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

2020 Power Rate Schedules and General Rate Schedule Provisions (FY 2020–2021)

October 2019
(Rev. 1-21-2020; 7-1-2020)

United States Department of Energy
Bonneville Power Administration
905 N.E. 11th Avenue
Portland, OR 97232

Bonneville Power Administration's 2020 Power Rate Schedules and General Rate Schedule Provisions (Power Rate Schedules and GRSPs), effective October 1, 2019, and contained herein, were approved on a final basis by the Federal Energy Regulatory Commission (FERC) on April 17, 2020. *U.S. Dep't of Energy – Bonneville Power Admin.*, FERC Docket No. EF19-5, Order Confirming and Approving Rates on a Final Basis (Apr. 17, 2020).

In June, 2020, a rate case proceeding was conducted to propose revisions to the Power Rate Schedules and GRSPs to implement the suspension of the FRP Surcharge. On July 23, 2020, FERC issued interim approval of that rate proposal effective July 1, 2020. *Bonneville Power Admin.*, FERC Docket No. EF20-2, Order Approving Rates on an Interim Basis and Providing Opportunity for Additional Comments (July 23, 2020).

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BONNEVILLE POWER ADMINISTRATION

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SCHEDULE PF-20
PRIORITY FIRM POWER RATE

1. Availability

This schedule is available for the contract purchase of Firm Requirements Power by public bodies, cooperatives, and Federal agencies pursuant to Section 5(b) of the Northwest Power Act. 16 U.S.C. § 839c(b). Firm Requirements Power may be purchased for use within the Pacific Northwest by public bodies, cooperatives, and Federal agencies for resale to ultimate consumers; for direct consumption; and for Construction, Test and Start-Up, and Station Service.

This schedule is also available for the contract purchase of Residential Exchange Program Power by utilities participating in the Residential Exchange Program under Section 5(c) of the Northwest Power Act. 16 U.S.C. § 839c(c). Purchases are made pursuant to a Residential Purchase and Sale Agreement or Residential Exchange Program Settlement Implementation Agreement.

With the exception of sales under the Residential Exchange Program, transmission and ancillary services for use of the Federal Columbia River Transmission System facilities shall be charged separately under the applicable rate schedules.

Effective October 1, 2019, this rate schedule supersedes the PF-18 rate schedule. Sales under the PF-20 rate schedule are subject to the General Rate Schedule Provisions (GRSPs). For sales under this rate schedule, bills shall be rendered and payments due pursuant to the GRSPs and billing process.

2. Priority Firm Public Rate

The PF Public Rate is applicable to the sale of Firm Requirements Power under CHWM Contracts for Load Following, Block, and Slice/Block power products.

2.1 Tier 1 Charges

Tier 1 charges for each customer include two of three Customer charges, a Demand charge, and a Load Shaping charge.

2.1.1 Customer Charges

The Customer Charges are applicable to customers that purchase the following products: Load Following, Block, and Slice/Block.

2.1.1.1 Customer Rates

The monthly Composite, Non-Slice, and Slice Customer rates are specified in the following table:

	Customer Charge ***Rate in dollars per percentage point of billing determinant***		
	Composite	***Non-Slice***	***Slice***
Customer Rate	1,980,553	(200,365)	0

2.1.1.2 Customer Billing Determinants

The Composite, Non-Slice, and Slice Customer billing determinants are specified in the following table:

	Customer Charge ***Billing determinant for each rate***		
	Composite	***Non-Slice***	***Slice***
Load Following	TOCA	TOCA	N/A
Block only	TOCA	TOCA	N/A
Block portion of Slice/Block	Non-Slice TOCA	Non-Slice TOCA	N/A
Slice portion of Slice/Block	Slice %	N/A	Slice %

N/A = Not Applicable

Where:

TOCA = Tier 1 Cost Allocator, expressed as a percentage

For each customer for each Fiscal Year of the Rate Period, the TOCA shall be calculated according to the following formula:

$$\frac{\begin{array}{c}\textit{Minimum of the Customer's:}\\ \textit{a) RHWM, or}\\ \textit{b) Forecast Net Requirement for each Fiscal Year}\end{array}}{\textit{Sum of all Customers' RHWMs}} \times 100$$

The TOCA for a Joint Operating Entity (JOE) is the sum of the TOCAs of the individual members of the JOE.

All customer TOCAs shall be posted on the BPA website. A customer's TOCA may be revised pursuant to the TOCA Adjustment, GRSP II.G.

Slice % = The Slice percentage for the relevant Fiscal Year as specified in Exhibit K of the Slice customer's CHWM Contract.

Non-Slice TOCA = TOCA minus Slice %, expressed as a percentage.

A customer's Non-Slice TOCA may be revised pursuant to the TOCA Adjustment, GRSP II.G.

2.1.2 Demand Charge

The Demand Charge is applicable to customers that purchase the following products: Load Following and Block with Shaping Capacity.

2.1.2.1 Demand Rate

Month	***Rate in $/kW***
October	11.42
November	12.07
December	13.45
January	12.10
February	11.66
March	9.19
April	8.61
May	5.60
June	5.04
July	10.27
August	12.10
September	11.91

2.1.2.2 Demand Billing Determinant

The Demand billing determinant for each billing month equals:

Tier 1 CSP – aHLH – CDQ – SuperPeak

Where:

Tier 1 CSP = Tier 1 Customer System Peak; the customer's maximum Actual Hourly Tier 1 Load during the Heavy Load Hours of the month, in kilowatts

aHLH = Average of the customer's Actual Hourly Tier 1 Loads during the HLH, in kilowatts

CDQ = Contract Demand Quantity specified in the customer's CHWM Contract, Exhibit B, Section 2, in kilowatts

SuperPeak = Super Peak Credit, if any, specified in the customer's CHWM Contract, Exhibit A, Section 9, in kilowatts

If the Demand Charge billing determinant calculation results in a value less than zero, the billing determinant is deemed to be zero.

If a customer does not supply the Super Peak amount listed in its CHWM Contract, Exhibit A, Section 9, for at least two hours of the Super Peak Period, then the customer does not receive a Super Peak Credit for that month.

The Demand billing determinant may be adjusted pursuant to the Demand Rate Billing Determinant Adjustments, GRSP II.D.

2.1.3 Load Shaping Charge

The Load Shaping Charge is applicable to customers that purchase the following products: Load Following, Block, and the Block portion of Slice/Block. In any diurnal period (HLH or LLH), the Load Shaping Charge may be a charge or a credit, depending upon whether the Load Shaping billing determinant is positive or negative.

2.1.3.1 Load Shaping Rate

Month	***Rate in mills/kWh***	
	HLH	***LLH***
October	23.84	18.88
November	25.19	21.84
December	28.09	23.56
January	25.24	19.21
February	24.36	19.28
March	19.19	16.11
April	17.98	14.40
May	11.71	6.55
June	10.52	1.68
July	21.45	15.31
August	25.24	20.21
September	24.86	19.98

2.1.3.2 Load Shaping Billing Determinant

The Load Shaping billing determinant for each of the two diurnal periods, HLH and LLH, for each month equals:

Customer's Actual Monthly/Diurnal Tier 1 Load,
in kilowatthours
minus
Customer's System Shaped Load for the relevant
diurnal period, in kilowatthours.

2.1.3.2.1 System Shaped Load

A System Shaped Load is calculated for each diurnal period of each month. The customer's System Shaped Load for each diurnal period equals:

$RT1SC \times TOCA$

Where:

RT1SC = RHWM Tier 1 System Capability for the relevant diurnal period, in kilowatthours. The RT1SC for each diurnal period of the Rate Period is specified in GRSP II.A.

TOCA = The effective TOCA for a Load Following or Block customer, or the effective Non-Slice TOCA for a Slice/Block customer, expressed as a percentage. The TOCA used in this System Shaped Load calculation shall reflect a customer's Adjusted TOCA pursuant to GRSP II.G.

2.1.3.2.2 Joint Operating Entity (JOE)

For calculating the Load Shaping Charge billing determinant for a JOE, the sum of the Actual Monthly/Diurnal Tier 1 Loads of the JOE's individual members and the sum of System Shaped Loads of the JOE's individual members shall be used.

2.1.4 Risk Adjustments

The Power CRAC (GRSP II.O), the Power RDC (GRSP II.P), and the Power FRP Surcharge (GRSP II.Q) are adjustments to certain Tier 1 rates that apply to the following products under the PF-20 rate schedule: Load Following, Block, and the Block portion of Slice/Block. Any adjustments to rates and GRSPs during the Rate Period due to such risk adjustments are summarized in GRSP Appendix A.

2.2 Tier 2 Charges

2.2.1 Tier 2 Load Shaping Charge

Pursuant to Section 4.3 of the Tiered Rate Methodology (TRM), BP-12-A-03, the Tier 2 Load Shaping charge is applicable to customers that have elected to serve Above-RHWM Load with purchases at Tier 2 rates and are forecast to have Above-RHWM Load less than 8,760 MWh.

2.2.1.1 Tier 2 Load Shaping Rates

The Tier 2 Load Shaping Rates shall be the rates specified in Section 2.1.3.1.

2.2.1.2 Tier 2 Load Shaping Billing Determinant

The Tier 2 Load Shaping billing determinant for each billing period is incorporated into the billing determinant established in Section 2.1.3.2.

2.2.2 Short-Term Charge

The Short-Term Charge is applicable to customers that have elected to purchase power at the Tier 2 Short-Term Rate, as specified in the customers' CHWM Contracts, Exhibit C, Section 2.5.

2.2.2.1 Short-Term Rate

Fiscal Year	*Rate in mills/kWh*
2020	30.32
2021	33.00

2.2.2.2 Short-Term Billing Determinant

The billing determinant is the annual amount of power specified in the customer's CHWM Contract. For the relevant billing month, the contract amount shall be converted from average megawatts to kilowatthours assuming a Flat Annual Shape.

3. Priority Firm Melded Rate

The PF Melded rate is applicable to the sale of Firm Requirements Power under contracts other than CHWM Contracts.

Rates under contracts that contain charges that escalate based on BPA's PF rate shall be based on the rates listed in this section in addition to any applicable transmission and ancillary service charges.

The PF Melded rate is not available to loads that are considered Unanticipated Loads as defined in Unanticipated Load Service, GRSP II.M.1.

3.1 Energy Charge

3.1.1 Energy Rate

Month	*Rate in mills/kWh*	
	HLH	*LLH*
October	38.68	33.72
November	40.03	36.68
December	42.93	38.40
January	40.08	34.05
February	39.20	34.12
March	34.03	30.95
April	32.82	29.24
May	26.55	21.39
June	25.36	16.52
July	36.29	30.15
August	40.08	35.05
September	39.70	34.82

The PF Melded energy rates in the table above are subject to risk adjustments during the Rate Period pursuant to the Power CRAC (GRSP II.O), the Power RDC (GRSP II.P), and the Power FRP Surcharge (GRSP II.Q). Any adjustments to rates and GRSPs during the Rate Period due to such risk adjustments are summarized in GRSP Appendix A.

3.1.2 Energy Billing Determinant

The Energy billing determinant is the total of the hourly loads, as specified in the customer's contract, for each diurnal period, in kilowatthours.

3.2 Demand Charge

3.2.1 Demand Rate

Month	***Rate in $/kW***
October	11.42
November	12.07
December	13.45
January	12.10
February	11.66
March	9.19
April	8.61
May	5.60
June	5.04
July	10.27
August	12.10
September	11.91

3.2.2 Demand Billing Determinant

The Demand billing determinant is the maximum hourly load, as specified in the customer's contract, during the HLH of the month, in kilowatts, less the average of the hourly loads during the HLH of the month, in kilowatts.

4. Unanticipated Load Service Charge

The Unanticipated Load Service Charge under the PF-20 Rate Schedule, specified in GRSP II.M.2, is applicable to the sale of Firm Requirements Power to serve Unanticipated Loads.

5. Resource Support Services Rates

Resource Support Services rates are applicable to customers that elect to take Diurnal Flattening Service, Secondary Crediting Service, or Grandfathered Generation Management Service for non-Federal resources. The Resource Shaping Charge and Adjustment are applicable to customers that elect this option to financially convert the output of certain types of non-Federal resources to a flat annual block of power as specified in their CHWM Contracts.

5.1 Diurnal Flattening Service (DFS)

Customers that have elected to take DFS for their non-Federal resources are subject to the DFS Energy and Capacity Charges specified in GRSP II.I.1.

5.2 Resource Shaping Charge and Adjustment

Customers that have elected to take this option for their new resources other than small non-dispatchable resources are subject to the Resource Shaping Charge and Adjustment specified in GRSP II.I.2.

5.3 Secondary Crediting Service (SCS)

Customers that have elected to take SCS for their non-Federal resources are subject to the SCS Shortfall Energy Charge, SCS Secondary Energy Charge, and SCS Administrative Charge specified in GRSP II.I.3.

5.4 Grandfathered Generation Management Service (GMS)

Load Following customers dedicating to their Tier 1 Load the entire output of an Existing Resource that received GMS under Subscription are subject to a GMS Reservation Fee specified in GRSP II.I.6.

6. Priority Firm Exchange Rate

The PF Exchange rate applies to sales of Residential Exchange Program Power under a Residential Purchase and Sale Agreement or Residential Exchange Program Settlement Implementation Agreement.

6.1. Energy Rate

A utility-specific PF Exchange rate is calculated for each utility purchasing Residential Exchange Program Power. For investor-owned utilities, the PF Exchange rate equals the Base PF Exchange rate plus a utility-specific 7(b)(3) Surcharge. For consumer-owned utilities, the PF Exchange rate equals the Base Tier 1 PF Exchange rate plus a utility-specific 7(b)(3) Surcharge.

