Acquisition	67,000	67,000
46	Low Income Energy Efficiency	5,739	5,853
47	Reimbursable Energy Efficiency Development	8,000	8,000
48	Legacy Conservation	590	590
49	Market Transformation	12,050	12,050

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2019 - September 2021
($ 000)

	B	D	E
4		**2020**	**2021**
50			
51	**Transmission Acquisition and Ancillary Services**		
52	Trans & Ancillary Svcs	77,499	73,025
53	Trans & Ancillary Svcs (sys oblig)	32,028	32,028
54	Third Party GTA Wheeling	96,200	96,200
55	Power 3rd Party Trans & Ancillary Svcs (Non-Slice Cost)	-	-
56	Power 3rd Party Trans & Ancillary Svcs (Composite Cost)	2,338	2,384
57	Trans Acq Generation Integration	13,577	13,671
58	Power Telemetering/Equipment Replacement	-	-
59			
60	**Power Non-Generation Operations**		
61	Efficiencies Program	-	-
62	Information Technology	6,714	6,775
63	Generation Project Coordination	6,059	6,205
64	Slice costs Charged to Slice Customers	-	-
65	Slice Implementation	555	575
66			
67	**PS Scheduling**		
68	Operations Scheduling	8,806	9,148
69	Operations Planning	5,643	5,839
70			
71	**PS Marketing and Business Support**		
72	Sales and Support	23,191	23,954
73	Strategy, Finance & Risk Mgmt	11,978	12,345
74	Executive and Administrative Svcs	3,879	3,967
75	Conservation Support	8,399	8,699
76	Power R&D	1,008	1,010
77	KSI Asset Management Expense	-	-
78	KSI LT Finance & Rates Expense	-	-
79	KSI Commercial Operations Expense	4,125	4,125
80			
81	**Fish and Wildlife/USF&W/Planning Council/Env Req.**		
82	Fish and Wildlife	249,603	250,031
83	USF&W Lower Snake Hatcheries	30,483	30,483
84	Planning Council	11,725	11,956
85	Environmental Requirements	-	-
86			
87	**BPA Internal Support**		
88	Additional Post-Retirement Contribution	19,577	20,831
89	Agency Svs for Power for Rev Req schedule	37,099	36,877
90	F&W Corporate Support - G&A	10,828	10,850
91	Agency Svs for Energy Efficiency for Rev Req schedule	9,932	9,916
92			
93	**Bad Debt Expense/Other**		
94	Bad Debt Expense (composite)	-	-
95	Bad Debt Expense (non-slice)	-	-
96	Other Income & Expense (composite) - Decommissioning	-	(20,000)

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2019 - September 2021
($ 000)

	B	D	E
4		**2020**	**2021**
100			
101	**Depreciation and Amortization**		
102	**Depreciation**		
103	Depreciation - BPA	10,418	9,245
104	Depreciation - Corps	100,017	102,628
105	Depreciation - Bureau	28,532	29,177
106			
107	**Amortization**		
108	Amortization - Legacy Conservation	17	-
109	Amortization - Conservation Acquisitions	42,078	42,078
110	Amortization - CRFM	11,247	11,466
111	Amortization - Fish & Widlife	34,051	36,257
112	Amortization -- CGS	149,823	150,977
113	Amortization -- CGS Decomm Trust asset	24,031	24,031
114	Accretion -- CGS Decomm Trust liability	33,738	35,213
115	Amortization -- WNP1	34,506	34,506
116	Amortization -- WNP3	42,630	42,630
117	Amortization -- Cowlitz Falls	5,267	5,267
118	Amortization -- N. Wasco	1,940	1,940
119			
120	**Interest Expense**		
121	**Net Interest**		
122	Interest On Appropriated Funds	44,685	45,908
123	Capitalization Adjustment	(45,937)	(45,937)
124	Interest On Treasury Bonds	61,145	68,928
125	Non Federal Interest (Prepay)	9,826	8,863
126	Non Federal Interest (CGS)	147,477	72,125
127	Non Federal Interest (WNP 1)	39,346	39,612
128	Non Federal Interest (WNP 3)	45,270	45,573
129	Non Federal Interest (N Wasco)	410	355
130	Non Federal Interest (Lewis County)	3,471	3,280
131	Premiums/Discounts	13	10
132	AFUDC	(15,904)	(16,493)
133	Interest Income on Decommissioning Trust	(8,818)	(9,112)
134	Other Expense and (Income) (Gains/Losses on Decomm Trust)	(5,052)	(5,220)
135	Interest Earned on BPA Fund for Power (composite)	(5,279)	(5,485)
136	Interest Earned on BPA Fund for Power (non-slice)	320	(1,268)
137			
138	**Net Interest into Cost Pools**		
139	Power Net Interest - Hydro Allocation	36,976	42,206
140	Power Net Interest - Fish & Wildlife Allocation	6,131	7,209
141	Power Net Interest - Conservation Allocation	4,854	4,164
142	Power Net Interest - BPA Programs Allocation	909	947
143			

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2019 - September 2021
($ 000)

	B	D	E
4		**2020**	**2021**
144	**Net Interest into Cost Pools 7b2**		
145	Power Net Interest Hydro 7b2 Allocation	36,976	42,206
146	Power Net Interest Fish & Wildlife 7b2 Allocation	6,131	7,209
147	Power Net Interest BPA Programs 7b2 Allocation	5,763	5,111
148			
149	**Net Revenue**		
150	**Minimum Required Net Revenue**		
151	Repayment of Treasury Borrowings	173,072	518,065
152	Payment of Irrigation Assistance	24,331	14,747
153	Depreciation (MRNR - Reverse sign)	(138,968)	(141,050)
154	Amortization (MRNR - Reverse sign)	(379,327)	(384,364)
155	Non Federal Interest (Prepay) (MRNR - Reverse Sign)	(9,826)	(8,863)
156	Capitalization Adjustment (MRNR - Reverse Sign)	45,937	45,937
157	Repayment of Federal Appropriations	-	-
158	Accrual Revenues (MRNR Adjustment - Reverse Sign)	-	-
159	Prepay Revenue Credits (MRNR - Reverse Sign)	30,600	30,600
160	Non-Cash Expenses	-	-
161	Repayment of NF Obligations (LOC)	227,000	-
162	Repayment of NF Obligations (CGS)	33,848	15,473
163	Repayment of NF Obligations (WNP 1)	1,226	-
164	Repayment of NF Obligations (WNP 3)	1,150	1,785
165	Repayment of NF Obligations (N Wasco)	1,527	1,593
166	Repayment of NF Obligations (Cowlitz Falls)	3,830	4,020
167	Cash freed up by DSR refinancing	(16,590)	(15,885)
168	Customer Proceeds	-	-
169	Cash Contribution to CGS Decomm Trust	4,100	4,300
170	Interest Income on Decommissioning Trust (MRNR - Reverse Sign)	8,818	9,112
171	Other Expense and (Income) (Gains/Losses on Decomm Trust) (MRNR - Reverse Sign)	5,052	5,220
172	Revenue Financing Requirement	-	-
173	Depreciation Exceeds Cash Expense	(15,780)	(100,690)
174			
175	**Minimum Net Revenue into Cost Pools**		
176	Power MNetRev - Hydro Allocation	11,940	77,939
177	Power MNetRev - Fish & Wildlife Allocation	1,979	13,313
178	Power MNetRev - Conservation Allocation	1,567	7,689
179	Power MNetRev - BPA Programs Allocation	294	1,749
180			
181	**Minimum Net Revenue into Cost Pools 7b2**		
182	Power MNetRev - Hydro 7b2 Allocation	11,940	77,939
183	Power MNetRev - Fish & Wildlife 7b2 Allocation	1,979	13,313
184	Power MNetRev - PBA Programs 7b2 Allocation	1,861	9,438
185			
186	**Planned Net Revenues for Risk into Cost Pools**		
187	Power PNetRev - Hydro Allocation	-	-
188	Power PNetRev - Fish & Wildlife Allocation	-	-
189	Power PNetRev - Conservation Allocation	-	-
190	Power PNetRev - BPA Programs Allocation	-	-
191			
192	**Planned Net Revenues for Risk into Cost Pools 7b2**		
193	Power PNetRev - Hydro 7b2 Allocation	-	-
194	Power PNetRev - Fish & Wildlife 7b2 Allocation	-	-
195	Power PNetRev - BPA Programs 7b2 Allocation	-	-

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2019 - September 2021
($ 000)

	B	D	E
4		**2020**	**2021**
196			
197	**Internally Computed Line Items**		
198	Augmentation Power Purchases	-	-
199	Balancing Purchases	69,692	53,773
200	Secondary Energy Credit	(346,862)	(305,234)
201	Low Density Discount Costs	38,505	39,107
202	Irrigation Rate Mitigation Costs	20,905	20,905
203	**Charges/Credits to Tiered Rate Pools**		
204	Firm Surplus and Secondary Credit (from unused RHWM)	(68,746)	(61,756)
205	Balancing Augmentation	(1,213)	(4,273)
206	Transmission Loss Adjustment	(30,066)	(30,308)
207	Demand Revenue	53,201	53,857
208	Load Shaping Revenue	25,902	30,182
209	**Tier 2 and RSS Charges/Credits to Tiered Rate Pools**		
210	Augmentation RSS & RSC Adder	2,319	2,319
211	Tier 2 Purchase Costs	12,430	16,203
212	Tier 2 Rate Design Adjustments (Cost)	563	676
213	Tier 2 Other Costs	-	-
214			
215	**Revenue Credits / Rate Design Adjustments**		
216	Downstream Benefits and Pumping Power	(19,364)	(19,364)
217	Generation Inputs Revenue	(119,815)	(119,815)
218	4(h)(10)(C)	(86,250)	(86,852)
219	Colville and Spokane Settlements	(4,600)	(4,600)
220	Green Tags (FBS resources)	-	-
221	Green Tags (New resources)	-	-
222	Energy Efficiency Revenues	(8,000)	(8,000)
223	Miscellaneous Credits (incl. GTA)	(12,362)	(12,397)
224	Pre-sub/Hungry Horse	-	-
225	Other Locational/Seasonal Exchange	-	-
226	Upper Baker	(353)	(347)
227	Other Surplus Sales (Non-Slice)	-	-
228	PF Load Forecast Deviation Liquidated Damages	(9,499)	(9,458)
229	NR Revenues from ESS energy and capacity charges	-	-
230	**Tier 2**		
231	Composite Augmentation RSS Revenue Debit/(Credit)	(1,668)	(1,668)
232	Composite Tier 2 RSS Revenue Debit/(Credit)	(52)	(61)
233	Composite Tier 2 Rate Design Adjustment Debit/(Credit)	(510)	(615)
234	Composite Non-Federal RSS Revenue Debit/(Credit)	(1,008)	(1,084)
235	Non-Slice Augmentation RSC Revenue Debit/(Credit)	(651)	(651)
236	Non-Slice Tier 2 RSC Revenue Debit/(Credit)	-	-
237	Non-Slice Tier 2 Rate Design Debit/(Credit)	-	-
238	Non-Slice Non-Federal RSC Revenue Debit/(Credit)	43	34

Table 2.3.2

Cost of Service Analysis
Cost Pool Aggregation
Test Period October 2019 - September 2021
($ 000)

	B	D	E
3		**2020**	**2021**
4			
5	**Federal Base System**	**1,815,762**	**1,876,021**
6	Hydro	651,458	724,176
7	Operating Expense	602,542	604,031
8	Net Interest	36,976	42,206
9	PNRR	-	-
10	MRNR	11,940	77,939
11	BPA Fish and Wildlife Program	314,316	329,616
12	Operating Expense	306,206	309,094
13	Net Interest	6,131	7,209
14	PNRR	-	-
15	MRNR	1,979	13,313
16	Trojan	1,200	1,200
17	WNP #1	74,283	74,449
18	WNP #2	603,670	587,475
19	WNP #3	87,900	88,202
20	System Augmentation	-	-
21	Balancing	69,942	54,023
22	Tier 2 Costs	12,993	16,879
23			
24	**New Resources**	**55,019**	**53,661**
25	Idaho Falls	-	-
26	Tier 1 Aug (Klondike III)	10,048	10,158
27	Cowlitz Falls	11,125	11,570
28	Other NR	33,846	31,932
29			
30	**Residential Exchange**	**3,358,037**	**3,356,215**
31			
32	**Conservation**	**195,331**	**201,147**
33	Operating Expense	188,910	189,294
34	Net Interest	4,854	4,164
35	PNRR	-	-
36	MRNR	1,567	7,689
37			
38	**BPA Programs**	**140,256**	**123,592**
39	Operating Expense	139,053	120,896
40	Net Interest	909	947
41	PNRR	-	-
42	MRNR	294	1,749
43			
44			
45	**Transmission**	**221,643**	**217,308**
46	TBL Transmission/Ancillary Services	125,443	121,108
47	3Rd Party Trans/Ancillary Services	-	-
48	General Transfer Agreements	96,200	96,200
49			
50	**Total PBL Revenue Requirement**	**5,786,049**	**5,827,943**
51			

Table 2.3.3.1

Cost of Service Analysis
Computation of Low Density and Irrigation Rate Discount Costs
Test Period October 2019 - September 2021
($ 000)

	B	D	E	F	G	H
18	**Program Totals**	**2020**	**2021**			
19	**Low Density Discount Expenses........................**	**$ 38,505**	**$ 39,107**			
20	**Irrigation Rate Discount...................................**	**$ 20,905**	**$ 20,905**			
21						
22						
23	**TRM Costs after Adjustments**	**2020**	**2021**			
24	**Composite..**	$ 2,239,305	$ 2,249,322			
25	**Non-Slice..**	$ (172,773)	$ (173,787)			
26	**Slice..**	$ -	$ -			
27	**Tier 2...**	$ 12,993	$ 16,879			
28	**Total Costs**	$ 2,079,524	$ 2,092,414			
29						
30	**Low Density Discount**					
31	**Customer Charge LDD**	**2020**	**2021**			
32	**TOCA LDD Offest %.......................................**	1.73%	1.75%			
33	**LDD Customer Charge ($000).........................**	$ 35,750	$ 36,260			
34						
35	**Irrigation Rate Discount**					
36	**IRD Percentage..**	37.06%				
37	**Total Irrigation Load (MWh)..........................**	1,881,605				
38	**RT1SC...**	7,025				
39	**Irrigation Load Weighted LDD.......................**	4.8%				
40						
41		**2020**	**2021**			
42	**Hours..**	8784	8760			
43	**IRD TOCA...**	3.04944%	3.05779%			
44	**Composite Revenue...**	$ 72,474,929	$ 72,673,380			
45	**Non-Slice Revenue..**	$ (7,332,001)	$ (7,352,078)			
46	**Load Shaping Revenue.....................................**	$ (5,995,523)	$ (5,978,695)			
47	**Total after LDD...**	$ 56,308,329	$ 56,494,163			
48						
49	**Irrigation Rate Discount...................................**	**11.11**				
50						
51						

Cost of Service Analysis
Computation of Low Density and Irrigation Rate Discount Costs
Test Period October 2019 - September 2021
($ 000)

	B	D	E	F	G	H
52	**Demand and Load Shaping Discount**	**Demand BD (kW)**	**LoadShp BD (MWh)**	**Demand Rate**	**LoadShp Rate**	**Total LDD Discount**
53	Oct-19	16,473	(5,565)	$ 11.42	$ 23.84	$ 55,460
54	Oct-19	-	488	$ 11.42	$ 18.88	$ 9,204
55	Nov-19	15,221	(13,030)	$ 12.07	$ 25.19	$ (144,546)
56	Nov-19	-	(2,763)	$ 12.07	$ 21.84	$ (60,347)
57	Dec-19	26,204	(1,710)	$ 13.45	$ 28.09	$ 304,400
58	Dec-19	-	4,922	$ 13.45	$ 23.56	$ 115,986
59	Jan-20	27,790	6,679	$ 12.10	$ 25.24	$ 504,863
60	Jan-20	-	10,498	$ 12.10	$ 19.21	$ 201,668
61	Feb-20	17,410	5,146	$ 11.66	$ 24.36	$ 328,333
62	Feb-20	-	7,189	$ 11.66	$ 19.28	$ 138,641
63	Mar-20	21,690	(4,428)	$ 9.19	$ 19.19	$ 114,348
64	Mar-20	-	1,608	$ 9.19	$ 16.11	$ 25,901
65	Apr-20	19,979	4,798	$ 8.61	$ 17.98	$ 258,287
66	Apr-20	-	5,120	$ 8.61	$ 14.40	$ 73,749
67	May-20	13,192	(10,530)	$ 5.60	$ 11.71	$ (49,395)
68	May-20	-	2,506	$ 5.60	$ 6.55	$ 16,414
69	Jun-20	18,283	(20,066)	$ 5.04	$ 10.52	$ (118,877)
70	Jun-20	-	(5,809)	$ 5.04	$ 1.68	$ (9,733)
71	Jul-20	23,096	(2,111)	$ 10.27	$ 21.45	$ 191,921
72	Jul-20	-	13,123	$ 10.27	$ 15.31	$ 200,897
73	Aug-20	20,470	(1,138)	$ 12.10	$ 25.24	$ 218,953
74	Aug-20	-	10,029	$ 12.10	$ 20.21	$ 202,692
75	Sep-20	16,692	(3,541)	$ 11.91	$ 24.86	$ 110,764
76	Sep-20	-	3,275	$ 11.91	$ 19.98	$ 65,426
77	**Total**					**$ 2,755,008**

Cost of Service Analysis
Computation of Low Density and Irrigation Rate Discount Costs
Test Period October 2019 - September 2021
($ 000)

	B	D	E	F	G	H
78	**Demand and Load Shaping Discount**	**Demand BD (kW)**	**LoadShp BD (MWh)**	**Demand Rate**	**LoadShp Rate**	**Total LDD Discount**
79	Oct-20	17,235	(5,391)	$ 11.42	$ 23.84	$ 68,307
80	Oct-20	-	410	$ 11.42	$ 18.88	$ 7,742
81	Nov-20	12,555	(13,410)	$ 12.07	$ 25.19	$ (186,287)
82	Nov-20	-	(2,356)	$ 12.07	$ 21.84	$ (51,458)
83	Dec-20	30,844	(1,108)	$ 13.45	$ 28.09	$ 383,728
84	Dec-20	-	4,552	$ 13.45	$ 23.56	$ 107,252
85	Jan-21	24,724	6,366	$ 12.10	$ 25.24	$ 459,883
86	Jan-21	-	11,073	$ 12.10	$ 19.21	$ 212,716
87	Feb-21	16,018	6,165	$ 11.66	$ 24.36	$ 336,910
88	Feb-21	-	7,617	$ 11.66	$ 19.28	$ 146,887
89	Mar-21	25,131	(4,046)	$ 9.19	$ 19.19	$ 153,292
90	Mar-21	-	1,191	$ 9.19	$ 16.11	$ 19,188
91	Apr-21	20,685	4,943	$ 8.61	$ 17.98	$ 266,965
92	Apr-21	-	5,081	$ 8.61	$ 14.40	$ 73,186
93	May-21	13,708	(10,712)	$ 5.60	$ 11.71	$ (48,637)
94	May-21	-	2,499	$ 5.60	$ 6.55	$ 16,371
95	Jun-21	18,798	(20,194)	$ 5.04	$ 10.52	$ (117,629)
96	Jun-21	-	(5,977)	$ 5.04	$ 1.68	$ (10,014)
97	Jul-21	23,653	(2,140)	$ 10.27	$ 21.45	$ 197,014
98	Jul-21	-	13,237	$ 10.27	$ 15.31	$ 202,651
99	Aug-21	20,957	(1,068)	$ 12.10	$ 25.24	$ 226,622
100	Aug-21	-	9,991	$ 12.10	$ 20.21	$ 201,931
101	Sep-21	17,216	(3,602)	$ 11.91	$ 24.86	$ 115,498
102	Sep-21	-	3,225	$ 11.91	$ 19.98	$ 64,410
103	**Total**					**$ 2,846,527**

Cost of Service Analysis
Allocation of Costs
Test Period October 2019 - September 2021
($ 000)

	B		C		D
4	**Costs ($000)**		**2020**		**2021**
5	**FBS...**	$	1,815,762	$	1,876,021
6	**New Resources....................................**	$	55,019	$	53,661
7	**Residential Exchange..........................**	$	3,358,037	$	3,356,215
8	**Conservation.......................................**	$	195,331	$	201,147
9	**BPAPrograms.....................................**	$	140,256	$	123,592
10	**Transmission.......................................**	$	221,643	$	217,308
11	**Irrigation/Low Density Discounts......**	$	59,410	$	60,011
12	Total...	$	5,845,459	$	5,887,955
13					
14	**Cost Allocation**				
15					
16	**FBS...**	$	1,815,762	$	1,876,021
17					
18	**Federal Base System Allocators..........**		**2020**		**2021**
19	Priority Firm - 7(b) Loads....................		1.0000		1.0000
20	Industrial Firm - 7(c) Loads.................		0.0000		0.0000
21	New Resources - 7(f) Loads.................		0.0000		0.0000
22	Surplus Firm - SP Loads......................		0.0000		0.0000
23	Total...		1.0000		1.0000
24					
25	**FBS Cost Allocation...........................**		**2020**		**2021**
26	Priority Firm - 7(b) Loads....................	$	1,815,762	$	1,876,021
27	Industrial Firm - 7(c) Loads.................	$	-	$	-
28	New Resources - 7(f) Loads.................	$	-	$	-
29	Surplus Firm - SP Loads......................	$	-	$	-
30	Total...	$	1,815,762	$	1,876,021
31					
32					
33	**Irrigation/Low Density Discounts......**	$	59,410	$	60,011
34					
35	**Irrigation/LDD Allocators.................**		**2020**		**2021**
36	Priority Firm - 7(b) Loads....................		1.0000		1.0000
37	Industrial Firm - 7(c) Loads.................		0.0000		0.0000
38	New Resources - 7(f) Loads.................		0.0000		0.0000
39	Surplus Firm - SP Loads......................		0.0000		0.0000
40	Total...		1.0000		1.0000
41					
42	**Irrigation/LDD Cost Allocation..........**		**2020**		**2021**
43	Priority Firm - 7(b) Loads....................	$	59,410	$	60,011
44	Industrial Firm - 7(c) Loads.................	$	-	$	-
45	New Resources - 7(f) Loads.................	$	-	$	-
46	Surplus Firm - SP Loads......................	$	-	$	-
47	Total...	$	59,410	$	60,011

Cost of Service Analysis
Allocation of Costs
Test Period October 2019 - September 2021
($ 000)

	B		C		D
4	**Costs ($000)**		**2020**		**2021**
5	**FBS..**	$	1,815,762	$	1,876,021
6	**New Resources......................................**	$	55,019	$	53,661
7	**Residential Exchange............................**	$	3,358,037	$	3,356,215
8	**Conservation...**	$	195,331	$	201,147
9	**BPAPrograms.......................................**	$	140,256	$	123,592
10	**Transmission...**	$	221,643	$	217,308
11	**Irrigation/Low Density Discounts........**	$	59,410	$	60,011
12	Total..	$	5,845,459	$	5,887,955
13					
14	**Cost Allocation (continued)**				
15					
16	**New Resources......................................**	$	55,019	$	53,661
17					
18	**New Resources Allocators**		**2020**		**2021**
19	Priority Firm - 7(b) Loads.....................		0.0000		0.0000
20	Industrial Firm - 7(c) Loads...................		0.0307		0.0571
21	New Resources - 7(f) Loads..................		0.00000287		0.00000534
22	Surplus Firm - SP Loads........................		0.9693		0.9429
23	Total..		1.0000		1.0000
24					
25	**New Resources Cost Allocation...........**		**2020**		**2021**
26	Priority Firm - 7(b) Loads.....................	$	-	$	-
27	Industrial Firm - 7(c) Loads...................	$	1,688	$	3,065
28	New Resources - 7(f) Loads..................	$	0.1578	$	0.2864
29	Surplus Firm - SP Loads........................	$	53,331	$	50,596
30	Total..	$	55,019	$	53,661
31					
32					
33	**Residential Exchange............................**	$	3,358,037	$	3,356,215
34	Costs Functionalized to Transmission....	$	(235,141)	$	(234,989)
35	Costs Functionalized to Generation........	$	3,122,896	$	3,121,225
36					
37	**Residential Exchange Allocators**		**2020**		**2021**
38	Priority Firm - 7(b) Loads.....................		0.9424		0.9758
39	Industrial Firm - 7(c) Loads...................		0.0018		0.0014
40	New Resources - 7(f) Loads..................		0.00000017		0.00000013
41	Surplus Firm - SP Loads........................		0.0558		0.0228
42	Total..		1.0000		1.0000
43					
44	**Residential Exchange Cost Allocation**		**2020**		**2021**
45	Priority Firm - 7(b) Loads.....................	$	2,943,030	$	3,045,618
46	Industrial Firm - 7(c) Loads...................	$	5,518	$	4,318
47	New Resources - 7(f) Loads..................	$	0.516	$	0.404
48	Surplus Firm - SP Loads........................	$	174,348	$	71,289
49	Total..	$	3,122,896	$	3,121,225

Cost of Service Analysis
Allocation of Costs
Test Period October 2019 - September 2021
($ 000)

	B		C		D
4	**Costs ($000)**		**2020**		**2021**
5	**FBS...**	$	1,815,762	$	1,876,021
6	**New Resources.................................**	$	55,019	$	53,661
7	**Residential Exchange......................**	$	3,358,037	$	3,356,215
8	**Conservation....................................**	$	195,331	$	201,147
9	**BPAPrograms..................................**	$	140,256	$	123,592
10	**Transmission....................................**	$	221,643	$	217,308
11	**Irrigation/Low Density Discounts..**	$	59,410	$	60,011
12	Total...	$	5,845,459	$	5,887,955
13					
14	**Cost Allocation (continued)**				
15					
16	**Conservation....................................**	$	195,331	$	201,147
17					
18	**BPAPrograms..................................**	$	140,256	$	123,592
19					
20	**Transmission....................................**	$	221,643	$	217,308
21					
22					
23	**Conservation & General Allocators**		**2020**		**2021**
24	Priority Firm - 7(b) Loads................		0.9685		0.9829
25	Industrial Firm - 7(c) Loads.............		0.0010		0.0010
26	New Resources - 7(f) Loads.............		0.0000		0.0000
27	Surplus Firm - SP Loads..................		0.0306		0.0161
28	Total...		1.0000		1.0000
29					
30	**Conservation Cost Allocation.........**		**2020**		**2021**
31	Priority Firm - 7(b) Loads................	$	189,170	$	197,706
32	Industrial Firm - 7(c) Loads.............	$	189	$	196
33	New Resources - 7(f) Loads.............	$	0	$	0
34	Surplus Firm - SP Loads..................	$	5,972	$	3,244
35	Total...	$	195,331	$	201,147
36					
37	**BPA Programs Cost Allocation......**		**2020**		**2021**
38	Priority Firm - 7(b) Loads................	$	135,832	$	121,478
39	Industrial Firm - 7(c) Loads.............	$	136	$	121
40	New Resources - 7(f) Loads.............	$	0	$	0
41	Surplus Firm - SP Loads..................	$	4,288	$	1,993
42	Total...	$	140,256	$	123,592
43					
44	**Transmission Cost Allocation.........**		**2020**		**2021**
45	Priority Firm - 7(b) Loads................	$	214,652	$	213,591
46	Industrial Firm - 7(c) Loads.............	$	214	$	212
47	New Resources - 7(f) Loads.............	$	0	$	0
48	Surplus Firm - SP Loads..................	$	6,777	$	3,505
49	Total...	$	221,643	$	217,308

Cost of Service Analysis
Allocation of Costs Summary
Test Period October 2019 - September 2021
($ 000)

	B		C		D
4	**Costs ($000)**		**2020**		**2021**
5	**FBS..**	$	1,815,762	$	1,876,021
6	**New Resources.....................................**	$	55,019	$	53,661
7	**Residential Exchange...........................**	$	3,358,037	$	3,356,215
8	**Conservation..**	$	195,331	$	201,147
9	**BPAPrograms.......................................**	$	140,256	$	123,592
10	**Transmission..**	$	221,643	$	217,308
11	**Irrigation/Low Density Discounts.......**	$	59,410	$	60,011
12	Total..	$	5,845,459	$	5,887,955
13					
14	**Cost Allocation (continued)**				
15					
16					
17	**Initial Cost Allocation (Costs /$1000)**		**2020**		**2021**
18	Priority Firm - 7(b) Loads.....................	$	5,357,856	$	5,514,425
19	Industrial Firm - 7(c) Loads..................	$	7,745	$	7,912
20	New Resources - 7(f) Loads..................	$	0.72	$	0.74
21	Surplus Firm - SP Loads.......................	$	244,716	$	130,627
22	Total Costs Functionalized to Power.....	$	5,610,318	$	5,652,965
23					
24					
25					
26	REP Cost Functionalized to Transmissio	$	235,141	$	234,989
27					
28	Total COSA Revenue Requirement	$	5,845,459	$	5,887,955

Cost of Service Analysis
General Revenue Credits
Test Period October 2019 - September 2021
($ 000)

	B	C	D
5	**General Revenue Credits ($000))**	**2020**	**2021**
6			
7	**FBS**	**$ (110,777)**	**$ (111,492)**
8	Hydro and Renewable	$ (23,964)	$ (23,964)
9	Downstream Benefits and Pumping Power	$ (19,364)	$ (19,364)
10	Colville and Spokane Settlements	$ (4,600)	$ (4,600)
11	Green Tags (FBS resources)	$ -	$ -
12	Fish and Wildlife	$ (86,250)	$ (86,852)
13	4(h)(10)(c)	$ (86,250)	$ (86,852)
14	Tier 2 Adjustment	$ (563)	$ (676)
15	**Contract Obligations**	**$ (353)**	**$ (347)**
16	Pre-sub/Hungry Horse	$ -	$ -
17	Other Locational/Seasonal Exchange	$ -	$ -
18	Upper Baker	$ (353)	$ (347)
19	**New Resources**	**$ -**	**$ -**
20	Green Tags (New resources)	$ -	$ -
21	**Conservation**	**$ (8,000)**	**$ (8,000)**
22	Energy Efficiency Revenues	$ (8,000)	$ (8,000)
23	**BPAPrograms**	**$ -**	**$ -**
24	**Transmission**	**$ (12,362)**	**$ (12,397)**
25	Miscellaneous Credits (incl. GTA)	$ (12,362)	$ (12,397)
26			
27	**Other Revenue Credits ($ 000))**	**2020**	**2021**
28	Secondary Revenue	**$ (367,691)**	**$ (335,677)**
29	Incl. Slice	$ (367,691)	$ (335,677)
30	Generation Inputs Revenue	**$ (119,815)**	**$ (119,815)**
31	Composite Non-Federal RSS Revenue Debit/(Credit)	**$ (1,008)**	**$ (1,084)**
32	Non-Slice Non-Federal RSC Revenue Debit/(Credit)	**$ 43**	**$ 34**
33	NR Revenues from ESS energy and capacity charges	**$ -**	**$ -**
34	PF Load Forecast Deviation Liquidated Damages	$ (9,499)	$ (9,458)
35	**Firm Surplus and from Other Long-term Sales**	**$ (52,743)**	**$ (41,686)**
36	Other Surplus Sales (Non-Slice)	$ -	$ -
37	Firm Surplus Secondary Sales	$ (52,743)	$ (41,686)
38			
39	**Total Revenue Credits**	$ (682,205)	$ (639,922)

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2019 - September 2021
($ 000)

	B		C		D
4	**Allocation of Revenue Requirement**		**2020**		**2021**
5	Priority Firm - 7(b) Loads......................................	$	5,357,856	$	5,514,425
6	Industrial Firm - 7(c) Loads....................................	$	7,745	$	7,912
7	New Resources - 7(f) Loads....................................	$	1	$	1
8	Surplus Firm - SP Loads...	$	244,716	$	130,627
9	Total..	$	5,610,318	$	5,652,965
10					
11	**General Revenue Credits ($000))**		**2020**		**2021**
12					
13	**FBS...**	**$**	**(111,130)**	**$**	**(111,839)**
14	Hydro and Renewable.......................................	$	(23,964)	$	(23,964)
15	Downstream Benefits and Pumping Power..	$	(19,364)	$	(19,364)
16	Colville and Spokane Settlements................	$	(4,600)	$	(4,600)
17	Green Tags (FBS resources)........................	$	-	$	-
18	Fish and Wildlife..	$	(86,250)	$	(86,852)
19	4(h)(10)(c)...	$	(86,250)	$	(86,852)
20	Tier 2 Adjustment...	$	(563)	$	(676)
21	Contract Obligations...	$	(353)	$	(347)
22	Pre-sub/Hungry Horse.................................	$	-	$	-
23	Other Locational/Seasonal Exchange..........	$	-	$	-
24	Upper Baker...	$	(353)	$	(347)
25					
26	**Federal Base System Allocators**		**2020**		**2021**
27	Priority Firm - 7(b) Loads......................................		1.0000		1.0000
28	Industrial Firm - 7(c) Loads....................................		0.0000		0.0000
29	New Resources - 7(f) Loads....................................		0.0000		0.0000
30	Surplus Firm - SP Loads...		0.0000		0.0000
31	Total..		1.0000		1.0000
32					
33	**FBS Credit Allocation**		**2020**		**2021**
34	Priority Firm - 7(b) Loads......................................	$	(111,130)	$	(111,839)
35	Industrial Firm - 7(c) Loads....................................	$	-	$	-
36	New Resources - 7(f) Loads....................................	$	-	$	-
37	Surplus Firm - SP Loads...	$	-	$	-
38	Total..	$	(111,130)	$	(111,839)
39					
40	**Allocation of Revenue Requirement**		**2020**		**2021**
41	Priority Firm - 7(b) Loads......................................	$	5,246,726	$	5,402,586
42	Industrial Firm - 7(c) Loads....................................	$	7,745	$	7,912
43	New Resources - 7(f) Loads....................................	$	1	$	1
44	Surplus Firm - SP Loads...	$	244,716	$	130,627
45	Total..	$	5,499,189	$	5,541,126