Investor-Owned Utilities	*Rates in mills/kWh*		
	Base PF Exchange Rates	*7(b)(3) Surcharge*	*PF Exchange Rates*
Avista	52.03	11.87	63.89580
Idaho Power	52.03	9.09	61.11240
NorthWestern	52.03	22.15	74.17480
PacifiCorp	52.03	20.46	72.48300
Portland General	52.03	18.29	70.31570
Puget Sound Energy	52.03	16.99	69.01780
Consumer-Owned Utilities	*Base Tier 1 PF Exchange Rates*	*7(b)(3) Surcharge*	*PF Exchange Rates*
Clark Public Utilities	52.13	2.22	54.35
Snohomish County PUD No 1	52.13	1.86	53.99

6.2 Energy Billing Determinant

The billing determinant for the PF Exchange Power charge is the customer's Residential Load specified in GRSP II.S, Table H.

7. Adjustments, Charges, and Special Rate Provisions

Adjustments, charges, and special rate provisions are applicable to PF rates as shown in the following tables.

GRSP II.	*Adjustments, Charges, and Special Rate Provisions*	*Applicable to:*			
		Firm Requirements			
		Load Following	*Block only and Block Portion of Slice/Block*	*Slice Portion of Slice/Block*	*REP*
Calculating Rates (including Discounts and Adjustments)					
A	RHWM Tier 1 System Capability (RT1SC)	X	X		
B	Low Density Discount (LDD)	X	X	X	
C	Irrigation Rate Discount	X	X	X	
D	Demand Rate Billing Determinant Adjustments	X			
E	Load Shaping Charge True-Up Adjustment	X			
F	Tier 2 Rate TCMS Adjustment	X			
G	TOCA Adjustment	X	X	X	
Resource Support Services & Related Services					
I	Resource Support Services and Transmission Scheduling Service	X	X	X	
K	Remarketing	X	X	X	

GRSP II.	Adjustments, Charges, and Special Rate Provisions	Applicable to:			
		Firm Requirements			
		Load Following	*Block only and Block Portion of Slice/Block*	*Slice Portion of Slice/Block*	*REP*
Transfer Service					
L	Transfer Service Charges	X	X	X	
Other Charges					
M	Unanticipated Load Service	X	X	X	
N	Unauthorized Increase (UAI) Charge	X	X	X	X
Risk Adjustments					
O	Power Cost Recovery Adjustment Clause (Power CRAC)	X	X		
P	Power Reserves Distribution Clause (Power RDC)	X	X		
Q	Power Financial Reserves Policy (Power FRP) Surcharge	X	X		
Slice True-Up					
R	Slice True-Up Adjustment			X	
Residential Exchange Program					
S	Residential Exchange Program Residential Load				X
T	Residential Exchange Program 7(b)(3) Surcharge Adjustment				X
Conservation					
U	Conservation Surcharge	X	X	X	
Payment Options					
W	Flexible Priority Firm Power (PF) Rate Option	X	X	X	
X	Priority Firm Power (PF) Shaping Option	X	X	X	
Informational					
Z	Cost Contributions	X	X	X	X

GRSP Appendix	*Adjustments and Charges*	*Applicable to:*		
		Load Following	*Block only and Block Portion of Slice/Block*	*Slice Portion of Slice/Block*
A	Supplemental Information	X	X	X

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SCHEDULE NR-20
NEW RESOURCE FIRM POWER RATE

1. Availability

This schedule is available for the contract purchase of firm power to be used within the Pacific Northwest. New Resource Firm Power (NR) is available to investor-owned utilities under Northwest Power Act Section 5(b) requirements contracts for resale to ultimate consumers; for direct consumption; and for Construction, Test and Start-Up, and Station Service. New Resource Firm Power also is available to any public body, cooperative, or Federal agency to the extent such power is used to serve any new large single load (NLSL), as defined by the Northwest Power Act, including planned NLSLs, as defined in Exhibit D of a customer's CHWM Contract. This schedule also is available for services provided to Load Following customers that are serving NLSLs with non-Federal resources.

Transmission and ancillary services for use of the Federal Columbia River Transmission System facilities shall be charged separately under the applicable rate schedules.

Effective October 1, 2019, this rate schedule supersedes the NR-18 rate schedule. Sales under the NR-20 rate schedule are subject to the GRSPs. For sales under this rate schedule, bills shall be rendered and payments due pursuant to the GRSPs and billing process.

2. New Resource Rates

2.1 Energy Charge

2.1.1 Energy Rate

Month	***Rate in mills/kWh***	
	HLH	***LLH***
October	84.43	79.47
November	85.78	82.43
December	88.68	84.15
January	85.83	79.80
February	84.95	79.87
March	79.78	76.70
April	78.57	74.99
May	72.30	67.14
June	71.11	62.27
July	82.04	75.90
August	85.83	80.80
September	85.45	80.57

2.1.1.1 REP Surcharge

Each energy rate in the table above reflects an REP Surcharge of 6.93 mills/kWh.

2.1.1.2 Risk Adjustments

The NR energy rates in Section 2.1.1 are subject to risk adjustments during the Rate Period pursuant to the Power CRAC (GRSP II.O), the Power RDC (GRSP II.P), and the Power FRP Surcharge (GRSP II.Q). Any adjustments to rates and GRSPs during the Rate Period due to such risk adjustments are summarized in GRSP Appendix A.

2.1.2 Energy Billing Determinant

The billing determinant is the total of NR Hourly Loads for each diurnal period.

2.2 Demand Charge

2.2.1 Demand Rate

Month	***Rate in $/kW***
October	11.42
November	12.07
December	13.45
January	12.10
February	11.66
March	9.19
April	8.61
May	5.60
June	5.04
July	10.27
August	12.10
September	11.91

2.2.2 Demand Billing Determinant

The billing determinant is the highest NR Hourly Load during HLH, in kilowatts, for the billing period minus the average of the NR Hourly Load during the HLH, in kilowatts.

3. Unanticipated Load Service Charge

The Unanticipated Load Service Charge under the NR-20 Rate Schedule, specified in GRSP II.M.3, is applicable to the sale of Firm Requirements Power to serve Unanticipated Loads.

4. Energy Shaping Service for New Large Single Loads (NLSLs) Charge

The Energy Shaping Service (ESS) for NLSLs Charge, specified in GRSP II.J.1, is applicable to Load Following customers that serve NLSLs with non-Federal resources.

5. NR Resource Flattening Service Charge

The NR Resource Flattening Service charge, specified in GRSP II.J.2, is applicable to Load Following customers that apply the generation output of a non-dispatchable Specified Resource to serve an NLSL.

6. Adjustments, Charges, and Special Rate Provisions

Adjustments, charges, and special rate provisions are applicable as shown in the following tables.

GRSP II.	*Adjustments, Charges, and Special Rate Provisions*
B	Low Density Discount (LDD)
D	Demand Rate Billing Determinant Adjustments
J.1	Energy Shaping Service for NLSLs Charge
J.2	NR Resource Flattening Service Charge
M	Unanticipated Load Service
N	Unauthorized Increase (UAI) Charge
O	Power Cost Recovery Adjustment Clause (Power CRAC)
P	Power Reserves Distribution Clause (Power RDC)
Q	Power Financial Reserves Policy (Power FRP) Surcharge
U	Conservation Surcharge
Y	Flexible New Resource Firm Power (NR) Rate Option
Z	Cost Contributions

GRSP Appendix	*Adjustments and Charges*
A	Supplemental Information

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SCHEDULE IP-20
INDUSTRIAL FIRM POWER RATE

1. Availability

This schedule is available to BPA's direct service industrial (DSI) customers, as defined by the Northwest Power Act, for firm power to be used in their industrial operations in the Pacific Northwest. Industrial Firm Power is available under Northwest Power Act Section 5(d) contracts to DSIs for direct consumption. 16 U.S.C. § 839c(d).

Transmission and ancillary services for use of the Federal Columbia River Transmission System facilities shall be charged separately under the applicable rate schedules.

Effective October 1, 2019, this rate schedule supersedes the IP-18 rate schedule. Sales under the IP-20 rate schedule are subject to the GRSPs. For sales under this rate schedule, bills shall be rendered and payments due pursuant to the GRSPs and billing process.

DSIs purchasing power pursuant to the IP-20 rate schedule shall be required to provide the Minimum DSI Operating Reserve – Supplemental.

2. Industrial Firm Rates

2.1 Energy Charge

2.1.1 Energy Rates

Month	*Rate in mills/kWh*	
	HLH	***LLH***
October	45.43	40.47
November	46.78	43.43
December	49.68	45.15
January	46.83	40.80
February	45.95	40.87
March	40.78	37.70
April	39.57	35.99
May	33.30	28.14
June	32.11	23.27
July	43.04	36.90
August	46.83	41.80
September	46.45	41.57

2.1.1.1 REP Surcharge

Each energy rate in the table above reflects an REP Surcharge of 6.93 mills/kWh.

2.1.1.2 Value of Reserves Credit

Each energy rate in the table above reflects a 0.967 mills/kWh credit for the value of the Minimum DSI Operating Reserve – Supplemental.

2.1.1.3 Risk Adjustments

The IP energy rates in Section 2.1.1 are subject to risk adjustments during the Rate Period pursuant to the Power CRAC (GRSP II.O), the Power RDC (GRSP II.P), and the Power FRP Surcharge (GRSP II.Q). Any adjustments to rates and GRSPs during the Rate Period due to such risk adjustments are summarized in GRSP Appendix A.

2.1.2 Energy Billing Determinant

The billing determinant is the Energy Entitlement that is specified in the customer’s contract.

2.2 Demand Charge

2.2.1 Demand Rate

Month	***Rate in $/kW***
October	11.42
November	12.07
December	13.45
January	12.10
February	11.66
March	9.19
April	8.61
May	5.60
June	5.04
July	10.27
August	12.10
September	11.91

2.2.2 Demand Billing Determinant

The billing determinant is the customer’s maximum schedule amount during HLH, in kilowatts, for the billing period minus the average of the customer’s monthly schedule amount during the HLH, minus the Industrial Demand Adjuster, if any, in kilowatts.

Port Townsend Paper Corporation's Industrial Demand Adjuster values are specified in the table below.

Month	***Industrial Demand Adjuster (kW)***
October	2046
November	1646
December	1160
January	1019
February	1115
March	1598
April	795
May	1122
June	763
July	793
August	903
September	731

If Port Townsend Paper's Contract Demand (15.75 MW) is reduced in part or in full through a contract action, then the Industrial Demand Adjuster value in the above table will be reduced proportionately and reflected in GRSP Appendix A.

If the Demand Charge billing determinant calculation results in a value less than zero, the billing determinant is deemed to be zero.

3. Adjustments, Charges, and Special Rate Provisions

Adjustments, charges, and special rate provisions are applicable as shown in the following tables.

GRSP II.	***Adjustments, Charges, and Special Rate Provisions***
D	Demand Rate Billing Determinant Adjustments
H	DSI Reserves
N	Unauthorized Increase (UAI) Charge
O	Power Cost Recovery Adjustment Clause (Power CRAC)
P	Power Reserves Distribution Clause (Power RDC)
Q	Power Financial Reserves Policy (Power FRP) Surcharge
U	Conservation Surcharge
Z	Cost Contributions

GRSP Appendix	***Adjustments and Charges***
A	Supplemental Information

SCHEDULE FPS-20
FIRM POWER AND SURPLUS PRODUCTS AND SERVICES RATE

1. Availability

This rate schedule is available for the sale of Firm Power (capacity and/or energy), Capacity Without Energy, Shaping Services, Reservation and Rights to Change Services, Reassignment or Remarketing of Surplus Transmission Capacity, Services for Non-Federal Resources, Unanticipated Load Service, and other capacity, energy, and power scheduling products and services for use inside and outside the Pacific Northwest. This rate schedule is not available for sales of non-firm power outside of the region.

Sales under this rate schedule are discretionary. BPA is not obligated to sell any of these products, even if such sales will not displace PF, NR, or IP sales. Ancillary Services needed for transmission service over Federal Columbia River Transmission System facilities shall be charged separately under the applicable transmission rate schedule.

Effective October 1, 2019, this rate schedule supersedes the FPS-18 rate schedule. Sales under the FPS-20 rate schedule are subject to the GRSPs. For sales under this rate schedule, bills shall be rendered and payments due pursuant to the GRSPs and billing process.

2. Firm Power and Capacity Without Energy

2.1 Flexible Rates and Billing Determinants

Demand and/or energy charges shall be as specified by BPA or as mutually agreed by BPA and the customer. Billing determinants shall be Contract Demand and Contract Energy unless otherwise agreed by BPA and the customer.

3. Shaping Services

3.1 Rates and Billing Determinants

The charge for Shaping Services shall be the applicable rate(s) times the applicable billing determinant(s), pursuant to the agreement between BPA and the customer.

The rate(s) and billing determinant(s) for use of Shaping Services shall be as established by BPA or as mutually agreed by BPA and the customer.

4. Reservations and Rights to Change Services

4.1 Rates and Billing Determinants

The charge for Reservation and Rights to Change Services shall be the applicable rate(s) times the applicable billing determinant(s), pursuant to the agreement between BPA and the customer.

The rate(s) and billing determinant(s) for Reservation and Rights to Change Services shall be as established by BPA or as mutually agreed by BPA and the customer.

5. Reassignment or Remarketing of Surplus Transmission Capacity

Power Services may reassign or remarket surplus transmission capacity that it has reserved for its own use consistent with the terms of the transmission provider's Open Access Transmission Tariff (OATT).

5.1 Rates and Billing Determinants

The charges for Reassignment or Remarketing of Surplus Transmission Capacity shall be the applicable rate(s) times the applicable billing determinant(s), pursuant to the agreement between BPA and the customer.

The rate(s) and billing determinant(s) for Reassignment or Remarketing of Surplus Transmission Capacity shall be as established by BPA or as mutually agreed to by BPA and the customer.

6. Other Capacity, Energy, and Scheduling Products and Services

Power Services may sell energy or capacity (including energy or capacity provided to balancing authorities and transmission providers, other than the BPA Balancing Authority, for use as ancillary services) and power scheduling products and services under this rate schedule. Such products and services may include, but are not limited to: (1) firm energy with negotiated curtailment rights; (2) resource support and scheduling services for non-Federal resources not eligible for services under Section 7 of this FPS rate schedule; (3) reserve-based products and services (including but not limited to operating reserves, imbalance energy, frequency response reserves, and regulation for use outside the BPA Balancing Authority Area); and (4) non-firm energy within the region.

6.1 Rates and Billing Determinants

Rate(s) and billing determinant(s) applicable to such products and services shall be as specified by BPA or as agreed to by BPA and the customer. The charge(s) for these services shall be the applicable rate(s) times the applicable billing determinant(s) pursuant to the agreement between BPA and the customer.

7. Services for Non-Federal Resources

7.1 Transmission Scheduling Service/Transmission Curtailment Management Service (TSS/TCMS)

Customers that have elected to take TSS/TCMS for their non-Federal resources are subject to the TSS and TCMS Charges specified in GRSP II.I.5.

7.2 Forced Outage Reserve Service (FORS)

Customers that have elected to take FORS for their non-Federal resources are subject to the FORS Energy and Capacity Charges specified in GRSP II.I.4.

7.3 Resource Remarketing Service (RRS)

Customers that have requested and have been granted permission to take RRS for their non-Federal resources shall receive the RRS credit specified in GRSP II.I.7.

8. Unanticipated Load Service

The Unanticipated Load Service Charge under the FPS-20 Rate Schedule, specified in GRSP II.M.4, is applicable to the sale of firm power to serve Unanticipated Loads resulting from a request for service under Section 9(i) of the Northwest Power Act. 16 U.S.C. § 839f(i).

9. Adjustments, Charges, and Special Rate Provisions

Adjustments, charges, and special rate provisions are applicable as shown in the following table and/or as specified by BPA or as agreed to by BPA and the customer.

GRSP II.	*Adjustments, Charges, and Special Rate Provisions*
I.4	Forced Outage Reserve Service (FORS)
I.5	Transmission Scheduling Service/Transmission Curtailment Management Service (TSS/TCMS)
I.7	Resource Remarketing Service (RRS)
M.4	Unanticipated Load Service
N	Unauthorized Increase (UAI) Charge
Z	Cost Contributions

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GENERAL RATE SCHEDULE PROVISIONS

GENERAL RATE SCHEDULE PROVISIONS

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GENERAL RATE SCHEDULE PROVISIONS

SECTION I. ADOPTION OF POWER RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS

A. Approval of Rates

BPA has requested that the Federal Energy Regulatory Commission approve these rate schedules and GRSPs effective October 1, 2019. All rate schedules shall remain in effect until they are replaced or expire on their own terms.

B. General Provisions

The Power Rate Schedules and associated GRSPs supersede BPA's 2018 Power rate schedules, which became effective October 1, 2017, to the extent stated in the Availability section of each rate schedule. The schedules and these GRSPs shall be applicable to all BPA contracts, including contracts executed prior to and subsequent to enactment of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act).

All sales under these rate schedules are subject to the following acts, as amended: The Bonneville Project Act (Pub. L. No. 75-329), *codified at* 16 U.S.C. § 832 *et seq.*, the Regional Preference Act (Pub. L. No. 88-552), *codified at* 16 U.S.C. § 837 *et seq.*, the Transmission System Act (Pub. L. No. 93-454), *codified at* 16 U.S.C. § 838 *et seq.*, the Northwest Power Act (Pub. L. No. 96-501), *codified at* 16 U.S.C. § 839 *et seq.*, and the Energy Policy Act of 1992 (Pub. L. No. 102-486), *codified at* 16 U.S.C. § 824(i)-(l).

The rate schedules do not supersede any previously established rate schedule that is required, by agreement, to remain in effect.

If a provision in an executed agreement is in conflict with a provision contained herein, the former shall prevail.

C. Bill Payment Provisions

Payment must be received by the 20th day after the issue date of the bill (Due Date). If the 20th day is a Saturday, Sunday, or Federal holiday, the Due Date is the next business day. After the Due Date, a late payment charge shall be applied each day to any unpaid balance. The late payment charge shall be equal to the higher of (1) the Prime Rate (as reported in the Wall Street Journal or successor publication in the first issue published during the month in which payment was due) plus four percent, divided by 365; or (2) the Prime Rate times 1.5, divided by 365. The customer shall pay by electronic funds transfer using BPA's established procedures.

D. Notices

For the purpose of determining elapsed time from receipt of a notice applicable to rate schedule and GRSP administration, a notice shall be deemed to have been received at 0000 hours on the first calendar day following actual receipt of the notice.

E. Supplemental Guidelines for Direct Assignment of Facilities Costs Incurred Under Transfer Agreements

BPA will use this set of Supplemental Guidelines to assign costs to Transfer Service customers. Such costs are comparable to the costs purchasers of Transfer Services would incur if such purchasers were directly connected to the BPA transmission system.

This set of Supplemental Guidelines augments the BPA Transmission Services "Facility Ownership and Cost Assignment Guidelines," as amended or superseded (Transmission Services Guidelines), currently posted at: http://www.bpa.gov/transmission/Doing%20Business/Interconnection/Documents/BPA_Facility_Ownership_and_Cost_Assignment_Guidelines.pdf

In determining whether to directly assign to a Transfer customer costs incurred by BPA in providing transfer service to the customer, BPA will apply the current Transmission Services Guidelines and these Supplemental Guidelines. The Supplemental Guidelines apply only to transfer service acquired by BPA from third-party transmission providers for service to Preference customers. The Supplemental Guidelines use some terms defined in the 20-year Agreement Regarding Transfer Service (ARTS). Also, Direct Assignment Facilities, as defined in most pro forma Open-Access Transmission Tariffs (OATT), are:

> Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission customer…

These Supplemental Guidelines are designed to supplement, not replace, the Transmission Service Guidelines and to assist in predicting how BPA, as the default transmission customer for transfer arrangements, will recover costs for Direct Assignment Facilities assessed by third-party transmission providers. Unless otherwise specifically excluded in the Transmission Services Guidelines or below, the cost of Direct Assignment Facilities will be passed through to the customer.

Supplemental Guideline Regarding Directly-Assigned Facilities

For new facilities or new service over existing third-party transmission provider facilities that meet the definition of Direct Assignment Facilities, metered quantities for customer deliveries will be adjusted for losses such that BPA is not responsible for losses across such directly assigned facilities. Loss calculations should be similar whether the customer or the transmission provider owns the directly assigned facilities.

Supplemental Guidelines Regarding Replacement with a Higher Capacity Facility or Addition of a Transformer in Parallel

Pursuant to the Transmission Services Guidelines, for a new transmission provider-owned facility that also adds capacity, the costs that exceed the cost of replacing the previous capacity may be directly assigned to the benefiting customer. Alternatively, BPA and the customer may agree to full direct assignment in lieu of payment of the Transfer Service Delivery Charge. Similarly, when a parallel transformer is added, BPA and the customer may agree to a simplified direct assignment of all delivery costs in lieu of some combination of Delivery Charge and direct assignment.

Supplemental Guidelines Regarding Construction Option

The customer may work directly with the third-party transmission provider to develop and select among options regarding construction, cost sharing, and ownership. BPA will work with the customer and the transmission provider to arrive at the best one-utility plan, workable cost-sharing options, equitable ownership, and interconnection arrangements. Due to regulatory issues, it is Power Services' policy not to own facilities.

Additional Guidelines:

Rolled-in Rate Treatment by Transmission Provider

If a customer receives new Transfer Service over new or pre-existing facilities offered by the transmission provider under a rolled-in rate or revenue requirement, BPA reserves the right to assess the Transfer Service Delivery Charge. BPA will not assess the Transfer Service Delivery Charge for a new point of delivery (POD) if specific facilities' costs are not rolled in but are directly assigned to BPA and in turn passed through to the customer.

Wholesale Distribution Facilities Beyond the Step-Down Substation

On any new arrangement for a directly assigned facility (new or pre-existing facilities), the incremental cost for use of any facilities (other than potential transformers or current transformers for revenue metering) beyond the fence of the corresponding step-down transformer substation (or beyond a 20-foot radius of the step-down, for pole-top substations) shall be passed through to the customer, whether such costs are directly assigned to BPA or are imposed pursuant to a discrete wholesale distribution rate or Load Ratio Share of a discrete wholesale distribution revenue requirement.

Customer Arrangements Directly with the Third-Party Transmission Provider

A customer may, in lieu of paying the Transfer Service Delivery Charge, choose to contract directly with the third-party transmission provider for delivery service at an existing POD, but must then do so for all similar PODs with that transmission provider. The customer must take transmission service from BPA at these PODs such that the customer is responsible for costs of and losses through the delivering facilities. A customer contracting with the third party for a new POD does not create a requirement that the customer contract with the third party for its pre-existing low-voltage PODs.

F. Metering Usage Data Estimation Provision

Pursuant to Section 15.1 of the CHWM Contract for the Load Following product, BPA shall apply the Meter Usage Data Estimations procedures posted on the BPA Metering website.

SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

A. RHWM Tier 1 System Capability (RT1SC)

The RT1SC is an element of the Tier 1 Load Shaping Charge billing determinant, described in Section 2.1.3.2 of the PF-20 rate schedule. RT1SC is the Tier 1 System Firm Critical Output plus RHWM Augmentation. The RT1SC values for the FY 2020–2021 rate period are shown in Table A below.

Table A
FY 2020-2021 RHWM Tier 1 System Capability

Month	***RT1SC in kWh***	
	HLH	***LLH***
October	3,009,065,388	1,608,251,808
November	3,677,367,528	2,188,065,711
December	3,598,456,672	2,196,143,524
January	3,035,580,672	1,794,571,524
February 2020	2,760,597,124	1,615,019,676
February 2021	2,648,204,932	1,558,823,580
March	3,094,593,816	1,772,482,121
April	2,493,584,744	1,469,193,736
May	3,468,087,100	1,876,310,596
June	4,425,608,244	2,393,479,736
July	3,680,313,244	1,666,067,952
August	3,567,762,744	1,638,547,952
September	2,993,385,600	1,680,773,880

B. Low Density Discount (LDD)

1. Application and Definitions

For eligible customers, as defined in Section 2 below, a Low Density Discount (LDD) shall be applied each billing month to the PF-20 Composite Customer charge, PF-20 Non-Slice Customer charge, PF-20 Load Shaping charge, PF-20 Load Shaping Charge True-Up Adjustment, PF-20 Demand charge, the Power CRAC (GRSP II.O); the Power RDC (GRSP II.P); and the Power FRP Surcharge (GRSP II.Q). The LDD also applies to eligible customers under the PF-20 Melded rate schedule and the NR-20 rate schedule. The LDD shall be applied to only those charges listed in this GRSP II.B.

For Load Following and Block purchases, the applicable discount percentage will apply to all charges for purchases by the customer under the Tier 1 rates (Composite Customer charge, Non-Slice Customer charge, Load Shaping charge, Load Shaping Charge True-Up Adjustment, Demand charge, and risk adjustments). The applicable discount percentage will be adjusted for Above-RHWM Load, as described in Section 6 below.

An LDD dollar benefit will be calculated by BPA for Slice/Block purchases as though it were a Load Following purchase. BPA will use the customer's previous fiscal year's load data to calculate an annual LDD dollar benefit amount. This amount will be divided by 12 to derive a monthly LDD dollar credit, which will be applied to the customer's monthly power bills over the next 12 months. The applicable discount percentage will also be applied to the customer's monthly billed risk adjustments, if any. The applicable discount percentage will be adjusted for Above-RHWM Load, as described in Section 6 below.

The eligible and applicable discount percentages shall be revised annually based on data supplied by June 30 of each calendar year (CY) for the previous calendar year and shall become effective on the following October 1.

The calculation of the ratios below shall be based on calendar year data the customer provides from its annual financial and operating reports (*e.g.*, Rural Utilities Service Financial and Operating Report - Electrical Distribution, National Rural Utilities Cooperative Finance Corporation Financial and Statistical Report (CFC Form 7), audited financial report, or annual report). The provided annual financial and operating reports shall include the customer's Total Retail Load, depreciated electric plant, number of consumers, pole miles of distribution lines, total kilowatthours sold, and total electric retail sales revenue. The annual financial and operating report is to be enclosed with the customer's calendar year data if not previously submitted to BPA. The customer shall certify that the data submitted is true and correct.

Load acquired by a customer as a direct result of retail access rights established by Federal, state, or local legislation that would not otherwise have been acquired absent such legislation is not eligible to receive the benefits provided by the LDD. The customer shall certify that the data submitted does not include such load. The customer shall not pass the benefits of the LDD to such acquired consumers.