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2019 - September 2021
($ 000)

	B	C		D	
40	**Allocation of Revenue Requirement**		**2020**		**2021**
41	Priority Firm - 7(b) Loads.......................................	$	5,246,726	$	5,402,586
42	Industrial Firm - 7(c) Loads....................................	$	7,745	$	7,912
43	New Resources - 7(f) Loads....................................	$	1	$	1
44	Surplus Firm - SP Loads...	$	244,716	$	130,627
45	Total...	$	5,499,189	$	5,541,126
46					
47					
48	**General Revenue Credits (/$1000))**		**2020**		**2021**
49					
50	**Transmission..**	**$**	**(12,362)**	**$**	**(12,397)**
51	Miscellaneous Credits (incl. GTA)....................	$	(12,362)	$	(12,397)
52					
53	**Conservation & General Cost Allocators**		**2020**		**2021**
54	Priority Firm - 7(b) Loads.......................................		0.9685		0.9829
55	Industrial Firm - 7(c) Loads....................................		0.0010		0.0010
56	New Resources - 7(f) Loads....................................		0.0000		0.0000
57	Surplus Firm - SP Loads...		0.0306		0.0161
58	Total...		1.0000		1.0000
59					
60	**Transmission Allocation**		**2020**		**2021**
61	Priority Firm - 7(b) Loads.......................................	$	(11,972)	$	(12,185)
62	Industrial Firm - 7(c) Loads....................................	$	(12)	$	(12)
63	New Resources - 7(f) Loads....................................	$	(0)	$	(0)
64	Surplus Firm - SP Loads...	$	(378)	$	(200)
65	Total...	$	(12,362)	$	(12,397)
66					
67	**Allocation of Revenue Requirement**		**2020**		**2021**
68	Priority Firm - 7(b) Loads.......................................	$	5,234,754	$	5,390,401
69	Industrial Firm - 7(c) Loads....................................	$	7,733	$	7,900
70	New Resources - 7(f) Loads....................................	$	1	$	1
71	Surplus Firm - SP Loads...	$	244,338	$	130,428
72	Total...	$	5,486,826	$	5,528,729

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2019 - September 2021
($ 000)

	B	C		D	
4	**Allocation of Revenue Requirement**		**2020**		**2021**
5	Priority Firm - 7(b) Loads................................	$	5,234,754	$	5,390,401
6	Industrial Firm - 7(c) Loads.............................	$	7,733	$	7,900
7	New Resources - 7(f) Loads............................	$	1	$	1
8	Surplus Firm - SP Loads.................................	$	244,338	$	130,428
9	Total..	$	5,486,826	$	5,528,729
10					
11					
12	**General Revenue Credits ($000))**		**2020**		**2021**
13					
14	**New Resources...**	**$**	**-**	**$**	**-**
15	Green Tags (New resources)......................	$	-	$	-
16					
17					
18	**New Resources Cost Allocators**		**2020**		**2021**
19	Priority Firm - 7(b) Loads................................		0.0000		0.0000
20	Industrial Firm - 7(c) Loads.............................		0.0307		0.0571
21	New Resources - 7(f) Loads............................		0.000003		0.000005
22	Surplus Firm - SP Loads.................................		0.9693		0.9429
23	Total..		1.0000		1.0000
24					
25	**New Resources Allocation**		**2020**		**2021**
26	Priority Firm - 7(b) Loads................................	$	-	$	-
27	Industrial Firm - 7(c) Loads.............................	$	-	$	-
28	New Resources - 7(f) Loads............................	$	-	$	-
29	Surplus Firm - SP Loads.................................	$	-	$	-
30	Total..	$	-	$	-
31					
32	**Allocation of Revenue Requirement**		**2020**		**2021**
33	Priority Firm - 7(b) Loads................................	$	5,234,754	$	5,390,401
34	Industrial Firm - 7(c) Loads.............................	$	7,733	$	7,900
35	New Resources - 7(f) Loads............................	$	0.723	$	0.738
36	Surplus Firm - SP Loads.................................	$	244,338	$	130,428
37	Total..	$	5,486,826	$	5,528,729
38					

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2019 - September 2021
($ 000)

	B		C		D
32	**Allocation of Revenue Requirement**		**2020**		**2021**
33	Priority Firm - 7(b) Loads................................	$	5,234,754	$	5,390,401
34	Industrial Firm - 7(c) Loads.............................	$	7,733	$	7,900
35	New Resources - 7(f) Loads............................	$	0.723	$	0.738
36	Surplus Firm - SP Loads..................................	$	244,338	$	130,428
37	Total..	$	5,486,826	$	5,528,729
39					
40	**General Revenue Credits (/$1000))**		**2020**		**2021**
41					
42	**Conservation...**	**$**	**(8,000)**	**$**	**(8,000)**
43	Energy Efficiency Revenues......................	$	(8,000)	$	(8,000)
44					
45	**Conservation & General Cost Allocators**		**2020**		**2021**
46	Priority Firm - 7(b) Loads................................		0.9685		0.9829
47	Industrial Firm - 7(c) Loads.............................		0.0010		0.0010
48	New Resources - 7(f) Loads............................		0.0000001		0.0000001
49	Surplus Firm - SP Loads..................................		0.0306		0.0161
50	Total..		1.0000		1.0000
51					
52	**Conservation Allocation**		**2020**		**2021**
53	Priority Firm - 7(b) Loads................................	$	(7,748)	$	(7,863)
54	Industrial Firm - 7(c) Loads.............................	$	(8)	$	(8)
55	New Resources - 7(f) Loads............................	$	(0.001)	$	(0.001)
56	Surplus Firm - SP Loads..................................	$	(245)	$	(129)
57	Total..	$	(8,000)	$	(8,000)
58					
59	**Allocation of Revenue Requirement**		**2020**		**2021**
60	Priority Firm - 7(b) Loads................................	$	5,227,006	$	5,382,538
61	Industrial Firm - 7(c) Loads.............................	$	7,725	$	7,892
62	New Resources - 7(f) Loads............................	$	0.722	$	0.738
63	Surplus Firm - SP Loads..................................	$	244,094	$	130,299
64	Total..	$	5,478,826	$	5,520,729

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2019 - September 2021
($ 000)

	B		C		D
4	**Allocation of Revenue Requirement**		**2020**		**2021**
5	Priority Firm - 7(b) Loads..	$	5,227,006	$	5,382,538
6	Industrial Firm - 7(c) Loads..	$	7,725	$	7,892
7	New Resources - 7(f) Loads..	$	0.7223	$	0.7376
8	Surplus Firm - SP Loads..	$	244,094	$	130,299
9	Total...	$	5,478,826	$	5,520,729
10					
11	**General Revenue Credits (/$1000))**		**2020**		**2021**
12					
13	**Generation Inputs Revenue...**	**$**	**(119,815)**	**$**	**(119,815)**
14					
15	**NR Revenues from ESS energy and capacity charges....................**	**$**	**-**	**$**	**-**
16					
17	**PF Load Forecast Deviation Liquidated Damages..........................**	**$**	**(9,499)**	**$**	**(9,458)**
19					
20	**Conservation & General Cost Allocators**		**2020**		**2021**
21	Priority Firm - 7(b) Loads..		0.9685		0.9829
22	Industrial Firm - 7(c) Loads..		0.0010		0.0010
23	New Resources - 7(f) Loads..		0.0000001		0.0000001
24	Surplus Firm - SP Loads..		0.0306		0.0161
25	Total...		1.0000		1.0000
26					
27	**Gen Inputs & Wind Integration Credit Allocation**		**2020**		**2021**
28	Priority Firm - 7(b) Loads..	$	(125,235)	$	(127,062)
29	Industrial Firm - 7(c) Loads..	$	(125)	$	(126)
30	New Resources - 7(f) Loads..	$	(0)	$	(0)
31	Surplus Firm - SP Loads..	$	(3,954)	$	(2,085)
32	Total...	$	(129,314)	$	(129,273)
33					
34	**Allocation of Revenue Requirement**		**2020**		**2021**
35	Priority Firm - 7(b) Loads..	$	5,101,772	$	5,255,476
36	Industrial Firm - 7(c) Loads..	$	7,600	$	7,766
37	New Resources - 7(f) Loads..	$	0.7106	$	0.7258
38	Surplus Firm - SP Loads..	$	240,140	$	128,213
39	Total...	$	5,349,513	$	5,391,456
40					

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2019 - September 2021
($ 000)

	B	C		D	
34	**Allocation of Revenue Requirement**		**2020**		**2021**
35	Priority Firm - 7(b) Loads..	$	5,101,772	$	5,255,476
36	Industrial Firm - 7(c) Loads...	$	7,600	$	7,766
37	New Resources - 7(f) Loads..	$	0.7106	$	0.7258
38	Surplus Firm - SP Loads..	$	240,140	$	128,213
39	Total...	$	5,349,513	$	5,391,456
41					
42	**Other Revenue Credits**		**2020**		**2021**
43	Composite Non-Federal RSS Revenue Debit/(Credit)...................	$	(1,008)	$	(1,084)
44	Non-Slice Non-Federal RSC Revenue Debit/(Credit).....................	$	43	$	34
45					
46					
47	**Conservation & General Cost Allocators**		**2020**		**2021**
48	Priority Firm - 7(b) Loads..		0.9685		0.9829
49	Industrial Firm - 7(c) Loads...		0.0010		0.0010
50	New Resources - 7(f) Loads..		0.0000001		0.0000001
51	Surplus Firm - SP Loads..		0.0306		0.0161
52	Total...		1.0000		1.0000
53					
54	**Non-Federal RSS Revenues**		**2020**		**2021**
55	Priority Firm - 7(b) Loads..	$	(935)	$	(1,032)
56	Industrial Firm - 7(c) Loads...	$	(1)	$	(1)
57	New Resources - 7(f) Loads..	$	(0.0001)	$	(0.0001)
58	Surplus Firm - SP Loads..	$	(30)	$	(17)
59	Total...	$	(966)	$	(1,050)
60					
61	**Allocation of Revenue Requirement**		**2020**		**2021**
62	Priority Firm - 7(b) Loads..	$	5,100,836	$	5,254,444
63	Industrial Firm - 7(c) Loads...	$	7,599	$	7,765
64	New Resources - 7(f) Loads..	$	0.7105	$	0.7257
65	Surplus Firm - SP Loads..	$	240,110	$	128,197
66	Total...	$	5,348,547	$	5,390,406

Table 2.3.8

Cost of Service Analysis
Calculation and Allocation of Secondary Revenue Credit
Test Period October 2019 - September 2021
(aMW, $ 000)

	C	D	E
4	**General Revenue Credits ($000))**	**2020**	**2021**
9			
10	BPA Secondary Sales Post-Slice (aMW)	1849	1803
11			
12	Slice Percentage	22.3627%	22.3627%
13			
14	Secondary Sales Pre-Slice, aMW	2382	2322
15			
16	aMW to GWh Multiplier	8.784	8.760
17			
18	Secondary Sales Price (Weighted Average, $/MWh)	$ 14.10	$ 14.01
19			
20	BPA Secondary Sales Post-Slice	$ 228,998	$ 221,267
21	Committed Sales	$ 65,121	$ 42,281
22			
23	Firm Surplus Serving Tier 2	$ 12,018	$ 16,629
24	Firm Surplus Sold @ Forward Market Price	$ 40,725	$ 25,057
25	Total Firm Surplus Secondary Sales	$ 52,743	$ 41,686
26			
27	Slice Secondary Sales ($000)	$ 73,572	$ 72,129
28			
29	BPA Secondary Sales Pre-Slice $000 (incl. CAISO Adjust, excl. Firm Surplus)	$ 367,691	$ 335,677
30			
35			
36	**Federal Base System + NR Cost Allocators**	**2020**	**2021**
37	Priority Firm - 7(b) Loads..	0.9880	0.9884
38	Industrial Firm - 7(c) Loads..	0.0004	0.0007
39	New Resources - 7(f) Loads..	0.0000	0.0000
40	Surplus Firm - SP Loads...	0.0116	0.0110
41	Total...	1.0000	1.0000
42			
43			
44	**Allocation of Secondary Revenues Credit**	**2020**	**2021**
45	Priority Firm - 7(b) Loads..	$ (363,294)	$ (331,769)
46	Industrial Firm - 7(c) Loads..	$ (135)	$ (223)
47	New Resources - 7(f) Loads..	$ (0.0126)	$ (0.0209)
48	Surplus Firm - SP Loads...	$ (4,263)	$ (3,685)
49	Total...	$ (367,691)	$ (335,677)
50			
51	**Allocation of Revenue Requirement**	**2020**	**2021**
52	Priority Firm - 7(b) Loads..	$ 4,737,542	$ 4,922,676
53	Industrial Firm - 7(c) Loads..	$ 7,464	$ 7,542
54	New Resources - 7(f) Loads..	$ 0.6979	$ 0.7049
55	Surplus Firm - SP Loads...	$ 235,848	$ 124,511
56	Total...	$ 4,980,855	$ 5,054,729

Cost of Servise Analysis
Calculation and Allocation of FPS Revenue Deficiency Delta
Test Period October 2019 - September 2021
($ 000)

	B		C		D
5	**Allocation of Revenue Requirement**		2020		2021
6	Priority Firm - 7(b) Loads..	$	4,737,542	$	4,922,676
7	Industrial Firm - 7(c) Loads..	$	7,464	$	7,542
8	New Resources - 7(f) Loads...	$	0.6979	$	0.7049
9	Surplus Firm - SP Loads...	$	235,848	$	124,511
10	Total...	$	4,980,855	$	5,054,729
11					
12	**Firm Surplus and from Other Long-term Sales.............**	**$**	**(52,743)**	**$**	**(41,686)**
13	Other Surplus Sales (Non-Slice).............................	$	-	$	-
14	Firm Surplus Secondary Sales................................	$	(52,743)	$	(41,686)
15					
16	**Calculation of FPS Revenue Deficiency**		2020		2021
17	Surplus Firm - SP Loads...	$	235,848	$	124,511
18					
19	**Deficiency...**	**$**	**183,105**	**$**	**82,826**
20					
21					
22					
23	**Surplus Deficit Cost Allocators**		2020		2021
24	Priority Firm - 7(b) Loads..		0.9990		0.9990
25	Industrial Firm - 7(c) Loads..		0.0010		0.0010
26	New Resources - 7(f) Loads...		0.0000001		0.0000001
27	Surplus Firm - SP Loads...		-1.0000		-1.0000
28	Total...		0.0000		0.0000
29					
30	**Surplus Deficit Cost Allocation**		2020		2021
31	Priority Firm - 7(b) Loads..	$	182,922	$	82,743
32	Industrial Firm - 7(c) Loads..	$	183	$	82
33	New Resources - 7(f) Loads...	$	0.0171	$	0.0077
34	Surplus Firm - SP Loads...	$	(183,105)	$	(82,826)
35	Total...	$	-	$	-
36					
37					
38	**Initial Allocation of Net Revenue Requirement**		2020		2021
39	Priority Firm - 7(b) Loads..	$	4,920,465	$	5,005,419
40	Industrial Firm - 7(c) Loads..	$	7,647	$	7,624
41	New Resources - 7(f) Loads...	$	0.7150	$	0.7126
42	Surplus Firm - SP Loads...	$	52,743	$	41,686
43	Total...	$	4,980,855	$	5,054,729

Cost of Service Analysis
Calculation of Initial Allocation Power Rates
Test Period October 2019 - September 2021
($ 000, aMW, $/MWh)

	B	C		D	
5	**Initial Allocation of Net Revenue Requirement ($000)**		**2020**		**2021**
6	Unbifurcated Priority Firm - 7(b) Loads.......................................	$	4,920,465	$	5,005,419
7	Industrial Firm - 7(c) Loads..	$	7,647	$	7,624
8	New Resources - 7(f) Loads...	$	0.7150	$	0.7126
9	Surplus Firm - SP Loads..	$	52,743	$	41,686
10	Total..	$	4,980,855	$	5,054,729
11					
12					
13	**Energy Billing Determinants (aMW)**		**2020**		**2021**
14					
15	Unbifurcated Priority Firm - 7(b) Loads.......................................		12,011		12,072
16	Industrial Firm - 7(c) Loads..		12		12
17	New Resources - 7(f) Loads...		0.001		0.001
18					
19					
20	**Average Power Rates ($/MWh)**		**2020**		**2021**
21					
22	Unbifurcated Priority Firm - 7(b) Loads.......................................		46.64		47.33
23	Industrial Firm - 7(c) Loads..		72.54		72.53
24	New Resources - 7(f) Loads...		72.54		72.53

Rate Directive Step
Calculation of DSI VOR and Net Industrial Margin
Test Period October 2019 - September 2021

	B	C	D	E	F	G	H	I
5								
6	Operating Reserves - Supplemental							
8			Embedded Cost $/kW/Mo			$ 7.08		
9								
10	1) Assumed DSI sale					12	aMW	
11	Assumed Wheel Turning Load					0	aMW	
12	Interruptible Load					12		
13	percent of DSI sale that is interruptible					10%		
14	MWs of interruptible load					1	MW	
15								
16	Total value of Operating Reserves per year					$ 101,952	per year	
17	Value converted to $/MWh on total load					$ 0.967	$/MWh	
18								
19					industrial margin	0.788		
20								
21					**net industrial margin**	**$ (0.179)**		

Table 2.4.2

Rate Directive Step
Calculation of Annual Energy Rate Scalars for First IP-PF Link Calculation
Test Period October 2019 - September 2021

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	PQ	R	S	T
6	**Load Shaping Rate**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
7	HLH (mills/kWh)		23.84	25.19	28.09	25.24	24.36	19.19	17.98	11.71	10.52	21.45	25.24	24.86				
8	LLH (mills/kWh)		18.88	21.84	23.56	19.21	19.28	16.11	14.40	6.55	1.68	15.31	20.21	19.98				
9	Demand Rate ($/kW/mo)		11.42	12.07	13.45	12.10	11.66	9.19	8.61	5.60	5.04	10.27	12.10	11.91				
10																		
11																		
12	**Unbifurcated PF+NR Load**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2020**	
13	**2020**	HLH	4871	5705	6279	6166	5455	5424	4665	4608	5160	5344	5281	4752			Energy (GWH)	105505
14		LLH	2988	3911	4481	4254	3580	3613	2991	3188	3135	3302	3211	3140			Allocated Cost	**$ 4,923,332**
15		Demand	654	587	955	1069	719	829	765	477	708	843	782	692			Rate Scalar	**25.94**
16	Revenue at marginal Rates		$ 180,004	$ 236,223	$ 294,822	$ 250,314	$ 210,270	$ 169,933	$ 133,524	$ 77,496	$ 63,106	$ 173,818	$ 207,668	$ 189,118		**$ 2,186,297**		
17			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2021**	
18	**2021**	HLH	4915	5659	6414	6109	5367	5535	4589	4702	5141	5338	5307	4770			Energy (GWH)	105753
19		LLH	3011	4008	4399	4376	3558	3542	2962	3162	3129	3365	3235	3161			Allocated Cost	**$ 5,008,206**
20		Demand	662	498	1120	963	631	946	788	492	716	857	796	718			Rate Scalar	**26.62**
21	Revenue at marginal Rates		$ 181,577	$ 236,116	$ 298,891	$ 249,933	$ 206,686	$ 171,994	$ 131,958	$ 78,512	$ 62,927	$ 174,788	$ 208,967	$ 190,289		**$ 2,192,639**		
43																		
50																		
51		**IP Load**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2020**	
52	**2020**	HLH	5	5	5	5	5	5	5	5	5	5	5	5			Energy (GWH)	105
53		LLH	4	4	4	4	4	4	4	4	4	4	4	4			Allocated Cost	**$ 4,781**
54		Demand	0	0	0	0	0	0	0	0	0	0	0	0			Rate Scalar	**26.12**
55	Revenue at marginal Rates		$ 194	$ 205	$ 232	$ 201	$ 185	$ 160	$ 142	$ 84	$ 58	$ 166	$ 206	$ 195		**$ 2,027**		
56			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2021**	
57	**2021**	HLH	5	5	5	5	5	5	5	5	5	5	5	5			Energy (GWH)	105
58		LLH	4	4	4	4	4	4	4	4	4	4	4	4			Allocated Cost	**$ 4,837**
59		Demand	0	0	0	0	0	0	0	0	0	0	0	0			Rate Scalar	**26.80**
60	Revenue at marginal Rates		$ 194	$ 205	$ 232	$ 201	$ 178	$ 159	$ 142	$ 84	$ 58	$ 166	$ 206	$ 195		**$ 2,020**		

Table 2.4.3

Rate Directive Step
Calculation of Monthly Energy Rate Scalars for First IP-PF Link Calculation
Test Period October 2019 - September 2021
($/MWh)

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
5	**Load Shaping Rate**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
6		HLH (mills/kWh)	23.84	25.19	28.09	25.24	24.36	19.19	17.98	11.71	10.52	21.45	25.24	24.86				
7		LLH (mills/kWh)	18.88	21.84	23.56	19.21	19.28	16.11	14.40	6.55	1.68	15.31	20.21	19.98				
8		Demand Rate ($/kW/mo)	11.42	12.07	13.45	12.10	11.66	9.19	8.61	5.60	5.04	10.27	12.10	11.91				
9																		
10																		
11		**Unbifurcated PF/NR**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
12	**2020**	HLH	49.78	51.13	54.03	51.19	50.30	45.14	43.92	37.65	36.46	47.39	51.19	50.80				**2020**
13		LLH	44.82	47.78	49.50	45.15	45.22	42.05	40.34	32.49	27.62	41.25	46.15	45.92				**25.94**
14		Demand	11.42	12.07	13.45	12.10	11.66	9.19	8.61	5.60	5.04	10.27	12.10	11.91				**Scalar**
15			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
16	**2021**	HLH	50.46	51.82	54.72	51.87	50.98	45.82	44.60	38.33	37.14	48.07	51.87	51.48				**2021**
17		LLH	45.50	48.46	50.18	45.83	45.90	42.73	41.02	33.17	28.30	41.93	46.83	46.60				**26.62**
18		Demand	11.42	12.07	13.45	12.10	11.66	9.19	8.61	5.60	5.04	10.27	12.10	11.91				**Scalar**
36																		
42																		
43		**IP**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
44	**2020**	HLH	49.96	51.31	54.21	51.37	50.48	45.32	44.10	37.83	36.64	47.57	51.37	50.98				**2020**
45		LLH	45.00	47.96	49.68	45.33	45.40	42.23	40.52	32.67	27.80	41.43	46.33	46.10				**26.12**
46		Demand	11.42	12.07	13.45	12.10	11.66	9.19	8.61	5.60	5.04	10.27	12.10	11.91				**Scalar**
47			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
48	**2021**	HLH	50.64	52.00	54.90	52.05	51.16	46.00	44.78	38.51	37.32	48.25	52.05	51.66				**2021**
49		LLH	45.68	48.64	50.36	46.01	46.08	42.91	41.20	33.35	28.48	42.11	47.01	46.78				**26.80**
50		Demand	11.42	12.07	13.45	12.10	11.66	9.19	8.61	5.60	5.04	10.27	12.10	11.91				**Scalar**

Table 2.4.4

Rate Directive Step
Calculation of First IP-PF Link Delta
Test Period October 2019 - September 2021
($ 000)

	B	C	D	E	F	G	H
89		**FY 2020**	**FY 2021**	**FY 2022**	**FY 2023**	**FY 2024**	**FY 2025**
90	Average PF Rate	$ 46.64	$ 47.33	$ 49.48	$ 50.52	$ 51.88	$ 53.27
91	Net Industrial Margin	(0.179)	(0.179)	(0.179)	(0.179)	(0.179)	(0.179)
92	Flat DSI Load (GWh)	105	105	105	105	105	105
93	Revenue 1	4,898	4,956	5,197	5,291	5,450	5,580
94							
95	IP Rate	$ 72.54	$ 72.53	$ 76.76	$ 76.99	$ 81.89	$ 81.40
96	Flat DSI Load (GWh)	105	105	105	105	105	105
97	Revenue 2	7,647	7,623	8,092	8,092	8,633	8,556
98							
99	Starting Difference	2,749	2,668	2,895	2,801	3,183	2,976
100							
101	Adjustment (calculated using Goal Seek)	117.17	118.86	313.76	318.45	323.14	323.79
102							
103	Delta	2,866	2,786	3,209	3,119	3,506	3,299

Rate Directive Step
Reallocation of First IP-PF Link Delta and Recalculation of Rates
Test Period October 2019 - September 2021
($ 000, aMW, $/MWh)

	B	C	D
5	**Initial Allocation of Net Revenue Requirement)**	**2020**	**2021**
6	Unbifurcated Priority Firm - 7(b) Loads..............................	$ 4,920,465	$ 5,005,419
7	Industrial Firm - 7(c) Loads...	$ 7,647	$ 7,624
8	New Resources - 7(f) Loads..	$ 0.7150	$ 0.7126
9	Surplus Firm - SP Loads..	$ 52,743	$ 41,686
10	Total...	$ 4,980,855	$ 5,054,729
11			
12			
13	**First IP-PF Link Delta**	**$ 2,866**	**$ 2,786**
14			
15			
16	**7(c)(2) Delta Cost Allocators**	**2020**	**2021**
17	Unbifurcated Priority Firm - 7(b) Loads..............................	0.999999907	0.999999907
18	Industrial Firm - 7(c) Loads...	-1.000000000	-1.000000000
19	New Resources - 7(f) Loads..	0.000000093	0.000000093
20			
21	**7(c)(2) Delta Cost Allocation**	**2020**	**2021**
22	Unbifurcated Priority Firm - 7(b) Loads..............................	$ 2,866	$ 2,786
23	Industrial Firm - 7(c) Loads...	$ (2,866)	$ (2,786)
24	New Resources - 7(f) Loads..	$ 0.000	$ 0.000
25	Total...	$ (0)	$ 0
26			
27	**Cost Allocation After 7c2 Delta ($ 000)**	**2020**	**2021**
28	Unbifurcated Priority Firm - 7(b) Loads..............................	$ 4,923,331	$ 5,008,205
29	Industrial Firm - 7(c) Loads...	$ 4,781	$ 4,837
30	New Resources - 7(f) Loads..	$ 0.715	$ 0.713
31	Surplus Firm - SP Loads..	$ 52,743	$ 41,686
32	Total...	$ 4,980,855	$ 5,054,729
33			
34	**Energy Billing Determinants (aMW)**	**2020**	**2021**
35	Unbifurcated Priority Firm - 7(b) Loads..............................	12,011	12,072
36	Industrial Firm - 7(c) Loads...	12.00136612	11.99863014
37	New Resources - 7(f) Loads..	0.00112204	0.001121461
38			
39			
40	**Average Power Rates ($/MWh)**	**2020**	**2021**
41			
42	Unbifurcated Priority Firm - 7(b) Loads..............................	46.66	47.36
43	Industrial Firm - 7(c) Loads...	45.35	46.02
44	New Resources - 7(f) Loads..	72.57	72.56
45			
46			
47	Base PF Exchange Rate w/o Transmission Adder..............	**47.01**	

Rate Directive Step
Calculation of IP Floor Calculation
Test Period October 2019 - September 2021

	B	C	D	E	F	G	H	I	J
10		Industrial Firm Power Floor Rate Calculation							
11				**A**	**B**	**C**	**D**	**E**	**F**
12									
13				**DEMAND**		**ENERGY**		**Customer**	**Total/**
14				**Winter**	**Summer**	**Winter**	**Summer**	**Charge**	**Average**
15				(Dec-Apr)	(May-Nov)	(Sep-Mar)	(Apr-Aug)		
16									
17	1	IP Billing Determinants[1]		118	167	122	88	285	211
18	2	IP-83 Rates		4.62	2.21	14.70	12.20	7.34	
19	3	Revenue		546	368	1,799	1,075	2,091	5,880
20	4	Exchange Adj Clause for OY 1985							
21	5	New ASC Effective Jul 1, 1984							
22	6	Actual Total Exchange Cost (AEC)		938,442					
23	7	Actual Exchange Revenue (AER)		772,029					
24	8	Forecasted Exchange Cost (FEC)		1,088,690					
25	9	Forecasted Exchange Revenue (FER)		809,201					
26	10	Total Under/Over-recovery (TAR)							
27	11	(TAR=(AEC-AER)-(FEC-FER))		(113,076)					
28	12	Exchange Cost Percentage for IP (ECP)		0.521					
29	13	Rebate or Surcharge for IP (CCEA=TAR*ECP)		(58,913)					
30	14	OY 1985 IP Billing Determinants[2]		24,368					
31	15	OY 1985 DSI Transmission Costs[3]		92,960					
32	16	Adjustment for Transmission Costs[4]		(3.81)					
33	17	Adjustment for the Exchange (mills/kWh)[5]		(2.42)					
34	18	Adjustment for the Deferral (mills/kWh)[6]		(0.90)					
35	19	IP-83 Average Rate (mills/kWh)[7]		27.93					
36	20	Floor Rate (mills/kWh)[8]		20.80					
37									
38		Note 1 - Demand billing determinants are the test period DSI load expressed in noncoincidental demand MWs.							
39		Note 2 - Billing determinants as forecast in the 1983 Rate Case Final Proposal (WP-83-FS-BPA-07, p. 82).							
40		Note 3 - Transmission Costs as forecast in the 1983 Rate Case Final Proposal (WP-83-FS-BPA-07, p. 80).							
41		Note 4 - Line 15 / Line 14							
42		Note 5 - Rebate or Surcharge for IP divided by OY 1985 IP Billing Determinants							
43		Note 6 - 1985 Final Rate Proposal (WP-85-FS-BPA-08A, p. 15).							
44		Note 7 - Total Revenue Col F, divided by IP Billing Determinants, Col F							
45		Note 8 - IP-83 Avg Rate adjusted for the effects of the Exchange and Deferral, Lines 16 + 17 + 18 + 19							

Rate Directive Step
IP Floor Rate Test
Test Period October 2019 - September 2021

	B	C	D	E	F	G	H	I
8								
9								
10								
11		Industrial Firm Power Floor Rate Test						
12						**A**	**B**	**C**
13								
14								
15						**Total**		**Average**
16						**Energy**	**TOTALS**	**Rate**
17								
18								
19	1	IP Billing Determinants				211		
20	2	Floor Rate (mills/kWh)				20.80		
21	3	Value of Reserves Credit (mills/kWh)						
22	4	Revenue at Floor Rate Less VOR Credit				4,379	4,379	20.80
23	5	IP Revenue Under Proposed Rates					9,618	45.69
24	6	Difference[1]					0	
25								
26		Note 1 - Difference is Line 4 - Line 5. If difference is negative, Floor Rate does not trigger and difference is set to zero.						
27								

Rate Directive Step
Calculation of IOU and COU Base PF Exchange Rates
Test Period October 2019 - September 2021

	B	C	D	E	F
9		**Cost Allocation After 7c2 Delta**	**2020**	**2021**	Total
10		Unbifurcated Priority Firm - 7(b) Loads.............................	$ 4,923,331	$ 5,008,205	$ 9,931,537
11					
12		Exchange Unbifurcated Costs to 7(b) Loads......................	$ 2,181,455	$ 2,212,424	$ 4,393,879
13					
14					
15					
16					
17		**Energy Billing Determinants (aMW)**	**2020**	**2021**	
18		Unbifurcated Priority Firm - 7(b) Loads.............................	5,322	5,333	
19					
20					
21		**Average Power Rates**	**2020**	**2021**	
22					
23		Unbifurcated Priority Firm - 7(b) Loads.............................	46.66	47.36	
24					
25					
26			(GWh)		
27		Two Year PF Public Load T1	116761		
28		Two Year PF Public Load T2	1032		
29		Two Year IOU PF Exchange Load	81215		
30		Two Year COU PF Exchange Load	12250		
31		Total Two-Year Unbifurcated PF Load	211258		
32					
33					
34		T 2 Costs	$ 29,872		
35		T 1 Costs	$ 9,901,665		
36		Total	$ 9,931,537		
37					
45		Total PF Costs Minus PF T2 Costs	$ 9,901,665		
46		Total PF Load Minus PF T2 Load	210,226		
47		COU Base PF w/o Transmission	47.10		
48		Exchange Transmission Adder	5.03		
49		**COU Base PFx**	**52.13**		
50					
51					
52		Two Year COU PF Exchange Load	12250		
53		Two Year Base PF Public Exchange T2 Revenue	$ 576,991		
54					
55		Total Exchange Costs minus COU Exchange Costs	$ 3,816,888		
56		Total IOU Exchange Loads	81,215		
57		IOU Base PF w/o Transmission	47.00		
58		Exchange Transmission Adder	5.03		
59		**IOU Base PFx**	**52.03**		
60					

Table 2.4.9

Rate Directive Step
Calculation of IOU REP Benefits in Rates
Test Period October 2019 - September 2021

	B	C		D	
8					
9	EOFY 2011 Lookback Amount		($510,030)		
10					
11	Mortgage Payment Variables				
12	PMT Interest Rate		0.0425		
13	Number of Periods		8		
14					
15	Annual Lookback Mortgage Payment		$76,538		
16					
17					
18	IOU Scheduled Amount		$245,200		
19	Refund Amount*		$0		
20	REP Recovery Amount		$245,200		
21					
26					
27					
28			**2020**		**2021**
29			($000)		($000)
30	IOU Unconstrained Benefits	$	907,544	$	907,544
31	REP Recovery Amount	**$**	**245,200**	**$**	**245,200**
32	Rate Protection Delta	$	662,344	$	662,344
33					
34	**Refund of Initial EOFY2011 Lookback Completed by end of FY 2019*				

Table 2.4.10

Rate Directive Step
Calculation of REP Base Exchange Benefits
Test Period October 2019 - September 2021

	B	C	D	E	F	G	H	I	J	K		L	
5	**IOU Base PFx**	**52.03**											
6	**COU Base PFx**	**52.13**		**ASCs**			**Exchange Loads**			**Unconstrained Benefits**			
7										(load * (ASC - Base PFx)			
8				**2020**	**2021**		**2020**	**2021**		**2020**		**2021**	
9													
10													
11	Avista Corporation	1		67.60	67.60		3,936	3,936		$	61,288	$	61,288
12	Idaho Power Company	1		64.41	64.41		6,760	6,760		$	83,708	$	83,708
13	NorthWestern Energy,	1		82.91	82.91		702	702		$	21,685	$	21,685
14	PacifiCorp	1		79.43	79.43		9,172	9,172		$	251,336	$	251,336
15	Portland General Elect	1		77.53	77.53		8,168	8,168		$	208,308	$	208,308
16	Puget Sound Energy, Ir	1		75.72	75.72		11,869	11,869		$	281,219	$	281,219
17	Clark Public Utilities	1		55.17	55.17		2,541	2,543		$	7,723	$	7,731
18	Franklin	0		0.00	0.00		0	0		$	-	$	-
19	Snohomish PUD	1		54.68	54.68		3,600	3,567		$	9,179	$	9,095
31	Total									**$**	**924,445**	**$**	**924,370**
32													
33									IOU	**$**	**907,544**	**$**	**907,544**

Table 2.4.11

Rate Directive Step
Calculation of Utility Specific PF Exchange Rates and REP Benefits
Test Period October 2019 - September 2021

	B	D	E	F	G	H	I	J	K	L	M	N	O	P
4	**Initial Allocations**			**FY 2020**	**FY 2021**	**Average**				**Interim**	**Refund**	**Interim**	**Interim**	**Interim**
5			**Base**	**Exchange**	**Exchange**	**Exchange**	**Unconstrained**	**Scheduled**	**Refund**	**Protection**	**Cost**	**7(b)(3)**	**Utility**	**REP**
6		**ASC**	**PFx**	**Load**	**Load**	**Load**	**Benefits**	**Amount**	**Amount**	**Allocation**	**Allocation**	**Surcharge**	**PFx**	**Benefits**
7		a	b	c	d	e=avg(c,d)	f=(a-b)*e	g=contract	h=contract	Σi=Σf - Σh	Σj=h	k=(i+j)/e	l=b+k	m=(a-l)*e
8	Avista Corporation	67.6	52.03	3,936	3,936	3,936	$ 61,288			$ 44,729	$ -	11.37	63.39	$ 16,559
9	Idaho Power Company	64.41	52.03	6,760	6,760	6,760	$ 83,708			$ 61,092	$ -	9.04	61.06	$ 22,616
10	NorthWestern Energy, LLC	82.91	52.03	702	702	702	$ 21,685			$ 15,826	$ -	22.54	74.57	$ 5,859
11	PacifiCorp	79.43	52.03	9,172	9,172	9,172	$ 251,336			$ 183,430	$ -	20.00	72.03	$ 67,906
12	Portland General Electric Company	77.53	52.03	8,168	8,168	8,168	$ 208,308			$ 152,027	$ -	18.61	70.64	$ 56,281
13	Puget Sound Energy, Inc.	75.72	52.03	11,869	11,869	11,869	$ 281,219			$ 205,239	$ -	17.29	69.32	$ 75,980
14	Clark Public Utilities	55.17	52.13	2,541	2,543	2,542	$ 7,727			$ 5,639		2.22	54.35	$ 2,088
15	Franklin	0	0.00	0	0	0	$ -			$ -		0.00	0.00	$ -
16	Snohomish PUD	54.68	52.13	3,600	3,567	3,583	$ 9,137			$ 6,668		1.86	53.99	$ 2,469
17	Total						$ 924,408	$245,200	$0	$ 674,651	$0			$ 249,756
18														
19	rounding to	places =	$454			IOU Σ(g)	$ 907,544	$245,200	$245,200	$ 662,344	IOU Σ(j)		IOU REP	$ 245,200
20						COU Σ(g)	$ 16,864		$4,556	$ 12,308	COU Σ(j)		COU REP	$ 4,556
21														
22	**IOU Reallocations**													
23		**Interim**				**Final**	**Final**	**Final**		**Final**			**FY 2020**	**FY 2021**
24		**REP**	**Annual**	**Reallocation**	**Reallocated**	**Protection**	**7(b)(3)**	**Utility**		**REP**			**REP**	**REP**
25		**Benefits**	**Adjustment**	**Adjustment**	**Benefits**	**Allocation**	**Surcharge**	**PFx**		**Benefits**			**Benefits**	**Benefits**
26		n=m	o=contract	p=below	q=n-o+p	r=f-q	s=r/e	t=b+s		u=(a-t)*e			v=(a-t)*c	w=(a-t)*d
27	Avista Corporation	$ 16,559	$ 2,005	$ 24	$ 14,578	$ 46,710	11.87	63.89580		$ 14,578		Avista	$ 14,578	$ 14,578
28	Idaho Power Company	$ 22,616	$ 324	$ -	$ 22,292	$ 61,416	9.09	61.11240		$ 22,292		Idaho Power	$ 22,292	$ 22,292
29	NorthWestern Energy, LLC	$ 5,859	$ -	$ 275	$ 6,134	$ 15,551	22.15	74.17480		$ 6,134		NorthWestern	$ 6,134	$ 6,134
30	PacifiCorp	$ 67,906	$ 4,287	$ 99	$ 63,718	$ 187,619	20.46	72.48300		$ 63,718		PacifiCorp	$ 63,718	$ 63,718
31	Portland General Electric Company	$ 56,281	$ -	$ 2,646	$ 58,927	$ 149,381	18.29	70.31570		$ 58,927		Portland	$ 58,927	$ 58,927
32	Puget Sound Energy, Inc.	$ 75,980	$ -	$ 3,572	$ 79,552	$ 201,667	16.99	69.01780		$ 79,551		Puget Sound	$ 79,551	$ 79,551
33	Total	$ 245,200	$ 6,616	$ 6,616	$ 245,200	$ 662,344				$ 245,200		IOU REP	$ 245,200	$ 245,200
34														
35												Clark	$ 2,087	$ 2,089
36												Franklin	$ -	$ -
37	**IOU Reallocation Adjustments**											Snohomish	$ 2,480	$ 2,457
38		Avista	Idaho	NorthWestern	PacifiCorp	Portland	Puget Sound	Total				COU REP	$ 4,566	$ 4,546
39		$ 2,005	$ 324	$ -	$ 4,287	$ -	$ -					Total REP	$ 249,767	$ 249,747
40		p1=o1*(f/Σf)	p2=o2*(f/Σf)	p3=o3*(f/Σf)	p4=o4*(f/Σf)	p5=o5*(f/Σf)	p6=o6*(f/Σf)	p=Σ(p1…p6)						
41	Avista Corporation		$ 24	$ -				$ 24				Refund Amt	$ -	$ -
42	Idaho Power Company							$ -				REP Cost	$ 249,767	$ 249,747
43	NorthWestern Energy, LLC	$ 85	$ 8		$ 182	$ -	$ -	$ 275						
44	PacifiCorp		$ 99	$ -				$ 99						
45	Portland General Electric Company	$ 817	$ 82	$ -	$ 1,747			$ 2,646						
46	Puget Sound Energy, Inc.	$ 1,103	$ 111	$ -	$ 2,359	$ -		$ 3,572						
47		$ 2,005	$ 324	$ -	$ 4,287	$ -	$ -	$ 6,616						

Table 2.4.12

Rate Directive Step
IOU Reallocation Balances
Test Period October 2019 - September 2021

	B	C	D	E	F	G
4	**2012 REP Settlement Agreement Section 6 Reallocations**					
5						
6		**Initial Amount**	**Max Annual**		**Receiving Utilities**	
7	Avista Corporation	$ 22,985,810	$ 2,004,778		NWE, PGE, PSE	
8	Idaho Power Company -- total	$ 45,140,170				
9	Idaho Power Company -- 92%	$ 41,528,956	50% of benefits		AVA, NWE, PAC, PGE, PSE	
10	Idaho Power Company -- 8%	$ 3,611,214	50% of benefits		AVA, PAC, PGE, PSE	
11	NorthWestern Energy, LLC	N/A	N/A		AVA, IDA, PAC, PGE, PSE	
12	PacifiCorp	$ 66,721,315	$ 8,442,636		NWE, PGE, PSE	
13	Portland General Electric Company	$ 4,669,222	$ 1,237,583		NWE, PSE	
14	Puget Sound	N/A	N/A		NWE	
15						
16			**Max Annual**	**Max Annual**		
17	**Section 6.2.4 Adjustment**	**Initial Amount**	**2012–2015**	**2016–2017**	**Paying Utilities**	
18	NorthWestern Energy, LLC	$ (3,830,000)	$ (766,000)	$ (383,000)	AVA, PAC, PGE, PSE	
19						
20						
21						
22		**FY2012 Realloc**	**Accrued Interest**	**FY2013 Realloc**	**Accrued Interest**	**Remain Balance**
23	Avista Corporation	$ 2,004,778	$ 659,503	$ 2,004,778	$ 619,144	$ 20,254,901
24	Idaho Power Company	$ 2,521,193	$ 1,316,387	$ 2,521,193	$ 1,280,243	$ 42,694,414
25	NorthWestern Energy, LLC	$ (766,000)	$ -	$ (766,000)	$ -	$ (2,298,000)
26	PacifiCorp	$ 8,442,636	$ 1,875,000	$ 8,442,636	$ 1,677,971	$ 53,389,014
27	Portland General Electric Company	$ 1,237,583	$ 121,513	$ 1,237,583	$ 88,031	$ 2,403,600
28						
29		**FY2014 Realloc**	**Accrued Interest**	**FY2015 Realloc**	**Accrued Interest**	**Remain Balance**
30	Avista Corporation	$ 2,004,778	$ 577,575	$ 4,287	$ 534,759	$ 17,357,680
31	Idaho Power Company	$ 3,001,474	$ 1,235,810	$ 3,001,474	$ 1,182,840	$ 39,110,117
32	NorthWestern Energy, LLC	$ (766,000)	$ -	$ (766,000)	$ -	$ (766,000)
33	PacifiCorp	$ 8,442,636	$ 1,475,031	$ 8,442,636	$ 1,266,003	$ 39,244,775
34	Portland General Electric Company	$ 1,237,583	$ 53,544	$ 1,237,583	$ 18,023	$ -
35						
36		**FY2016 Realloc**	**Accrued Interest**	**FY2017 Realloc**	**Accrued Interest**	**Remain Balance**
37	Avista Corporation	$ 2,004,778	$ 490,659	$ 2,004,778	$ 445,235	$ 14,284,017
38	Idaho Power Company	$ 10,183,223	$ 1,020,555	$ 10,183,223	$ 745,675	$ 20,509,901
39	NorthWestern Energy, LLC	$ (383,000)	$ -	$ (383,000)	$ -	$ -
40	PacifiCorp	$ 8,442,636	$ 1,050,704	$ 8,442,636	$ 828,946	$ 24,239,153
41	Portland General Electric Company	$ -	$ -	$ -	$ -	$ -
42						
43		**FY2018 Realloc**	**Accrued Interest**	**FY2019 Realloc**	**Accrued Interest**	**Remain Balance**
44	Avista Corporation	$ 2,004,778	$ 398,449	$ 2,004,778	$ 350,259	$ 11,023,169
45	Idaho Power Company	$ 10,254,951	$ 461,473	$ 10,254,951	$ 167,668	$ 629,141
46	NorthWestern Energy, LLC	$ -	$ -	$ -	$ -	$ -
47	PacifiCorp	$ 8,442,636	$ 600,535	$ 8,442,636	$ 365,272	$ 8,319,688
48	Portland General Electric Company	$ -	$ -	$ -	$ -	$ -
49						
50		**FY2020 Realloc**	**Accrued Interest**	**FY2021 Realloc**	**Accrued Interest**	**Remain Balance**
51	Avista Corporation	$ 2,004,778	$ 300,623	$ 2,004,778	$ 249,499	$ 7,563,736
52	Idaho Power Company	$ 314,571	$ 14,156	$ 314,571	$ 5,143	$ -
53	NorthWestern Energy, LLC	$ -	$ -	$ -	$ -	$ -
54	PacifiCorp	$ 4,159,844	$ 187,193	$ 4,159,844	$ 68,013	$ -
55	Portland General Electric Company	$ -	$ -	$ -	$ -	$ -
56						
57						

Rate Directive Step
Calculation and Allocation of the Increase in PF Exchange Revenue Requirement Due to REP Settlement
Test Period October 2019 - September 2021

	B	C		D	
4	**Cost Allocation After 7c2 Delta**		**2020**		**2021**
5	Priority Firm Public - 7(b) Loads...	$	2,741,876	$	2,795,781
6	Priority Firm Exchange - 7(b) Loads...................................	$	2,181,455	$	2,212,424
7	Industrial Firm - 7(c) Loads...	$	4,781	$	4,837
8	New Resources - 7(f) Loads...	$	0.715	$	0.713
9	Surplus Firm - SP Loads..	$	52,743	$	41,686
10	Total..	$	4,980,855	$	5,054,729
11					
12					
13	**Calc Rate Protection to PFx Rate**		**2020**		**2021**
14	Unconstrained Benefits	$	924,445	$	924,370
15	REP Recovery Amount plus COU Benefits	$	(249,766)	$	(249,746)
16	delta	$	674,679	$	674,624
17					
18					
19	**Allocation Factors**		**2020**		**2021**
20	Priority Firm Public - 7(b) Loads...		-1.0000000		-1.0000000
21	Priority Firm Exchange - 7(b) Loads...................................		1.0000000		1.0000000
22	Industrial Firm - 7(c) Loads...		0.0000000		0.0000000
23	New Resources - 7(f) Loads...		0.0000000		0.0000000
24					
25					
26	**Allocation of Rate Protection Cost**		**2020**		**2021**
27	Priority Firm Public - 7(b) Loads...	$	(674,679)	$	(674,624)
28	Priority Firm Exchange - 7(b) Loads...................................	$	674,679	$	674,624
29	Industrial Firm - 7(c) Loads...	$	-	$	-
30	New Resources - 7(f) Loads...	$	-	$	-
31	Total..	$	-	$	-
32					
33					
34	**Cost Allocation After Rate Protection to PFx**		**2020**		**2021**
35	Priority Firm Public - 7(b) Loads...	$	2,067,197	$	2,121,158
36	Priority Firm Exchange - 7(b) Loads...................................	$	2,856,134	$	2,887,048
37	Industrial Firm - 7(c) Loads...	$	4,781	$	4,837
38	New Resources - 7(f) Loads...	$	0.715	$	0.713
39	Surplus Firm - SP Loads..	$	52,743	$	41,686
40	Total..	$	4,980,855	$	5,054,729
41					
42					
43	**Energy Billing Determinants (aMW)**		**2020**		**2021**
44	Priority Firm Public - 7(b) Loads...		6,689		6,739
45	Priority Firm Exchange - 7(b) Loads...................................		5,322		5,333
46	Industrial Firm - 7(c) Loads...		12		12
47	New Resources - 7(f) Loads...		0.00112204		0.001121461
48					
50					
51	**Average Power Rates**		**2020**		**2021**
52	Priority Firm Public - 7(b) Loads...		35.18		35.93
53	Priority Firm Exchange - 7(b) Loads...................................		66.13		66.83
54	Industrial Firm - 7(c) Loads...		45.35		46.02
55	New Resources - 7(f) Loads...		72.57		72.56

Table 2.4.14

Rate Directive Step
Calculation of PF, IP and NR Rate Contribution to Net REP Benefit Costs
Test Period October 2019 - September 2021

	B	C		D	
25			**2020**		**2021**
26	WP-10 Average IOU REP Benefits (before Lookback recovery)	$	265,847	$	265,847
27					
28	WP-10 7b3 Supplemental Rate Charge	$	7.38	$	7.38
29	IP/NR REP Surcharge	$	6.93	$	6.93
30	IP Load		105		105
31	NR Load		0		0
32	REP Surcharge Revenue from IP Rate	$	731	$	729
33	REP Surcharge Revenue from NR Rate	$	0	$	0
34					
35	Amount of REP Recovery remaining after IP/NR REP Surcharge	$	249,035	$	249,017
36	Remaining REP Recovery in PF, IP and NR Rates ($/MWh)	$	4.23	$	4.21
37					
38	Before Reallocation				
39	IP REP Recovery Amount in Rates	$	1,177	$	1,171
40	NR REP Recovery Amount in Rates	$	0	$	0
41					
42	After Reallocation				
43	IP REP Recovery Amount in Rates	$	730	$	727
44	NR REP Recovery Amount in Rates	$	0	$	0
45					
46					
47	Reallocation that Should be in Rates		**2020**		**2021**
48	Priority Firm Public - 7(b) Loads..	$	248,589	$	248,575
49	Industrial Firm - 7(c) Loads...	$	1,177	$	1,171
50	New Resources - 7(f) Loads...	$	0.110	$	0.109
51		$	249,766	$	249,746
52					
53	Adjustment Necessary to Achieve Reallocation		**2020**		**2021**
54	Priority Firm Public - 7(b) Loads..	$	(730)	$	(727)
55	Industrial Firm - 7(c) Loads...	$	730	$	727
56	New Resources - 7(f) Loads...	$	0.068	$	0.068
57		$	0	$	(0)
58					
59			**2020**		**2021**
60	PF Contribution to Net REP Benefits $/MWh............................		4.23		4.21
61	IP Contribution to Net REP Benefits $/MWh............................		11.16		11.14
62	NR Contribution to Net REP Benefits $/MWh............................		11.16		11.14

Rate Directive Step
Reallocation of Rate Protection Provided by the IP and NR Rates
Test Period October 2019 - September 2021

	B	C		D	
4	**Cost Allocation After Rate Protection Provided by PFx**		**2020**		**2021**
5	Priority Firm Public - 7(b) Loads..	$	2,067,197	$	2,121,158
6	Priority Firm Exchange - 7(b) Loads..	$	2,856,134	$	2,887,048
7	Industrial Firm - 7(c) Loads..	$	4,781	$	4,837
8	New Resources - 7(f) Loads...	$	0.715	$	0.713
9	Surplus Firm - SP Loads..	$	52,743	$	41,686
10	Total..	$	4,980,855	$	5,054,729
11					
12					
13					
14	**Allocation of Rate Protection Provided by IP and NR**		**2020**		**2021**
15	Priority Firm Public - 7(b) Loads..	$	(730)	$	(727)
16					
17	Industrial Firm - 7(c) Loads..	$	730	$	727
18	New Resources - 7(f) Loads...	$	0.068	$	0.068
19	Total..	$	0	$	(0)
20					
21					
22	**Cost Allocation After Rate Protection Provided by IP and NR**		**2020**		**2021**
23	Priority Firm Public - 7(b) Loads..	$	2,066,468	$	2,120,430
24	Priority Firm Exchange - 7(b) Loads..	$	2,856,134	$	2,887,048
25	Industrial Firm - 7(c) Loads..	$	5,510	$	5,565
26	New Resources - 7(f) Loads...	$	0.783	$	0.781
27	Surplus Firm - SP Loads..	$	52,743	$	41,686
28	Total..	$	4,980,855	$	5,054,729
29					
30					
31	**Energy Billing Determinants (aMW)**		**2020**		**2021**
32	Priority Firm Public - 7(b) Loads..		6,689		6,739
33	Priority Firm Exchange - 7(b) Loads..		5,322		5,333
34	Industrial Firm - 7(c) Loads..		12		12
35	New Resources - 7(f) Loads...		0.00112204		0.001121461
36					
38					
39	**Average Power Rates After Rate Protection Reallocations**		**2020**		**2021**
40	Priority Firm Public - 7(b) Loads..		35.17		35.92
41	Priority Firm Exchange - 7(b) Loads..		66.13		66.83
42	Industrial Firm - 7(c) Loads..		52.27		52.94
43	New Resources - 7(f) Loads...		79.49		79.48

Table 2.4.16

Rate Directive Step
Calculation of Annual Energy Rate Scalars for Second IP-PF Link Calculation
Test Period October 2019 - September 2021

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	PQ	R	S	T
5																		
6	**Load Shaping Rate**		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
7	HLH (mills/kWh)		23.84	25.19	28.09	25.24	24.36	19.19	17.98	11.71	10.52	21.45	25.24	24.86				
8	LLH (mills/kWh)		18.88	21.84	23.56	19.21	19.28	16.11	14.40	6.55	1.68	15.31	20.21	19.98				
9	Demand Rate ($/kW/mo)		11.42	12.07	13.45	12.10	11.66	9.19	8.61	5.60	5.04	10.27	12.10	11.91				
10																		
11	**PF+NR Load**		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep			**2020**	
12	**2020**	HLH	2713	3177	3497	3434	3038	3021	2598	2566	2874	2976	2941	2646			Energy (GWH)	58757
13		LLH	1664	2178	2496	2369	1994	2012	1665	1775	1746	1839	1788	1749			Allocated Cost	$ 2,067,715
14		Demand	364	327	532	595	401	462	426	266	395	470	435	386			Rate Scalar	14.47
15	Revenue at marginal Rates		$ 100,247	$ 131,556	$ 164,191	$ 139,404	$ 117,103	$ 94,638	$ 74,362	$ 43,159	$ 35,145	$ 96,802	$ 115,653	$ 105,323		$ 1,217,581		
16			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep			**2021**	
17	**2021**	HLH	2744	3159	3581	3410	2996	3090	2562	2625	2870	2980	2962	2663			Energy (GWH)	59036
18		LLH	1681	2238	2456	2443	1986	1977	1654	1765	1746	1878	1806	1764			Allocated Cost	$ 2,121,667
19		Demand	370	278	625	537	352	528	440	275	400	478	444	401			Rate Scalar	15.21
20	Revenue at marginal Rates		$ 101,363	$ 131,810	$ 166,853	$ 139,523	$ 115,381	$ 96,014	$ 73,664	$ 43,828	$ 35,129	$ 97,574	$ 116,654	$ 106,227		$ 1,224,019		
21			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
22																		
23																		
24																		
25	**IP Load**		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep			**2020**	
26	**2020**	HLH	5	5	5	5	5	5	5	5	5	5	5	5			Energy (GWH)	105
27		LLH	4	4	4	4	4	4	4	4	4	4	4	4			Allocated Cost	$ 4,264
28		Demand	0	0	0	0	0	0	0	0	0	0	0	0			Rate Scalar	21.22
29	Revenue at marginal Rates		$ 194	$ 205	$ 232	$ 201	$ 185	$ 160	$ 142	$ 84	$ 58	$ 166	$ 206	$ 195		$ 2,027		
30			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep			**2021**	
31	**2021**	HLH	5	5	5	5	5	5	5	5	5	5	5	5			Energy (GWH)	105
32		LLH	4	4	4	4	4	4	4	4	4	4	4	4			Allocated Cost	$ 4,328
33		Demand	0	0	0	0	0	0	0	0	0	0	0	0			Rate Scalar	21.96
34	Revenue at marginal Rates		$ 194	$ 205	$ 232	$ 201	$ 178	$ 159	$ 142	$ 84	$ 58	$ 166	$ 206	$ 195		$ 2,020		
35																		

Table 2.4.17

Rate Directive Step
Calculation of Monthly Energy Rate Scalars for Second IP-PF Link Rate Calculation
Test Period October 2019 - September 2021

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
5		**Load Shaping Rate**	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
6		HLH (mills/kWh)	23.84	25.19	28.09	25.24	24.36	19.19	17.98	11.71	10.52	21.45	25.24	24.86				
7		LLH (mills/kWh)	18.88	21.84	23.56	19.21	19.28	16.11	14.40	6.55	1.68	15.31	20.21	19.98				
8		Demand Rate ($/kW/mo)	11.42	12.07	13.45	12.10	11.66	9.19	8.61	5.60	5.04	10.27	12.10	11.91				
9																		
10																		
11		**PFp /NR**	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
12	**2020**	HLH	38.31	39.66	42.56	39.71	38.82	33.66	32.45	26.17	24.99	35.91	39.71	39.33				**2020**
13		LLH	33.35	36.31	38.03	33.68	33.75	30.58	28.87	21.02	16.15	29.78	34.68	34.45				**14.47**
14		Demand	11.42	12.07	13.45	12.10	11.66	9.19	8.61	5.60	5.04	10.27	12.10	11.91				**Scalar**
15			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
16	**2021**	HLH	39.05	40.40	43.30	40.45	39.56	34.40	33.19	26.91	25.72	36.65	40.45	40.07				**2021**
17		LLH	34.09	37.05	38.77	34.42	34.49	31.32	29.61	21.76	16.89	30.52	35.42	35.19				**15.21**
18		Demand	11.42	12.07	13.45	12.10	11.66	9.19	8.61	5.60	5.04	10.27	12.10	11.91				**Scalar**
19																		
20																		
21		**IP**	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
22	**2020**	HLH	45.06	46.42	49.32	46.47	45.58	40.42	39.20	32.93	31.74	42.67	46.47	46.08				**2010**
23		LLH	40.10	43.06	44.78	40.43	40.50	37.33	35.62	27.77	22.90	36.53	41.43	41.20				**21.22**
24		Demand	11.42	12.07	13.45	12.10	11.66	9.19	8.61	5.60	5.04	10.27	12.10	11.91				**Scalar**
25			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
26	**2021**	HLH	45.80	47.15	50.05	47.20	46.32	41.15	39.94	33.67	32.48	43.40	47.20	46.82				**2011**
27		LLH	40.84	43.80	45.52	41.17	41.24	38.07	36.36	28.51	23.64	37.27	42.17	41.94				**21.96**
28		Demand	11.42	12.07	13.45	12.10	11.66	9.19	8.61	5.60	5.04	10.27	12.10	11.91				**Scalar**

Rate Directive Step
Calculation of Second IP-PF Link Delta
Test Period October 2019 - September 2021

	B	C		D	
45			**FY 2020**		**FY 2021**
46	Average PF Rate	$	35.17	$	35.92
47	Net Industrial Margin		(0.179)		(0.179)
48	Flat DSI Load (GWh)		105		105
49	Revenue 1		3,689		3,756
50					
51	IP Rate	$	52.27	$	52.94
52	Flat DSI Load (GWh)		105		105
53	Revenue 2		5,510		5,565
54					
55	Difference		1,822		1,808
56					
57	Adjustment (calculated using Goal Seek)		(575.62)		(571.80)
58					
59	Delta		1,246		1,236

Rate Directive Step
Reallocation of IP-PF Link Delta and Recalculation of Rates
Test Period October 2019 - September 2021

	B	C	D	E
4	**Cost Allocation After Rate Protection Provided by IP and NR**	**2020**	**2021**	
5	Priority Firm Public - 7(b) Loads	$ 2,066,468	$ 2,120,430	
6	Priority Firm Exchange - 7(b) Loads	$ 2,856,134	$ 2,887,048	
7	Industrial Firm - 7(c) Loads	$ 5,510	$ 5,565	
8	New Resources - 7(f) Loads	$ 0.783	$ 0.781	
9	Surplus Firm - SP Loads	$ 52,743	$ 41,686	
10	Total	$ 4,980,855	$ 5,054,729	
11				
12				
13	IP-PF Link Delta	$ 1,246	$ 1,236	
14				
15		**2020**	**2021**	
16	Priority Firm Public - 7(b) Loads	0.99999983	0.99999983	
17	Industrial Firm - 7(c) Loads	(1.00000000)	(1.00000000)	
18	New Resources - 7(f) Loads	0.00000017	0.00000017	
19				
20				
21	**Allocation of Second IP-PF Link Delta**	**2020**	**2021**	
22	Priority Firm Public - 7(b) Loads	$ 1,246	$ 1,236	
23	Priority Firm Exchange - 7(b) Loads	$ -	$ -	
24	Industrial Firm - 7(c) Loads	$ (1,246)	$ (1,236)	
25	New Resources - 7(f) Loads	$ 0.000	$ 0.000	
26	Total	$ (0)	$ (0)	
27				
28				
29	**Cost Allocation After Second IP-PF Link**	**2020**	**2021**	
30	Priority Firm Public - 7(b) Loads	$ 2,067,714	$ 2,121,667	
31	Priority Firm Exchange - 7(b) Loads	$ 2,856,134	$ 2,887,048	
32	Industrial Firm - 7(c) Loads	$ 4,264	$ 4,328	
33	New Resources - 7(f) Loads	$ 0.784	$ 0.781	
34	Surplus Firm - SP Loads	$ 52,743	$ 41,686	
35	Total	$ 4,980,855	$ 5,054,729	
36				
37				
38	**Energy Billing Determinants (aMW)**	**2020**	**2021**	
39	Priority Firm Public - 7(b) Loads	6,689	6,739	
40	Priority Firm Exchange - 7(b) Loads	5,322	5,333	
41	Industrial Firm - 7(c) Loads	12	12	
42	New Resources - 7(f) Loads	0.00112204	0.001121461	
43				
45				
46	**Average Power Rates After Second IP-PF Link**	**2020**	**2021**	Average
47	Priority Firm Public - 7(b) Loads	35.19	35.94	**35.56**
48	Priority Firm Exchange - 7(b) Loads	66.13	66.83	**66.48**
49	Industrial Firm - 7(c) Loads	40.45	41.18	**40.82**
50	New Resources - 7(f) Loads	79.51	79.50	**79.51**

Table 2.4.20

Rate Design Step
REP Benefit Reconciliation
Test Period October 2019 to September 2021

	B	D	E	F	G H	I	J	K	L
4		**2020**	**2021**	**Avg**			**2020**	**2021**	**Avg**
5	Resource Costs	3,357,234	3,355,590	3,356,412		PFx Alloc Cost	(2,856,133)	(2,887,047)	
6	PFx Revenues	(3,091,274)	(3,122,037)	(3,106,655)		Exch Tmn Cost	(235,141)	(234,989)	
7	REP Benefits	265,960	233,554	249,757			(3,091,274)	(3,122,037)	(3,106,655)
8									
9	**REP Benefits**					**PFx Revenues**			
10	Avista Corporation	14,578	14,578			Avista Corporation	260,251	263,011	
11	Idaho Power Company	22,292	22,292			Idaho Power Company	447,024	451,764	
12	NorthWestern Energy, LLC	6,134	6,134			NorthWestern Energy, LLC	46,433	46,925	
13	PacifiCorp	63,718	63,718			PacifiCorp	606,514	612,944	
14	Portland General Electric Company	58,927	58,927			Portland General Electric Compa	540,130	545,856	
15	Puget Sound Energy, Inc.	79,551	79,551			Puget Sound Energy, Inc.	784,890	793,211	
16	IOU REP	245,200	245,200	245,200		IOU REP	2,685,242	2,713,710	2,699,476
17									
18	Clark Public Utilities	2,087	2,089			Clark Public Utilities	167,996	169,952	
19	Franklin	-	-			Franklin	-	-	
20	Snohomish PUD	2,480	2,457			Snohomish PUD	238,036	238,374	
21	COU REP	4,566	4,546	4,556		COU REP	406,032	408,326	407,179
22									
23	Refund Amounts	-	-			Refund Amounts	-	-	
24	Total REP	249,767	249,747	249,757		Total REP	3,091,274	3,122,037	3,106,655
25				(0)			0	(0)	0
26									
27	**For Slice True-Up**								100.00%
28	IOU REP	245,200	245,200						
29	COU REP	4,566	4,546						
30	Refund Amounts	-	-						
31	Total REP	249,767	249,747						

Table 2.5.1

Rate Design Study
Allocated Cost and Unit Cost Priority Firm Rates
Test Period October 2019 - September 2021