In calculating the ratios below, BPA shall compile the data submitted by the customer based on the customer's entire electric utility system in the Pacific Northwest (PNW). For customers with service territories that include any areas outside the PNW, BPA shall compile data submitted by the customer separately on the customer's system in the PNW and on the customer's entire electric system, including areas outside the PNW. BPA shall apply the eligibility criteria and discount percentages to the customer's system within the PNW and, where applicable, also to its entire system inside and outside the PNW. The customer's eligibility for the LDD shall be determined by the lesser amount of discount applicable to its PNW system or to its combined system inside and outside the PNW. BPA, in its sole discretion, may waive the requirement to submit separate data for the customer with a small amount of its system outside the PNW. Results of the calculations shall not be rounded.

If a customer does not provide BPA with the requisite information and reports by June 30 of each year for BPA to calculate the K/I and C/M ratios (see below), the customer shall be ineligible for the LDD effective the following October 1. The customer may reapply for the LDD in any subsequent year.

If a customer's data and reports are submitted prior to the June 30 deadline and a revision is necessary, the customer must submit the revised data within 12 months of the original submission date to be considered for an adjustment.

(a) The Kilowatthour/Investment (K/I) Ratio

The K/I ratio is calculated annually based on the data the customer supplies by June 30 of each calendar year. The K/I ratio is calculated by dividing the customer's Total Retail Load during the previous calendar year by the value of the customer's depreciated electric plant (excluding generation plant) at the end of the previous calendar year.

(b) The Consumers/Pole (C/M) Miles Ratio

The C/M ratio is calculated annually based on the data the customer supplies by June 30 of each calendar year. The C/M ratio is calculated by dividing the customer's number of consumers within the distribution system at the end of the previous calendar year, as defined below, by the number of pole miles of distribution lines at the end of the previous calendar year.

"Consumers" means the number of consumers, by classification, having a current service connection in December of each year. Residential consumers (seasonal and non-seasonal) are counted on the basis of the number of residences served. If one meter serves two residences, then two consumers are counted. If a water heater is metered separately from other appliances on the same premises, the water heater load will not count as a separate consumer.

Security or safety lights billed to a residential consumer will not be counted as an additional consumer.

Additional meters used for net metering consumers will not be counted as an additional consumer.

Seasonal consumers expected to resume service during the next seasonal period will be counted during off-season periods as well.

A residence and commercial establishment on the same premises receiving service through the same meter and being billed under the same rate schedule would be classified as one consumer based on the rate schedule. If the same rate schedule applies to both the residential and the commercial class, the consumer should be classified according to the principal use.

Consumers for Public Street and Highway Lighting shall be counted by the number of billings, regardless of the number of lights per billing.

Pole miles of distribution lines are defined as lines that deliver electric energy from a substation or metering point at a voltage of 34.5 kV or below to the point of attachment to the consumer's wiring and include primary, secondary, and service facilities. (Service drops are considered service facilities.)

2. Eligibility Criteria

To qualify for a discount, the customer must meet all five of the following eligibility criteria:

(a) The customer must serve as an electric utility offering power for resale to retail consumers.

(b) The customer must agree to pass the benefits of the discount through to its eligible consumers within the region served by BPA.

(c) The customer's average retail rate for the reporting year must exceed BPA's average Priority Firm Power rate for the most closely corresponding fiscal year by at least 25 percent, which is 46.30 mills/kWh for FY 2020 and FY 2021.

(d) The customer's K/I ratio must be less than 100.

(e) The customer's C/M ratio must be less than 12.

Each year BPA shall determine whether a customer is eligible for a discount. Such determination shall not be dependent on whether the customer was determined to be eligible in the previous year.

3. Determination of Eligible Discount percentage

For each customer, an eligible discount percentage shall be determined using Table B below. The eligible discount percentage shall be the sum of the two potential discount percentages for which the customer qualifies, based on Table B. The total eligible discount percentage shall not exceed 7 percent and may be adjusted pursuant to Sections 4, 5, and 6 below.

Table B
LDD Eligible Discount percentage

Percentage Discount	*Applicable Range for kWh/Investment (K/I) Ratio*	*Applicable Range for Consumers/Mile (C/M) Ratio*
0.0%	35.0 < X	12.0 < X
0.5%	31.5 < X ≤ 35.0	10.8 < X ≤ 12.0
1.0%	28.0 < X ≤ 31.5	9.6 < X ≤ 10.8
1.5%	24.5 < X ≤ 28.0	8.4 < X ≤ 9.6
2.0%	21.0 < X ≤ 24.5	7.2 < X ≤ 8.4
2.5%	17.5 < X ≤ 21.0	6.0 < X ≤ 7.2
3.0%	14.0 < X ≤ 17.5	4.8 < X ≤ 6.0
3.5%	10.5 < X ≤ 14.0	3.6 < X ≤ 4.8
4.0%	7.0 < X ≤ 10.5	2.4 < X ≤ 3.6
4.5%	3.5 < X ≤ 7.0	1.2 < X ≤ 2.4
5.0%	X ≤ 3.5	X ≤ 1.2

4. LDD Phase-In Adjustment

If the customer satisfies the eligibility criteria in Sections 2(a) through (e) above and the calculated eligible discount percentage differs from the existing eligible discount percentage by more than one-half of 1 percentage point, the applicable eligible discount percentage shall be one of the following amounts:

(a) the existing eligible discount percentage plus a maximum of one-half percent if the calculated eligible discount percentage exceeds the existing discount; or

(b) the existing eligible discount percentage minus a maximum of one-half percent if the calculated eligible discount percentage is less than the existing discount.

The foregoing formula shall be applied each October 1 until the existing eligible discount percentage is equal to the calculated eligible discount percentage.

The customer is not eligible to receive any discount, effective each October, if the customer fails to meet the eligibility criteria in Sections 2(a) through (e) above. If the customer is eligible to receive a discount in a year following a year in which the customer was not eligible to receive the discount, then the one-half percent phase-in adjustment described above shall apply to the most recent eligible discount.

Customers receiving the LDD for the first time shall receive the full discount amount as determined in Section 3.

When determining the LDD percentage pursuant to Sections 3 and 4, the calculations shall not include any Additional Adjustment for Very Low Densities as determined in Section 5.

5. **Additional Adjustment for Very Low Densities**

   If a customer's C/M ratio is 3 or less and its K/I ratio is 26 or less, after the annual determination of the eligible discount percentage pursuant to Sections 3 and 4 above, an additional one-half percent shall be added to the customer's eligible discount percentage, not to exceed a total eligible discount of 7 percent.

6. **Applicable Discount for Customers with Above-RHWM Load**

   A discount is not provided for the costs of power used to serve the customer's Above-RHWM Load; however, the LDD benefit will be adjusted to be approximately the same as if the Above-RHWM Load was included. This adjustment modifies the customer's eligible discount percentage. The formula used to calculate the applicable discount percentage for eligible purchases on the customer's power bill during the rate period is:

$$applicableLDD = eligibleLDD \times \max\left(\frac{adjTRL}{RHWM}, 1.0\right)$$

   Where:

   applicableLDD = the discount percentage to be applied to the Tier 1 charges on a customer's bill

   eligibleLDD = the customer's eligible discount percentage as computed according to Sections 2 through 5 above

   adjTRL = the customer's Total Retail Load less output of Existing Resources and NLSLs, as determined in the RHWM Process for the applicable fiscal year

   RHWM = the customer's Rate Period High Water Mark for the applicable fiscal year

   Any customer with *adjTRL* less than its *RHWM* will have its applicable discount percentage set equal to its eligible discount percentage.

7. **Treatment for Joint Operating Entity**

   The LDD benefit to a JOE will be equivalent to the sum of LDD benefits for all eligible individual members of the JOE. Except for LDD benefits for Tier 1 demand, the LDD benefits for the JOE will be based on each such individual utility member's applicable discount percentage applied to all charges for purchases by the individual utility member under the Tier 1 rates according to Section 1 above. The monthly LDD benefit for demand for a JOE is calculated as follows:

   (a) Each individual utility member's demand billing determinant is calculated as if such member were not a member of a JOE.

   (b) The demand billing determinants for all individual utility members are summed.

   (c) The individual utility members' calculated demand billing determinants are scaled (up or down) so that the sum of all individual utility members' calculated demand billing determinants equals the JOE's demand billing determinant.

(d) The demand LDD benefit attributable to each eligible individual member of the JOE is equal to the member's scaled demand billing determinant multiplied by the member's applicable discount percentage and the applicable monthly Tier 1 demand charge.

(e) The demand LDD benefits of the eligible individual members of the JOE are summed to yield the demand LDD benefit to the JOE.

C. Irrigation Rate Discount

1. Discount for Eligible Customers

Section 3 of Exhibit D of the CHWM Contracts describes Irrigation Rate Mitigation (IRM), and Section 10.3 of the Tiered Rate Methodology describes an Irrigation Rate Mitigation Product (IRMP). Both the IRM and IRMP are implemented through the Irrigation Rate Discount (IRD) set forth in this provision.

In May, June, July, August, and September, an eligible customer shall have the Irrigation Rate Discount of 11.11 mills/kWh applied to the lesser of the amount of energy purchased at Tier 1 rates in the month or the irrigation load amounts listed in Exhibit D of its CHWM Contract.

The eligibility amounts for the Irrigation Rate Discount are set forth in Section 3.1 of Exhibit D of the CHWM Contracts and are subject to the True-Up process referenced in Section 3.2 of the Contract and described more fully below.

For a Load Following or Block customer, the energy purchased at Tier 1 rates will be equal to its Actual Monthly/Diurnal Tier 1 Load used to calculate its Load Shaping billing determinant. For a Slice/Block customer, the energy purchased at Tier 1 rates will be equal to the sum of the customer's monthly Block purchase at Tier 1 rates plus the customer's Slice percentage multiplied by the monthly/diurnal RHWM Tier 1 System Capability.

The Irrigation Rate Discount for a JOE will be calculated based on individual utility members' loads and billed to the JOE and designated for each eligible utility.

BPA requires a participating customer to implement cost-effective conservation measures on eligible irrigation systems in its service territories. The customer may use its Energy Efficiency Incentive fund for this purpose.

2. Metering Requirements

The customer is required to read irrigation meters at the beginning of May and after the end of the Irrigation Rate Discount season (September 30). The customer shall provide to BPA monthly metered irrigation load information for the months of May through September in a form that is acceptable to BPA no later than October 31 of each year to ensure a timely True-Up calculation.

3. Irrigation Rate Discount True-Up and Reimbursement

There will be an assessment of the Irrigation Rate Discount each November to ensure the customer served the full amount of irrigation load for which it received an Irrigation Rate Discount. The actual metered irrigation kilowatthour amounts submitted by the customer each year will be increased by 7 percent to account for losses (measured irrigation load) before they are compared to the billed irrigation load amounts.

If the sum of a customer's May through September measured irrigation load is less than the sum of the May through September billed irrigation load amounts, a True-Up calculation is required. However, if the sum of a customer's May through September measured irrigation load is greater than or equal to the sum of the May through September billed irrigation load amounts, a True-Up calculation is not applicable.

The True-Up is calculated as follows. The measured irrigation load for the May through September period will be subtracted from the sum of the May through September billed irrigation load amounts. The result, if positive, will be multiplied by the Irrigation Rate Discount to determine the True-Up reimbursement. The True-Up reimbursement shall appear as a charge on a subsequent monthly power bill.

D. Demand Rate Billing Determinant Adjustments

BPA may adjust customers' bills after the fact for changes to demand charge billing determinants, as described below.

1. Extreme Load Shift Demand Billing Determinant Adjustment

(a) Calculating the Billing Determinant

If a customer's monthly CDQ-adjusted HLH load factor (aHLH divided by the quantity (i) Tier 1 CSP minus (ii) CDQ minus (iii) SuperPeak) is less than 55 percent, BPA may recompute a customer's demand billing determinant for the month. The month shall first be separated into two or more partial-month periods using the extreme load shift events that occur during the month as demarcations for the periods. For each partial-month period, a separate demand value shall be calculated using the same arithmetic method used to compute the customer's demand billing determinant for the full month, but such calculation shall use only the peak and energy consumed during each partial-month period. If BPA agrees to an adjustment, the largest of the partial-month demand values among the partial-month periods shall be used as the customer's demand billing determinant for the entire month.

(b) Notification Requirement

The customer shall be responsible for notifying BPA in the event it believes it may qualify for an extreme load shift demand billing determinant recalculation. BPA shall not be responsible for demand billing determinant recalculation without customer notification. BPA will not consider a customer request to recalculate a demand billing determinant when such request occurs more than 90 days after the customer's power bill is produced and communicated to the customer.

2. Recovery Peak Demand Billing Determinant Adjustment

(a) Calculating the Billing Determinant

The demand CSP may be reduced by the kilowatt difference between the CSP resulting from a Recovery Peak and the next highest HLH peak during the month that is not a Recovery Peak.

Recovery Peak shall mean an extraordinary CSP measured in a customer's load following return to service from an outage. A Recovery Peak for which BPA would consider a Recovery Peak Demand Billing Determinant Adjustment must have all three of the following characteristics:

(1) the CSP occurred during one of the two (2) hours immediately following restoration of service after an outage due to an Uncontrollable Force, provided that the outage lasted for two hours or more;

(2) the outage reduced the utility's Total Retail Load (TRL) by 25 percent or more; and

(3) the demand billing determinant resulting from such a CSP is 10 percent or more of those CSP kilowatts.

In determining the 25 percent threshold, the TRL reduction is computed by comparing the TRL measured during any hour of the outage to the TRL measured in the hour ended immediately prior to the hour in which the outage began. BPA may consider evidence that an observed CSP is not extraordinary. Such evidence may include that substantial restoration of service occurred more than two hours prior to the potential Recovery Peak hour, the hourly load patterns before and after the outage, and loads of similarly situated customers that did not experience a simultaneous outage due to an Uncontrollable Force.