	B	C	D	E	F	G	H	I	J	K	L
11											
12			**A**	**B**	**C**		**PF Public**		**PF Exchange**		
13			**ALLOCATED**	**UNIT**	**PERCENT**		**ALLOCATED**		**ALLOCATED**		
14			**COSTS**	**COSTS**	**CONTRIBUTION**		**COSTS**		**COSTS**		
15		GENERATION ENERGY	($ Thousands)	(Mills/kWh)	(Percent)						
16											
17		Federal Base System									
18		Hydro	1,375,634	6.512	13.85%		767,024	6.512	608,610	6.512	
19		Fish & Wildlife	643,933	3.048	6.48%		359,043	3.048	284,890	3.048	
20		Trojan	2,400	0.011	0.02%		1,338	0.011	1,062	0.011	
21		WNP #1	148,731	0.704	1.50%		82,929	0.704	65,802	0.704	
22		WNP #2	1,191,146	5.638	11.99%		664,157	5.638	526,989	5.638	
23		WNP #3	176,102	0.834	1.77%		98,191	0.834	77,911	0.834	
24		System Augmentation									
25		Balancing Power Purchases	123,965	0.587	1.25%		69,120	0.587	54,845	0.587	
26		Tier 2 Costs	29,872	0.141	0.30%		16,656	0.141	13,216	0.141	
27		Total Federal Base System	3,691,783	17.475	37.17%		2,058,458	17.475	1,633,325	17.475	
28		New Resources									
29		Gross Residential Exchange	5,988,648	28.348	60.30%		3,339,140	28.348	2,649,508	28.348	
30		Conservation	386,876	1.831	3.90%		215,714	1.831	171,162	1.831	
31		BPA Programs	257,310	1.218	2.59%		143,471	1.218	113,840	1.218	
32		Power Transmission	428,243	2.027	4.31%		238,779	2.027	189,464	2.027	
33		TOTAL COSA ALLOCATIONS	10,752,860	50.899	108.27%		5,995,561	50.899	4,757,299	50.899	
34											
35											
36		Nonfirm Excess Revenue Credit	(695,063)	-3.290	-7.00%		(387,552)	-3.290	(307,511)	-3.290	
37		Low Density Discount Expense	119,422	0.565	1.20%		66,587	0.565	52,835	0.565	
38		Other Revenue Credits	(517,000)	-2.447	-5.21%		(288,268)	-2.447	(228,732)	-2.447	
39		Irrigation Rate Mitigation Expense									
40		SP Revenue Surplus/Dfct Adj.	265,666	1.258	2.67%		148,129	1.258	117,536	1.258	
41		7(c)(2) Delta Adjustment	5,653	0.027	0.06%		3,152	0.027	2,501	0.027	
42		7(c)(2) Floor Rate Adjustment									
43		TOTAL RATE DESIGN ADJUSTMENTS	(821,323)	-3.888	-8.27%		(457,952)	-3.888	(363,371)	-3.888	
44											
45		Total Generation	9,931,537	**47.0114**	100.00%		5,537,609	**47.01**	4,393,928	**47.01**	
46											
47											
48		REP Settlement Rate Protection Adjustment					(1,350,760)	-11.467	1,349,303	1,349,303	
49		7(b)(2) - 7(c)(2) Industrial Adjustment					2,483	0.021	76	0.001	
50		Total Generation					**4,189,332**	**35.57**	5,743,306	**61.45**	
51											
52		Total Transmission							470,130	5.030	
53									6,213,436	**66.48**	
54											

Table 2.5.2

Rate Design Study
Allocated Cost and Unit Costs for Industrial Firm Power Rate
Test Period October 2019 - September 2021

	C	D	E	F
13		**ALLOCATED**	**UNIT**	**PERCENT**
14		**COSTS**	**COSTS**	**CONTRIBUTION**
15	GENERATION ENERGY	($ Thousands)	(Mills/kWh)	(Percent)
16				
17	Federal Base System			
18	Hydro			
19	Fish & Wildlife			
20	Trojan			
21	WNP #1			
22	WNP #2			
23	WNP #3			
24	System Augmentation			
25	Balancing Power Purchases			
26	Total Federal Base System			
27	New Resources	4,753	22.574	55.32%
28	Gross Residential Exchange	9,836	46.720	114.48%
29	Conservation	386	1.831	4.49%
30	BPA Programs	256	1.218	2.98%
31	Power Transmission	427	2.027	4.97%
32	TOTAL COSA ALLOCATIONS	15,657	74.371	182.24%
33				
34	Nonfirm Excess Revenue Credit	(358)	-1.701	-4.17%
35				
36	Other Revenue Credits	(293)	-1.392	-3.41%
37				
38	SP Revenue Surplus/Dfct Adj.	265	1.259	3.08%
39	7(c)(2) Delta Adjustment	(5,653)	-26.851	-65.79%
40	7(c)(2) Floor Rate Adjustment			
41	TOTAL RATE DESIGN ADJSTMTS	(6,039)	-28.685	-70.29%
42	Total Generation	9,618	45.686	111.95%
43				
55	Total Allocated & Adjusted Costs	9,618	45.686	111.95%
56				
57	Settlement Adjustments			
58	REP Settlement Rate Protection Adjustment	1,457	6.921	16.96%
59	7(b)(2) - 7(c)(2) Industrial Adjustment	(2,483)	-11.792	-28.90%
60		8,593	**40.81**	100.00%
61				
62	Billing Determinants:			
63	Energy (GwH)	211		

Table 2.5.3

Rate Design Study
Allocated Costs and Unit Costs for New Resources Firm Power Rate
Test Period October 2019 - September 2021

	C	D	E	F
12		**ALLOCATED**	**UNIT**	**PERCENT**
13		**COSTS**	**COSTS**	**CONTRIBUTION**
14	GENERATION ENERGY	($ Thousands)	(Mills/kWh)	(Percent)
15				
16	Federal Base System			
17	Hydro			
18	Fish & Wildlife			
19	Trojan			
20	WNP #1			
21	WNP #2			
22	WNP #3			
23	System Augmentation			
24	Balancing Power Purchases			
25	Total Federal Base System			
26	New Resources	0.4442	22.573	28.39%
27	Gross Residential Exchange	0.9195	46.721	58.76%
28	Conservation	0.0360	1.831	2.30%
29	BPA Programs	0.0639	3.245	4.08%
30	TOTAL COSA ALLOCATIONS	1.4636	74.370	93.54%
31				
32	Nonfirm Excess Revenue Credit	(0.0335)	-1.701	-2.14%
33				
34	Other Revenue Credits	(0.0274)	-1.392	-1.75%
35				
36	SP Revenue Surplus/Dfct Adj.	0.0248	1.259	1.58%
37	7(c)(2) Delta Adjustment	0.0005	0.027	0.03%
38	7(c)(2) Floor Rate Adjustment			
39	TOTAL RATE DESIGN ADJSTMTS	(0.0356)	-1.807	-2.27%
40	Total Generation Energy	1.4280	72.563	91.27%
41				
50				
51	Total Allocated & Adjusted Costs	1.4280	72.563	91.27%
52	Settlement Adjustments			
53	REP Settlement Rate Protection Adjustment	0.1362	6.921	8.71%
54	7(b)(2) - 7(c)(2) Industrial Adjustment	0.0004	0.021	0.03%
55				
56	Total With 7(b)(2) Adjustments	1.5647	**79.51**	100.00%
57				
58	Billing Determinant / Energy (GWh)	0.01968		

Table 2.5.4

Rate Design Study
Resource Cost Percent Contribution to Load Pools
Test Period October 2019 - September 2021

	B	C	D	E	F	G	H	I	J	K
9		**ALLOCATED GENERATION COSTS**					**PERCENTAGES**			
10										
11		**FBS**	**Exchange**	**New**			**FBS**	**Exchange**	**New**	
12		**Resources**	**Resources**	**Resources**	**Total**		**Resources**	**Resources**	**Resources**	**Total**
13										
14	**CLASSES OF SERVICE:**									
15										
16	**Power Rates**									
17	Priority Firm - Public	2,058,458	3,339,140		5,397,598		38.14%	61.86%		100.00%
18	Priority Firm - Exchange	1,633,325	2,649,508		4,282,833		38.14%	61.86%		100.00%
19	Priority Firm Power - Total	3,691,783	5,988,648		9,680,430		38.14%	61.86%		100.00%
20	Industrial Firm Power		9,836	4,753	14,588			67.42%	32.58%	100.00%
21	New Resources Firm		0.919	0	1			67.42%	32.58%	100.00%
22	Firm Power Products and Services		245,637	103,927	349,564			70.27%	29.73%	100.00%
23										
24										
25	**TOTALS**	**3,691,783**	**6,244,121**	**108,680**	**10,044,584**		**36.75%**	**62.16%**	**1.08%**	**100.00%**
26										
27					211,469					
28										
29				Average Cost of Resources	47.50					
30										
31				Average Cost to Serve Load Growth	31.76					

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SECTION 3: RATE DESIGN

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Table Descriptions

Table 3.1.1
Cost Aggregation under Tiered Rate Methodology (DS 01)
Worksheet aggregates costs and credits to be used in the TRM ratemaking. The TRM specifies a cost allocation methodology different from what is used in the COSA to separate costs into the various TRM cost pools. The mapping of costs to the TRM cost pools includes costs passed from the Power Revenue Requirement Study, credits passed from the revenue forecast, and cost and credit line items internally computed in RAM2020. For each cost pool under TRM, costs are conveniently grouped according to their COSA classification.

Table 3.1.2
Calculation of Unused RHWM (net) Credit (DS 02)
Worksheet calculates the $/MWh value for unused Rate Period High Water Mark. That value is used to determine the reallocation adjustment to distribute costs between the Composite and Non-Slice cost pools.

Table 3.1.3
Calculation of Slice Return of Network Losses Adjustment (DS 03)
Worksheet calculates the value of power associated with Non-Slice network losses such that these costs can explicitly be included in the Non-Slice cost pool. This leaves only system losses for which all Composite customers pay (regardless of product subscription) in the Composite cost pool, and properly accounts for Customer return of Slice-Resource losses. That value is used to determine the reallocation credit that will shift costs between the Composite and Non-Slice TRM cost pools.

Table 3.1.4
Balancing Augmentation Adjustment for Change to the Equivalent Tier 1 System Firm Critical Output (DS 04)
Worksheet calculates the change in the TI SFCO from the RHWM to 7(i) processes, and values the difference at the system augmentation price when the system augmentation amount is greater than zero.

Table 3.1.5
Calculation of Load Shaping and Demand Revenues (DS 05)
Worksheet calculates the Load Shaping and Demand revenues under the TRM rate design. These revenues are used as a credit against the costs in the Non-Slice rate pool.

Table 3.1.6
Calculation of PF Public Rates under Tiered Rate Methodology (DS 06)
Worksheet applies the costs, revenue credits and inter-rate-pool reallocations to the Composite, Non-Slice, Slice, and Tier 2 TRM rate pools to produce TRM rates. The TRM rates are in the form of monthly $/percent TOCA.

Table 3.1.7.1
Calculation of Net REP Ratemaking and Recovery Demonstration (DS 07-1)
Worksheet applies all power costs and revenue credits to the PF Public rate pool. The IP revenues are calculated with a macro to arrive at the proper relationship between the PFp rate and the IP rate. The net REP benefits are used in the calculations. The worksheet demonstrates that the PFp rate using the net REP benefits is identical to the PFp calculated with BPA's standard gross REP methodology.

Table 3.1.7.2
TRM PFp Revenues Equal to Non-TRM PFp Revenues (DS 07-2)
Worksheet demonstrates that the TRM revenues from Table 3.1.6 are equal to the non-TRM revenues from Table 3.1.7.1. This table completes the proof process for revenue recovery and cost allocation under the Northwest Power Act, REP Settlement, and the TRM.

Table 3.1.8.1
Calculation of Priority Firm Public Tier 1 Rate Equivalent Components (DS 08-1)
Worksheet calculates the energy and demand components for a PF Public rate that is equivalent to a Tier 1 PF rate. The monthly energy Load Shaping rates are adjusted by a scalar in all periods so that they and the monthly demand rates will recover the Tier 1 PF revenue requirement.

Table 3.1.8.2
Calculation of Priority Firm Public Melded Rate Equivalent Components (DS 08-2)
Worksheet calculates the energy and demand components for a PF Public rate that is equivalent to a melded Tier 1 and Tier 2 PF rate. The monthly energy Load Shaping rates are adjusted by a scalar in all periods so that they and the monthly demand rates will recover the Tier 1 and Tier 2 PF revenue requirement. These monthly energy PF rates are necessary to calculate the Industrial Firm Power rates.

Table 3.1.8.3
Calculation of Industrial Firm Power Rate Components (DS 08-3)
Worksheet calculates the Industrial Firm Power (IP) rate monthly energy and demand components. The IP rate is a formula rate derived from the "applicable wholesale rate." In this rate proceeding, with no NR load, the applicable wholesale rate is the melded PF Public rate. The monthly IP energy rates are set equal to the melded PF rate, plus the DSI value of reserve (VOR), plus the Industrial Margin, plus the Settlement Charge.

Table 3.1.8.4
Calculation of New Resource Rate Components (DS 08-4)
Worksheet calculates the energy and demand components for the New Resources (NR) rate. The monthly energy Load Shaping rates are adjusted by a scalar in all periods so that they and the monthly demand rates will recover the NR revenue requirement.

Table 3.1.8.5
Calculation of the Non-Slice Priority Firm Tier 1 Equivalent and Load Shaping True-Up Rate Components (DS 08-5)
Worksheet calculates the Load Shaping True-up rate by comparing the non-Slice Tier 1 market energy revenue (the non-Slice Tier 1 loads times the market rates) with the non-Slice Tier 1 energy revenue at Tier 1 rates. The difference in the form of a $/MWh is the Load Shaping True-up rate.

Table 3.2
Summary RSS Revenue Credits for Tier 1 Cost Pools
Table summarizes the total revenue credits associated with RSS and related services, delineated by Tier 1 cost pool.

Table 3.3
Tier 2 Purchases Made by BPA
Table lists information pertaining to Mid-C purchases made by BPA to meet Tier 2 rate load obligations.

Table 3.4
Inputs to TSS Monthly Rate and Charge
Table shows costs used as the numerator and the megawatt hours sold as the denominator for the TSS rate. The transaction values are used to calculate the charge cap.

Table 3.5
Tier 2 Short-Term Rate Costing Table
Costing table used to calculate the Tier 2 Short-Term rates for each year of the rate period.

Table 3.6
Tier 2 Overhead Adder Inputs
Table lists inputs to Tier 2 Overhead Cost Adder.

Table 3.7
Tier 2 Rate Revenues
Table summarizes the Tier 2 rate-related revenues and adjustments to Tier 1 cost pools.

Table 3.8
Total Remarketing Charges and Credits
Table summarizes the sources of power for meeting different Tier 2 loads, including purchases, executed and forecast, remarketed power from other Tier 2 cost pools, and remarketed power from non-Federal resources with DFS.

Table 3.9
Tier 2 Rate Inputs
Table lists prices used for Tier 2 surplus credit or deficit debit.

Table 3.10
Remarketing Value Inputs
Table lists prices used to calculate the Remarketing Value.

Table 3.11
RSS and Related Charges fir FY 2020 and FY 2021
Table summarizes the RSS model forecast results for the purchaser's grandfathered GMS, SCS, DFS, FORS, and TSS/TCMS. This table also shows who is taking which service, during which year, and for which resource. Table summarizes the revenue credits by customers produced by the RSS model when applying the RSS and related services charges to the identified resources. Also included is the all-in forecast $/MWh equivalent rate for the identified services.

Table 3.12
PF Load Forecast Deviation Liquidated Damages Revenue
Table summarizes the total revenue credits associated with the PF Load Forecast Deviation Liquidated Damages.

Rate Design Step
Cost Aggregation under Tiered Rate Methodology
Test Period October 2019 to September 2021

	A	B	C	D	E	G	H
4						**2020**	**2021**
5		**Composite**					
6			Federal Base System				
7				Hydro			
8					Operating Expense	602,542	604,031
9					Interest	36,976	42,206
10					MRNR	11,940	77,939
11				Fish & Wildlife			
12					Operating Expense	306,206	309,094
13					Interest	6,131	7,209
14					MRNR	1,979	13,313
15				Trojan		1,200	1,200
16				WNP #1		74,283	74,449
17				Columbia Generating Station		603,670	587,475
18				WNP #3		87,900	88,202
19				Augmentation		-	-
20			Residentail Exchange Program				
21				REP Net Cost		249,766	249,746
22				Program Support		803	624
23				Settlement Interest Accrual		-	-
24			NewResources				
25				Cowlitz		11,125	11,570
26				Idaho		-	-
27				Tier 1 Aug (Klondike III)		12,367	12,477
28				Other		33,846	31,932
29			Conservation				
30				Operating Expense		188,910	189,294
31				Interest		4,854	4,164
32				MRNR		1,567	7,689
33			BPAPrograms				
34				Operating Expense		139,053	120,896
35				Interest		909	947
36				MRNR		294	1,749
37			Transmission				
38				Transmission and Ancillary Services		47,943	48,083
39				General Transfer Agreements		96,200	96,200
40			Nonslice Interest and MRNR Allocated to Cost Pools				
41				Interest on BPA fund Credit to Nonslice		(320)	1,268
42				Accrual Revenue (MRNR Adjustment)		-	-
43			**Total**			**2,520,146**	**2,581,759**

Table 3.1.1.2

Rate Design Step
Cost Aggregation under Tiered Rate Methodology
Test Period October 2019 to September 2021

	A	B	C	D	E	G	H
4						**2020**	**2021**
44		**Non-Slice**					
45			FBS				
46				Balancing Purchases from Risk Mod		31,137	24,393
47				Balancing in Revenue Requirement		38,805	29,630
48				PNRR			
49					Hydro	-	-
50					Fish & Wildlife	-	-
51			Conservation				
52				PNRR		-	-
53			BPAPrograms				
54				Hedging Mitigation		-	-
55				RCD Expense Offset Non-Slice		-	-
56				PNRR		-	-
57			Transmission				
58				Transmission and Ancillary Services		77,499	73,025
59				Third-party T&A		-	-
60			Nonslice Interest and MRNR				
61				BPA Fund		320	(1,268)
62				Non-Slice MRNR Adjustment		-	-
63			**Total**			**147,762**	**125,780**
64		**Slice**					
65			BPAPrograms				
66				Other Slice Costs		-	-
67			**Total**			-	-
68		**Tier 2**					
69			FBS				
70				Tier 2 Purchase Costs		12,430	16,203
71				Tier 2 Rate Design Adjustments		563	676
72				Tier 2 Other Costs		-	-
73			**Total**			**12,993**	**16,879**

Rate Design Step
Cost Aggregation under Tiered Rate Methodology
Test Period October 2019 to September 2021

	A	B	C	D	E	G	H
4						**2020**	**2021**
74		**Rate Direct/Design Adjustments**					
75			Credits Allocated Against Cost Pools				
76				FBS (excluding T2 Adjustment)		(110,214)	(110,816)
77				Contract Obligations		(353)	(347)
78				New Resources		-	-
79				Conservation		(8,000)	(8,000)
80				BPAPrograms		-	-
81				Transmission		(12,362)	(12,397)
82							
83			Secondary Energy Credit (includes pre-sale and Slice)			(367,691)	(335,677)
84			Firm Surplus Secondary Sales			(52,743)	(41,686)
85			Generation Inputs Credit			(119,815)	(119,815)
86			NR Revenues from ESS services			-	-
87			Composite FPS Revenues (excl. secondary)			(9,499)	(9,458)
88			Non-Slice FPS Revenues (excl. secondary)			-	-
89							
90			Low Density Discount			38,505	39,107
91			Irrigation Rate Mitigation Costs			20,905	20,905
92							
93			Composite Augmentation RSS Revenue Debit/(Credit)			(1,668)	(1,668)
94			Composite Tier 2 RSS Revenue Debit/(Credit)			(52)	(61)
95			Composite Tier 2 Rate Design Adjustment Debit/(Credit)			(510)	(615)
96			Composite Non-Federal RSS Revenue Debit/(Credit)			(1,008)	(1,084)
97			Non-Slice Augmentation RSC Revenue Debit/(Credit)			(651)	(651)
98			Non-Slice Tier 2 RSC Revenue Debit/(Credit)			-	-
99			Non-Slice Tier 2 Rate Design Debit/(Credit)			-	-
100			Non-Slice Non-Federal RSC Revenue Debit/(Credit)			43	34
101							
102			Firm Surplus and Secondary Credit (from unused RHWM)			(68,746)	(61,756)
103			Demand Revenue			53,201	53,857
104			Load Shaping Revenue			25,902	30,182
105							

Table 3.1.2

Rate Design Step
Unused RHWM (net) Credit Computation
Test Period October 2019 to September 2021

	B	C	D
4		**2020**	**2021**
5	Secondary (aMW)	2,382	2,322
6	T1SFCO (aMW)	6,955	6,955
7	RHWM Augmentation (aMW)	69	69
8	RP Augmentation (aMW)	-	-
9	System Augmentation (aMW)	-	-
10	Firm Surplus (aMW)	212	154
11	IP and NR Loads contributing to avoided cost	12	12
12			
13	Value of Secondary	$ 14.10	$ 14.01
14	Value of T1SFCO ($/MWh)	$ 19.41	$ 19.41
15	Value of Augmentation	$ 24.67	$ 24.71
16	Value of Firm Surplus	$ 28.27	$ 30.84
17			
18	Secondary (MWh)	20,922,772	20,345,013
19	T1SFCO (MWh)	61,094,942	60,928,016
20	RHWM Augmentation (MWh)	608,371	606,709
21	IP and NR Loads (MWh)	108,657	108,335
22	Change in T1SFCO (MWh)	599,265	1,166,963
23			
24	Unused RHWM (MWh)	3,566,124	3,297,018
25			
26	Unused Secondary	1,209,225	1,090,082
27	Unused T1SFCO	3,530,964	3,264,511
28	Unused Augmentation	35,161	32,507
29			
30	Value of Unused	$ 86,437,167	$ 79,425,300
31	Value of System Augmentation not Purchased	$ 17,691,107	$ 17,669,131
32			
33	Net Credit/(Cost)	$ 68,746,060	$ 61,756,169
34			
35	$/MWh value of Unused RHWM	**$ 24.17**	

Table 3.1.3

Rate Design Step
Slice Return of Network Losses Adjustment
Test Period October 2019 - September 2021

	B	C	D
4		**2020**	**2021**
5	Non Slice Loads (MWh)	44,424,703	44,781,926
6	Loss Percent Assumption	1.90%	1.90%
7	Implied Non Slice Losses	844,069	850,857
8	Average Slice&Non-Slice Tier 1 Rate	35.62	35.62
9	Implied Cost/Credit ($1000)	30,066	30,308

Table 3.1.4

Rate Design Step
Balancing Augmentation Adjustment for Change to the Equivalent Tier 1 System Firm Critical Output
Test Period October 2019 - September 2021

	A	B	C	E	F	G
4				**2020**	**2021**	
5		**Table 3.1**				
6			Regulated	6,115	6,119	
7			Independent	348	348	
8		**Table 3.2**				
9			Ashland Solar Project	0	-	
10			Columbia Generating Station	1,116	994	
11			Condon Wind Project	12	12	
12			Dworshak/Clearwater Small Hydropower	3	3	
13			Elwha Hydro	-	-	
14			Foote Creek 1	4	4	
15			Foote Creek 2	-	-	
16			Foote Creek 4	4	-	
17			Fourmile Hill Geothermal	-	-	
18			Georgia-Pacific Paper (Wauna)	-	-	
19			Glines Canyon Hydro	-	-	
20			Klondike I	6	6	
21			Stateline Wind Project	21	21	
22		**Table 3.3**				
23			Canadian Entitlement	135	135	
24			Libby Coordination	-	-	
25			BC Hydro Power Purchase	1	1	
26			Pasadena Capacity	-	-	
27			Pasadena Seasonal	-	-	
28			Pasadena Exchange Energy	-	-	
29			PacifiCorp (So Idaho)	-	-	
30			Riverside Capacity	-	-	
31			Riverside Seasonal	-	-	
32			Riverside Exchange Energy	-	-	
33			Sierra Pacific (Wells)	-	-	
34			PacifiCorp	4	-	
35		**Table 3.4**				
36			USBR Pump Load	178	178	
37			Canadian Entitlement	454	454	
38			Non-Treaty Storage	11	11	
39			Libby Coordination	-	-	
40			Hungry Horse	-	-	
41			Riverside Capacity	-	-	
42			Riverside Seasonal	-	-	
43			Pasadena Capacity	-	-	
44			Pasadena Seasonal	-	-	
45			Sierra Pacific (Wells)	-	-	
46			Intertie Losses	-	-	
47			WNP3	-	-	
48			PacifiCorp	4	0	
49			PacifiCorp (So Idaho)	-	-	
50			Upper Baker	1	1	
51			Dittmer Station Service	9	9	
52						
53			Federal Power Deliveries			
54			Preference	6,689	6,739	
55			Tier 2	54	63	
56			Net Preference	6,635	6,676	
57			Industrial	12	12	
58			New Resource	0	0	
59			Intraregional Transfer	11	11	
60			FBS Obligation	644	645	
61			Seasonal or Capacity Exchange	6	1	
62			Conservation Augmentation	-	-	
63			Transmission Losses Before Slice Return	224	225	
64			Slice Return of Losses	30	30	
65			Transmission Losses After Slice Return	194	195	
66						
67		**Annual T1SFCO**		6,917	6,792	
68		**RHWM Process T1SFCO (annual)**		6,985	6,926	
69		**Difference**		(68)	(133)	
70		**Augmentation Price (zero if no incremental Augmentation)**		$ -	$ -	
71		**Hours**		8,784	8,760	
72		**Credit/Cost to Balancing Augmentation**		$ -	$ -	

Table 3.1.5

Rate Design Step
Calculation of Load Shaping and Demand Revenues
Test Period October 2019 - September 2021

	B	E	F	G	H	I	J	K	L
5	**2020**	Demand (kW)	Demand Rate ($/kW/mo.)	**Demand**	Load Shaping HLH (MWh)	Load Shaping LLH (MWh)	Load Shaping HLH Rate ($/MWh)	Load Shaping LLH Rate ($/MWh)	**Load Shaping**
6	Oct-19	364,236	$ 11.42	$ 4,159,577	(144,533)	131,713	$ 23.84	$ 18.88	$ (958,933)
7	Nov-19	326,802	$ 12.07	$ 3,944,497	(305,552)	96,013	$ 25.19	$ 21.84	$ (5,599,938)
8	Dec-19	532,035	$ 13.45	$ 7,155,871	88,033	406,127	$ 28.09	$ 23.56	$ 12,041,174
9	Jan-20	595,108	$ 12.10	$ 7,200,812	553,249	659,502	$ 25.24	$ 19.21	$ 26,633,027
10	Feb-20	400,695	$ 11.66	$ 4,672,099	415,878	458,422	$ 24.36	$ 19.28	$ 18,969,166
11	Mar-20	461,568	$ 9.19	$ 4,241,808	84,800	323,737	$ 19.19	$ 16.11	$ 6,842,716
12	Apr-20	425,981	$ 8.61	$ 3,667,696	195,569	250,659	$ 17.98	$ 14.40	$ 7,125,828
13	May-20	265,601	$ 5.60	$ 1,487,365	(705,510)	(25,887)	$ 11.71	$ 6.55	$ (8,431,085)
14	Jun-20	394,534	$ 5.04	$ 1,988,452	(1,334,634)	(534,027)	$ 10.52	$ 1.68	$ (14,937,515)
15	Jul-20	469,561	$ 10.27	$ 4,822,389	(524,430)	262,191	$ 21.45	$ 15.31	$ (7,234,887)
16	Aug-20	435,330	$ 12.10	$ 5,267,488	(444,584)	227,503	$ 25.24	$ 20.21	$ (6,623,475)
17	Sep-20	385,641	$ 11.91	$ 4,592,980	(196,873)	148,662	$ 24.86	$ 19.98	$ (1,923,994)
18	**Total**			**$ 53,201,033**		$ 86,025			**$ 25,902,084**
19									
20	**2021**	Demand (kW)	Demand Rate ($/kW/mo.)	**Demand**	Load Shaping HLH (MWh)	Load Shaping LLH (MWh)	Load Shaping HLH Rate ($/MWh)	Load Shaping LLH Rate ($/MWh)	**Load Shaping**
21	Oct-20	369,691	$ 11.42	$ 4,221,874	(132,732)	139,180	$ 23.84	$ 18.88	$ (536,607)
22	Nov-20	278,106	$ 12.07	$ 3,356,736	(349,173)	148,593	$ 25.19	$ 21.84	$ (5,550,408)
23	Dec-20	625,035	$ 13.45	$ 8,406,723	145,553	358,287	$ 28.09	$ 23.56	$ 12,529,816
24	Jan-21	537,495	$ 12.10	$ 6,503,683	510,505	723,481	$ 25.24	$ 19.21	$ 26,783,202
25	Feb-21	352,384	$ 11.66	$ 4,108,802	465,112	490,437	$ 24.36	$ 19.28	$ 20,785,750
26	Mar-21	527,904	$ 9.19	$ 4,851,439	131,561	281,088	$ 19.19	$ 16.11	$ 7,052,978
27	Apr-21	439,681	$ 8.61	$ 3,785,653	206,217	258,150	$ 17.98	$ 14.40	$ 7,425,145
28	May-21	274,865	$ 5.60	$ 1,539,242	(699,704)	(17,828)	$ 11.71	$ 6.55	$ (8,310,305)
29	Jun-21	399,880	$ 5.04	$ 2,015,397	(1,329,043)	(529,140)	$ 10.52	$ 1.68	$ (14,870,488)
30	Jul-21	478,333	$ 10.27	$ 4,912,475	(519,057)	270,315	$ 21.45	$ 15.31	$ (6,995,256)
31	Aug-21	444,472	$ 12.10	$ 5,378,105	(438,601)	233,395	$ 25.24	$ 20.21	$ (6,353,386)
32	Sep-21	401,073	$ 11.91	$ 4,776,773	(194,323)	152,758	$ 24.86	$ 19.98	$ (1,778,773)
33	**Total**			**$ 53,856,902**		$ 305,029			**$ 30,181,668**

Rate Design Step
Calculation of PF Preference Rates under Tiered Rate Methodology
Test Period October 2019 - September 2021

	B		C		D		E
5	**Costs ($000)**		**2020**		**2021**		**Rate Period**
6	**Composite**	$	2,520,146	$	2,581,759	$	5,101,905
7	**Non-Slice**	$	147,762	$	125,780	$	273,541
8	**Slice**	$	-	$	-	$	-
9	**Tier 2**	$	12,993	$	16,879	$	29,872
13							
14	**Revenues from Rate Pools to Composite Cost Pool**		**2020**		**2021**		**Rate Period**
15	DSI Revenue Credit	**$**	**(4,303)**	**$**	**(4,291)**	**$**	**(8,594)**
16	Exchange Revenues	**$**	**-**	**$**	**-**	**$**	**-**
17	New Resource Revenues	**$**	**(0.78)**	**$**	**(0.78)**	**$**	**(2)**
18	FPS Revenues	$	(9,499)	$	(9,458)	$	(18,957)
19	Non-Federal RSS Revenues	$	(1,008)	$	(1,084)	$	(2,092)
20	Other Credits	$	(250,744)	$	(251,375)	$	(502,119)
21	Tiered Rate Elements					$	-
22	Unused RHWM Credit Reallocation	$	(68,746)	$	(61,756)	$	(130,502)
23	Balancing Augmentation Adjustment Reallocation	$	(1,213)	$	(4,273)	$	(5,486)
24	Composite Augmentation RSS Revenue Debit/(Credit)	$	(1,668)	$	(1,668)	$	(3,336)
25	Composite Tier 2 RSS Revenue Debit/(Credit)	$	(52)	$	(61)	$	(114)
26	Composite Tier 2 Rate Design Adjustment Debit/(Credit)	$	(510)	$	(615)	$	(1,125)
27	Transmission Losses Adjustment Reallocation	$	(30,066)	$	(30,308)	$	(60,373)
28	Total	$	(367,810)	$	(364,889)	$	(732,699)
29							
30	**Rate Discount Costs Applied to Composite Pool**		**2020**		**2021**		**Rate Period**
31	Irigation Rate Discout Costs	$	20,905	$	20,905	$	41,809
32	Low Density Discount Costs	$	38,505	$	39,107	$	77,612
33	Total	$	59,410	$	60,011	$	119,422
34							
35			**2020**		**2021**		**Rate Period**
36	**Composite**	$	2,211,745	$	2,276,882	$	4,488,627

Rate Design Step
Calculation of PF Preference Rates under Tiered Rate Methodology
Test Period October 2019 - September 2021

	B	C	D	E
5	**Costs ($000)**	**2020**	**2021**	**Rate Period**
6	**Composite**	$ 2,520,146	$ 2,581,759	$ 5,101,905
7	**Non-Slice**	$ 147,762	$ 125,780	$ 273,541
8	**Slice**	$ -	$ -	$ -
9	**Tier 2**	$ 12,993	$ 16,879	$ 29,872
37				
38	**Non-Slice Revenues, Credits, and Costs**	**2020**	**2021**	**Rate Period**
39	Secondary Revenue	$ (346,862)	$ (305,234)	$ (652,096)
40	Unused RHWM Credit Reallocation	$ 68,746	$ 61,756	$ 130,502
41	Other Long Term Contract Revenues	$ -	$ -	$ -
42	Non-federal RSC Revenues	$ 43	$ 34	$ 77
43	NR Revenues from ESS services	$ -	$ -	$ -
44	Load Shaping Revenue	$ (25,902)	$ (30,182)	$ (56,084)
45	Balancing Augmentation Adjustment Reallocation	$ 1,213	$ 4,273	$ 5,486
46	Demand Revenue	$ (53,201)	$ (53,857)	$ (107,058)
47	Non-Slice Augmentation RSC Revenue Debit/(Credit)	$ (651)	$ (651)	$ (1,302)
48	Non-Slice Tier 2 RSC Revenue Debit/(Credit)	$ -	$ -	$ -
49	Non-Slice Tier 2 Rate Design Debit/(Credit)	$ -	$ -	$ -
50	Transmission Losses Adjustment Reallocation	$ 30,066	$ 30,308	$ 60,373
51	Total	$ (326,549)	$ (293,553)	$ (620,101)
52				
53		**2020**	**2021**	**Rate Period**
54	**Non-Slice**	$ (178,787)	$ (167,773)	$ (346,560)

Rate Design Step
Calculation of PF Preference Rates under Tiered Rate Methodology
Test Period October 2019 - September 2021

	B	C		D		E	
5	**Costs ($000)**		**2020**		**2021**	**Rate Period**	
6	**Composite**......	$	2,520,146	$	2,581,759	$	5,101,905
7	**Non-Slice**......	$	147,762	$	125,780	$	273,541
8	**Slice**......	$	-	$	-	$	-
9	**Tier 2**......	$	12,993	$	16,879	$	29,872
55							
56	**TRM Costs after Adjustments**		**2020**		**2021**	**Rate Period**	
57	**Composite**......	$	2,211,745	$	2,276,882	$	4,488,627
58	**Non-Slice**......	$	(178,787)	$	(167,773)	$	(346,560)
59	**Slice**......	$	-	$	-	$	-
60	**Tier 2**......	$	12,993	$	16,879	$	29,872
61	**Total Costs**	$	2,045,951	$	2,125,988	$	4,171,939
62							
63	**Billing Determinants**		**2020**		**2021**	**Rate Period**	
64	**TOCA**......		94.2205		94.6420		94.4313
65	**Non-slice TOCA**......		71.8579		72.2794		72.0686
66	**Slice Percentage**......		22.3627		22.3627		22.3627
67							
68	**Annual TRM Rates ($000/percent)**		**2020**		**2021**	**Rate Period**	
69	**Composite**......	$	23,474	$	24,058	$	23,767
70	**Non-Slice**......	$	(2,488)	$	(2,321)	$	(2,404)
71	**Slice**......	$	-	$	-	$	-
72							
73	**Monthly TRM Rates ($/percent)**		**2020**		**2021**	**Rate Period**	
74	**Composite**......		1,956,178		2,004,819		1,980,553
75	**Non-Slice**......		(207,339)		(193,431)		(200,365)
76	**Slice**......		-		-		-
77							
78	**Tier 2 Rates ($/MWh)**		**2020**		**2021**	**Rate Period**	
79	**Tier 2 Short Term**......	$	30.32	$	33.00	$	31.76
80	**Tier 2 Load Growth**......	$	-	$	-	$	-

Table 3.1.7.1

Rate Design Step
Calculation of Net REP Ratemaking and Recovery Demonstration
Test period October 2019 - September 2021
($ 000, $/MWh)

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
11			2020	2021		PF p	IP	NR	FPS				PF p	IP	NR
12	GENERATION ENERGY														
13													117,793	211	0.01968
14	Federal Base System														
15	Hydro		651,458	724,176		1,375,634	0.0	0.0	0				11.68	0.00	0.00
16	Fish & Wildlife		314,316	329,616		643,933	0.0	0.0	0				5.47	0.00	0.00
17	Trojan		1,200	1,200		2,400	0.0	0.0	0				0.02	0.00	0.00
18	WNP #1		74,283	74,449		148,731	0.0	0.0	0				1.26	0.00	0.00
19	WNP #2		603,670	587,475		1,191,146	0.0	0.0	0				10.11	0.00	0.00
20	WNP #3		87,900	88,202		176,102	0.0	0.0	0				1.50	0.00	0.00
21	System Augmentation		0	0		0	0.0	0.0	0				0.00	0.00	0.00
22	Balancing Power Purchases		69,942	54,023		123,965	0.0	0.0	0				1.05	0.00	0.00
23	Tier 2 Costs		12,993	16,879		29,872	0.0	0.0	0				0.25	0.00	0.00
24	Total Federal Base System		1,815,762	1,876,021		3,691,783	0.0	0.0	0.0				31.34	0.00	0.00
25															
26	New Resources		55,019	53,661		108,680	0.0	0.0	0		PFx Revenue		0.92	0.00	0.00
27	Residential Exchange		3,122,896	3,121,225		500,940	0.0	0.0	0		5,743,182		4.25	0.00	0.00
28	Conservation		195,331	201,147		396,478	0.0	0.0	0				3.37	0.00	0.00
29	BPA Programs & Transmission		361,899	340,900		702,800	0.0	0.0	0		NR Revenue		5.97	0.00	0.00
30	TOTAL COSA ALLOCATIONS		5,550,908	5,592,954		5,400,680	0	0	0		1.6		45.85	0.00	0.00
31															
32															
33	Nonfirm Excess Revenue Credit		(367,691)	(335,677)		(703,368)	0.0	0.0	0.0				-5.97	0.00	0.00
34	LDD/IRD Expense		59,410	60,011		119,422	0.0						1.01	0.00	0.00
35	Other Revenue Credits		(261,771)	(262,559)		(524,330)	0.0	0.0	0.0				-4.45	0.00	0.00
36						0	0.0						0.00	0.00	0.00
37	SP Revenue Surplus/Dfct Adj.		0	0		(94,429)	0	0.0	94,429				-0.80	0.00	0.00
38	NR Rate Revenue					(1.6)		1.6					0.00	0.00	79.51
39	IP Rate Revenue		0	0		(8,592)	8,592						-0.07	40.81	0.00
40															
41	TOTAL RATE DESIGN ADJUSTMENTS		(570,053)	(538,224)		(1,211,300)	8,592	1.6	94,429				-10.28	40.81	79.51
42															
43	Total Generation		4,980,855	5,054,729									**35.57**	**40.81**	**79.51**
44				**PFp Revenue Recovery**		**4,189,381**	8,592	1.6	94,429						

Rate Design Step
Demonstration that TRM PFp Rates Collect the Same Revenue Requirement as the Non-TRM PFp Rate
Test Period October 1, 2019 to September 30, 2021

	B	C	D		E		F	G
4								
5								
6		**Proof: TRM PF Revenues = Non-TRM PF Revenues**						
7								
8				2020		2021		
9		Composite Revenue..............................	$	2,239,305	$	2,249,322		
10		Non-Slice Revenue...............................	$	(172,773)	$	(173,787)		
11		Slice Revenue..	$	-	$	-		
12		Tier 2...	$	12,993	$	16,879		
13		Load Shaping Revenue.........................	$	25,902	$	30,182		
14		Demand Revenue.................................	$	53,201	$	53,857		
15		Total TRM PF Revenue	$	2,158,628	$	2,176,453		
16								
17		Slice Portion of Secondary Revenue......	$	(73,572)	$	(72,129)		
18		Total Net TRM PF Revenue	$	2,085,055	$	2,104,324		
19								
20							PF Rate	
21		Total TRM PF Revenue Analogous to w/ Slice PF			$	4,189,379	35.57	
22								
23		w/ Slice PF Public Rate Revenue from "Net REP" Table			**$**	**4,189,381**	35.57	
24				delta	$	1		
25								
26								

Table 3.1.8.1

Rate Design Step
Calculation of Priority Firm Tier 1 Equivalent Rate Components
Test Period October 2019 - September 2021

Load Shaping Rate	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	
HLH (mills/kWh)	23.84	25.19	28.09	25.24	24.36	19.19	17.98	11.71	10.52	21.45	25.24	24.86	
LLH (mills/kWh)	18.88	21.84	23.56	19.21	19.28	16.11	14.40	6.55	1.68	15.31	20.21	19.98	
Demand Rate ($/kW/mo)	11.42	12.07	13.45	12.10	11.66	9.19	8.61	5.60	5.04	10.27	12.10	11.91	
													Totals
Classic Billing Determinants	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	Tier 1 Energy (GWh)
HLH (GWh)	5,405	6,290	7,030	6,797	5,988	6,061	5,111	5,144	5,695	5,907	5,855	5,262	116,761
LLH (GWh)	3,308	4,377	4,912	4,772	3,946	3,952	3,283	3,500	3,457	3,679	3,555	3,475	Tier 1 Demand (MW/mo)
Demand (MW)	734	605	1,157	1,133	753	989	866	540	794	948	880	787	10,186
Revenue @ Mkt Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	Mkt Energy Revenue ($000)
HLH ($000)	$ 128,867	$ 158,465	$ 197,477	$ 171,577	$ 145,846	$ 116,328	$ 91,896	$ 60,220	$ 59,887	$ 126,676	$ 147,789	$ 130,818	$ 2,314,663
LLH ($000)	$ 62,457	$ 95,592	$ 115,723	$ 91,673	$ 76,072	$ 63,668	$ 47,281	$ 22,924	$ 5,807	$ 56,324	$ 71,856	$ 69,440	Demand Revenue ($000)
Demand ($000)	$ 8,381	$ 7,301	$ 15,563	$ 13,704	$ 8,781	$ 9,093	$ 7,453	$ 3,027	$ 4,004	$ 9,735	$ 10,646	$ 9,370	$ 107,058
													$ 2,421,721
													Tier 1 Revenue Requirement (RR) ($000)
													$ 4,159,509
													Tier 1 RR less Demand Revenue ($000)
													$ 4,052,451
Slice&Non-Slice Tier 1 Equivalent	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	Market Energy Delta (mills/kWh)
HLH (mills/kWh)	38.72	40.07	42.97	40.12	39.24	34.07	32.86	26.59	25.40	36.33	40.12	39.74	(14.88)
LLH (mills/kWh)	33.76	36.72	38.44	34.09	34.16	30.99	29.28	21.43	16.56	30.19	35.09	34.86	
Demand ($/kW/mo)	11.42	12.07	13.45	12.10	11.66	9.19	8.61	5.60	5.04	10.27	12.10	11.91	
Classic Rate Design Revenues	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	Allocated Cost Energy ($000)
HLH ($000)	$ 209,300	$ 252,046	$ 302,058	$ 272,676	$ 234,974	$ 206,489	$ 167,947	$ 136,786	$ 144,643	$ 214,601	$ 234,885	$ 209,115	$ 4,052,043
LLH ($000)	$ 111,681	$ 160,720	$ 188,812	$ 162,682	$ 134,784	$ 122,476	$ 96,137	$ 75,003	$ 57,245	$ 111,066	$ 124,762	$ 121,154	Allocated Cost Demand ($000)
Demand ($000)	$ 8,381	$ 7,301	$ 15,563	$ 13,704	$ 8,781	$ 9,093	$ 7,453	$ 3,027	$ 4,004	$ 9,735	$ 10,646	$ 9,370	$ 107,058
													$ 4,159,101

Average Slice&Non-Slice Tier 1 Rate		
	($000)	(mills/kWh)
Allocated Cost Energy	$ 4,052,043	34.70
Allocated Cost Demand	$ 107,058	0.92
Total Allocated Costs	$ 4,159,101	35.62
Tier 1 Energy (GWh)		116,761
Market Energy Delta (mills/kWh)		(14.88)

Table 3.1.8.2

Rate Design Step
Calculation of Priority Firm Public Melded Rate Equivalent Components
Test Period October 2019 - September 2021

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20		
15	HLH (mills/kWh)	23.84	25.19	28.09	25.24	24.36	19.19	17.98	11.71	10.52	21.45	25.24	24.86		
16	LLH (mills/kWh)	18.88	21.84	23.56	19.21	19.28	16.11	14.40	6.55	1.68	15.31	20.21	19.98		
17	Demand Rate ($/kW/mo)	11.42	12.07	13.45	12.10	11.66	9.19	8.61	5.60	5.04	10.27	12.10	11.91		
18															
19															**Totals**
20	Classic Billing Determinants	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Tier 1&2 Energy (GWh)
21	HLH (GWh)	5,456	6,336	7,078	6,844	6,034	6,111	5,160	5,191	5,744	5,956	5,904	5,309		117,793
22	LLH (GWh)	3,345	4,416	4,951	4,812	3,980	3,990	3,319	3,540	3,493	3,717	3,594	3,513		Tier 1 Demand (MW/mo)
23	Demand (MW)	734	605	1,157	1,133	753	989	866	540	794	948	880	787		10,186
24															
25															
26															
27	Revenue @ Mkt Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Mkt Energy Revenue ($000)
28	HLH ($000)	$ 130,079	$ 159,625	$ 198,828	$ 172,788	$ 146,968	$ 117,287	$ 92,776	$ 60,771	$ 60,402	$ 127,726	$ 149,025	$ 131,988		$ 2,334,542
29	LLH ($000)	$ 63,150	$ 96,439	$ 116,653	$ 92,434	$ 76,734	$ 64,272	$ 47,796	$ 23,190	$ 5,868	$ 56,915	$ 72,637	$ 70,192		Demand Revenue ($000)
30	Demand ($000)	$ 8,381	$ 7,301	$ 15,563	$ 13,704	$ 8,781	$ 9,093	$ 7,453	$ 3,027	$ 4,004	$ 9,735	$ 10,646	$ 9,370		$ 107,058
31															$ 2,441,600
32															Tier 1&2 Revenue Requirement (RR) ($000)
33															$ 4,189,380
34															T1&2RR less Demand Revenue ($000)
35															$ 4,082,323
36	PF Melded Rate Equivalent	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		PF Melded Equivalent Energy Scalar (mills/kWh)
37	HLH (mills/kWh)	38.68	40.03	42.93	40.08	39.20	34.03	32.82	26.55	25.36	36.29	40.08	39.70		(14.84)
38	LLH (mills/kWh)	33.72	36.68	38.40	34.05	34.12	30.95	29.24	21.39	16.52	30.15	35.05	34.82		
39	Demand ($/kW/mo)	11.42	12.07	13.45	12.10	11.66	9.19	8.61	5.60	5.04	10.27	12.10	11.91		
40															
41															
42															
43	Classic Rate Design Revenues	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Allocated Cost Energy ($000)
44	HLH ($000)	$ 211,051	$ 253,638	$ 303,842	$ 274,326	$ 236,540	$ 207,947	$ 169,349	$ 137,830	$ 145,657	$ 216,142	$ 236,613	$ 210,773		$ 4,082,570
45	LLH ($000)	$ 112,787	$ 161,968	$ 190,131	$ 163,840	$ 135,797	$ 123,477	$ 97,052	$ 75,729	$ 57,698	$ 112,082	$ 125,973	$ 122,327		Allocated Cost Demand ($000)
46	Demand ($000)	$ 8,381	$ 7,301	$ 15,563	$ 13,704	$ 8,781	$ 9,093	$ 7,453	$ 3,027	$ 4,004	$ 9,735	$ 10,646	$ 9,370		$ 107,058
47															$ 4,189,628
48	Average Slice&Non-Slice Tier 1&2 Rate														
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 4,082,570	34.66												
51	Allocated Cost Demand	$ 107,058	0.91												
52	Total Allocated Costs	$ 4,189,628	35.57												
53															
54	Tier 1&2 Energy (GWh)		117,793												
55	PF Melded Equivalent Energy Scalar (mills/kWh)		(14.84)												

Table 3.1.8.3

Rate Design Step
Calculation of Industrial Firm Power Rate Components
Test Period October 2019 - September 2021

PF Melded Equiv Rate	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20
HLH (mills/kWh)	38.68	40.03	42.93	40.08	39.20	34.03	32.82	26.55	25.36	36.29	40.08	39.70
LLH (mills/kWh)	33.72	36.68	38.40	34.05	34.12	30.95	29.24	21.39	16.52	30.15	35.05	34.82
Demand Rate ($/kW/mo)	11.42	12.07	13.45	12.10	11.66	9.19	8.61	5.60	5.04	10.27	12.10	11.91

IP Billing Determinants	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	Totals IP Energy (GWh)
HLH (GWh)	10	9	10	10	9	10	10	10	10	10	10	9	211
LLH (GWh)	8	8	8	8	7	8	8	8	7	8	8	8	
Demand (MW)	-	-	-	-	-	-	-	-	-	-	-	-	

Revenue @ PF Melded Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	Energy Rev & Tier1&2 ($000)
HLH ($000)	$ 393	$ 380	$ 413	$ 387	$ 362	$ 346	$ 321	$ 259	$ 250	$ 350	$ 411	$ 363	$ 7,171
LLH ($000)	$ 259	$ 286	$ 316	$ 279	$ 245	$ 238	$ 220	$ 173	$ 122	$ 247	$ 266	$ 283	Demand Rev ($000)
Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
													$ 7,171

VOR
(0.97)
Industrial Margin (mills/kWh)
0.788
Net industrial Margin
(0.179)
Settlement Charge
6.933

IP Rate	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
HLH (mills/kWh)	45.43	46.78	49.68	46.83	45.95	40.78	39.57	33.30	32.11	43.04	46.83	46.45
LLH (mills/kWh)	40.47	43.43	45.15	40.80	40.87	37.70	35.99	28.14	23.27	36.90	41.80	41.57
Demand ($/kW/mo)	11.42	12.07	13.45	12.10	11.66	9.19	8.61	5.60	5.04	10.27	12.10	11.91

Revenues @ Posted IP Rate	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	Allocated Cost Energy ($000)
HLH ($000)	$ 462	$ 444	$ 478	$ 452	$ 424	$ 415	$ 387	$ 325	$ 317	$ 415	$ 480	$ 425	$ 8,592
LLH ($000)	$ 311	$ 339	$ 372	$ 335	$ 294	$ 289	$ 270	$ 228	$ 172	$ 303	$ 317	$ 338	Allocated Cost Demand ($000)
Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
													$ 8,592

Average IP Rate	($000)	(mills/kWh)
Allocated Cost Energy	$ 8,592	40.81
Allocated Cost Demand	$ -	-
Total Allocated Costs	$ 8,592	40.81
IP Energy (GWh)		211
Industrial Margin (mills/kWh)		0.79
VOR		(0.97)
Settlement Charge		6.93

Table 3.1.8.4

Rate Design Step
Calculation of New Resource Rate Components
Test Period October 2017 - September 2019

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20		
15	HLH (mills/kWh)	23.84	25.19	28.09	25.24	24.36	19.19	17.98	11.71	10.52	21.45	25.24	24.86		
16	LLH (mills/kWh)	18.88	21.84	23.56	19.21	19.28	16.11	14.40	6.55	1.68	15.31	20.21	19.98		
17	Demand Rate ($/kW/mo)	11.42	12.07	13.45	12.10	11.66	9.19	8.61	5.60	5.04	10.27	12.10	11.91		
18															
19															**Totals**
20	NR Determinants	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		NR Energy (GWh)
21	HLH (GWh)	0.0009	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008		0.0197
22	LLH (GWh)	0.0009	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008		Demand (MW/mo)
23	Demand (MW)														-
24															
25															
26															
27	Revenue @ Mkt Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Mkt Energy Revenue ($000)
28	HLH ($000)	$ 0.0206	$ 0.0198	$ 0.0229	$ 0.0206	$ 0.0191	$ 0.0163	$ 0.0150	$ 0.0094	$ 0.0087	$ 0.0178	$ 0.0210	$ 0.0199		$ 0.3723
29	LLH ($000)	$ 0.0163	$ 0.0171	$ 0.0192	$ 0.0157	$ 0.0151	$ 0.0137	$ 0.0120	$ 0.0052	$ 0.0014	$ 0.0127	$ 0.0168	$ 0.0160		Demand Revenue ($000)
30	Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
31															$ 0.3723
32															NR Revenue Requirement (RR) ($000)
33															$ 1.5647
34															NR RR less Demand Revenue ($000)
35															$ 1.5647
36	NR Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Market Energy Delta (mills/kWh)
37	HLH (mills/kWh)	84.43	85.78	88.68	85.83	84.95	79.78	78.57	72.30	71.11	82.04	85.83	85.45		(60.59)
38	LLH (mills/kWh)	79.47	82.43	84.15	79.80	79.87	76.70	74.99	67.14	62.27	75.90	80.80	80.57		
39	Demand ($/kW/mo)	11.42	12.07	13.45	12.10	11.66	9.19	8.61	5.60	5.04	10.27	12.10	11.91		
40															
41															
42															
43	evenues @ Posted NR Rate	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Allocated Cost Energy ($000)
44	HLH ($000)	$ 0.0729	$ 0.0673	$ 0.0724	$ 0.0700	$ 0.0666	$ 0.0677	$ 0.0654	$ 0.0578	$ 0.0592	$ 0.0683	$ 0.0714	$ 0.0684		$ 1.5647
45	LLH ($000)	$ 0.0687	$ 0.0646	$ 0.0687	$ 0.0651	$ 0.0626	$ 0.0650	$ 0.0624	$ 0.0537	$ 0.0518	$ 0.0631	$ 0.0672	$ 0.0645		Allocated Cost Demand ($000)
46	Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
47															$ 1.5647
48		Average NR Rate													
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 1.5647	79.51												
51	Allocated Cost Demand	$ -	-												
52	Total Allocated Costs	$ 1.5647	79.51												
53															
54	NR Energy (GWh)		0.0197												
55															

Table 3.1.8.5

Rate Design Step
Calculation of the Non-Slice Priority Firm Tier 1 Equivalent and Load Shaping True-Up Rate Components
Test Period October 2019 - September 2021

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20		
15	HLH (mills/kWh)	23.84	25.19	28.09	25.24	24.36	19.19	17.98	11.71	10.52	21.45	25.24	24.86		
16	LLH (mills/kWh)	18.88	21.84	23.56	19.21	19.28	16.11	14.40	6.55	1.68	15.31	20.21	19.98		
17	Demand Rate ($/kW/mo)	11.42	12.07	13.45	12.10	11.66	9.19	8.61	5.60	5.04	10.27	12.10	11.91		
18															
19															**Totals**
20	Classic Billing Determinants	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Tier 1 Energy (GWh) [FAT1L]
21	HLH (GWh) [FMDT1L]	4,060	4,646	5,420	5,439	4,779	4,677	3,996	3,594	3,715	4,261	4,259	3,923		89,207
22	LLH (GWh) [FMDT1L]	2,589	3,398	3,930	3,970	3,236	3,160	2,626	2,661	2,387	2,934	2,823	2,724		Tier 1 Demand (MW/mo)
23	Demand (MW)	734	605	1,157	1,133	753	989	866	540	794	948	880	787		10,186
24															
25															
26															
27	Revenue @ Mkt Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Mkt Energy Revenue ($000) [MktR]
28	HLH ($000)	$ 96,788	$ 117,038	$ 152,270	$ 137,311	$ 116,392	$ 89,765	$ 71,848	$ 42,067	$ 39,071	$ 91,382	$ 107,519	$ 97,537		$ 1,779,878
29	LLH ($000)	$ 48,880	$ 74,222	$ 92,588	$ 76,257	$ 62,392	$ 50,902	$ 37,821	$ 17,428	$ 4,010	$ 44,918	$ 57,046	$ 54,426		Demand Revenue ($000)
30	Demand ($000)	$ 8,381	$ 7,301	$ 15,563	$ 13,704	$ 8,781	$ 9,093	$ 7,453	$ 3,027	$ 4,004	$ 9,735	$ 10,646	$ 9,370		$ 107,058
31															$ 1,886,936
32															Tier 1 Non-Slice PF Public RR minus Tier 2 Costs
33															$ 3,242,238
34															Tier 1 RR less Demand Revenue ($000) [BLFRnD]
35															$ 3,135,180
36	Non-Slice Tier 1 PF Rate Equivalent	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Load Shaping True-up Rate (mills/kWh) [LSTUR]
37	HLH (mills/kWh)	39.03	40.38	43.28	40.43	39.55	34.38	33.17	26.90	25.71	36.64	40.43	40.05		(15.19)
38	LLH (mills/kWh)	34.07	37.03	38.75	34.40	34.47	31.30	29.59	21.74	16.87	30.50	35.40	35.17		
39	Demand ($/kW/mo)	11.42	12.07	13.45	12.10	11.66	9.19	8.61	5.60	5.04	10.27	12.10	11.91		
40															
41															
42															
43	Classic Rate Design Revenues	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Allocated Cost Energy ($000)
44	HLH ($000)	$ 158,459	$ 187,595	$ 234,591	$ 219,905	$ 189,002	$ 160,789	$ 132,546	$ 96,668	$ 95,520	$ 156,131	$ 172,203	$ 157,132		$ 3,134,908
45	LLH ($000)	$ 88,207	$ 125,844	$ 152,283	$ 136,555	$ 111,548	$ 98,896	$ 77,717	$ 57,845	$ 40,264	$ 89,485	$ 99,922	$ 95,804		Allocated Cost Demand ($000)
46	Demand ($000)	$ 8,381	$ 7,301	$ 15,563	$ 13,704	$ 8,781	$ 9,093	$ 7,453	$ 3,027	$ 4,004	$ 9,735	$ 10,646	$ 9,370		$ 107,058
47															$ 3,241,966
48	Average Non-Slice Tier 1 Rate														
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 3,134,908	35.14												
51	Allocated Cost Demand	$ 107,058	1.20												
52	Total Allocated Costs	$ 3,241,966	36.34												
53															
54	Tier 1 Energy (GWh) [FAT1L]		89,207												
55	Load Shaping True-up Rate (mills/kWh) [LSTUR]		(15.19)												

Table 3.2
Summary RSS Revenue Credits for Tier 1 Cost Pools
($ 000)

	A	B	C	D	E	F	G	H	I	J
1	TRM	COSA	AggregationKey	Category	FY2020	FY2021	FY2022	FY2023	FY2024	FY2025
2	C	RDS	CNTA	Augmentation RSS & RSC Adder	$ 2,319	$ 2,319	$ 2,319	$ 2,319	$ 2,319	$ 2,319
3	C	RDS	CD2RCF	Composite Augmentation RSS Revenue Debit/(Credit)	$ (1,668)	$ (1,668)	$ (1,668)	$ (1,668)	$ (1,668)	$ (1,668)
4	2.0	RDS	2D2RCF	Composite Tier 2 RSS Revenue Debit/(Credit)	$ -	$ -	$ -	$ -	$ -	$ -
5	C	RDS	CD2RCN	Composite Non-Federal RSS Revenue Debit/(Credit)	$ (1,008)	$ (1,084)	$ (1,084)	$ (1,084)	$ (1,084)	$ (1,084)
6	N	RDS	ND2RNF	Non-Slice Augmentation RSC Revenue Debit/(Credit)	$ (651)	$ (651)	$ (651)	$ (651)	$ (651)	$ (651)
7	2.0	RDS	2D2RNF	Non-Slice Tier 2 RSC Revenue Debit/(Credit)	$ -	$ -	$ -	$ -	$ -	$ -
8	N	RDS	ND2RNN	Non-Slice Non-Federal RSC Revenue Debit/(Credit)	$ 43	$ 34	$ 34	$ 34	$ 34	$ 34

Table 3.3
Tier 2 Purchases Made by BPA

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**Start_ Date**	**Maturity_ Date**	**Trade_ Date**	**Internal_ Portfolio**	**Tran_ Status**	**Hours**	**Price**	**Revenue**	**Position**	**Choice**	**Product**	**Term**	**Description**	**Reference**	**Buy_ Sell**	**Pt_of_ Receipt**
2	No FY 2020 and FY 2021 Tier 2 purchases as of June 1, 2019.															

Table 3.4
Inputs to TSS Monthly Rate and Charge

	A	B	C	D	E	F
1	FY2020 PTK + PTFR Scheduling Costs	FY2021 PTK + PTFR Scheduling Costs	FY2017 Scheduled MWh	FY2018 Scheduled MWh	FY2017 Number of Transactions	FY2018 Number of Transactions
2	$3,965,445	$4,100,021	34,474,043	39,316,097	137,738	132,344

Table 3.5
Tier 2 Short-Term Rate Costing Table

	A	B	C
1		ST.3.2020_2024	ST.3.2020_2024
2	Hours	8784	8760
3	Fiscal Year	FY2020	FY2021
4	Rate Period	BP-20	
5	Total Forecast Expected Cost	$ 14,432,053	$ 18,355,175
6	Base Power Purchase Cost (Provided by PTL)	$ -	$ -
7	Power Purchase Cost	$ -	$ -
8	Transmission	$ -	$ -
9	Third Party PTP	$ -	$ -
10	Ancillary Services	$ -	$ -
11	Scheduling, System Control, Dispatch Services		
12	Operating Reserves (Spinning and Non-Spinning)		
13	Within Hour Balancing		
14	Other BA Losses	$ -	$ -
15	Rate Design Components	$ 562,728	$ 675,851
16	Resource Support Services	$ 52,363	$ 61,186
17	Diurnal Flattening Service	$ -	$ -
18	DFS Energy (Variable)	$ -	$ -
19	DFS Capacity (Fixed)	$ -	$ -
20	Forced Outage Reserve	$ -	$ -
21	Forced Outage Reserve Capacity (Fixed)	$ -	$ -
22	Transmission Scheduling Services	$ 52,363	$ 61,186
23	Transmission Curtailment Management Service Capacity (Fixed)	$ -	$ -
24	Transmission Curtailment Management Service Energy (Variable)	$ -	$ -
25	Alternative Transmission Path Costs	$ -	$ -
26	Generation Imbalance	$ -	$ -
27	TSS - Overhead	$ 52,363	$ 61,186
28	Resource Shaping Charge	$ -	$ -
29	Tier 2 Overhead	$ 510,365	$ 614,665
30	Risk Adder	$ -	$ -
31	Carbon Costs Pass Through	$ -	$ -
32	Renewable Energy Credits (MWh)	0	0
33	Quantity Purchased (MWh)	0	0
34	Tier 2 Obligation w/o losses (Billing Determinant)	476,031	556,234
35	Tier 2 Obligation w losses	490,602	573,260
36	Energy (Short)/Long (MWh)	-490,602	-573,260
37	Composite Cost Pool Augmentation (MWh) - BP12 Only	0	0
38	Energy Short (MWh)	-490,602	-573,260
39	Energy to be Remarketed (MWh)	0	0
40	Remarketing Available (MWh)	50,912	47,873
41	Total Tier 2 Pool Shortfall (MWh)	-490,602	-573,260
42	Augmentation Price ($/MWh)	$24.67	$24.71
43	Flat Block RSC ($/MWh)	$19.34	$19.17
44	Remarketing Value ($/MWh)	$28.27	$30.84
45	Remarketed Purchase (MWh)	50,912	47,873
46	Remarketed Purchase Cost	$ 1,439,284	$ 1,476,416
47	Remaining Shortfall (MWh)	-439,690	-525,386
48	Remaining Shortfall Cost	$ 12,430,040	$ 16,202,908
49	Tier 2 Balancing Adjustment Debit/(Credit) - BP12 Only		
50	Remarketing Treatment (Remove From Rate) (Yes or No)	No	No
51	Additional Remarketing (MWh)		
52	Total Fixed Costs	$ 14,432,053	$ 18,355,175
53	Billing Components		
54	ShortTerm ($/MWh)	$ 30.32	$ 33.00
55	Remarketing Credit	$ -	$ -
56	Remarketing Charge	$ -	$ -
57	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (510,365)	$ (614,665)
58	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
59	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (52,363)	$ (61,186)

Table 3.6
Tier 2 Overhead Adder Inputs

	A	B	C	D	E
1		**BP-20**			
2		**FY2020**		**FY2021**	
3	**Line Item**	**FY2020**	**Total Forecast Sales (MWh)**	**FY2021**	**Total Forecast Sales (MWh)**
4	Executive and Administrative Services	$ 3,879,271	76,676,866	$ 3,966,843	75,424,776
5	Generation Project Coordination	$ 6,059,444		$ 6,204,974	
6	Sales & Support	$ 23,191,279		$ 23,954,175	
7	Strategy, Finance & Risk Mgmt.	$ 11,977,967		$ 12,344,564	
8	Agency Services G&A	$ 37,099,206		$ 36,877,499	
9	Total Costs	$ 82,207,167		$ 83,348,055	
10	**Total Costs Divided by Total Sales**		**$1.07**		**$1.11**

Table 3.7
Tier 2 Rate Revenues

	A	B	C
1	Hours	8,784	8,760
2	Fiscal Year	FY2020	FY2021
3	Rate Period	BP-20	
4	ShortTerm Rate $/MWh	$ 30.32	$ 33.00
5	LoadGrowth Rate $/MWh	$ -	$ -
6	Vintage Rate $/MWh	$ -	$ -
7			
8	**ShortTerm**		
9	Portfolio Purchased aMW	0.000	0.000
10	Portfolio Purchased MWh	0	0
11	Portfolio Obligation w/ Losses aMW	55.852	65.441
12	Portfolio Obligation w/ Losses MWh	490,602	573,260
13	Portfolio Billing Determinant aMW	54.193	63.497
14	Portfolio Billing Determinant MWh	476,031	556,234
15	RECs MWh	0	0
16	Base Power Purchase Cost	$ -	$ -
17	Rate Design Components	$ 562,728	$ 675,851
18	Other Costs	$ -	$ -
19	Rate $/MWh	$ 30.32	$ 33.00
20	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (510,365)	$ (614,665)
21	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
22	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (52,363)	$ (61,186)
23	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
24	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
25	Total ShortTerm Rate Revenue	$ 14,433,269	$ 18,355,713
26	Remarketing Credit	$ -	$ -
27	Remarketing Charge	$ -	$ -
28	Forecast Power Purchase Costs	$ 12,430,040	$ 16,202,908
29			
30	**Total Costs**		
31	Total Base Power Purchase Cost	$ -	$ -
32	Total Rate Design Components	$ 562,728	$ 675,851
33	Total Other Costs	$ -	$ -
34	Forecast Power Purchase Costs	$ 12,430,040	$ 16,202,908
35	Total Cost	$ 12,992,768	$ 16,878,759
36			
37	**Total Revenue**		
38	Total Tier 2 Rate Revenue Collection	$ 14,433,269	$ 18,355,713
39	Total Tier 2 Remarketing Charge	$ -	$ -
40	Total Tier 2 Remarketing Credit	$ -	$ -
41	Non-Federal Remarketing Credit	$ (1,439,284)	$ (1,476,416)
42	Total Revenue	$ 12,993,985	$ 16,879,297
43	Value of BPA Purchased Remarketing	$ -	$ -
44	Total Tier 2 Revenue and Value of BPA Purchased Remarketing	$ 12,993,985	$ 16,879,297
45			
46	Total Tier 2 Adjustments and Credits*		
47	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (510,365)	$ (614,665)
48	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
49	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (52,363)	$ (61,186)
50	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
51	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
52			
53	*This amount is in addition to any RSS credits that result from the RSS model		

Table 3.8
Total Remarketing Charges and Credits

	A	B	C
1	Rate Period	BP-20	
2	Fiscal Year	FY2020	FY2021
3	ShortTerm Remarket (MWh)	0	0
4	LoadGrowth Remarket (MWh)	0	0
5	Vintage Remarket (MWh)	0	0
6	Non-Federal Remarket (MWh)	50,912	47,873
7	Total	50,912	47,873
8		0	0
9	ShortTerm Purchase of Remarket (MWh)	50,912	47,873
10	LoadGrowth Purchase of Remarket (MWh)	0	0
11	Vintage Purchase of Remarket (MWh)	0	0
12	BPA Purchase of Remarket (MWh)	0	0
13	Total	50,912	47,873
14			
15	ShortTerm Remarket Credit	$ -	$ -
16	ShortTerm Remarket Charge	$ -	$ -
17	LoadGrowth Remarket Credit	$ -	$ -
18	LoadGrowth Remarket Charge	$ -	$ -
19	Vintage Remarket Credit	$ -	$ -
20	Vintage Remarket Charge	$ -	$ -
21	Non-Federal Resource Remarketing Credit	$ 1,439,284	$ 1,476,416
22			
23	ShortTerm Open Position (MWh)	439,690	525,386
24	LoadGrowth Open Position (MWh)	0	0
25	Vintage Opern Position (MWh)	0	
26	BPA Purchase of Remarket (MWh)	0	0
27	Total Open Position (MWh)	439,690	525,386

Table 3.9
Tier 2 Rate Inputs

	A	B	C	D	E	F	G
1	**Fiscal Year**	**TSS Rate ($/MWh)**	**Aurora Flat Annual Block Market Forecast ($/MWh)**	**Augmentation Price ($/MWh)**	**Augmentation Amount (MWh)**	**Remarketing Value ($/MWh)**	**Available Non-Federal Resource Remarketing (MWh)**
2	FY2020	$ 0.11	$ 19.34	$ 24.67	-	$ 28.27	50,912
3	FY2021	$ 0.11	$ 19.17	$ 24.71	-	$ 30.84	47,873

Table 3.10
Remarketing Value Inputs

	A	B	C	D	E	F	G	H
1	**Pricing Date**	**ICE Settlement[1/] FY 2020 $/MWh**	**ICE Settlement[1/] FY 2021 $/MWh**		**Comparison of Tier 2 purchases made by BPA to ICE Settlements[1/]:**			
2								
3								
4								
5								
6								
7					**Delta $/MWh**	**0.18**	**0.67**	**0.78**
8								
9								
10								
11								
12	**Average**	**27.77**	**30.34**					
13								
14	1/ All ICE Settlements in this table are calculated flat annual average prices based on ICE Settlements for monthly Mid-C electricity peak and off-peak fixed price futures.							