(b) Notification Requirement

The customer shall be responsible for notifying BPA in the event it believes it may qualify for a demand billing determinant recalculation. BPA shall not be responsible for demand billing determinant recalculation without customer notification. BPA shall not consider a customer request to recalculate a demand billing determinant when such request occurs more than 90 days after the customer's power bill is produced and communicated to the customer.

E. Load Shaping Charge True-Up Adjustment

The Load Shaping Charge True-Up Adjustment is applicable to customers purchasing the Load Following product in specific circumstances. The Adjustment shall be determined following each fiscal year of the rate period and shall appear on the customers' power bills.

1. Load Shaping Charge True-Up Rate

Fiscal Year	***Rate in mills/kWh***
2020	–15.19
2021	–15.19

The Load Shaping Charge True-Up rates are subject to adjustment during the Rate Period by the Power CRAC (GRSP II.O); the Power RDC (GRSP II.P); and the Power FRP Surcharge (GRSP II.Q). See GRSP Appendix A, Supplemental Information, for adjusted Load Shaping Charge True-Up rates.

2. Load Shaping Charge True-Up Billing Determinants

(a) Annual Deviation

The Annual Deviation for each customer determines whether the customer may be eligible for a True-Up charge or credit.

$$\textit{Annual Deviation} \quad = \quad \begin{array}{c}\textit{Actual Annual Tier 1 Load (measured)}\\ \textit{minus}\\ \textit{TOCA Load (calculated)}\end{array}$$

TOCA Load is the annual amount of energy that is used to calculate the customer's TOCA. If the customer's TOCA is modified pursuant to the TOCA Adjustment, GRSP II.G, TOCA Load will reflect the Adjusted TOCA. If Annual Deviation is zero, there may be no True-Up; see Special Implementation Provision, Section 3 below.

(b) True-Up Credit

If Annual Deviation is positive, the customer is eligible for a True-Up credit if Above-Forecast Amount is positive (greater than zero).

$$\textit{Above-Forecast Amount} \quad = \quad \begin{array}{c}\textit{RHWM (calculated)}\\ \textit{minus}\\ \textit{TOCA Load (calculated)}\end{array}$$

If Above-Forecast Amount is positive, the True-Up Credit billing determinant equals negative one (-1) multiplied by the lesser of:

(1) Annual Deviation, or

(2) Above-Forecast Amount.

There is no True-Up if Above-Forecast Amount equals zero (0).

(c) True-Up Charge

If Annual Deviation is negative, the customer may be subject to a True-Up charge. If Above-RHWM Load is less than the absolute value of the Annual Deviation, the customer is subject to a True-Up charge.

True-Up Charge Billing Determinant	=	*Absolute value of the Annual Deviation minus Above-RHWM Load*

The True-Up Charge billing determinant cannot be less than zero.

3. Special Implementation Provision

Special implementation provisions apply if two conditions are met:

(a) the customer has Above-RHWM Load, and
(b) the customer has an Above-Forecast Amount greater than zero.

If both these conditions are met, the customer may be eligible for an additional Load Shaping True-Up credit.

If the Annual Deviation is negative or zero and the absolute value of the Annual Deviation is less than the customer's Above-RHWM Load, then the Special True-Up Credit billing determinant is negative one (-1) multiplied by the least of (i) the customer's Above-RHWM Load; (ii) the Above-RHWM Load minus the absolute value of the Annual Deviation; or (iii) the Above-Forecast Amount.

If the Annual Deviation is positive and the Annual Deviation amount is less than the Above-Forecast amount, then the Special True-Up Credit billing determinant is negative one (-1) multiplied by the lesser of (i) the customer's Above-RHWM Load; or (ii) the Above-Forecast amount minus the Annual Deviation.

4. Load Shaping Charge True-Up Adjustment

The Load Shaping Charge True-Up Adjustment is equal to the Load Shaping Charge True-Up rate multiplied by the sum of (i) the True-Up Credit billing determinant; (ii) the True-Up Charge billing determinant; and (iii) the Special True-Up Credit billing determinant.

The final Load Shaping Charge True-Up Adjustment for each customer shall be applied as either a one-month credit (if the adjustment is negative) or a three-month charge (if the adjustment is positive) spread equally across the three months following the month the final Load Shaping Charge True-Up Adjustment is determined by BPA. Load Shaping customers have the option to pay the entire charge in one month. There shall be no interest component applied to the Load Shaping Charge True-Up payment schedule.

F. Tier 2 Rate TCMS Adjustment

This adjustment will recover the cost BPA incurs as a result of a transmission event (in the form of either a planned transmission outage or a transmission curtailment) along the transmission path, between the Point of Receipt and the Point of Delivery, used to deliver energy associated with the power purchases for the Tier 2 cost pools. In such a transmission event situation, a TCMS adjustment will be applied to customers' bills if they purchase power at the applicable Tier 2 rate. The method used to calculate the aggregate TCMS adjustment is specified in GRSP II.I.5(c) and (d). The aggregate TCMS adjustment will be allocated to customers based on each customer's proportional energy share of the applicable Tier 2 cost pool.

G. TOCA Adjustment

For each customer purchasing Firm Requirements Power service under a CHWM Contract, a TOCA for each year of the rate period is calculated in the BP-20 7(i) process and will be made available to the customer prior to October 1, 2019. A customer's TOCA for a fiscal year will be revised only as specified below.

The customer's adjusted TOCA will be used to establish the billing determinant for the Composite, Slice, and Non-Slice customer charges for the relevant fiscal year. No other customer's TOCA shall be affected by this TOCA adjustment.

If a TOCA is modified after the October power bill is issued for the fiscal year to which the modified TOCA applies, the customer will be billed retroactively to October 1 of that fiscal year through a one-time billing adjustment. The billing adjustment will be calculated as (i) the sum of the amount billed for the months prior to any mid-year TOCA adjustment minus (ii) the sum of the amount that should have been billed for those same months with the mid-year adjusted TOCA. A positive calculation is a credit to the customer, and a negative calculation is a charge to the customer.

1. Load Following Customers

If there is substantial reason for BPA to believe that the customer's Actual Annual Tier 1 Load will differ from its Forecast Net Requirement determined in the RHWM Process for the applicable year, BPA shall calculate an Adjusted TOCA for that Load Following customer using an updated estimate of the customer's Actual Annual Tier 1 Load in place of the customer's Forecast Net Requirement, as follows:

$$\frac{\textit{Updated estimate of Customer's Actual Annual Tier 1 Load}}{\textit{Sum of all Customers' RHWMs}} \times 100$$

If the resulting TOCA differs from the TOCA calculated in the BP-20 7(i) process by at least 20 percent, this Adjusted TOCA will be used in place of the TOCA calculated in the BP-20 7(i) process.

The Load Following customer and BPA may agree to revise a TOCA for a difference of less than 20 percent.

If the customer's CHWM has changed due to (1) acquiring annexed load from a utility with a CHWM, or (2) having its load annexed by a utility with a CHWM, then the customer's RHWM and TOCA will be updated to account for such change. Additionally, if the customer's Existing Resource amounts in Exhibit A have changed in accordance with its CHWM Contract, then the customer's TOCA may be updated for such change. Such TOCA changes may occur prior to the start of the fiscal year or within the fiscal year.

2. Slice/Block or Block Customers

BPA will revise the TOCA of a Slice/Block or Block customer in four circumstances:

(a) If the customer's Annual Net Requirement is less than its RHWM and differs from the Forecast Net Requirement used in the BP-20 7(i) process, the customer's TOCA shall be recalculated for that fiscal year using the customer's Annual Net Requirement.

(b) If the customer's Annual Net Requirement equals or exceeds its RHWM, and its Forecast Net Requirement used in the BP-20 7(i) process is less than its RHWM, then the customer's TOCA shall be recalculated for that fiscal year using the customer's RHWM.

(c) If a customer's Annual Net Requirement changes within a fiscal year due to a change in the customer's Specified Resource amounts within a fiscal year, then the customer's TOCA shall be recalculated.

(d) If the customer's CHWM has changed due to (1) acquiring annexed load from a utility with a CHWM, or (2) having its load annexed by a utility with a CHWM, then the customer's RHWM and TOCA will be updated to account for such change. Such TOCA changes may occur prior to the start of the fiscal year or within the fiscal year.

H. DSI Reserves

DSI Value of Reserves Adjustment. Pursuant to Section 7(c)(3) of the Northwest Power Act, a DSI customer's wholesale power bill will be adjusted to reflect the value of the Minimum DSI Operating Reserve – Supplemental. 16 U.S.C. § 839e(c)(3). The DSI Operating Reserve – Supplemental is a contractual right for BPA to interrupt DSI load being served with Industrial Firm Power in a megawatt amount equal to 10 percent of the amount of power scheduled for delivery at the time the interruption request occurs. The Minimum DSI Operating Reserve – Supplemental provided by a DSI customer must be consistent with North American Electric Reliability Corporation (NERC), Western Electricity Coordinating Council (WECC), and Northwest Power Pool (NWPP) standards and criteria, including the following:

1. The interruptible load must be off-line or the increased generation must be on-line within 10 minutes after a call from BPA.
2. In the event of a system disturbance, the interruptible load or increased generation must be accessible in advance of any need for BPA to request reserves from other Northwest Power Pool members.
3. The interruptible load must be available to be off-line for up to 105 minutes, or increased generation must be available to be on-line for up to 105 minutes.
4. There are no limitations on the number of times or aggregate minutes the Minimum DSI Operating Reserve – Supplemental may be utilized.

Optional Reserves. BPA is not obligated to purchase any DSI Reserves(s) beyond the Minimum DSI Operating Reserve – Supplemental. However, BPA's contracts with DSI customers contain a contingent right to purchase additional reserves to the extent they are needed for operational purposes and can be made available by the customer. These contract provisions are designed to provide flexibility that will allow BPA to negotiate company-specific interruption rights, with the price for such reserves based on the characteristics of the DSI Reserve(s) provided. To ensure that any such purchases by BPA are cost-effective, the maximum amount to be paid by Power Services for Operating Reserves – Supplemental is capped at $7.08 per kW per month.

The availability of optional DSI Reserve(s) purchased by BPA must be consistent with NERC, WECC, and NWPP standards and criteria specific to balancing authority area Operating Reserve Requirements, including the following characteristics:

1. The interruptible load must be off-line or the increased generation on-line within the period specified for the applicable DSI Reserve purchased.
2. The interruptible load or increased generation must be accessible in advance of any need to request reserves from other Northwest Power Pool members.

In addition to these two characteristics, the issues identified below will guide consideration of when BPA may pay the maximum value for DSI Reserves:

1. The degree to which BPA has discretion with respect to when and how to use the reserves and to determine what resources to call on in the event of system disturbance or for some other purpose specified in any negotiated agreement for optional reserves.
2. Duration of time the interruptible load is available to be off-line or increased generation is available to be on-line.

I. Resource Support Services and Transmission Scheduling Service

Unless stated otherwise, the resource generation amounts used in the calculations below that are from the customer's CHWM Contract are (1) amounts specified in monthly/diurnal megawatthour amounts and annual average megawatt amounts in Sections 2, 3, and 4 of Exhibit A (Exhibit A amounts); (2) planned amounts specified in monthly/diurnal megawatthour amounts in Section 2.3.6.2(2) of Exhibit D (Exhibit D planned amounts); or (3) planned amounts listed in monthly/diurnal megawatt-per-hour amounts in Section 2.3.6.2(3) of Exhibit D (Exhibit D hourly average planned amounts).

1. Diurnal Flattening Service Charges

DFS financially converts the output of a variable, non-dispatchable generating resource into output that is equivalent to a flat amount of power within each diurnal period of a month. Generally, DFS does not apply to small, non-dispatchable resources as defined in the customer's CHWM Contract. When DFS charges are coupled with Resource Shaping Charges, the variable generating resource is financially converted to one that is equivalent to a flat annual block of power. These charges are applied to each resource that is receiving this service.

DFS shall apply to the non-Federal resource the customer is applying to its load and any portion of the resource remarketed by BPA.

(a) DFS Energy Charge

(1) DFS Energy Rate

The RSS module of BPA's RAM2020 calculates the DFS energy rate for each resource. Generally, for each monthly/diurnal period, the sum of hourly generation in excess of average monthly/diurnal Exhibit D planned amounts is multiplied by 25 percent. The result is multiplied by the applicable monthly/diurnal Resource Shaping rate in GRSP II.I.2(a)(1) below. The monthly/diurnal results are summed for the year and divided by the total Exhibit D planned amounts for that same year to calculate the DFS energy rate.

(2) DFS Energy Billing Determinant

The DFS energy billing determinant is the actual generation for the particular resource during the billing month. The actual generation amounts will be either the resource meter readings, or resource transmission schedules if the resource requires an e-Tag.

(3) Calculation of DFS Energy Charge

For each resource, the DFS energy charge is calculated by multiplying the DFS energy rate by the DFS energy billing determinant for each month.

(b) DFS Capacity Charge

(1) DFS Capacity Rate

The rates are the monthly PF Tier 1 demand rates shown in Section 2.1.2.1 of the PF-20 rate schedule.

(2) DFS Capacity Billing Determinant

The billing determinant is the difference between the resource's monthly average HLH Exhibit D planned amounts in one year and the calculated monthly firm capacity of the resource.

The RSS module of BPA's RAM2020 calculates monthly firm capacity amounts for each resource. Generally, the firm capacity calculation represents the lowest level of historical generation in a HLH period of a month after accounting for planned outages and forced outages.