Table 3.11
RSS and Related Charges for FY 2020 and FY 2021

	A	B	C	D	E	F	G	H	I	J
	Purchaser	Resource Name	Services & RSC	Applicable Year(s)	"Resource Input" Tab Adj. for Schedule Annual aMW	Exh. A FY2020 Annual aMW	Exh. A FY2021 Annual aMW	DFS Energy Rate $/MWh	DFS Capacity Charge $/mo	DFS Capacity $/MWh Equiv.
1	Richland	Unspecified Resource Amounts	TSS TCMS	FY2020&FY2021	N/A	8.000	8.000	$ -	$ -	$ -
2	Richland	Horn Rapids Solar	DFS TSS TCMS RSC	FY2021	0.607	0.000	0.582	$ 2.27	$ 6,238	$ 14.09
3	Big Bend	Unspecified Resource Amounts	TSS TCMS	FY2020&FY2021	N/A	4.000	4.000	$ -	$ -	$ -
4	Kootenai	Unspecified Resource Amounts	TSS TCMS	FY2020&FY2021	N/A	4.000	4.000	$ -	$ -	$ -
5	Tier 1	Klondike 3 (07PB-11860)	DFS TSS TCMS RSC	FY2020&FY2021	14.747	15.923	15.945	$ 2.01	$ 138,070	$ 12.79
6	City of Bonners Ferry	Moyie	GMS	FY2020&FY2021	2.852	1.878	1.881	$ -	$ -	$ -
7	City of Centralia	Yelm Hydro	GMS	FY2020&FY2021	9.555	7.109	7.114	$ -	$ -	$ -
8	City of Centralia	Unspecified Resource Amounts	TSS TCMS	FY2020&FY2021	N/A	4.000	5.000	$ -	$ -	$ -
9	City of Cheney	Unspecified Resource Amounts	TSS TCMS	FY2020&FY2021	N/A	1.000	1.000	$ -	$ -	$ -
10	City of Forest Grove	Priest Rapids	SCS	FY2020&FY2021	N/A	1.457	1.457	$ -	$ -	$ -
11	City of Forest Grove	Wanapum	SCS	FY2020&FY2021	N/A	1.483	1.484	$ -	$ -	$ -
12	City of Forest Grove	Unspecified Resource Amounts	TSS TCMS	FY2020&FY2021	N/A	1.000	1.000	$ -	$ -	$ -
13	The City of McMinnville, a municipal corporation o	Priest Rapids	SCS	FY2020&FY2021	N/A	1.457	1.457	$ -	$ -	$ -
14	The City of McMinnville, a municipal corporation o	Wanapum	SCS	FY2020&FY2021	N/A	1.483	1.484	$ -	$ -	$ -
15	The City of McMinnville, a municipal corporation o	Riverbend Biogas	DFS FOR RSC	FY2020&FY2021	3.787	4.069	4.069	$ 0.10	$ 5,790	$ 2.09
16	City of Milton-Freewater	Priest Rapids	SCS	FY2020&FY2021	N/A	1.457	1.457	$ -	$ -	$ -
17	City of Milton-Freewater	Wanapum	SCS	FY2020&FY2021	N/A	1.483	1.484	$ -	$ -	$ -
18	Public Utility District No. 1 of Clallam County	Packwood	DFS FOR TSS TCMS RSC	FY2020&FY2021	1.052	0.673	0.673	$ 0.62	$ 5,888	$ 7.67
19	Columbia REA	Walla Walla Hydro	DFS FOR RSC	FY2020&FY2021	1.353	1.231	1.231	$ 0.30	$ 4,459	$ 4.51
20	Columbia REA	Unspecified Resource Amounts	TSS TCMS	FY2020&FY2021	N/A	5.000	5.000	$ -	$ -	$ -
21	Flathead Electric Cooperative, Inc.	Flathead LFGTE	DFS FOR RSC	FY2020&FY2021	1.361	1.077	1.077	$ 0.18	$ 4,499	$ 4.53
22	Flathead Electric Cooperative, Inc.	Stoltze Lumber	DFS FOR RSC	FY2020&FY2021	2.509	2.499	2.500	$ 0.08	$ 7,569	$ 4.13
23	Public Utility District No. 1 of Kittitas County	Priest Rapids	SCS	FY2020&FY2021	N/A	0.486	0.486	$ -	$ -	$ -
24	Public Utility District No. 1 of Kittitas County	Wanapum	SCS	FY2020&FY2021	N/A	0.495	0.495	$ -	$ -	$ -
25	Inland	Unspecified Resource Amounts	TSS TCMS	FY2020&FY2021	N/A	5.000	8.000	$ -	$ -	$ -
26	Lower Valley Energy, Inc.	Horse Butte TSS Only	TSS TCMS	FY2020&FY2021	N/A	2.577	2.573	$ -	$ -	$ -
27	Lower Valley Energy, Inc.	Unspecified Resource Amounts	TSS TCMS	FY2020&FY2021	N/A	8.000	10.000	$ -	$ -	$ -
28	Public Utility District No. 3 of Mason County	Packwood	SCS TSS TCMS	FY2020&FY2021	N/A	0.656	0.656	$ -	$ -	$ -
29	Public Utility District No. 3 of Mason County	Nine Canyon Wind	DFS TSS TCMS RSC	FY2020&FY2021	0.906	0.809	0.809	$ 2.19	$ 9,319	$ 14.09
30	Public Utility District No. 3 of Mason County	White Creek Wind	DFS TSS TCMS RSC	FY2020&FY2021	1.029	0.919	0.920	$ 2.12	$ 10,348	$ 13.77
31	Mission Valley Power	Kerr	TSS TCMS	FY2020&FY2021	7.704	9.651	9.657	$ -	$ -	$ -
32	PNGC	Lake Creek	SCS	FY2020&FY2021	N/A	1.527	1.530	$ -	$ -	$ -
33	PNGC	Chester Hydro	DFS FOR RSC	FY2020&FY2021	0.706	0.966	0.967	$ 0.25	$ 2,711	$ 5.26
34	PNGC	Island Park	SCS	FY2020&FY2021	N/A	0.989	0.992	$ -	$ -	$ -
35	PNGC	Unspecified Resource Amounts	TSS TCMS	FY2020&FY2021	N/A	120.000	120.000	$ -	$ -	$ -
36	PNGC	NLSL Unspecified Resource Amour	TSS TCMS	FY2020&FY2021	N/A	192.846	226.473	$ -	$ -	$ -
37	Northern Wasco County People's Utility District	NLSL Unspecified Resource Amour	TSS TCMS	FY2020&FY2021	N/A	14.578	20.780	$ -	$ -	$ -
38	Northern Wasco County People's Utility District	Unspecified Resource Amounts	TSS TCMS	FY2020&FY2021	N/A	19.000	26.000	$ -	$ -	$ -
39	Northern Wasco County People's Utility District	McNary Fishway	GMS TSS	FY2020&FY2021	N/A	4.405	4.404	$ -	$ -	$ -
40	Vera Water & Power	Unspecified Resource Amounts	TSS TCMS	FY2020&FY2021	N/A	1.000	1.000	$ -	$ -	$ -
41	Klickitat	McNary Fishway	SCS TSS TCMS	FY2020&FY2021	N/A	4.222	4.222	$ -	$ -	$ -
42	Klickitat	Packwood	SCS TSS TCMS	FY2020&FY2021	N/A	0.197	0.197	$ -	$ -	$ -
43	Klickitat	Unspecified Resource Amounts	TSS TCMS	FY2020&FY2021	N/A	7.000	8.000	$ -	$ -	$ -
44	United Electric Co-op, Inc.	Unspecified Resource Amounts	TSS TCMS	FY2020&FY2021	N/A	3.000	3.000	$ -	$ -	$ -
45	SeaTac	Unspecified Resource Amounts	TSS TCMS	FY2020&FY2021	N/A	0.000	3.000	$ -	$ -	$ -

Table 3.11 Continued
RSS and Related Charges for FY 2020 and FY 2021

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
	RSC $/mo	RSC $/MWh Equiv.	FOR Capacity $/mo	FOR Capacity $/MWh Equiv.	TSS $/mo	TSS $/MWh Equiv.	TCMS $/mo	TCMS $/MWh Equiv.	SCS $/mo	SCS $/MWh Equiv.	GMS $/mo	GMS $/MWh Equiv.	Revenue Credit to Composite Cost Pool FY2020	Revenue Credit to Non-Slice Cost Pool FY2020	Revenue Credit to Composite Cost Pool FY2021	Revenue Credit to Non-Slice Cost Pool FY2021	Forecast Total $/MWh Equivalent Rate
1	$ -	$ -	$ -	$ -	$ 652	$ 0.11	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,819	$ -	$ 7,819	$ -	$ 0.11
2	$ (291)	$ (0.66)	$ -	$ -	$ 55	$ 0.12	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 75,517	$ 8,546	$ 15.82
3	$ -	$ -	$ -	$ -	$ 338	$ 0.12	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,060	$ -	$ 4,060	$ -	$ 0.12
4	$ -	$ -	$ -	$ -	$ 338	$ 0.12	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,060	$ -	$ 4,060	$ -	$ 0.12
5	$ 32,559	$ 3.02	$ -	$ -	$ 913	$ 0.08	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,667,791	$ 650,833	$ 1,667,791	$ 650,833	$ 17.90
6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 805	$ 0.59	$ 9,664	$ 5,582	$ 9,664	$ 5,582	$ 0.59
7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,663	$ 0.70	$ 43,958	$ 15,076	$ 43,958	$ 15,076	$ 0.70
8	$ -	$ -	$ -	$ -	$ 378	$ 0.12	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,541	$ -	$ 4,541	$ -	$ 0.12
9	$ -	$ -	$ -	$ -	$ 97	$ 0.13	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,165	$ -	$ 1,165	$ -	$ 0.13
10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 714	$ 0.67	$ -	$ -	$ 8,564	$ -	$ 8,564	$ -	$ 0.67
11	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 719	$ 0.66	$ -	$ -	$ 8,628	$ -	$ 8,628	$ -	$ 0.66
12	$ -	$ -	$ -	$ -	$ 97	$ 0.13	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,165	$ -	$ 1,165	$ -	$ 0.13
13	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 714	$ 0.67	$ -	$ -	$ 8,564	$ -	$ 8,564	$ -	$ 0.67
14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 719	$ 0.66	$ -	$ -	$ 8,628	$ -	$ 8,628	$ -	$ 0.66
15	$ 2,481	$ 0.90	$ 2,310	$ 0.84	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 97,197	$ 33,036	$ 97,197	$ 33,036	$ 3.93
16	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 714	$ 0.67	$ -	$ -	$ 8,564	$ -	$ 8,564	$ -	$ 0.67
17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 719	$ 0.66	$ -	$ -	$ 8,628	$ -	$ 8,628	$ -	$ 0.66
18	$ (5,417)	$ (7.05)	$ 218	$ 0.28	$ 71	$ 0.09	$ -	$ -	$ -	$ -	$ -	$ -	$ 74,124	$ (59,268)	$ 74,124	$ (59,268)	$ 1.61
19	$ (1,343)	$ (1.36)	$ 461	$ 0.47	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 59,040	$ (12,588)	$ 59,040	$ (12,588)	$ 3.92
20	$ -	$ -	$ -	$ -	$ 419	$ 0.11	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,025	$ -	$ 5,025	$ -	$ 0.11
21	$ (4,510)	$ (4.54)	$ 644	$ 0.65	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 61,717	$ (51,990)	$ 61,717	$ (51,990)	$ 0.82
22	$ (1,678)	$ (0.92)	$ 1,489	$ 0.81	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 108,699	$ (18,377)	$ 108,699	$ (18,377)	$ 4.10
23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 238	$ 0.67	$ -	$ -	$ 2,855	$ -	$ 2,855	$ -	$ 0.67
24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 240	$ 0.66	$ -	$ -	$ 2,875	$ -	$ 2,875	$ -	$ 0.66
25	$ -	$ -	$ -	$ -	$ 539	$ 0.11	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,470	$ -	$ 6,470	$ -	$ 0.11
26	$ -	$ -	$ -	$ -	$ 215	$ 0.11	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,584	$ -	$ 2,584	$ -	$ 0.11
27	$ -	$ -	$ -	$ -	$ 732	$ 0.11	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,783	$ -	$ 8,783	$ -	$ 0.11
28	$ -	$ -	$ -	$ -	$ 58	$ 0.12	$ -	$ -	$ 314	$ 0.65	$ -	$ -	$ 4,464	$ -	$ 4,464	$ -	$ 0.77
29	$ (1,737)	$ (2.63)	$ -	$ -	$ 71	$ 0.11	$ -	$ -	$ -	$ -	$ -	$ -	$ 112,675	$ (3,480)	$ 112,675	$ (3,480)	$ 13.76
30	$ (1,334)	$ (1.78)	$ -	$ -	$ 79	$ 0.11	$ -	$ -	$ -	$ -	$ -	$ -	$ 125,130	$ 3,067	$ 125,130	$ 3,067	$ 14.22
31	$ -	$ -	$ -	$ -	$ 793	$ 0.11	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,515	$ 23,809	$ 9,515	$ 23,809	$ 0.11
32	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 636	$ 0.57	$ -	$ -	$ 7,632	$ -	$ 7,632	$ -	$ 0.57
33	$ 1,749	$ 3.39	$ 183	$ 0.36	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 34,733	$ 22,553	$ 34,733	$ 22,553	$ 9.26
34	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 419	$ 0.58	$ -	$ -	$ 5,033	$ -	$ 5,033	$ -	$ 0.58
35	$ -	$ -	$ -	$ -	$ 2,696	$ 0.03	$ -	$ -	$ -	$ -	$ -	$ -	$ 32,352	$ -	$ 32,352	$ -	$ 0.03
36	$ -	$ -	$ -	$ -	$ 904	$ 0.01	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,851	$ -	$ 10,851	$ -	$ 0.01
37	$ -	$ -	$ -	$ -	$ 901	$ 0.07	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,817	$ -	$ 10,817	$ -	$ 0.07
38	$ -	$ -	$ -	$ -	$ 1,814	$ 0.11	$ -	$ -	$ -	$ -	$ -	$ -	$ 21,773	$ -	$ 21,773	$ -	$ 0.11
39	$ -	$ -	$ -	$ -	$ 360	$ 0.11	$ -	$ -	$ -	$ -	$ 2,250	$ 0.70	$ 31,313	$ -	$ 31,313	$ -	$ 0.81
40	$ -	$ -	$ -	$ -	$ 97	$ 0.13	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,165	$ -	$ 1,165	$ -	$ 0.13
41	$ -	$ -	$ -	$ -	$ 345	$ 0.11	$ -	$ -	$2,157	$ 0.70	$ -	$ -	$ 30,025	$ -	$ 30,025	$ -	$ 0.81
42	$ -	$ -	$ -	$ -	$ 21	$ 0.15	$ -	$ -	$ 94	$ 0.65	$ -	$ -	$ 1,384	$ -	$ 1,384	$ -	$ 0.80
43	$ -	$ -	$ -	$ -	$ 609	$ 0.11	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,303	$ -	$ 7,303	$ -	$ 0.11
44	$ -	$ -	$ -	$ -	$ 258	$ 0.12	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,095	$ -	$ 3,095	$ -	$ 0.12
45	$ -	$ -	$ -	$ -	$ 137	$ 0.13	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,645	$ -	$ 1,645	$ -	$ 0.13

Table 3.12
PF Load Forecast Deviation Liquidated Damages

	A	B	C
1		FY 2020	FY 2021
2	Forecast of Annual Consumer Load MWh	702,720	700,800
3	Actual Annual Consumer Load MWh	1,328,053	1,323,451
4	Actual Annual Consumer Load Above Forecast Amount MWh	625,333	622,651
5	Absolute Value of Load Shaping True-Up Rate	$ 15.19	$ 15.19
6	Annual Liquidated Damages Charge	$ 9,498,808	$ 9,458,069

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SECTION 4: RATE SCHEDULES

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Table Descriptions

Table 4.1
Demand Rates
Table shows calculation of the Tier 1 Demand rate.

Table 4.2
Load Shaping Rates
Table shows calculation of the PF Load Shaping rates, NR Load Shaping Rates, and the flat annual block AURORA market price forecast.

Table 4.3
Tier 2 Load Obligations
Table lists Tier 2 load obligation by Tier 2 rate and year. Also includes load obligation after accounting for transmission losses incurred when delivering Tier 2-priced power to loads.

Table 4.1

Demand Rates

	A	B	C	D	E	F	G	H	I	J
1				**Calendar Year**	**Chained GDP IPD**		**Month**	**Load Shaping Rate HLH $/MWh**	**Demand Shaping Factor**	**Monthly Demand Rate $/kW/mo**
2	Start Year of Operation (FY)	2020		2013	101.76		Oct	23.84	9.25%	$ 11.42
3	Cost of Debt	3.94%	/1	2014	103.68		Nov	25.19	9.78%	$ 12.07
4				2015	104.79		Dec	28.09	10.90%	$ 13.45
5	Inflation Rate	1.64%		2016	105.94		Jan	25.24	9.80%	$ 12.10
6	Insurance Rate	0.25%	/2	2017	107.95		Feb	24.36	9.45%	$ 11.66
7				2018	110.38		Mar	19.19	7.45%	$ 9.19
8	Debt Finance Period (years)	30	/2				Apr	17.98	6.98%	$ 8.61
9	Plant Lifecycle (years)	30	/2		101.64%	5-year Ave.	May	11.71	4.54%	$ 5.60
10							Jun	10.52	4.08%	$ 5.04
11	Plant in service 2020 Vintaged Heat Rate Btu/kWh	8,541	/3	Chained GDP IPD from BEA -- Table 1.1.9. Implicit Price Deflators for Gross Domestic Product (2012 Base year) - Last Revised April 26, 2019			Jul	21.45	8.32%	$ 10.27
12							Aug	25.24	9.80%	$ 12.10
13	Eastside Fixed Fuel $/kW/yr with 10000 Heat Rate 2012$	$ 41.17	/3				Sep	24.86	9.65%	$ 11.91
14	Westside Fixed Fuel $/kW/yr with 10000 Heat Rate 2012$	$ 45.76	/3						**Average $/kW/mo**	**$ 10.29**
15	Eastside Fixed Fuel $/kW/yr with 10000 Heat Rate 2020$	$ 46.90								
16	Westside Fixed Fuel $/kW/yr with 10000 Heat Rate 2020$	$ 52.12								
17	Average of Existing Eastside and Westside with 10000 Heat Rate 2020$	$ 49.51								
18	Average of Existing Eastside and Westside with 8541 Heat Rate 2020$	$ 42.29								
19										
20	All-in Nominal Capital Cost LMS100 $/kW	$ 1,139.06	/4	**End of Fiscal Year**	**Midyear Assessed Value**	**Debt Payment**	**Fixed O&M**	**Insurance**	**Fixed Fuel**	**Cash Expense Each Year**
21	Fixed O&M $/kW/yr 2020$	12.53	/5	2020	$ 1,120.08	$65.39	$ 12.53	$ 2.80	$ 42.29	$ 123.01
22	Fixed Fuel $/kW/yr	$ 42.29		2021	$ 1,082.11	$65.39	$ 12.74	$ 2.71	$ 42.98	$ 123.82
23									**Rate Period Average Expense $/kW/year**	**$ 123.42**
24										
25	/1 Source BPA FY 2019 Third-Party Tax-Exempt Borrowing Rate Forecast 30-year									
26	/2 Source NWPCC 7th Power Plan Appendix H.									
27	/3 Source NWPCC Microfin Model, Version 15.0.5									
28	/4 Source NWPCC Microfin Model assumption of $1000/kW in 2012$, with 100% PUD ownership at 3.94% with plant in service 2020.									
29	/5 Source NWPCC Microfin Model assumption of $11/kW/yr in 2012$.									

Table 4.2
Load Shaping Rates

	A	B	C	D	E	F	G
1		**Aurora Market Prices**				**Load Shaping Rates**	
2		HLH - $/MWh	LLH - $/MWh			HLH - $/MWh	LLH - $/MWh
3	Oct-19	24.98	19.87		October	23.84	18.88
4	Nov-19	26.23	22.39		November	25.19	21.84
5	Dec-19	28.51	23.94		December	28.09	23.56
6	Jan-20	25.75	19.44		January	25.24	19.21
7	Feb-20	24.06	18.75		February	24.36	19.28
8	Mar-20	18.69	15.43		March	19.19	16.11
9	Apr-20	17.24	13.58		April	17.98	14.40
10	May-20	11.54	6.15		May	11.71	6.55
11	Jun-20	10.38	1.86		June	10.52	1.68
12	Jul-20	21.84	16.05		July	21.45	15.31
13	Aug-20	25.31	20.19		August	25.24	20.21
14	Sep-20	24.58	19.55		September	24.86	19.98
15	Oct-20	22.69	17.88				
16	Nov-20	24.15	21.30				$/MWh
17	Dec-20	27.67	23.19	**FY2020 Aurora Flat Annual Block**			19.34
18	Jan-21	24.74	18.98	**FY2021 Aurora Flat Annual Block**			19.17
19	Feb-21	24.65	19.82				
20	Mar-21	19.70	16.79				
21	Apr-21	18.72	15.23				
22	May-21	11.88	6.96				
23	Jun-21	10.65	1.49				
24	Jul-21	21.05	14.57				
25	Aug-21	25.18	20.23				
26	Sep-21	25.14	20.40				

Table 4.3
Tier 2 Load Obligations

	A	B	C	D	E
1	**Sorting Key**	**Rate Pool**	**Fiscal Year**	**aMW Quantity w/o Losses**	**aMW Quantity w/ Losses (1)**
2	LG.1.2012_2028_FY2020	LG.1.2012_2028	FY2020	0.000	0.000
3	LG.1.2012_2028_FY2021	LG.1.2012_2028	FY2021	0.000	0.000
4	ST.3.2020_2024_FY2020	ST.3.2020_2024	FY2020	54.193	55.852
5	ST.3.2020_2024_FY2021	ST.3.2020_2024	FY2021	63.497	65.441
6					
7	*Notes*				
8	(1) Based on a loss factor of 3.06%				

SECTION 5: GENERAL RATE SCHEDULE PROVISIONS

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Table Descriptions

Table 5.1
Weighted LDD for IRD-Eligible Utilities
Table shows the weighted LDD calculation for all IRD-eligible utilities using the irrigation rate mitigation eligible load amounts from Exhibit D of the customers' Regional Dialogue contracts.

Table 5.2
Customers Receiving Remarketing Credits for Non-Federal Resources with DFS
List of customers with remarketed non-Federal resources with DFS and their associated credits.

Table 5.1
Weighted LDD for IRD Eligible Utilities

	A	B	C	D	E	F	G	H	I	J
1			Irrigation Rate Mitigation Amounts from Exhibit D of the Regional Dialogue Contracts (in MWh)						Calculation of Weighted LDD	
2	BES ID	Customer Name	May	June	July	August	September	TOTAL	Eligible LDD	Total IRD MWh * LDD %
3	10024	Benton PUD	53,115.401	75,243.324	89,003.560	62,842.958	32,033.957	312,239.200	0.00%	0.000
4	10183	Franklin PUD	13,084.284	22,897.496	23,715.264	22,079.728	12,630.475	94,407.247	0.00%	0.000
5	10231	Klickitat	3,082.499	4,137.060	5,575.639	4,578.816	4,258.715	21,632.729	7.00%	1,514.291
6	10286	Okanogan PUD	7,203.742	10,441.534	14,718.217	12,876.538	10,168.120	55,408.151	0.00%	0.000
7	10025	Benton REA	11,147.270	18,681.537	24,281.424	19,190.846	9,599.780	82,900.857	6.00%	4,974.051
8	10027	Big Bend	32,097.789	47,948.108	50,352.318	47,379.798	31,891.527	209,669.540	7.00%	14,676.868
9	10391	United	5,273.820	10,806.706	12,770.236	9,182.704	6,236.687	44,270.153	3.00%	1,328.105
10	10046	Central Elec	4,687.388	8,675.756	9,539.100	10,094.599	8,088.614	41,085.457	6.50%	2,670.555
11	10109	Columbia Basin	4,185.302	5,469.756	4,513.543	3,665.441	3,266.293	21,100.335	7.00%	1,477.023
12	10111	Columbia Power	706.641	866.742	1,530.227	1,432.169	691.870	5,227.649	7.00%	365.935
13	10113	Columbia REA	21,258.914	30,832.646	36,368.973	29,431.678	16,763.751	134,655.962	7.00%	9,425.917
14	10173	Fall River	721.884	12,605.402	20,135.316	9,028.407	1,818.987	44,309.996	7.00%	3,101.700
15	10197	Harney	19,540.495	20,142.982	26,028.119	22,023.182	12,164.427	99,899.205	7.00%	6,992.944
16	10209	Inland	10,963.601	14,641.767	12,471.610	11,584.325	10,451.398	60,112.701	7.00%	4,207.889
17	10242	Lost River	3,725.641	9,902.214	10,705.288	8,479.424	4,746.327	37,558.894	7.00%	2,629.123
18	10256	Midstate	7,679.733	8,829.777	11,222.582	9,712.913	4,044.309	41,489.314	6.50%	2,696.805
19	10273	Nespelem	1,216.565	1,778.549	2,517.152	2,274.786	1,734.973	9,522.025	7.00%	666.542
20	10291	OTEC	4,715.415	7,780.401	10,076.149	7,938.224	5,750.412	36,260.601	5.00%	1,813.030
21	10331	Raft River	23,443.131	30,794.718	32,636.209	27,344.114	18,868.686	133,086.858	7.00%	9,316.080
22	10142	East End	1,061.340	1,353.162	1,240.237	1,171.183	943.562	5,769.484	3.00%	173.085
23	10338	Riverside	528.123	986.578	1,167.444	906.478	566.587	4,155.210	3.50%	145.432
24	10360	Southside	2,180.245	5,429.243	5,273.390	4,387.577	2,738.885	20,009.340	4.50%	900.420
25	10343	Salmon River	1,257.157	2,671.504	2,659.622	2,533.409	1,383.969	10,505.661	7.00%	735.396
26	10369	Surprise Valley	6,464.252	9,066.424	11,421.596	11,671.642	7,586.987	46,210.901	7.00%	3,234.763
27	10388	Umatilla	39,288.078	52,679.345	55,478.176	49,073.469	32,253.359	228,772.427	5.50%	12,582.483
28	10442	Wasco	1,883.529	2,101.872	2,215.155	1,766.387	1,766.387	9,733.330	7.00%	681.333
29	10446	Wells	846.538	1,717.671	1,928.492	1,812.765	865.874	7,171.340	6.50%	466.137
30	10502	Yakama Power	1,463.062	1,175.985	1,228.497	1,619.426	1,702.727	7,189.697	7.00%	503.279
31	10436	Vigilante	5,362.005	10,090.787	11,936.481	8,014.268	3,459.717	38,863.258	7.00%	2,720.428
32	10258	Mission Valley	1,857.275	3,714.550	6,500.462	5,571.825	742.910	18,387.022	6.00%	1,103.221
33								**Wt. LDD**	**4.8%**	

Table 5.2
Customers Receiving Remarketing Credits for Non-Federal Resources with DFS

	A	B	C	D	E	F
1	**FY 2020**					
2	**Customers receiving remarketing credits for non-Federal resource(s) with DFS**	**Remarketing Amount (aMW)**	**Remarketing Amount (MWh)**	**Remarketing Value ($/MWh)**	**Annual Remarketing Credit**	**Monthly Remarketing Credit**
3	McMinnville Water and Light	4.069	35,742	28.27	$1,010,429	$84,202
4	Mason County PUD No. 3	1.727	15,170	28.27	$428,855	$35,738
5	Total	5.796	50,912		$1,439,284	$119,940
6	**FY 2021**					
7	**Customers receiving remarketing credits for non-Federal resource(s) with DFS**	**Remarketing Amount (aMW)**	**Remarketing Amount (MWh)**	**Remarketing Value ($/MWh)**	**Annual Remarketing Credit**	**Monthly Remarketing Credit**
8	McMinnville Water and Light	3.736	32,727	30.84	$1,009,312	$84,109
9	Mason County PUD No. 3	1.729	15,146	30.84	$467,104	$38,925
10	Total	5.465	47,873		$1,476,416	$123,034

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SECTION 6: TRANSFER SERVICE

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Table Descriptions

Table 6.1
Transfer Service Costs and Rates
Table shows the calculation of revenue credits associated with Transfer Service charges, including charges for holding reserves, regulation and frequency response, and transfer service delivery.

Table 6.2
Southeast Idaho Load Service (SILS) Market Purchases
Table shows SILS Monthly Power Purchase segmented by cost pool and by fiscal year for the term of the BP – 20 rate case, commencing October 2020 through June of 2021.

Table 6.3
Southeast Idaho Load Service Five-Year Market Purchases
Table provides additional details on computation of SILS costs that went into Table 6.2.