(3) Calculation of DFS Capacity Charge

For each resource, the DFS Capacity charge is the lesser of:

(1) the annual sum of (i) the monthly DFS Capacity rates multiplied by (ii) the monthly DFS billing determinants; or

(2) the annual average Exhibit D planned amount multiplied by the sum of the monthly PF Tier 1 demand rates.

The result is then divided by 12 to calculate a flat monthly charge that will be specified in Exhibit D of the customer's CHWM Contract. This charge is take-or-pay, such that if a customer can no longer apply the resource to load or if its application to load is delayed, the capacity charge shall still apply.

2. Resource Shaping Charge and Resource Shaping Charge Adjustment

(a) Resource Shaping Charge

(1) Resource Shaping Rate

The monthly/diurnal Resource Shaping rates are equal to the PF Tier 1 Load Shaping rates shown in Section 2.1.3.1 of the PF-20 rate schedule.

(2) Resource Shaping Billing Determinant

The billing determinant for each resource is the difference between (1) the monthly/diurnal Exhibit D planned amounts or the monthly/diurnal Exhibit A amounts; and (2) the annual average Exhibit A amount converted to a monthly/diurnal shape (in MWh) using the appropriate monthly/diurnal hours for the same year. Generally, RSC does not apply to small, non-dispatchable resources as defined in the customer's CHWM Contract. When DFS is provided to a resource to which RRS also applies, the billing determinant for each resource is the difference between (i) the monthly/diurnal Exhibit D planned amounts and (ii) the sum of the annual average Exhibit A amounts and Resource Remarketing amounts in Exhibit D for the same year.

(3) Calculation of Resource Shaping Charge

For each resource, the Resource Shaping Charge is calculated by multiplying the Resource Shaping rate by the Resource Shaping billing determinant for each monthly/diurnal period. The sum of the values is divided by 24 (or 12 if the service applies in only one fiscal year) to calculate a flat monthly charge.

(b) Resource Shaping Charge Adjustment

(1) Resource Shaping Charge Adjustment Rate

The rates are the monthly/diurnal Resource Shaping rates described in GRSP II.I.2(a)(1) above.

(2) Resource Shaping Charge Adjustment Billing Determinant

For each resource, the billing determinant is the difference between Exhibit D planned amounts and the actual monthly/diurnal generation. The actual generation amounts will be either the resource meter readings, or resource transmission schedules if the resource requires an e-Tag. The calculation of the Resource Shaping Charge Adjustment billing determinant will also include energy provided through FORS, TCMS, planned outage replacement, economic dispatch, and unauthorized increases (UAIs) in the determination of actual generation.

(3) Calculation of Resource Shaping Charge Adjustment

For each resource, the Resource Shaping Charge Adjustment is calculated by multiplying the Resource Shaping Charge Adjustment rate by the Resource Shaping Charge Adjustment billing determinant for each monthly/diurnal period. On a monthly/diurnal basis this calculation can result in either a charge or a credit.

3. Secondary Crediting Service (SCS) Charges

SCS provides a Load Following customer that dedicates the entire output of a hydroelectric Existing Resource with (1) a credit for the energy produced by that resource that is in excess of the Exhibit A amounts, and (2) a charge for any energy shortfall by the resource from the Exhibit A amounts. There is also an SCS Administrative Charge for providing this service.

When a resource has SCS applied to it, the PF Tier 1 demand and Load Shaping billing determinants will be calculated using the applicable monthly/diurnal Exhibit A amounts instead of either the actual metered values or annual average Exhibit A amounts.

(a) SCS Shortfall Energy Charges and Secondary Energy Credits

(1) SCS Energy Rate

The rates are the monthly/diurnal Resource Shaping rates described in GRSP II.I.2(a)(1) above.

(2) SCS Energy Billing Determinant

For each resource, the billing determinant is the difference between the actual monthly/diurnal generation and monthly/diurnal Exhibit A amounts. The actual generation amounts will be either the resource meter readings, or resource transmission schedules if the resource requires an e-Tag. The actual generation shall include energy amounts provided through TCMS.

(3) Calculation of SCS Shortfall Energy Charge/Secondary Energy Credit

For each resource, the charge or credit is calculated by multiplying the SCS energy rate by the SCS energy billing determinant for each monthly/diurnal period. On a monthly/diurnal basis, this calculation can result in a charge or a credit. If the actual generation exceeds the Exhibit A amount, the customer will receive a credit. If the actual generation is less than the Exhibit A amount, the customer will receive a charge.

(b) SCS Administrative Charge

(1) SCS Administrative Rate

The rate is the monthly PF Tier 1 demand rate shown in Section 2.1.2.1 of the PF-20 rate schedule.

(2) SCS Administrative Charge Billing Determinant

For each resource, the billing determinant is the monthly average HLH Exhibit A amount multiplied by the forced outage rating.

(3) Calculation of SCS Administrative Charge

For each resource, the SCS Administrative Charge is calculated by multiplying the SCS Administrative rate by the SCS Administrative billing determinant for each month. The sum of the values is divided by 12 to calculate a flat monthly charge. The SCS Administrative charge will be specified in Exhibit D of the customer's CHWM Contract.

4. Forced Outage Reserve Service (FORS) Charges

FORS is an optional service to provide an agreed-upon amount of capacity and energy to customers that have a qualifying resource that experiences a forced outage.

(a) FORS Capacity Charge

(1) FORS Capacity Rate

Month	***Rate in $/kW***
October	11.42
November	12.07
December	13.45
January	12.10
February	11.66
March	9.19
April	8.61
May	5.60
June	5.04
July	10.27
August	12.10
September	11.91

(2) FORS Capacity Billing Determinant

For each resource, the billing determinant is the monthly firm capacity multiplied by the forced outage rating. The monthly firm capacity is calculated in the manner described under the DFS Capacity billing determinant in GRSP II.I.1(b)(2).

(3) Calculation of FORS Capacity Charge

For each resource, the FORS Capacity Charge is calculated by multiplying the FORS Capacity rate and the FORS Capacity billing determinant for each month. The sum of the values is divided by 12 to calculate a flat monthly charge. The FORS Capacity charge will be specified in Exhibit D of the customer's CHWM Contract. This charge is take-or-pay, so that if a customer can no longer apply the resource to load or if its application to load is delayed, the capacity charge shall still apply.

(b) FORS Energy Charge

(1) FORS Energy Rate

The rate for the energy provided during the first 24 hours of a forced outage will be the average of the Powerdex Mid-C hourly index prices (or its replacement) during hours of the forced outage. The rate for energy provided after the first 24 hours of a forced outage will be the diurnal Intercontinental Exchange (ICE) Mid-C Day Ahead Power Price Index (or its replacement) over the applicable diurnal period for which energy is provided. If any Mid-C price used in computing the average is less than zero, the average of the prices will be computed using a zero price for such hours.

(2) FORS Energy Billing Determinant

The FORS energy billing determinant is the total actual replacement generation a resource requires to meet the Exhibit D hourly average planned amount, subject to the FORS energy limits specified therein.

(3) Calculation of FORS Energy Charge

For each resource, the monthly FORS energy charge is calculated by multiplying the FORS energy rate by the FORS energy billing determinant.

5. Transmission Scheduling Service Charges and Transmission Curtailment Management Service Charge

Transmission Scheduling Service (TSS) is a service provided by Power Services to undertake certain scheduling obligations on behalf of the customer. There are two available service levels of TSS: full service (TSS-Full) and partial service (TSS-Partial).

Transmission Curtailment Management Service (TCMS) is a feature of TSS (both TSS-Full and TSS-Partial) under which BPA provides either replacement transmission or power to customers that have a qualifying resource that experiences a transmission event pursuant to the conditions specified in Exhibit F of the CHWM Contract.

(a) Transmission Scheduling Service Full Service (TSS-Full) Charge

(1) TSS-Full Rate

Fiscal Year	***Rate in mills/kWh***
2020	0.11
2021	0.11

(2) TSS-Full Billing Determinant

The TSS-Full billing determinants are the annual Exhibit A amounts in kilowatthours. When TSS-Full is provided to a resource to which RRS also applies, the TSS-Full billing determinant for each resource is (1) the annual Exhibit A amounts in kilowatthours plus (2) the RRS Remarketed amounts that will be included in Exhibit D of the CHWM Contract for the same year.

(3) Calculation of TSS-Full Charge

For each eligible resource, the TSS-Full Charge is calculated by multiplying the TSS-Full rate and the TSS-Full billing determinant for each month of the rate period (or an individual fiscal year if this service applies only in one fiscal year). The sum of the values is divided by 24 (or 12 if the service applies in only one fiscal year) to calculate a flat monthly charge. The charge is subject to a cap (not including OATI registration fee recovery adjustments described below). Charges for Specified Resources and Unspecified Resource Amounts serving Above-RHWM Load are capped such that if the annual cost to the customer using the TSS rate exceeds $896/month, then the monthly charge is capped at $896/month. Charges for Unspecified Resource Amounts serving NLSL and 9(c) export decrement obligations are capped such that if the annual cost to the customer using the TSS rate exceeds $2,688/month, then the monthly charge is capped at $2,688/month.

For each TSS-Full customer, BPA will determine the number of resources receiving TSS-Full. Then the $200 annual OATI registration fee is applied evenly across those resources and divided by 12 months in the applicable fiscal years of the rate period.

(b) Transmission Scheduling Service Partial Service (TSS-Partial) Charge

(1) TSS-Partial Rate

Fiscal Year	*$ per TSS-Partial Event*
2020	$185
2021	$185

(2) TSS-Partial Billing Determinant

The TSS-Partial billing determinant is the total number of TSS-Partial events that occur within a month. Each of the following is considered a single TSS-Partial event:

(1) a customer, or its scheduling agent, fails to carbon copy (CC) Power Services on a schedule; or

(2) a day that a customer has a TCMS charge.

(3) Calculation of TSS-Partial Charge

The TSS-Partial charge is calculated by multiplying the TSS-Partial rate by the TSS-Partial billing determinant for each month of the rate period.

(c) TCMS Charge if Replacement Power is Provided

If BPA purchases replacement power during a transmission event for a resource supported by TCMS, then the TCMS charge will be the cost of such purchased power. If BPA does not purchase replacement power, then the TCMS charge will be calculated in accordance with the sections below.

(1) TCMS Rate

The TCMS rate will be the Powerdex Mid-C hourly index price (or its replacement) for the hour the event occurred. If any Mid-C price is less than zero, the TCMS energy rate will be zero for that hour. If a customer with TSS-Partial fails to CC Power Services on a schedule during a transmission event for a resource supported by TCMS, then the customer will be charged Unauthorized Increase in Energy (GRSP II.N.2) for the amount of energy that was curtailed in place of the TCMS rate. Additionally, the customer may be subject to Unauthorized Increase in Demand if the customer's HLH demand is in excess of its demand entitlement in accordance with GRSP II.N.1.

(2) TCMS Billing Determinant

The TCMS billing determinant is the total actual kilowatthours of replacement power BPA supplies.

(3) Calculation of TCMS Charge

The TCMS Charge shall equal the sum of charges for Bands 1 through 3. For each band, the charge shall be calculated as follows:

Apportioned TCMS billing determinant multiplied by the TCMS Rate multiplied by the Factor.

Where:

Band	Apportioned TCMS Billing Determinant	Factor
	The portion of the TCMS billing determinant that is:	
1	Less than or equal to (i) 1.5 percent of the TSS billing determinant or (ii) 2 MW, whichever is larger	1.00
2	Greater than the apportioned TCMS billing determinant for Band 1, up to and including (i) 7.5 percent of the TSS billing determinant or (ii) 10 MW, whichever is larger	1.10
3	Greater than the apportioned billing determinant for Band 2	1.25

(d) TCMS Charge if Alternative Transmission is Provided

When replacement Point-to-Point transmission is used to deliver the customer's eligible resource to load using an alternate transmission path, for each resource the TCMS charge is the cost of the additional transmission BPA purchases plus any additional costs, including real power losses associated with using the replacement transmission.

6. Grandfathered Generation Management Service (GMS)

GMS allows a Load Following customer that dedicated the entire output of an Existing Resource that received GMS during Subscription to run that resource against load and offset its Tier 1 Load.

(a) GMS Reservation Rate

The rate is the monthly PF Tier 1 demand rate shown in Section 2.1.2.1 of the PF-20 rate schedule.

(b) GMS Reservation Billing Determinant

For each resource, the billing determinant is the monthly firm capacity multiplied by the forced outage rating. The monthly firm capacity is calculated in the manner described under the DFS Capacity billing determinant in GRSP II.I.1(b)(2).

(c) Calculation of GMS Reservation Fee

For each resource, the GMS Reservation Fee is calculated by multiplying the GMS Reservation rate and the GMS Reservation billing determinant for each month. The sum of the values is divided by 12 to calculate a flat monthly charge. The GMS Reservation Fee will be specified in Exhibit D of the customer's CHWM Contract.

7. Resource Remarketing Service (RRS) Credits

RRS is an optional service to provide a remarketing credit to customers that have a qualifying non-Federal resource to which DFS applies that is expected to generate more than a customer's Above-RHWM Load. The non-Federal resource amounts used in these calculations are those specified in the customer's CHWM Contract Exhibit D RRS section (Exhibit D RRS amounts).

(a) RRS Credit

(1) RRS Rate

For each non-Federal resource, the rate shall be the Remarketing Value in GRSP II.K.3.

(2) RRS Billing Determinant

For each non-Federal resource, the billing determinant is the Exhibit D RRS amount.

(3) Calculation of RRS Credit

For each non-Federal resource, the RRS Credit is calculated by multiplying the RRS rate and the RRS billing determinant for each applicable year of the rate period. The annual value is divided by 12 to calculate a flat monthly credit.