Table 6.1
Transfer Service Costs and Rates

Rate Inputs

BPAT Loss Factor	0.019	
Schedule 5 & 6	0.015	
BPAT Spin Reserve Rate	0.00953	kWh
BPAT Supp Reserve Rate	0.00832	kWh
BPAT Reg & Freq Rate	0.00049	kWh

Regulation and Operating Reserves Charges

Transfer Loads Forecast (MWh)	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
FY 2020	856,371	995,728	1,191,826	1,169,201	1,031,897	968,981	890,691	904,697	965,366	1,059,221	1,010,364	867,331
FY 2021	862,494	1,002,360	1,198,889	1,174,131	1,016,408	973,473	895,984	910,032	970,724	1,064,712	1,015,789	872,550
Total	1,718,865	1,998,088	2,390,715	2,343,332	2,048,305	1,942,454	1,786,675	1,814,729	1,936,090	2,123,933	2,026,153	1,739,881

2020 Rate recovery ($1000s)	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Spin	125	145	174	170	150	141	130	132	141	154	147	126	1,735
Supp	109	127	152	149	131	123	113	115	123	135	128	110	1,515
Reg & Freq	420	488	584	573	506	475	436	443	473	519	495	425	5,837
WECC Fee	25	25	25	25	25	25	25	25	25	25	25	25	299
Total	678	785	934	917	812	764	704	715	761	833	796	687	9,386

2021 Rate recovery ($1000s)	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Spin	126	146	175	171	148	142	131	133	141	155	148	127	1,742
Supp	110	127	152	149	129	124	114	116	123	135	129	111	1,521
Reg & Freq	423	491	587	575	498	477	439	446	476	522	498	428	5,859
WECC Fee	25	25	25	25	25	25	25	25	25	25	25	25	299
Total	683	790	939	921	800	768	708	719	765	837	800	691	9,421

Delivery Charge (using FY18-19 actuals)

Distribution and Low Voltage Costs	2,976,214	$
BPA Customer System Peak	2,340,095	Peak kW
Proposed Rate	$ 1.27	Per kW

Table 6.2
Southeast Idaho Load Service Market Purchases - Monthly Cost by Fiscal Year

	A	B	C	D	E	F	G
		Composite Delta		**Non Slice Allocation**		**Total Purchase Cost**	
	Month	**FY 2020**	**FY 2021**	**FY 2020**	**FY 2021**	**FY 2020**	**FY 2021**
1	October	$ 512,140	$ 512,140	$ 3,490,820	$ 3,659,000	$ 4,002,960	$ 4,171,140
2	November	$ 493,506	$ 491,102	$ 3,350,374	$ 3,478,813	$ 3,843,880	$ 3,969,915
3	December	$ 507,331	$ 509,736	$ 3,434,989	$ 3,628,024	$ 3,942,320	$ 4,137,760
4	January	$ 509,736	$ 507,331	$ 3,566,264	$ 3,759,261	$ 4,076,000	$ 4,266,592
5	February	$ 478,478	$ 461,647	$ 3,353,522	$ 3,433,937	$ 3,832,000	$ 3,895,584
6	March	$ 509,135	$ 511,539	$ 3,562,365	$ 3,809,334	$ 4,071,500	$ 4,320,873
7	April	$ 403,942	$ 403,942	$ 2,058,618	$ 2,217,026	$ 2,462,560	$ 2,620,968
8	May	$ 403,942	$ 403,942	$ 2,027,098	$ 2,183,536	$ 2,431,040	$ 2,587,478
9	June	$ 403,942	$ 403,942	$ 2,058,618	$ 2,217,026	$ 2,462,560	$ 2,620,968
10	July	$ 411,155		$ 3,185,265		$ 3,596,420	
11	August	$ 411,155		$ 3,182,665		$ 3,593,820	
12	September	$ 396,728		$ 3,068,272		$ 3,465,000	
13	FY Total (Sum lines 1-12)	$ 5,441,189	$ 4,205,320	$ 36,338,871	$ 28,385,957	$ 41,780,060	$ 32,591,277
14	Total Service Cost		$ 9,646,509		$ 64,724,828		$ 74,371,337

Monthly Cost Breakdown

Table 6.2 displays the total monthly costs resulting from lines 21 (columns D & E), 23 (columns F & G), and 27 (columns B & C) of table 6.3. To do this additional calculations are needed. The average market delta (AMD) established in Step 8 of Table 6.3 is applied to the following formula $((M_H * SM_H) + (M_L * SM_L)) * AMD$. The Monthly heavy and light hours are multiplied by the contracted megawatt hours in the market purchases, and then multiplied by the average market delta resulting in the amounts shown in the table above. For the FY 2020 and 2021 rates, the annual totals for each fiscal year are added to the transfer services budget and thus included in the composite cost pool. Swapping out AMD for WFM (line 21) or WCP (line 23) will get the results in columns D & E and F & G respectively.

Table 6.3
Southeast Idaho Load Service Five-Year Market Purchases

	A	B	C	D
1	**Summer**	**MW**	**MWh**	**MW (SMF)**
2	HLH	125	1,538,000	
3	LLH	50	482,800	
4	Step 1. Flat			92
5				
6	**Summer**	**HLH**	**LLH**	**Flat**
7	Hours	12,304	9656	21,960
8				
9	**Winter**	**MW**	**MWh**	**MW (WMF)**
10	HLH	125	1,532,000	
11	LLH	100	960,800	
12	Step 2. Flat			114
13				
14	**Winter**	**HLH**	**LLH**	**Flat**
15	Hours	12,256	9,608	21,864
16				
17	Step 3. Total Contract Hours (TCH)			43,824
18				
19	Step 4. Total aMW (TCM)			103
20				
21	Step 5. Market (WFM)			$42.59
22				
23	Step 6. RFO (WCP)			$48.61
24				
25	Step 7. Total Contract Cost (TCC)			$219,386,064
26				
27	Step 8. Delta (AMD)			$6.01
28				
29	Step 9. Total Transfer Service Cost (T)			$27,131,407

Table 6.3 (continued)
Southeast Idaho Load Service Five-Year Market Purchases

Step 1: $((SM_H * S_H) + (SM_L * S_L)) / S_F = SM_F$ Step 1 calculates the combined summer flat weighted average megawatts associated with the five-year market purchases (SM_F). *See* Documentation Table 6.3, line 4. Summer and winter portions of the contract are addressed separately because of the different megawatt amounts associated with each period. This is achieved by taking the summer contracted megawatts multiplied by the associated hours for both heavy and light load, then dividing by the total hours for that period. **Step 2:** $((WM_H * W_H) + (WM_L * W_L)) / W_F = WM_F$ Step 2 calculates the combined winter flat weighted average megawatts associated with the five-year market purchases (WM_F). *See* Documentation Table 6.3, line 12. The calculation process for the winter equation is the same as the summer equation described in line 4. **Step 3:** $SUM (W_F, S_F) = TCH$ Step 3 calculates the sum of all megawatt hours associated with the market purchases (TCH) in line 17. **Step 4:** $((SM_F * S_F) + (WM_F * W_F)) / SUM (W_F, S_F) = TCM$ Once the combined flat weighted average has been calculated for the summer and winter portions of the market purchase, Step 4 calculates flat weighted average megawatts for the entire market purchase (TCM) on line 19. **Step 5:** $((M_1 * RMh_1) + (M_2 * RMh_2)) / TCH = WFM$ Step 5 calculates the weighted average forward market price (WFM) using the ICE forward market curves established at the time each purchase was finalized. To do so, the weighted average market price represented by "M" for each purchase is multiplied by its respective megawatthours (RMH) and then divided by the total megawatthours to yield the WFM, on line 21. **Step 6:** $((R_1 * RMh_1) + (R_2 * RMh_2)) / TCH = WCP$ Step 6 follows the same steps as in steps 1 through 5 but uses each contract's offer price in place of the ICE forward market price to yield the weighted average contract price (WCP), on line 23. **Step 7:** $(TCH * TCM * WCP) = TCC$ Step 7 multiplies the results from steps 3, 4, and 6 to yield the Total Contract Cost (TCC) on line 25. **Step 8:** $(WCP - WFM) = AMD$ Step 8 subtracts the result from Step 6 from the result in Step 5 to yield the Average Market Delta (AMD). The AMD will help determine the total cost to the transfer service customers, on line 27. **Step 9:** $(AMD * TCM) = T$ Step 9 multiplies the Average Market Delta by the TCM to yield the Total Transfer Service Cost (T) on line 29.	**Parameter Definitions** AMD = Average Market Delta M_H = Month heavy hours M_L = Month light hours M_1 = weighted forward market purchase #1 price M_2 = weighted forward market purchase #2 price R_1 = Market purchase #1 offer price R_2 = Market purchase #2 offer price R_A = RFO 1 & 2 weighted average market price RMh_1 = Market purchase #1 contract MW hours RMh_2 = Market purchase #2 contract MW hours S_F = summer flat hours S_H = summer heavy hours S_L = summer light hours SM_F = summer market purchase contract total MW flat SM_H = summer market purchase contract total MW heavy SM_L = summer market purchase contract total MW light T = Transfer service cost TCB = Total Contract Cost TCH = Total Contract Megawatt hours TCM = Total Contract average Megawatts W_F = winter flat hours W_H = winter heavy hours W_L = winter light hours WCP = Weighted average Contract Price WFM = Weighted average Forward Market price WM_F = winter market purchase contract MW flat load WM_H = winter market purchase contract MW heavy load WM_L = winter market purchase contract MW light load

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SECTION 7: SLICE

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SECTION 8: AVERAGE SYSTEM COSTS

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Table Descriptions

Table 8.1
Forecast Average System Costs (ASCs)
Table lists the Fiscal Year Forecast ASCs in $/MWh as determined through the ASC review process.

Table 8.2
IOUs' Exchange Loads and COUs' Forecast Exchange Loads (MWh)
Table lists the monthly two-year average IOU Exchange Loads based on actual loads as submitted by Exchanging Utilities, and the monthly Forecast COU Exchange Loads.

Table 8.1

Forecast Average System Costs (ASCs)
($/MWh)

	A	B		C	
1		**FY 2020**		**FY 2021**	
2	Avista	$	67.60	$	67.60
3	Idaho Power	$	64.41	$	64.41
4	NorthWestern	$	82.91	$	82.91
5	PacifiCorp	$	79.43	$	79.43
6	PGE	$	77.53	$	77.53
7	Puget Sound Energy	$	75.72	$	75.72
8	Clark	$	55.17	$	55.17
9	Snohomish	$	54.68	$	54.68
10					
11	Note: Rate Period ASCs are determined through the ASC review process				

Table 8.2

IOU FY 2020 - 2021 Residential Loads
(MWh)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1		**Oct-19**	**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**FY 2020**
2	Avista	250,017	305,576	401,987	497,120	405,183	374,164	315,687	262,906	245,752	275,401	323,491	278,352	**3,935,637**
3	Idaho Power	455,397	425,972	526,910	684,421	613,208	537,239	427,318	456,029	533,303	693,793	775,280	631,238	**6,760,107**
4	NorthWestern	50,568	54,946	66,837	80,582	68,644	65,532	55,062	48,967	46,873	50,761	60,861	52,544	**702,177**
5	PacifiCorp	576,333	692,983	947,062	1,107,582	881,735	816,242	677,011	603,411	632,963	739,061	805,266	692,335	**9,171,984**
6	PGE	532,636	581,131	746,598	1,026,820	865,450	808,602	671,919	560,527	551,487	591,163	613,550	618,209	**8,168,091**
7	Puget Sound Energy	781,402	966,100	1,207,552	1,447,257	1,272,447	1,266,524	1,013,046	854,074	758,340	742,772	796,096	763,849	**11,869,459**
8														
9		**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**FY 2021**
10	Avista	250,017	305,576	401,987	497,120	405,183	374,164	315,687	262,906	245,752	275,401	323,491	278,352	**3,935,637**
11	Idaho Power	455,397	425,972	526,910	684,421	613,208	537,239	427,318	456,029	533,303	693,793	775,280	631,238	**6,760,107**
12	NorthWestern	50,568	54,946	66,837	80,582	68,644	65,532	55,062	48,967	46,873	50,761	60,861	52,544	**702,177**
13	PacifiCorp	576,333	692,983	947,062	1,107,582	881,735	816,242	677,011	603,411	632,963	739,061	805,266	692,335	**9,171,984**
14	PGE	532,636	581,131	746,598	1,026,820	865,450	808,602	671,919	560,527	551,487	591,163	613,550	618,209	**8,168,091**
15	Puget Sound Energy	781,402	966,100	1,207,552	1,447,257	1,272,447	1,266,524	1,013,046	854,074	758,340	742,772	796,096	763,849	**11,869,459**
16														
17														
18	COU FY 2020 - 2021 Forecast Exchange													
19	Loads (MWh)													
20														
21		**Oct-19**	**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**FY 2020**
22	Clark	177,384	245,667	312,933	293,574	247,104	235,851	185,743	172,809	156,284	182,526	180,169	150,468	**2,540,513**
23	Snohomish	229,325	293,264	403,767	453,275	357,910	413,050	269,240	270,027	200,214	259,737	187,673	262,217	**3,599,699**
24														
25		**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**FY 2021**
26	Clark	178,198	246,662	313,779	294,444	239,012	236,735	186,278	173,727	157,345	183,990	181,623	151,343	**2,543,136**
27	Snohomish	227,458	290,877	400,481	449,012	354,544	409,165	266,708	267,488	198,331	257,295	185,908	259,751	**3,567,017**

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SECTION 9: REVENUE FORECAST

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Table Descriptions

Table 9.1
Revenues at Current Rates
Table provides breakdown of revenue and power purchases at current rates.

Table 9.2
Revenues at Proposed Rates
Table provides breakdown of revenue and power purchases at proposed rates.

Table 9.3
Inter-Business Line Allocations
The forecast revenue Power Services receives from Transmission Services for providing balancing reserve capacity, operating reserve capacity, and the other generation inputs included in the Settlement.

Table 9.4
Balancing Reserve Capacity Quantity Forecast for FY 2020-2021
The forecast quantities of balancing reserves needed on a monthly basis to support the 99.7 percent planning standard.

Table 9.1

Revenues at Current Rates

	A B C D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**Table 9.1 Revenues at Current Rates**													**2019**	
2	**Category**	**201810**	**201811**	**201812**	**201901**	**201902**	**201903**	**201904**	**201905**	**201906**	**201907**	**201908**	**201909**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 201,063	$ 201,063	$ 201,063	$ 201,063	$ 201,063	$ 201,063	$ 201,063	$ 201,063	$ 201,063	$ 201,063	$ 201,063	$ 201,063	$ 2,412,752	5,028
4	Non-Slice Revenue	$ (21,547)	$ (21,547)	$ (21,547)	$ (21,547)	$ (21,547)	$ (21,547)	$ (21,547)	$ (21,547)	$ (21,547)	$ (21,547)	$ (21,547)	$ (21,547)	$ (258,564)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	2,699
6	Load Shaping Revenue	$ (1,899)	$ (7,077)	$ 10,026	$ 28,180	$ 37,017	$ 10,310	$ (1)	$ (25,572)	$ (13,015)	$ 3,767	$ (6,204)	$ (1,898)	$ 33,635	(68)
7	Demand Revenue	$ 2,113	$ 2,271	$ 6,132	$ 3,355	$ 4,419	$ 4,234	$ 3,202	$ 1,980	$ 2,067	$ 4,011	$ 5,236	$ 3,391	$ 42,411	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,411)	$ (5,098)	$ (5,871)	$ (4,818)	$ (2,931)	$ (22,128)	-
9	Low Density Discount	$ (3,147)	$ (2,841)	$ (3,392)	$ (3,638)	$ (4,087)	$ (3,248)	$ (3,244)	$ (2,802)	$ (3,192)	$ (3,729)	$ (3,519)	$ (3,267)	$ (40,107)	-
10	Tier 2	$ 3,725	$ 3,603	$ 3,725	$ 3,725	$ 3,344	$ 3,694	$ 3,579	$ 3,699	$ 3,579	$ 3,699	$ 3,699	$ 3,579	$ 43,650	50
11	RSS (Non-Federal)	$ 2,476	$ 285	$ 308	$ 263	$ 247	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$6,101	$ 4,284	-
12	**PF customers (TRM) sub-total**	**$ 182,783**	**$ 175,756**	**$ 196,316**	**$ 211,401**	**$ 220,457**	**$ 194,606**	**$ 183,153**	**$ 153,510**	**$ 163,958**	**$ 181,492**	**$ 174,011**	**$ 178,491**	**$ 2,215,934**	**7,709**
13	**NR sub-total**	**$ (139)**	**$ (307)**	**$ (252)**	**$ (145)**	**$ (430)**	**$ (524)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (1,797)**	**-**
14	**DSIs sub-total**	**$ 2,912**	**$ 2,925**	**$ 3,147**	**$ 3,059**	**$ 2,764**	**$ 2,789**	**$ 2,511**	**$ 2,303**	**$ 2,211**	**$ 2,816**	**$ 3,050**	**$ 402**	**$ 30,891**	**162**
15	**FPS sub-total**	**$ 301**	**$ 341**	**$ 404**	**$ 406**	**$ 383**	**$ 300**	**$ 300**	**$ 300**	**$ 340**	**$ 360**	**$ 350**	**$ 295**	**$ 4,080**	**-**
16	**Short-term market sales sub-total**	**$ 21,996**	**$ 35,084**	**$ 21,589**	**$ 24,940**	**$ 41,877**	**$ 35,216**	**$ 13,472**	**$ 41,393**	**$ 47,248**	**$ 47,297**	**$ 20,595**	**$ 16,618**	**$ 367,329**	**2,349**
17	**Long Term Contractual Obligations sub-total**	**$ -**	**$ 3,367**	**$ 3,456**	**$ 3,456**	**$ 3,191**	**$ 1,358**	**$ 1,315**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 16,144**	**1,512**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**462**
19	**Other Sales sub-total**	**$ 6**	**$ 15**	**$ 10**	**$ 0**	**$ 0**	**$ 3**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 2,943**	**$ 3,826**	**-**
20	**Gross Sales**	**$207,858**	**$217,183**	**$224,670**	**$243,118**	**$268,242**	**$233,749**	**$200,921**	**$197,676**	**$213,926**	**$232,135**	**$198,177**	**$198,750**	**$2,636,405**	**12,194**
21	Transfer Service Delivery charge	$ 241	$ 280	$ 312	$ 300	$ 343	$ 240	$ 245	$ 240	$ 290	$ 295	$ 280	$ 240	$ 3,306	-
22	Energy Efficiency Revenues	$ 167	$ (131)	$ (350)	$ 268	$ 40	$ (180)	$ 1,631	$ 1,631	$ 1,631	$ 1,631	$ 1,631	$ 1,631	$ 9,600	-
23	Irrigation Pumping Power	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 1,254	15
24	Reserve Energy	$ 1,008	$ 1,008	$ 1,008	$ 1,008	$ 1,008	$ 1,008	$ 646	$ 646	$ 646	$ 646	$ 646	$ 646	$ 9,926	160
25	USBR Owyhee Wheeling Project	$ -	$ -	$ -	$ -	$ -	$ -	$ 107	$ 107	$ 107	$ 107	$ 107	$ 107	$ 640	-
26	Downstream Benefits	$596	$596	$596	$596	$596	$596	$600	$600	$600	$600	$600	$600	$7,175	-
27	Upper Baker Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
28	**Miscellaneous Revenue**	**$2,116**	**$1,856**	**$1,670**	**$2,276**	**$2,091**	**$1,768**	**$3,334**	**$3,329**	**$3,379**	**$3,384**	**$3,369**	**$3,329**	**$31,901**	**175**
29	Balancing Reserve Capacity	$ 4,047	$ 3,916	$ 4,047	$ 4,047	$ 3,655	$ 4,037	$ 3,907	$ 4,051	$ 3,920	$ 4,051	$ 4,051	$ 3,920	$ 47,650	-
30	ACS Risk Share	$ 58	$ 58	$ 58	$ 58	$ 58	$ 58	$ 58	$ 58	$ 58	$ 58	$ 58	$ 58	$ 700	-
31	Risk Mitigation Tool	$ 6	$ 6	$ 6	$ 6	$ 6	$ 6	$ 6	$ 6	$ 6	$ 6	$ 6	$ 6	$ 76	-
32	Imbalance Adjustment for Third-Party Deployed Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
33	Operating Reserve - Spinning	$ 1,537	$ 1,736	$ 1,868	$ 1,955	$ 1,791	$ 2,171	$ 1,855	$ 2,132	$ 2,282	$ 1,927	$ 1,859	$ 1,788	$ 22,901	-
34	Operating Reserve - Supplemental	$ 1,273	$ 1,438	$ 1,547	$ 1,619	$ 1,483	$ 1,798	$ 1,536	$ 1,765	$ 1,890	$ 1,596	$ 1,539	$ 1,480	$ 18,963	-
35	Operating Reserve - Spinning Adjustment	$ -	$ (19)	$ (20)	$ (20)	$ (18)	$ (10)	$ (9)	$ -	$ -	$ -	$ -	$ -	$ (96)	-
36	Operating Reserve - Supplemental Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
37	Energy Imbalance Persistent Deviation	$ -	$ -	$ 9	$ -	$ 44	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 53	-
38	Generation Imbalance Persistent Deviation	$ -	$ 16	$ 29	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 45	-
39	Synchronous Condensing	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 1,273	-
40	Generation Dropping	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 589	-
41	Redispatch	$ 75	$ -	$ -	$ 12	$ -	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 225	-
42	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 8,867	-
43	Station Service	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 1,996	8
44	Energy Imbalance	$ 93	$ 139	$ 167	$ 212	$ 331	$ 155	$ 129	$ 114	$ 30	$ (117)	$ (128)	$ (93)	$ 1,032	-
45	Generation Imbalance	$ 3	$ 180	$ 350	$ 164	$ 52	$ 704	$ 737	$ 473	$ 302	$ 190	$ 346	$ 272	$ 3,772	-
46	Operating Reserve - Energy	$ 40	$ 74	$ 74	$ 25	$ 69	$ 213	$ 67	$ 35	$ 38	$ 112	$ 82	$ 73	$ 902	-
47	**Generation Inputs / Inter-business line**	**$ 8,192**	**$ 8,605**	**$ 9,195**	**$ 9,137**	**$ 8,532**	**$ 10,213**	**$ 9,366**	**$ 9,715**	**$ 9,606**	**$ 8,905**	**$ 8,893**	**$ 8,586**	**$ 108,947**	**8**
48	4(h)(10)(c)	$ 9,302	$ 12,158	$ 22,248	$ 18,238	$ 7,899	$ 5,006	$ 8,065	$ 6,919	$ 5,562	$ 5,562	$ 5,813	$ 8,085	$ 114,857	-
49	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
50	**Treasury Credits**	**$ 9,685**	**$ 12,542**	**$ 22,631**	**$ 18,622**	**$ 8,283**	**$ 5,389**	**$ 8,448**	**$ 7,302**	**$ 5,946**	**$ 5,945**	**$ 6,196**	**$ 8,468**	**$ 119,457**	**-**
51	**Augmentation Power Purchase sub-total**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
52	**Balancing Power Purchase sub-total**	$ 7,270	$ 15,815	$ 27,321	$ 17,990	$ 82,178	$ 63,758	$ 17,109	$ 4,657	$ 3,271	$ 3,776	$ 6,249	$ 4,025	$ 253,418	444
53	**Other Power Purchase sub-total**	$ 2,244	$ 5,126	$ 5,918	$ 2,588	$ 13,261	$ 15,055	$ 3,382	$ 3,495	$ 3,382	$ 3,495	$ 3,495	$ 3,382	$ 64,825	79
54	**Power Purchases**	**$ 9,514**	**$ 20,941**	**$ 33,238**	**$ 20,578**	**$ 95,439**	**$ 78,813**	**$ 20,492**	**$ 8,152**	**$ 6,654**	**$ 7,271**	**$ 9,744**	**$ 7,408**	**$ 318,244**	**524**

Table 9.1

Revenues at Current Rates

	A B C D	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF
1	**Table 9.1 Revenues at Current Rates**													**2020**	
2	**Category**	**201910**	**201911**	**201912**	**202001**	**202002**	**202003**	**202004**	**202005**	**202006**	**202007**	**202008**	**202009**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 188,794	$ 188,794	$ 188,794	$ 188,794	$ 188,794	$ 188,794	$ 188,794	$ 188,794	$ 188,794	$ 188,794	$ 188,794	$ 188,794	$ 2,265,524	5,057
4	Non-Slice Revenue	$ (15,187)	$ (15,187)	$ (15,187)	$ (15,187)	$ (15,187)	$ (15,187)	$ (15,187)	$ (15,187)	$ (15,187)	$ (15,187)	$ (15,187)	$ (15,187)	$ (182,248)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	1,582
6	Load Shaping Revenue	$ (903)	$ (5,957)	$ 13,469	$ 31,999	$ 22,844	$ 8,748	$ 8,243	$ (12,024)	$ (28,608)	$ (7,938)	$ (7,353)	$ (2,202)	$ 20,318	10
7	Demand Revenue	$ 4,421	$ 3,590	$ 7,101	$ 7,471	$ 4,604	$ 5,829	$ 4,208	$ 2,824	$ 3,830	$ 6,379	$ 7,000	$ 6,501	$ 63,757	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,211)	$ (4,211)	$ (4,211)	$ (4,211)	$ (4,211)	$ (21,055)	-
9	Low Density Discount	$ (3,544)	$ (3,544)	$ (3,544)	$ (3,544)	$ (3,544)	$ (3,544)	$ (3,544)	$ (3,544)	$ (3,544)	$ (3,544)	$ (3,544)	$ (3,544)	$ (42,531)	-
10	Tier 2	$ 1,150	$ 1,150	$ 1,150	$ 1,150	$ 1,150	$ 1,150	$ 1,150	$ 1,150	$ 1,150	$ 1,150	$ 1,150	$ 1,150	$ 13,804	54
11	RSS (Non-Federal)	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 1,209	-
12	**PF customers (TRM) sub-total**	**$ 174,832**	**$ 168,946**	**$ 191,883**	**$ 210,782**	**$ 198,761**	**$ 185,890**	**$ 183,764**	**$ 157,902**	**$ 142,324**	**$ 165,543**	**$ 166,749**	**$ 171,401**	**$ 2,118,777**	**6,703**
13	**NR sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
14	**DSIs sub-total**	**$ 413**	**$ 411**	**$ 446**	**$ 430**	**$ 400**	**$ 391**	**$ 346**	**$ 317**	**$ 306**	**$ 388**	**$ 421**	**$ 402**	**$ 4,671**	**12**
15	**FPS sub-total**	**$ 901**	**$ 1,008**	**$ 1,157**	**$ 1,140**	**$ 1,035**	**$ 987**	**$ 927**	**$ 938**	**$ 984**	**$ 1,056**	**$ 1,019**	**$ 910**	**$ 12,063**	**-**
16	**Short-term market sales sub-total**	**$ 9,104**	**$ 17,799**	**$ 20,797**	**$ 35,280**	**$ 36,011**	**$ 26,125**	**$ 20,219**	**$ 32,148**	**$ 29,188**	**$ 39,335**	**$ 24,876**	**$ 13,714**	**$ 304,597**	**2,006**
17	**Long Term Contractual Obligations sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**462**
19	**Other Sales sub-total**	**$ 776**	**$ 776**	**$ 776**	**$ 776**	**$ 776**	**$ 776**	**$ 776**	**$ 776**	**$ 776**	**$ 776**	**$ 776**	**$ 776**	**$ 9,317**	**-**
20	**Gross Sales**	**$186,027**	**$188,940**	**$215,059**	**$248,409**	**$236,983**	**$214,169**	**$206,033**	**$192,082**	**$173,579**	**$207,099**	**$193,841**	**$187,203**	**$2,449,426**	**9,184**
21	Transfer Service Delivery charge	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 299	-
22	Energy Efficiency Revenues	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 8,000	-
23	Irrigation Pumping Power	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 1,278	15
24	Reserve Energy	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 9,746	159
25	USBR Owyhee Wheeling Project	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 1,640	-
26	Downstream Benefits	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 6,701	-
27	Upper Baker Revenues	$ -	$ 85	$ 97	$ 89	$ 81	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 352	-
28	**Miscellaneous Revenue**	**$2,305**	**$2,391**	**$2,403**	**$2,394**	**$2,386**	**$2,305**	**$2,305**	**$2,305**	**$2,305**	**$2,305**	**$2,305**	**$2,305**	**$28,016**	**175**
29	Balancing Reserve Capacity	$ 5,813	$ 5,813	$ 5,813	$ 5,816	$ 5,817	$ 5,818	$ 5,819	$ 5,817	$ 5,817	$ 5,817	$ 5,817	$ 5,817	$ 69,796	-
30	ACS Risk Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
31	Risk Mitigation Tool	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
32	Imbalance Adjustment for Third-Party Deployed Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
33	Operating Reserve - Spinning	$ 1,249	$ 1,428	$ 1,529	$ 1,550	$ 1,546	$ 1,637	$ 1,531	$ 1,546	$ 1,833	$ 1,515	$ 1,413	$ 1,253	$ 18,030	-
34	Operating Reserve - Supplemental	$ 1,249	$ 1,428	$ 1,529	$ 1,550	$ 1,546	$ 1,637	$ 1,531	$ 1,546	$ 1,833	$ 1,515	$ 1,413	$ 1,253	$ 18,030	-
35	Operating Reserve - Spinning Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
36	Operating Reserve - Supplemental Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
37	Energy Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
38	Generation Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
39	Synchronous Condensing	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 831	-
40	Generation Dropping	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 498	-
41	Redispatch	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 250	-
42	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 8,806	-
43	Station Service	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 1,660	9
44	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
45	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	**Generation Inputs / Inter-business line**	**$ 9,314**	**$ 9,673**	**$ 9,874**	**$ 9,919**	**$ 9,913**	**$ 10,096**	**$ 9,886**	**$ 9,913**	**$ 10,487**	**$ 9,852**	**$ 9,647**	**$ 9,328**	**$ 117,901**	**9**
48	4(h)(10)(c)	$ 9,090	$ 6,354	$ 8,413	$ 8,802	$ 7,266	$ 7,143	$ 8,172	$ 6,537	$ 5,928	$ 5,772	$ 5,748	$ 7,025	$ 86,250	-
49	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
50	**Treasury Credits**	**$ 9,474**	**$ 6,738**	**$ 8,797**	**$ 9,185**	**$ 7,649**	**$ 7,526**	**$ 8,555**	**$ 6,921**	**$ 6,311**	**$ 6,155**	**$ 6,131**	**$ 7,408**	**$ 90,850**	**-**
51	**Augmentation Power Purchase sub-total**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
52	**Balancing Power Purchase sub-total**	$ 5,807	$ 4,643	$ 9,433	$ 8,565	$ 5,612	$ 4,802	$ 7,241	$ 3,098	$ 3,122	$ 5,031	$ 7,063	$ 5,524	$ 69,942	216
53	**Other Power Purchase sub-total**	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 12,993	56
54	**Power Purchases**	**$ 6,890**	**$ 5,726**	**$ 10,516**	**$ 9,648**	**$ 6,695**	**$ 5,885**	**$ 8,324**	**$ 4,181**	**$ 4,204**	**$ 6,114**	**$ 8,146**	**$ 6,607**	**$ 82,935**	**272**

Table 9.1

Revenues at Current Rates

	A B C D	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT
1	**Table 9.1 Revenues at Current Rates**													**2021**	
2	**Category**	**202010**	**202011**	**202012**	**202101**	**202102**	**202103**	**202104**	**202105**	**202106**	**202107**	**202108**	**202109**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 189,638	$ 189,638	$ 189,638	$ 189,638	$ 189,638	$ 189,638	$ 189,638	$ 189,638	$ 189,638	$ 189,638	$ 189,638	$ 189,638	$ 2,275,659	6,637
4	Non-Slice Revenue	$ (15,276)	$ (15,276)	$ (15,276)	$ (15,276)	$ (15,276)	$ (15,276)	$ (15,276)	$ (15,276)	$ (15,276)	$ (15,276)	$ (15,276)	$ (15,276)	$ (183,317)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	1,564
6	Load Shaping Revenue	$ (419)	$ (5,846)	$ 13,938	$ 32,278	$ 25,015	$ 8,971	$ 8,584	$ (11,837)	$ (28,464)	$ (7,650)	$ (7,052)	$ (2,040)	$ 25,479	35
7	Demand Revenue	$ 5,122	$ 3,131	$ 9,200	$ 7,305	$ 4,531	$ 7,162	$ 4,777	$ 3,379	$ 4,282	$ 7,066	$ 7,902	$ 7,329	$ 71,186	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,211)	$ (4,211)	$ (4,211)	$ (4,211)	$ (4,211)	$ (21,055)	-
9	Low Density Discount	$ (3,676)	$ (3,676)	$ (3,676)	$ (3,676)	$ (3,676)	$ (3,676)	$ (3,676)	$ (3,676)	$ (3,676)	$ (3,676)	$ (3,676)	$ (3,676)	$ (44,107)	-
10	Tier 2	$ 1,558	$ 1,558	$ 1,558	$ 1,558	$ 1,558	$ 1,558	$ 1,558	$ 1,558	$ 1,558	$ 1,558	$ 1,558	$ 1,558	$ 18,691	63
11	RSS (Non-Federal)	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 1,209	-
12	**PF customers (TRM) sub-total**	**$ 177,047**	**$ 169,630**	**$ 195,482**	**$ 211,927**	**$ 201,891**	**$ 188,478**	**$ 185,706**	**$ 159,676**	**$ 143,951**	**$ 167,549**	**$ 168,983**	**$ 173,423**	**$ 2,143,744**	**8,299**
13	**NR sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
14	**DSIs sub-total**	**$ 413**	**$ 410**	**$ 446**	**$ 430**	**$ 386**	**$ 391**	**$ 346**	**$ 317**	**$ 306**	**$ 388**	**$ 421**	**$ 402**	**$ 4,656**	**12**
15	**FPS sub-total**	**$ 906**	**$ 1,013**	**$ 1,163**	**$ 1,144**	**$ 1,023**	**$ 991**	**$ 932**	**$ 942**	**$ 989**	**$ 1,060**	**$ 1,023**	**$ 914**	**$ 12,098**	**-**
16	**Short-term market sales sub-total**	**$ 9,245**	**$ 16,863**	**$ 17,623**	**$ 32,383**	**$ 34,078**	**$ 27,653**	**$ 22,505**	**$ 28,756**	**$ 25,845**	**$ 36,737**	**$ 24,529**	**$ 13,199**	**$ 289,417**	**1,837**
17	**Long Term Contractual Obligations sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**462**
19	**Other Sales sub-total**	**$ 773**	**$ 773**	**$ 773**	**$ 773**	**$ 773**	**$ 773**	**$ 773**	**$ 773**	**$ 773**	**$ 773**	**$ 773**	**$ 773**	**$ 9,278**	**-**
20	**Gross Sales**	**$188,385**	**$188,689**	**$215,486**	**$246,657**	**$238,151**	**$218,285**	**$210,262**	**$190,465**	**$171,865**	**$206,507**	**$195,728**	**$188,712**	**$2,459,193**	**10,611**
21	Transfer Service Delivery charge	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 299	-
22	Energy Efficiency Revenues	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 8,000	-
23	Irrigation Pumping Power	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 1,278	15
24	Reserve Energy	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 9,746	160
25	USBR Owyhee Wheeling Project	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 1,640	-
26	Downstream Benefits	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 6,701	-
27	Upper Baker Revenues	$ -	$ 82	$ 96	$ 87	$ 82	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 347	-
28	**Miscellaneous Revenue**	**$2,305**	**$2,387**	**$2,401**	**$2,392**	**$2,387**	**$2,305**	**$2,305**	**$2,305**	**$2,305**	**$2,305**	**$2,305**	**$2,305**	**$28,010**	**175**
29	Balancing Reserve Capacity	$ 5,825	$ 5,825	$ 5,825	$ 6,191	$ 6,191	$ 6,191	$ 6,191	$ 6,191	$ 6,191	$ 6,191	$ 6,191	$ 6,191	$ 73,189	-
30	ACS Risk Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
31	Risk Mitigation Tool	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
32	Imbalance Adjustment for Third-Party Deployed Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
33	Operating Reserve - Spinning	$ 1,274	$ 1,444	$ 1,545	$ 1,565	$ 1,563	$ 1,642	$ 1,564	$ 1,565	$ 1,841	$ 1,549	$ 1,432	$ 1,269	$ 18,254	-
34	Operating Reserve - Supplemental	$ 1,274	$ 1,444	$ 1,545	$ 1,565	$ 1,563	$ 1,642	$ 1,564	$ 1,565	$ 1,841	$ 1,549	$ 1,432	$ 1,269	$ 18,254	-
35	Operating Reserve - Spinning Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
36	Operating Reserve - Supplemental Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
37	Energy Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
38	Generation Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
39	Synchronous Condensing	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 831	-
40	Generation Dropping	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 498	-
41	Redispatch	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 250	-
42	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 8,806	-
43	Station Service	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 1,660	9
44	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
45	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	**Generation Inputs / Inter-business line**	**$ 9,376**	**$ 9,717**	**$ 9,918**	**$ 10,324**	**$ 10,320**	**$ 10,479**	**$ 10,323**	**$ 10,325**	**$ 10,876**	**$ 10,292**	**$ 10,059**	**$ 9,733**	**$ 121,742**	**9**
48	4(h)(10)(c)	$ 8,787	$ 6,314	$ 8,561	$ 8,778	$ 7,379	$ 7,313	$ 8,552	$ 6,654	$ 5,980	$ 5,776	$ 5,703	$ 7,053	$ 86,852	-
49	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
50	**Treasury Credits**	**$ 9,171**	**$ 6,697**	**$ 8,944**	**$ 9,161**	**$ 7,763**	**$ 7,697**	**$ 8,936**	**$ 7,038**	**$ 6,364**	**$ 6,160**	**$ 6,086**	**$ 7,436**	**$ 91,452**	**-**
51	**Augmentation Power Purchase sub-total**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
52	**Balancing Power Purchase sub-total**	$ 5,368	$ 4,227	$ 7,439	$ 7,774	$ 5,445	$ 4,279	$ 6,525	$ 3,667	$ 3,192	$ 1,016	$ 3,236	$ 1,854	$ 54,023	152
53	**Other Power Purchase sub-total**	$ 1,407	$ 1,407	$ 1,407	$ 1,407	$ 1,407	$ 1,407	$ 1,407	$ 1,407	$ 1,407	$ 1,407	$ 1,407	$ 1,407	$ 16,879	65
54	**Power Purchases**	**$ 6,774**	**$ 5,633**	**$ 8,846**	**$ 9,181**	**$ 6,852**	**$ 5,685**	**$ 7,932**	**$ 5,073**	**$ 4,599**	**$ 2,423**	**$ 4,643**	**$ 3,261**	**$ 70,902**	**217**

Table 9.2

Revenues at Proposed Rates

	A B C D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**Table 9.2 Revenues at Proposed Rates**													**2019**	
2	**Category**	**201810**	**201811**	**201812**	**201901**	**201902**	**201903**	**201904**	**201905**	**201906**	**201907**	**201908**	**201909**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 201,063	$ 201,063	$ 201,063	$ 201,063	$ 201,063	$ 201,063	$ 201,063	$ 201,063	$ 201,063	$ 201,063	$ 201,063	$ 201,063	$ 2,412,752	5,028
4	Non-Slice Revenue	$ (21,547)	$ (21,547)	$ (21,547)	$ (21,547)	$ (21,547)	$ (21,547)	$ (21,547)	$ (21,547)	$ (21,547)	$ (21,547)	$ (21,547)	$ (21,547)	$ (258,564)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	2,699
6	Load Shaping Revenue	$ (1,899)	$ (7,077)	$ 10,026	$ 28,180	$ 37,017	$ 10,310	$ (1)	$ (25,572)	$ (13,015)	$ 3,767	$ (6,204)	$ (1,898)	$ 33,635	(68)
7	Demand Revenue	$ 2,113	$ 2,271	$ 6,132	$ 3,355	$ 4,419	$ 4,234	$ 3,202	$ 1,980	$ 2,067	$ 4,011	$ 5,236	$ 3,391	$ 42,411	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,411)	$ (5,098)	$ (5,871)	$ (4,818)	$ (2,931)	$ (22,128)	-
9	Low Density Discount	$ (3,147)	$ (2,841)	$ (3,392)	$ (3,638)	$ (4,087)	$ (3,248)	$ (3,244)	$ (2,802)	$ (3,192)	$ (3,729)	$ (3,519)	$ (3,267)	$ (40,107)	-
10	Tier 2	$ 3,725	$ 3,603	$ 3,725	$ 3,725	$ 3,344	$ 3,694	$ 3,579	$ 3,699	$ 3,579	$ 3,699	$ 3,699	$ 3,579	$ 43,650	50
11	RSS (Non-Federal)	$ 2,476	$ 285	$ 308	$ 263	$ 247	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$6,101	$ 4,284	-
12	**PF customers (TRM) sub-total**	**$ 182,783**	**$ 175,756**	**$ 196,316**	**$ 211,401**	**$ 220,457**	**$ 194,606**	**$ 183,153**	**$ 153,510**	**$ 163,958**	**$ 181,492**	**$ 174,011**	**$ 178,491**	**$ 2,215,934**	**7,709**
13	**NR sub-total**	**$ (139)**	**$ (307)**	**$ (252)**	**$ (145)**	**$ (430)**	**$ (524)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (1,797)**	**-**
14	**DSIs sub-total**	**$ 2,912**	**$ 2,925**	**$ 3,147**	**$ 3,059**	**$ 2,764**	**$ 2,789**	**$ 2,511**	**$ 2,303**	**$ 2,211**	**$ 2,816**	**$ 3,050**	**$ 402**	**$ 30,891**	**162**
15	**FPS sub-total**	**$ 301**	**$ 341**	**$ 404**	**$ 406**	**$ 383**	**$ 300**	**$ 300**	**$ 300**	**$ 340**	**$ 360**	**$ 350**	**$ 295**	**$ 4,080**	**-**
16	**Short-term market sales sub-total**	**$ 21,996**	**$ 35,084**	**$ 21,589**	**$ 24,940**	**$ 41,877**	**$ 35,216**	**$ 13,472**	**$ 41,393**	**$ 47,248**	**$ 47,297**	**$ 20,595**	**$ 16,618**	**$ 367,329**	**2,349**
17	**Long Term Contractual Obligations sub-total**	**$ -**	**$ 3,367**	**$ 3,456**	**$ 3,456**	**$ 3,191**	**$ 1,358**	**$ 1,315**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 16,144**	**1,512**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**462**
19	**Other Sales sub-total**	**$ 6**	**$ 15**	**$ 10**	**$ 0**	**$ 0**	**$ 3**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 2,943**	**$ 3,826**	**-**
20	**Gross Sales**	**$207,858**	**$217,183**	**$224,670**	**$243,118**	**$268,242**	**$233,749**	**$200,921**	**$197,676**	**$213,926**	**$232,135**	**$198,177**	**$198,750**	**$2,636,405**	**12,194**
21	Transfer Service Delivery charge	$ 241	$ 280	$ 312	$ 300	$ 343	$ 240	$ 245	$ 240	$ 290	$ 295	$ 280	$ 240	$ 3,306	-
22	Energy Efficiency Revenues	$ 167	$ (131)	$ (350)	$ 268	$ 40	$ (180)	$ 1,631	$ 1,631	$ 1,631	$ 1,631	$ 1,631	$ 1,631	$ 9,600	-
23	Irrigation Pumping Power	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 1,254	15
24	Reserve Energy	$ 1,008	$ 1,008	$ 1,008	$ 1,008	$ 1,008	$ 1,008	$ 646	$ 646	$ 646	$ 646	$ 646	$ 646	$ 9,926	160
25	USBR Owyhee Wheeling Project	$ -	$ -	$ -	$ -	$ -	$ -	$ 107	$ 107	$ 107	$ 107	$ 107	$ 107	$ 640	-
26	Downstream Benefits	$596	$596	$596	$596	$596	$596	$600	$600	$600	$600	$600	$600	$7,175	-
27	Upper Baker Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
28	**Miscellaneous Revenue**	**$2,116**	**$1,856**	**$1,670**	**$2,276**	**$2,091**	**$1,768**	**$3,334**	**$3,329**	**$3,379**	**$3,384**	**$3,369**	**$3,329**	**$31,901**	**175**
29	Balancing Reserve Capacity	$ 4,047	$ 3,916	$ 4,047	$ 4,047	$ 3,655	$ 4,037	$ 3,907	$ 4,051	$ 3,920	$ 4,051	$ 4,051	$ 3,920	$ 47,650	-
30	ACS Risk Share	$ 58	$ 58	$ 58	$ 58	$ 58	$ 58	$ 58	$ 58	$ 58	$ 58	$ 58	$ 58	$ 700	-
31	Risk Mitigation Tool	$ 6	$ 6	$ 6	$ 6	$ 6	$ 6	$ 6	$ 6	$ 6	$ 6	$ 6	$ 6	$ 76	-
32	Imbalance Adjustment for Third-Party Deployed Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
33	Operating Reserve - Spinning	$ 1,537	$ 1,736	$ 1,868	$ 1,955	$ 1,791	$ 2,171	$ 1,855	$ 2,132	$ 2,282	$ 1,927	$ 1,859	$ 1,788	$ 22,901	-
34	Operating Reserve - Supplemental	$ 1,273	$ 1,438	$ 1,547	$ 1,619	$ 1,483	$ 1,798	$ 1,536	$ 1,765	$ 1,890	$ 1,596	$ 1,539	$ 1,480	$ 18,963	-
35	Operating Reserve - Spinning Adjustment	$ -	$ (19)	$ (20)	$ (20)	$ (18)	$ (10)	$ (9)	$ -	$ -	$ -	$ -	$ -	$ (96)	-
36	Operating Reserve - Supplemental Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
37	Energy Imbalance Persistent Deviation	$ -	$ -	$ 9	$ -	$ 44	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 53	-
38	Generation Imbalance Persistent Deviation	$ -	$ 16	$ 29	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 45	-
39	Synchronous Condensing	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 1,273	-
40	Generation Dropping	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 589	-
41	Redispatch	$ 75	$ -	$ -	$ 12	$ -	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 225	-
42	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 8,867	-
43	Station Service	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 1,996	8
44	Energy Imbalance	$ 93	$ 139	$ 167	$ 212	$ 331	$ 155	$ 129	$ 114	$ 30	$ (117)	$ (128)	$ (93)	$ 1,032	-
45	Generation Imbalance	$ 3	$ 180	$ 350	$ 164	$ 52	$ 704	$ 737	$ 473	$ 302	$ 190	$ 346	$ 272	$ 3,772	-
46	Operating Reserve - Energy	$ 40	$ 74	$ 74	$ 25	$ 69	$ 213	$ 67	$ 35	$ 38	$ 112	$ 82	$ 73	$ 902	-
47	**Generation Inputs / Inter-business line**	**$ 8,192**	**$ 8,605**	**$ 9,195**	**$ 9,137**	**$ 8,532**	**$ 10,213**	**$ 9,366**	**$ 9,715**	**$ 9,606**	**$ 8,905**	**$ 8,893**	**$ 8,586**	**$ 108,947**	**8**
48	4(h)(10)(c)	$ 9,302	$ 12,158	$ 22,248	$ 18,238	$ 7,899	$ 5,006	$ 8,065	$ 6,919	$ 5,562	$ 5,562	$ 5,813	$ 8,085	$ 114,857	-
49	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
50	**Treasury Credits**	**$ 9,685**	**$ 12,542**	**$ 22,631**	**$ 18,622**	**$ 8,283**	**$ 5,389**	**$ 8,448**	**$ 7,302**	**$ 5,946**	**$ 5,945**	**$ 6,196**	**$ 8,468**	**$ 119,457**	**-**
51	**Augmentation Power Purchase sub-total**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
52	**Balancing Power Purchase sub-total**	$ 7,270	$ 15,815	$ 27,321	$ 17,990	$ 82,178	$ 63,758	$ 17,109	$ 4,657	$ 3,271	$ 3,776	$ 6,249	$ 4,025	$ 253,418	444
53	**Other Power Purchase sub-total**	$ 2,244	$ 5,126	$ 5,918	$ 2,588	$ 13,261	$ 15,055	$ 3,382	$ 3,495	$ 3,382	$ 3,495	$ 3,495	$ 3,382	$ 64,825	79
54	**Power Purchases**	**$ 10,763**	**$ 19,178**	**$ 30,816**	**$ 21,485**	**$ 85,335**	**$ 67,249**	**$ 20,492**	**$ 8,152**	**$ 6,654**	**$ 7,271**	**$ 9,744**	**$ 7,408**	**$ 318,244**	**524**

Table 9.2

Revenues at Proposed Rates

	A B C D	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF
1	**Table 9.2 Revenues at Proposed Rates**													**2020**	
2	**Category**	**201910**	**201911**	**201912**	**202001**	**202002**	**202003**	**202004**	**202005**	**202006**	**202007**	**202008**	**202009**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 186,609	$ 186,609	$ 186,609	$ 186,609	$ 186,609	$ 186,609	$ 186,609	$ 186,609	$ 186,609	$ 186,609	$ 186,609	$ 186,609	$ 2,239,305	5,057
4	Non-Slice Revenue	$ (14,398)	$ (14,398)	$ (14,398)	$ (14,398)	$ (14,398)	$ (14,398)	$ (14,398)	$ (14,398)	$ (14,398)	$ (14,398)	$ (14,398)	$ (14,398)	$ (172,773)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	1,582
6	Load Shaping Revenue	$ (959)	$ (5,600)	$ 12,041	$ 26,633	$ 18,969	$ 6,843	$ 7,126	$ (8,431)	$ (14,938)	$ (7,235)	$ (6,623)	$ (1,924)	$ 25,902	10
7	Demand Revenue	$ 4,160	$ 3,944	$ 7,156	$ 7,201	$ 4,672	$ 4,242	$ 3,668	$ 1,487	$ 1,988	$ 4,822	$ 5,267	$ 4,593	$ 53,201	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,222)	$ (4,816)	$ (5,546)	$ (4,551)	$ (2,769)	$ (20,905)	-
9	Low Density Discount	$ (3,044)	$ (2,774)	$ (3,400)	$ (3,686)	$ (3,446)	$ (3,119)	$ (3,311)	$ (2,946)	$ (2,851)	$ (3,372)	$ (3,401)	$ (3,155)	$ (38,505)	-
10	Tier 2	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 12,993	54
11	RSS (Non-Federal)	$ 80	$ 80	$ 80	$ 80	$ 80	$ 80	$ 80	$ 80	$ 80	$ 80	$ 80	$ 80	$ 966	-
12	**PF customers (TRM) sub-total**	**$ 173,531**	**$ 168,944**	**$ 189,172**	**$ 203,522**	**$ 193,569**	**$ 181,339**	**$ 180,856**	**$ 160,262**	**$ 152,759**	**$ 162,043**	**$ 164,066**	**$ 170,119**	**$ 2,100,183**	**6,703**
13	**NR sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
14	**DSIs sub-total**	**$ 387**	**$ 392**	**$ 425**	**$ 394**	**$ 365**	**$ 352**	**$ 329**	**$ 277**	**$ 245**	**$ 359**	**$ 399**	**$ 382**	**$ 4,304**	**12**
15	**FPS sub-total**	**$ 901**	**$ 1,008**	**$ 1,157**	**$ 1,140**	**$ 1,035**	**$ 987**	**$ 927**	**$ 938**	**$ 984**	**$ 1,056**	**$ 1,019**	**$ 910**	**$ 12,063**	**-**
16	**Short-term market sales sub-total**	**$ 14,541**	**$ 23,050**	**$ 26,204**	**$ 38,503**	**$ 38,896**	**$ 29,209**	**$ 22,546**	**$ 34,570**	**$ 31,515**	**$ 42,674**	**$ 28,215**	**$ 16,940**	**$ 346,862**	**1,849**
17	**Long Term Contractual Obligations sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**462**
19	**Other Sales sub-total**	**$ 794**	**$ 794**	**$ 794**	**$ 794**	**$ 794**	**$ 794**	**$ 794**	**$ 794**	**$ 794**	**$ 794**	**$ 794**	**$ 794**	**$ 9,530**	**-**
20	**Gross Sales**	**$190,154**	**$194,188**	**$217,752**	**$244,353**	**$234,660**	**$212,682**	**$205,453**	**$196,841**	**$186,297**	**$206,926**	**$194,493**	**$189,145**	**$2,472,943**	**9,027**
21	Transfer Service Delivery charge	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 299	-
22	Energy Efficiency Revenues	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 8,000	-
23	Irrigation Pumping Power	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 1,278	15
24	Reserve Energy	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 9,746	159
25	USBR Owyhee Wheeling Project	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 1,640	-
26	Downstream Benefits	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 6,701	-
27	Upper Baker Revenues	$ -	$ 85	$ 97	$ 89	$ 81	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 352	-
28	**Miscellaneous Revenue**	**$2,305**	**$2,391**	**$2,403**	**$2,394**	**$2,386**	**$2,305**	**$2,305**	**$2,305**	**$2,305**	**$2,305**	**$2,305**	**$2,305**	**$28,016**	**174**
29	Balancing Reserve Capacity	$ 5,813	$ 5,813	$ 5,813	$ 5,816	$ 5,817	$ 5,818	$ 5,819	$ 5,817	$ 5,817	$ 5,817	$ 5,817	$ 5,817	$ 69,796	-
30	ACS Risk Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
31	Risk Mitigation Tool	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
32	Imbalance Adjustment for Third-Party Deployed Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
33	Operating Reserve - Spinning	$ 1,249	$ 1,428	$ 1,529	$ 1,550	$ 1,546	$ 1,637	$ 1,531	$ 1,546	$ 1,833	$ 1,515	$ 1,413	$ 1,253	$ 18,030	-
34	Operating Reserve - Supplemental	$ 1,249	$ 1,428	$ 1,529	$ 1,550	$ 1,546	$ 1,637	$ 1,531	$ 1,546	$ 1,833	$ 1,515	$ 1,413	$ 1,253	$ 18,030	-
35	Operating Reserve - Spinning Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
36	Operating Reserve - Supplemental Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
37	Energy Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
38	Generation Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
39	Synchronous Condensing	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 831	-
40	Generation Dropping	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 498	-
41	Redispatch	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 250	-
42	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 8,806	-
43	Station Service	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 1,660	9
44	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
45	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	**Generation Inputs / Inter-business line**	**$ 9,314**	**$ 9,673**	**$ 9,874**	**$ 9,919**	**$ 9,913**	**$ 10,096**	**$ 9,886**	**$ 9,913**	**$ 10,487**	**$ 9,852**	**$ 9,647**	**$ 9,328**	**$ 117,901**	**-**
48	4(h)(10)(c)	$ 9,090	$ 6,354	$ 8,413	$ 8,802	$ 7,266	$ 7,143	$ 8,172	$ 6,537	$ 5,928	$ 5,772	$ 5,748	$ 7,025	$ 86,250	-
49	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
50	**Treasury Credits**	**$ 9,474**	**$ 6,738**	**$ 8,797**	**$ 9,185**	**$ 7,649**	**$ 7,526**	**$ 8,555**	**$ 6,921**	**$ 6,311**	**$ 6,155**	**$ 6,131**	**$ 7,408**	**$ 90,850**	**-**
51	**Augmentation Power Purchase sub-total**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
52	**Balancing Power Purchase sub-total**	$ 5,807	$ 4,643	$ 9,433	$ 8,565	$ 5,612	$ 4,802	$ 7,241	$ 3,098	$ 3,122	$ 5,031	$ 7,063	$ 5,524	$ 69,942	216
53	**Other Power Purchase sub-total**	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 12,993	56
54	**Power Purchases**	**$ 6,890**	**$ 5,726**	**$ 10,516**	**$ 9,648**	**$ 6,695**	**$ 5,885**	**$ 8,324**	**$ 4,181**	**$ 4,204**	**$ 6,114**	**$ 8,146**	**$ 6,607**	**$ 82,935**	272

Table 9.2

Revenues at Proposed Rates

	A B C D	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT
1	**Table 9.2 -Revenues at Proposed Rates**													**2021**	
2	**Category**	**202010**	**202011**	**202012**	**202101**	**202102**	**202103**	**202104**	**202105**	**202106**	**202107**	**202108**	**202109**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 187,444	$ 187,444	$ 187,444	$ 187,444	$ 187,444	$ 187,444	$ 187,444	$ 187,444	$ 187,444	$ 187,444	$ 187,444	$ 187,444	$ 2,249,322	6,637
4	Non-Slice Revenue	$ (14,482)	$ (14,482)	$ (14,482)	$ (14,482)	$ (14,482)	$ (14,482)	$ (14,482)	$ (14,482)	$ (14,482)	$ (14,482)	$ (14,482)	$ (14,482)	$ (173,787)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	1,564
6	Load Shaping Revenue	$ (537)	$ (5,550)	$ 12,530	$ 26,783	$ 20,786	$ 7,053	$ 7,425	$ (8,310)	$ (14,870)	$ (6,995)	$ (6,353)	$ (1,779)	$ 30,182	35
7	Demand Revenue	$ 4,222	$ 3,357	$ 8,407	$ 6,504	$ 4,109	$ 4,851	$ 3,786	$ 1,539	$ 2,015	$ 4,912	$ 5,378	$ 4,777	$ 53,857	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,222)	$ (4,816)	$ (5,546)	$ (4,551)	$ (2,769)	$ (20,905)	-
9	Low Density Discount	$ (3,098)	$ (2,784)	$ (3,513)	$ (3,694)	$ (3,505)	$ (3,194)	$ (3,362)	$ (2,989)	$ (2,894)	$ (3,421)	$ (3,450)	$ (3,202)	$ (39,107)	-
10	Tier 2	$ 1,407	$ 1,407	$ 1,407	$ 1,407	$ 1,407	$ 1,407	$ 1,407	$ 1,407	$ 1,407	$ 1,407	$ 1,407	$ 1,407	$ 16,879	63
11	RSS (Non-Federal)	$ 87	$ 87	$ 87	$ 87	$ 87	$ 87	$ 87	$ 87	$ 87	$ 87	$ 87	$ 87	$ 1,050	-
12	**PF customers (TRM) sub-total**	**$ 175,043**	**$ 169,478**	**$ 191,879**	**$ 204,048**	**$ 195,844**	**$ 183,166**	**$ 182,304**	**$ 161,472**	**$ 153,890**	**$ 163,405**	**$ 165,478**	**$ 171,483**	**$ 2,117,491**	**8,299**
13	**NR sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
14	**DSIs sub-total**	**$ 387**	**$ 391**	**$ 425**	**$ 394**	**$ 353**	**$ 352**	**$ 329**	**$ 277**	**$ 245**	**$ 359**	**$ 399**	**$ 382**	**$ 4,291**	**12**
15	**FPS sub-total**	**$ 906**	**$ 1,013**	**$ 1,163**	**$ 1,144**	**$ 1,023**	**$ 991**	**$ 932**	**$ 942**	**$ 989**	**$ 1,060**	**$ 1,023**	**$ 914**	**$ 12,098**	**-**
16	**Short-term market sales sub-total**	**$ 12,201**	**$ 19,745**	**$ 20,586**	**$ 33,163**	**$ 34,857**	**$ 28,432**	**$ 23,285**	**$ 29,536**	**$ 26,625**	**$ 37,517**	**$ 25,308**	**$ 13,979**	**$ 305,234**	**1,803**
17	**Long Term Contractual Obligations sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**462**
19	**Other Sales sub-total**	**$ 791**	**$ 791**	**$ 791**	**$ 791**	**$ 791**	**$ 791**	**$ 791**	**$ 791**	**$ 791**	**$ 791**	**$ 791**	**$ 791**	**$ 9,489**	**-**
20	**Gross Sales**	**$189,327**	**$191,417**	**$214,844**	**$239,539**	**$232,869**	**$213,731**	**$207,640**	**$193,018**	**$182,539**	**$203,132**	**$192,999**	**$187,548**	**$2,448,603**	**10,577**
21	Transfer Service Delivery charge	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 299	-
22	Energy Efficiency Revenues	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 8,000	-
23	Irrigation Pumping Power	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 1,278	15
24	Reserve Energy	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 9,746	161
25	USBR Owyhee Wheeling Project	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 1,640	-
26	Downstream Benefits	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 6,701	-
27	Upper Baker Revenues	$ -	$ 82	$ 96	$ 87	$ 82	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 347	-
28	**Miscellaneous Revenue**	**$2,305**	**$2,387**	**$2,401**	**$2,392**	**$2,387**	**$2,305**	**$2,305**	**$2,305**	**$2,305**	**$2,305**	**$2,305**	**$2,305**	**$28,010**	**176**
29	Balancing Reserve Capacity	$ 5,825	$ 5,825	$ 5,825	$ 6,191	$ 6,191	$ 6,191	$ 6,191	$ 6,191	$ 6,191	$ 6,191	$ 6,191	$ 6,191	$ 73,189	-
30	ACS Risk Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
31	Risk Mitigation Tool	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
32	Imbalance Adjustment for Third-Party Deployed Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
33	Operating Reserve - Spinning	$ 1,274	$ 1,444	$ 1,545	$ 1,565	$ 1,563	$ 1,642	$ 1,564	$ 1,565	$ 1,841	$ 1,549	$ 1,432	$ 1,269	$ 18,254	-
34	Operating Reserve - Supplemental	$ 1,274	$ 1,444	$ 1,545	$ 1,565	$ 1,563	$ 1,642	$ 1,564	$ 1,565	$ 1,841	$ 1,549	$ 1,432	$ 1,269	$ 18,254	-
35	Operating Reserve - Spinning Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
36	Operating Reserve - Supplemental Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
37	Energy Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
38	Generation Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
39	Synchronous Condensing	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 831	-
40	Generation Dropping	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 498	-
41	Redispatch	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 250	-
42	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 8,806	-
43	Station Service	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 1,660	9
44	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
45	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	**Generation Inputs / Inter-business line**	**$ 9,376**	**$ 9,717**	**$ 9,918**	**$ 10,324**	**$ 10,320**	**$ 10,479**	**$ 10,323**	**$ 10,325**	**$ 10,876**	**$ 10,292**	**$ 10,059**	**$ 9,733**	**$ 121,742**	**9**
48	4(h)(10)(c)	$ 8,787	$ 6,314	$ 8,561	$ 8,778	$ 7,379	$ 7,313	$ 8,552	$ 6,654	$ 5,980	$ 5,776	$ 5,703	$ 7,053	$ 86,852	-
49	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
50	**Treasury Credits**	**$ 9,171**	**$ 6,697**	**$ 8,944**	**$ 9,161**	**$ 7,763**	**$ 7,697**	**$ 8,936**	**$ 7,038**	**$ 6,364**	**$ 6,160**	**$ 6,086**	**$ 7,436**	**$ 91,452**	**-**
51	**Augmentation Power Purchase sub-total**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
52	**Balancing Power Purchase sub-total**	$ 5,368	$ 4,227	$ 7,439	$ 7,774	$ 5,445	$ 4,279	$ 6,525	$ 3,667	$ 3,192	$ 1,016	$ 3,236	$ 1,854	$ 54,023	152
53	**Other Power Purchase sub-total**	$ 1,407	$ 1,407	$ 1,407	$ 1,407	$ 1,407	$ 1,407	$ 1,407	$ 1,407	$ 1,407	$ 1,407	$ 1,407	$ 1,407	$ 16,879	65
54	**Power Purchases**	**$ 6,774**	**$ 5,633**	**$ 8,846**	**$ 9,181**	**$ 6,852**	**$ 5,685**	**$ 7,932**	**$ 5,073**	**$ 4,599**	**$ 2,423**	**$ 4,643**	**$ 3,261**	**$ 70,902**	**217**

Table 9.3

Inter-Business Line Allocations

	A	B	C	D
	Generation Inputs	**Annual Average for FY 2020-2021 Forecast Quantity (MW)**	**Capacity Unit Cost ($/kW/mo)**	**Annual Average for FY 2020-2021 Revenue Forecast ($)**
1	Balancing Reserve Capacity	697.7	8.54	**$ 71,500,706**
2	Operating Reserve Capacity	463.6	6.52	**$ 36,269,247**
3	Synchronous Condensing			**$ 831,360**
4	Generation Dropping			**$ 497,838**
5	Redispatch			**$ 250,000**
6	Segmentation of COE/Reclamation Network and Delivery Facilities			**$ 8,806,000**
7	Station Service			**$ 1,660,037**
8	**Generation Inputs Total**			**$ 119,815,188**

Table 9.4

Total Balancing Reserve Capacity Requirement
for FY2020-2021 Balancing Reserve Capacity Quantity Forecast
(MW)

		INSTALLED CAPACITY				BALANCING RESERVE BY TYPE						BALANCING RESERVE TOTAL (FEDERAL VS. NON-FEDERAL)			
						REG		LF		GI		TOTAL FEDERAL		TOTAL NON FEDERAL	
		WIND	SOLAR	FCRPS	NON-FEDERAL THERMAL	INC	DEC	INC	DEC	INC	DEC	INC	DEC	INC	DEC
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Oct-19**	2,767	5	3,757	1,608	127.4	-127.4	283.7	-295.4	285.7	-438.1	16.0	-20.1	680.8	-840.8
2	**Nov-19**	2,767	5	3,757	1,608	127.4	-127.4	283.7	-295.4	285.7	-438.1	16.0	-20.1	680.8	-840.8
3	**Dec-19**	2,767	5	3,757	1,608	127.4	-127.4	283.7	-295.4	285.7	-438.1	16.0	-20.1	680.8	-840.8
4	**Jan-20**	2,767	48	3,757	1,608	127.3	-127.3	283.7	-295.7	286.0	-436.9	15.9	-20.0	681.1	-839.9
5	**Feb-20**	2,767	68	3,757	1,608	127.2	-127.3	283.5	-295.7	286.3	-436.1	15.8	-19.8	681.2	-839.4
6	**Mar-20**	2,767	88	3,757	1,608	127.4	-127.3	283.5	-295.7	286.2	-435.7	15.7	-19.7	681.4	-839.0
7	**Apr-20**	2,767	98	3,757	1,608	127.4	-127.3	283.5	-295.5	286.2	-435.8	15.7	-19.6	681.4	-839.0
8	**May-20**	2,767	118	3,757	1,608	127.5	-127.3	283.6	-295.5	285.7	-435.9	15.5	-19.4	681.3	-839.3
9	**Jun-20**	2,767	118	3,757	1,608	127.5	-127.3	283.6	-295.5	285.7	-435.9	15.5	-19.4	681.3	-839.3
10	**Jul-20**	2,767	118	3,757	1,608	127.5	-127.3	283.6	-295.5	285.7	-435.9	15.5	-19.4	681.3	-839.3
11	**Aug-20**	2,767	118	3,757	1,608	127.5	-127.3	283.6	-295.5	285.7	-435.9	15.5	-19.4	681.3	-839.3
12	**Sep-20**	2,767	118	3,757	1,608	127.5	-127.3	283.6	-295.5	285.7	-435.9	15.5	-19.4	681.3	-839.3
13	**Oct-20**	2,767	138	3,757	1,608	127.6	-127.6	284.3	-296.2	285.6	-434.4	15.3	-19.2	682.1	-839.0
14	**Nov-20**	2,767	138	3,757	1,608	127.6	-127.6	284.3	-296.2	285.6	-434.4	15.3	-19.2	682.1	-839.0
15	**Dec-20**	2,767	138	3,757	1,608	127.6	-127.6	284.3	-296.2	285.6	-434.4	15.3	-19.2	682.1	-839.0
16	**Jan-21**	3,067	138	3,757	1,608	130.5	-130.0	292.6	-303.7	317.2	-487.9	15.3	-19.3	725.0	-902.3
17	**Feb-21**	3,067	138	3,757	1,608	130.5	-130.0	292.6	-303.7	317.2	-487.9	15.3	-19.3	725.0	-902.3
18	**Mar-21**	3,067	138	3,757	1,608	130.5	-130.0	292.6	-303.7	317.2	-487.9	15.3	-19.3	725.0	-902.3
19	**Apr-21**	3,067	138	3,757	1,608	130.5	-130.0	292.6	-303.7	317.2	-487.9	15.3	-19.3	725.0	-902.3
20	**May-21**	3,067	138	3,757	1,608	130.5	-130.0	292.6	-303.7	317.2	-487.9	15.3	-19.3	725.0	-902.3
21	**Jun-21**	3,067	138	3,757	1,608	130.5	-130.0	292.6	-303.7	317.2	-487.9	15.3	-19.3	725.0	-902.3
22	**Jul-21**	3,067	138	3,757	1,608	130.5	-130.0	292.6	-303.7	317.2	-487.9	15.3	-19.3	725.0	-902.3
23	**Aug-21**	3,067	138	3,757	1,608	130.5	-130.0	292.6	-303.7	317.2	-487.9	15.3	-19.3	725.0	-902.3
24	**Sep-21**	3,067	138	3,757	1,608	130.5	-130.0	292.6	-303.7	317.2	-487.9	15.3	-19.3	725.0	-902.3
25	**BP-20 AVG**	**2,880**	**107**	**3,757**	**1,608**	**128.6**	**-128.4**	**287.1**	**-298.7**	**297.6**	**-455.5**	**15.5**	**-19.5**	**697.7**	**-863.1**

BONNEVILLE POWER ADMINISTRATION
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