(b) RRS Fee

The fee for providing RRS to customers is determined on a case-by-case basis.

J. NR Services for New Large Single Loads (NLSLs)

NR Services for NLSLs are applicable to Load Following customers serving NLSLs with non-Federal resources.

1. NR Energy Shaping Service for NLSL Charge

1.1 NR Energy Shaping Service Energy Charge

The energy component of the NR Energy Shaping Service either credits or debits the customer for the difference between energy amounts provided by the customer's non-Federal resources serving NLSLs and the measured load of their NLSLs.

The NR ESS energy charge can be either positive or negative and is determined through a two-step process. The first step determines the applicable rate treatment, A or B. The second step applies the rate treatment determined in the first step.

Step 1:
Determine if the customer received energy from BPA or provided energy to BPA on a net monthly basis, calculated as the measured load of the customer's NLSLs in the billing month minus the energy amounts provided by the customer's resources to serve its NLSLs during the same billing month. If this result is greater than zero, energy was purchased from BPA, and Rate Treatment A applies. If this result is zero or negative, Rate Treatment B applies.

Step 2:
ESS Energy Rate Treatment A.
Calculate two energy billing determinants for each month, one for HLH and one for LLH. Each monthly energy billing determinant is equal to (1) the total measured load of the customer's NLSL(s) receiving this service during the monthly/diurnal period minus (2) the energy amounts provided by the customer to serve those NLSLs during that same monthly/diurnal period. The billing determinant for either period can be negative. These billing determinants are multiplied by the applicable monthly/diurnal NR-20 energy rates in Section 2.1.1 of the NR-20 rate schedule to calculate the energy charge (or credit).

ESS Energy Rate Treatment B.
Calculate daily diurnal billing determinants for the month, resulting in two billing determinants for each day with both HLH and LLH periods and one billing determinant for each day with only a LLH period. Each energy billing determinant is equal to (1) the total measured load of the customer's NLSL(s) receiving this service during that daily/diurnal period minus (2) the energy amounts provided by the customer to those NLSLs during that same daily/diurnal period. The billing determinant for any period can be negative. These billing determinants are multiplied by the applicable Intercontinental Exchange (ICE) Mid-C Day Ahead Power Price Index (or its replacement) for the same daily/diurnal period to calculate each

daily/diurnal period energy charge. If a Mid-C price for any period is less than zero, the applicable rate for that period will be zero.

The monthly sum of such daily/diurnal energy charges may be adjusted as follows:

- Threshold 1: No adjustment is made if the absolute value of the monthly sum of the daily HLH plus LLH billing determinants is less than or equal to (1) 1.5 percent of the total monthly measured load of the NLSLs receiving this service, or (2) 1,488 MWh.

- Threshold 2: If Threshold 1 is exceeded, Threshold 2 will apply if the absolute value of the monthly sum of the daily HLH plus LLH billing determinants is less than or equal to (1) 7.5 percent of the total monthly measured load of the NLSLs receiving this service, or (2) 3,720 MWh. If Threshold 2 applies, the monthly sum of the daily/diurnal energy charges will be multiplied by 94 percent if the monthly sum is negative (money owed to the customer) or multiplied by 106 percent if the monthly sum is positive (money owed to BPA).

- Threshold 3: If both Threshold 1 and 2 are exceeded, Threshold 3 applies. When applying Threshold 3, the monthly sum of the daily HLH plus LLH energy charges is multiplied by 84 percent if the monthly sum is negative (money owed to the customer), or multiplied by 116 percent if the monthly sum is positive (money owed to BPA).

1.2 NR Energy Shaping Service Capacity Charge

The billing determinant for the NR ESS Capacity Charge is the amount of capacity the customer requests from BPA for standing ready to serve its NLSLs. The customer must have established monthly capacity amounts for the FY 2020–2021 rate period prior to February 1, 2019. However, at least 30 days prior to any month, the customer may notify BPA of a change to the amount of capacity it is requesting BPA to stand ready to serve its NLSLs for that month.

The billing determinant is multiplied by the applicable monthly NR demand rate (NR-20 rate schedule, Section 2.2.1) to calculate the monthly NR ESS Capacity Charge.

A monthly check will be performed to verify that the customer's actual capacity use did not exceed the monthly amount of capacity it requested BPA to provide. The actual capacity used is equal to (1) the largest hourly energy amount provided by BPA during the HLH of the month through the NR ESS minus (2) the greater of (i) the average HLH energy provided by BPA under Rate Treatment A in that same month, or (ii) zero. The Unauthorized Increase (UAI) Charge for demand will apply to the actual capacity used in excess of the monthly amounts of capacity included in the customer's request to BPA.

2. NR Resource Flattening Service Charge

The NR Resource Flattening Service (NRFS) is applicable to Load Following customers that apply the generation output of a non-dispatchable Specified Resource to serve an NLSL.

2.1 NR Resource Flattening Service Energy Charge

The NRFS energy charge is the product of multiplying the NRFS energy rate by the NRFS energy billing determinant for each month.

2.2 NR Resource Flattening Service Energy Rate

The NRFS energy rate is a unique rate developed for each resource to which NRFS is applied. For each monthly/diurnal period in a year, the sum of the hourly planned generation in excess of average monthly/diurnal planned generation amounts is multiplied by 25 percent (to reflect the energy lost when using a pumped storage hydroelectric unit to perform the energy storage). The result is multiplied by the applicable monthly/diurnal Resource Shaping rate. The monthly/diurnal results are summed for the year and divided by the total planned energy amounts to calculate the NRFS Energy rate.

2.3 NR Resource Flattening Service Energy Billing Determinant

The NRFS energy billing determinant is the total actual generation for the particular resource during the billing month. The actual generation amounts will be either the resource meter readings, or the resource transmission schedules if the resource requires an e-Tag.

K. Remarketing

1. Tier 2 Remarketing for Individual Customers

This credit and fee are applicable to customers when BPA is remarketing their Tier 2 rate purchase amounts pursuant to Section 10 of the CHWM Contract.

(a) Tier 2 Remarketing Rate

(1) For Load Following Customers

For each fiscal year, the Tier 2 Remarketing rate shall be the Remarketing Value in GRSP II.K.3.

(2) For Slice/Block and Block Customers

After notice is provided by the Slice/Block or Block customer, the rate shall be the flat annual equivalent market price forecast, as determined by BPA after the time of the notice, for the applicable fiscal year plus any additional costs incurred by BPA in purchasing power from other entities.

(b) Tier 2 Remarketing Billing Determinant

For each applicable Tier 2 rate, the billing determinant is (i) the customer's contracted annual Tier 2 amount at such rate plus real power losses, less (ii) the customer's annual Tier 2 load at such rate plus real power losses.

(c) Tier 2 Remarketing Credit

For each customer, the Tier 2 Remarketing credit is calculated by multiplying the applicable Tier 2 Remarketing rate and the Tier 2 Remarketing billing determinant. The annual value is divided by 12 to calculate a flat monthly credit.

(d) Tier 2 Remarketing Fee

The fee for remarketing customers' Tier 2 amounts is zero in FY 2020–2021.

2. Non-Federal Resource with DFS Remarketing

This credit and fee are applicable to customers when BPA is remarketing their non-Federal resources to which DFS applies, pursuant to Section 10 of the CHWM Contract.

(a) DFS Remarketing Rate

For each fiscal year, the DFS Remarketing rate shall be the Remarketing Value in GRSP II.K.3.

(b) DFS Remarketing Billing Determinant

For each applicable non-Federal resource to which DFS applies, the billing determinant is (1) the amount of the customer's non-Federal resource, as specified in the customer's CHWM Contract Exhibit A, prior to temporary resource removal; less (2) the amount of the customer's non-Federal resource needed to meet Above-RHWM Load, as specified in the customer's CHWM Contract Exhibit A, when updated for temporary resource removal.

(c) DFS Remarketing Credit

For each customer, the DFS Remarketing credit is calculated by multiplying the applicable DFS Remarketing Rate and the DFS Remarketing billing determinant. The annual value is divided by 12 to calculate a flat monthly credit.

(d) DFS Remarketing Fee

The DFS remarketing fee for a customer with a non-Federal resource supported with DFS is zero in FY 2020–2021.

3. Remarketing Value

For each fiscal year, the Remarketing Value rate shall be:

Fiscal Year	***Rate in mills/kWh***
2020	28.27
2021	30.84

L. Transfer Service Charges

Transfer Service applies to BPA Power Service customers that are served under non-Federal transmission service agreements.

1. Transfer Service Delivery Charge

The Transfer Service Delivery Charge shall apply to Power Services customers that purchase Federal power that is delivered over non-Federal low-voltage facilities. Low-voltage facilities are generally facilities operated below 34.5 kV.

(a) Transfer Service Delivery Rate

	Rate in $/kW
All months	1.27

(b) Transfer Service Delivery Billing Determinant

The monthly billing determinant for the Transfer Service Delivery Charge shall be the total load on the hour of the Total Customer System Peak minus behind-the-meter dedicated resources or resources contractually committed to serve customer load at the low-voltage Points of Delivery provided for in non-Federal transmission service arrangements.

2. Transfer Service Operating Reserve Charge

The Transfer Service Operating Reserve Charge shall apply to Public customers that meet the following criteria: (1) BPA serves the customer by transfer service; and (2) the customer is not paying BPA Transmission Services for operating reserves for the customer's load served by transfer.

(a) Transfer Service Operating Reserve Rate

(1) The rate for the Transfer Service Spinning Operating Reserve Charge shall be equal to the ACS-20 Operating Reserve – Spinning Reserve Service rate.

(2) The rate for the Transfer Service Supplemental Operating Reserve Charge shall be equal to the ACS-20 Operating Reserve – Supplemental Reserve Service rate.

(b) Transfer Service Operating Reserve Billing Determinant

(1) The monthly billing determinant for the Transfer Service Spinning Operating Reserve Charge shall be the same as that used for the applicable ACS-20 Operating Reserve – Spinning Reserve Service rate, except that the load used to calculate the billing determinant for Power Services' charge shall be the amount of the customer's metered load served by transfer (non-BPA Balancing Authority Area load) or a portion thereof (if applicable).

(2) The monthly billing determinant for the Transfer Service Supplemental Operating Reserve Charge shall be the same as that used for the applicable ACS-20 Operating Reserve – Supplemental Reserve Service rate, except that the load used to calculate the billing determinant for Power Services' charge shall be the amount of the customer's metered load served by transfer (non-BPA Balancing Authority Area load) or a portion thereof (if applicable).

3. Transfer Service Regulation and Frequency Response Charge

The Transfer Service Regulation and Frequency Response Charge shall apply to Public customers that meet the following criteria: (1) BPA serves the customer by transfer service; and (2) the customer is not paying BPA Transmission Services for Regulation and Frequency Response for the customer's load served by transfer.

(a) Transfer Service Regulation and Frequency Response Rate

The rate for the Transfer Service Regulation and Frequency Response Charge shall be equal to the ACS-20 Regulation and Frequency Response rate.

(b) Transfer Service Regulation and Frequency Response Billing Determinant

The monthly billing determinant for the Transfer Service Regulation and Frequency Response Charge shall be the same as that used for the applicable ACS-20 Regulation and Frequency Response rate, except that the load used to calculate the billing determinant for Power Services' charge shall be the amount of the customer's total load served by transfer (non-BPA Balancing Authority Area load) or a portion thereof (if applicable).

4. Transfer Service Regional Compliance Enforcement Charge

The Transfer Service Regional Compliance Enforcement Rate shall apply to Public customers with load outside the BPA Balancing Authority Area.

(a) Transfer Service Regional Compliance Enforcement Rate

	Rate in mills/kWh
All months	0.03

(b) Transfer Service Regional Compliance Enforcement Billing Determinant

The monthly billing determinant for the Transfer Service Regional Compliance Enforcement Charge shall be the public customer's metered load at points of delivery served by transfer (non-BPA Balancing Authority Area load).

M. Unanticipated Load Service

1. Availability

Unanticipated Load Service (ULS) applies to any request for Firm Requirements Power received after February 1, 2019, that results in an unanticipated increase in a customer's load placed on BPA during the FY 2020–2021 rate period. Contractual obligations that result from a request for service under Section 9(i) of the Northwest Power Act also will be considered ULS. ULS also may apply to a customer that adds load through retail access, including load that was once served by the customer and returns under retail access. ULS that is used for replacement of a customer's new Specified Resource is available on only a temporary basis for the FY 2020–2021 rate period and only when requested pursuant to the required notice.

The following list includes the only sources of Unanticipated Load that will be served by BPA along with the applicable rate schedule under which each type of unanticipated load will be served.

Under PF-20, Unanticipated Load is:

- Load of a New Public (Load Following customers only)
- Load annexed from investor-owned utilities by a Public (Load Following customers only)

Under NR-20, Unanticipated Load is:

- New Large Single Loads
- Requirements service requested by investor-owned utilities

Under FPS-20, Unanticipated Load is negotiated on a case-by-case basis.

BPA also will review annexations of load between public utility customers to assess if there will be an increase in BPA's Firm Requirements Power that will be considered Unanticipated Load.

To start service for Unanticipated Load, the customer must notify BPA three months in advance of the requested service date for load amounts up to 50 aMW and six months in advance of the requested service date for load amounts greater than 50 aMW. To stop service for Unanticipated Load, the customer must notify BPA three months in advance of the requested stop date.

ULS will apply for the length of the customer's contract for Unanticipated Load Service or the conclusion of the rate period on September 30, 2021, whichever occurs first. ULS is a temporary service and may be adjusted annually. For load annexed from investor-owned utilities by a Public (Load Following customers only) served under PF-20 and for resource replacement of a Public Load Following customer, the ULS and notification requirements will not apply to unanticipated loads less than 1 aMW per year. These loads will be included in the customer's Actual Hourly Tier 1 Loads and Actual Monthly/Diurnal Tier 1 Load for billing purposes. Any Unanticipated Load Service in a future rate period must comply with the provisions for ULS for that rate period.

2. Unanticipated Load Service Charge Under the PF-20 Rate Schedule

(a) Energy Charge

(1) Energy Rate

The energy rate may be adjusted each fiscal year and will be the greater of:

(1) the applicable diurnal period PF Tier 1 Equivalent energy rate (GRSP II.AA); or

(2) the applicable diurnal period forecast market price, as determined by BPA after the time of the request for load service, for purchased power plus any additional costs incurred by BPA in purchasing power from other entities.

(2) Energy Billing Determinant

The energy billing determinant shall be the total amount of Unanticipated Load for each diurnal period, measured in kilowatthours.

(b) Demand Charge

(1) Demand Rate

The Demand Rate is equal to the demand rate included in Section 2.1.2.1 of the PF-20 rate schedule.

(2) Demand Billing Determinant

The demand billing determinant shall be the lesser of:

(1) the maximum hourly Unanticipated Load in a month during the HLH minus the average HLH Unanticipated Load amount for the month; or

(2) 20 percent of the highest hourly Unanticipated Load amount in a month during the HLH.

3. Unanticipated Load Service Charge Under the NR-20 Rate Schedule

(a) Energy Charge

(1) Energy Rate

The energy rate may be adjusted each fiscal year and shall be the greater of:

(1) the applicable diurnal period energy rate in Section 2.1.1 of the NR-20 rate schedule; or

(2) the applicable diurnal period forecast market price, as determined by BPA after the time of the request for load service, for purchased power plus any additional costs incurred by BPA in purchasing power from other entities.

(2) Energy Billing Determinant

The energy billing determinant is the total of unanticipated NR Hourly Load for each diurnal period, measured in kilowatthours.

(b) Demand Charge

(1) Demand Rate

The Demand Rate is equal to the demand rate included in Section 2.2.1 of the NR-20 rate schedule.

(2) Demand Billing Determinant

The Demand billing determinant is the maximum unanticipated NR Hourly Load in a month during HLH, in kilowatts, for the billing period minus the average of the HLH unanticipated NR Hourly Load in a month.

4. Unanticipated Load Service Charge Under the FPS-20 Rate Schedule

(a) Energy Charge

(1) Energy Rate

The energy rate may be adjusted each fiscal year and shall be the greater of:

(1) the applicable diurnal period Resource Replacement rate that equals the PF Tier 1 Equivalent energy rate (GRSP II.AA) from the same diurnal period; or

(2) the applicable diurnal period forecast market price, as determined by BPA after the time of the request for load service, for purchased power plus any additional costs incurred by BPA in purchasing power from other entities.

(2) Energy Billing Determinant

The energy billing determinant is the total of Unanticipated Load for each diurnal period, measured in kilowatthours.

(b) Demand Charge

(1) Demand Rate

Month	***Rate in $/kW***
October	11.42
November	12.07
December	13.45
January	12.10
February	11.66
March	9.19
April	8.61
May	5.60
June	5.04
July	10.27
August	12.10
September	11.91

(2) Demand Billing Determinant

The Demand billing determinant is the highest maximum unanticipated Resource Replacement load in a month during HLH, in kilowatts, for the billing period minus the average of the HLH unanticipated Resource Replacement load in a month.

N. Unauthorized Increase (UAI) Charge

The Unauthorized Increase Charge is a charge to any customer taking more power from BPA than it is contractually entitled to take.

1. Charge for Unauthorized Increase in Demand

The amount of measured demand during a HLH billing hour that exceeds the amount of demand the customer is contractually entitled to take during that hour shall be billed at 1.25 times the applicable monthly demand rate.

The billing determinant for the UAI demand charge shall be equal to the customer's single highest HLH demand that is in excess of the customer's contractual demand entitlement.

For a Load Following customer, the demand in excess of its demand entitlement shall be the shortfall of its dedicated resources delivered to load on the hour of its Customer System Peak as compared to the customer's CHWM Contract Exhibit A amounts, not including Super Peak amounts in section 9 of Exhibit A if any, or Exhibit D amounts, whichever is applicable.

For a Block customer or for the Block portion of the Slice/Block product, the customer's contractual demand entitlement for each HLH shall be the sum of its Tier 1 and Tier 2 HLH predetermined hourly schedule amounts, provided by BPA to the customer in accordance with Exhibit C of the CHWM Contract.

For a Slice customer, the Slice portion of the Slice/Block product will be subject to a demand UAI if the Slice demand is in excess of the Slice entitlement during the peak Delivery Request (Right To Power) HLH of a month. The Slice demand in excess of the Slice entitlement is measured by subtracting (i) the largest final hourly Delivery Request (Right To Power) computed using the Slice Water Routing Simulator for any HLH of a month from (ii) the hourly amount of Slice power delivery (tagged + untagged energy) from BPA for the same HLH of the same month, as such terms are defined in the Slice/Block CHWM Contract.

2. Charge for Unauthorized Increase in Energy

The amount of measured energy or Residential Exchange Program contract load that exceeds the amount of energy the customer is contractually entitled to take during a diurnal billing period shall be billed at the greater of:

(a) 150 mills/kWh; or

(b) Two times the highest hourly Powerdex Mid-C Index price for firm power for the month in which the unauthorized increase occurs.

In the event the hourly Powerdex Mid-C price index expires, the index will be replaced for purposes of the Unauthorized Increase charge for energy by the highest price for the month from any applicable new hourly or diurnal energy index at a hub at which Northwest parties can trade between October 1, 2019, and September 30, 2021.

O. Power Cost Recovery Adjustment Clause (Power CRAC)

The Power CRAC is an upward adjustment to certain rates that apply to the following products under the PF-20 rate schedule: Load Following, Block, and the Block portion of Slice/Block. The Power CRAC also applies to power purchased at the PF Melded rate (PF-20), Industrial Firm Power rate (IP-20), and New Resource Firm Power rate (NR-20).

1. Power CRAC Amount

At the beginning of each fiscal year of the rate period (that is, each "applicable year"), BPA will calculate Accumulated Calibrated Net Revenue for Power (Power ACNR) for the fiscal year preceding the applicable year. If Power ACNR is less than the Power CRAC Threshold for that applicable year by at least $5 million, the Power CRAC will trigger, and a rate increase will go into effect for the period of December 1 through September 30 of the applicable year.

(a) Calculating Power Calibrated Net Revenue (Power CNR) and Accumulated Calibrated Net Revenue (Power ACNR)

Power CNR is Power Net Revenue (Power NR) plus Power Net Revenue Calibration (Power NR Calibration).

Power NR for any given fiscal year is defined as generation function accrued revenue less accrued expenses (in accordance with Generally Accepted Accounting Principles).

Power NR Calibration is the sum of the amounts of each Power NR Calibration Event. A Power NR Calibration Event is a financial event not forecast in the BP-20 rate case that (1) impacts Power NR differently than it impacts financial reserves available for risk attributed to Power, and (2) results in a difference between the amounts of such impacts that is greater than $5 million (positive or negative). Such events may include, but are not limited to, debt management transactions, contract settlements, and changes in non-cash expenses. The amount of a Power NR Calibration Event will be calculated as (1) the impact of the event on financial reserves available for risk attributed to Power, minus (2) the impact of the event on Power NR.

Power ACNR is Power CNR accumulated since the end of FY 2018. Actual Power ACNR is used to determine whether the Power CRAC Threshold has been reached, and if so, the required Power CRAC Amount to be collected. The Power ACNR for use in determining the Power CRAC that will apply to FY 2020 rates will be the actual Power CNR for FY 2019. The Power ACNR for use in determining the Power CRAC that will apply to FY 2021 rates will be the sum of the actual Power CNR for FY 2019 plus the actual Power CNR for FY 2020.

(b) Calculating the Power CRAC Amount

The Power CRAC Threshold is an amount of ACNR, below which Power is considered to have experienced an underrun. The underrun amount is equal to the Power CRAC Threshold minus Power ACNR.

The Power CRAC Amount is based on the underrun, limited by the Maximum Power CRAC Recovery Amount (the Power CRAC Cap.) There are four possibilities:

(1) If the underrun is less than $5 million, there is no Power CRAC.

(2) If the underrun is greater than or equal to $5 million and less than or equal to $100 million, the Power CRAC Amount is equal to the underrun.

(3) If the underrun is greater than $100 million and less than $500 million, the Power CRAC Amount is equal to $100 million plus one-half of the difference between $100 million and the underrun.

(4) If the underrun is greater than or equal to $500 million, the Power CRAC Amount is equal to $300 million.

The Power CRAC Cap and Thresholds are shown in Table C.

Table C
Power CRAC Annual Thresholds and Caps
(dollars in millions)

ACNR Calculated from CNR for Fiscal Year(s)	***CRAC Applied to Fiscal Year***	***Threshold Measured in ACNR***	***Threshold Measured in Reserves for Risk***	***Maximum CRAC Recovery Amount (Cap)***
2019	2020	($89)	$0	$300
2019 + 2020	2021	($44)	$0	$300

2. Power CRAC Surcharge Rate

(a) Calculating the Power CRAC Surcharge Rate

The Power CRAC Surcharge rate in mills per kilowatthour shall be:

$$\frac{\text{Power CRAC Amount}}{\sum \text{BD}}$$

Where:

∑ *BD* (*Sum of Billing Determinants*) is the sum of the following December through September forecasts, made on or about the beginning of each applicable year, in kilowatthours:

- service under the PF Melded, IP, and NR rates, and
- PF System Shaped Loads.

(b) Billing

For customers taking service at the PF Melded, IP, and NR rates, the Power CRAC Surcharge rate will be added to the December through September monthly/diurnal PF Melded, IP and NR energy rates for the applicable year.

For PF customers with a System Shaped Load, the Power CRAC Surcharge rate will be applied to the sum of each customer's HLH and LLH PF System Shaped Load for December through September of the applicable year. A customer's Low Density Discount shall be applied to the Power CRAC.

(c) Adjustment to the PF Tier 1 Equivalent Energy Rates

The Power CRAC Surcharge rate will be added to each of the monthly/diurnal PF Tier 1 Equivalent energy rates (GRSP II.AA) for December through September of the applicable year.

(d) Annual Power CRAC Surcharge Rate

An Annual Power CRAC Surcharge rate, in mills per kilowatthour, will be calculated so that the Load Shaping Charge True-up rate and PF Melded Equivalent Energy Scalar can be adjusted. The Annual Power CRAC Surcharge rate is calculated by dividing the Power CRAC Amount by the annual forecast, made around the beginning of each Fiscal Year, of service under the PF Melded, IP, and NR rates and the sum of PF System Shaped Loads for the applicable year, in kilowatthours. The Annual Power CRAC Surcharge rate will be:

(1) Subtracted from the Load Shaping Charge True-Up rate (GRSP II.E, Section 1)

(2) Subtracted from the PF Melded Equivalent Energy Scalar rate (GRSP II.R, Section 1(c)).

3. Power CRAC Notification Process

BPA shall follow these notification procedures:

(a) Financial Performance Status Reports

Each quarter, BPA shall post to its external website (www.bpa.gov) preliminary, unaudited, year-to-date aggregate financial results for the generation function.

For the Second and Third Quarter Reviews, BPA shall post to its external website (www.bpa.gov) a preliminary forecast of the Power CRAC Amount.

(b) Notification of Power CRAC

By November 30, 2019, BPA will complete the calculation of Power ACNR through the end of FY 2019, for use in calculating the Power CRAC applicable to rates for December through September of FY 2020. By November 30, 2020, BPA will complete the calculation of Power ACNR through the end of FY 2020, for use in calculating the Power CRAC applicable to rates for December through September of FY 2021.

If the Power CRAC triggers, BPA will notify customers of the preliminary Power CRAC Amount to be recovered by the Power CRAC Surcharge rate for the applicable year. Such notice will be provided as soon as practicable, but in no case later than November 30 of each applicable year. BPA will make available to customers the preliminary data relied upon to calculate the surcharge, including the calculation of Power ACNR.

BPA will hold at least one public meeting to discuss the calculations of Power ACNR, the Power CRAC Amount, the Power CRAC Surcharge rate, and the Annual Power CRAC Surcharge rate. BPA will provide customers an opportunity for comment on the preliminary data. BPA will issue the final Power CRAC Amount, Power CRAC Surcharge rate, and the Annual Power CRAC Surcharge rate as soon as practicable, but in no case later than December 15 of each applicable year.

P. Power Reserves Distribution Clause (Power RDC)

The Power RDC is a process for determining the distribution of financial reserves to purposes determined by the Administrator. The Power RDC is calculated each fiscal year.

If the Power RDC quantitative criteria (below) are met, the Administrator will calculate the Power RDC Amount, and determine what part, if any, will be applied to debt reduction, incremental capital investment, rate reduction through a Power Dividend Distribution (Power DD), distribution to customers, or any other Power-specific purposes determined by the Administrator.

A Power DD is a downward adjustment to certain rates that apply to the following products under the PF-20 rate schedule: Load Following, Block, and the Block portion of Slice/Block. The Power DD also applies to power purchased at the PF Melded rate (PF-20), Industrial Firm Power rate (IP-20), and New Resource Firm Power rate (NR-20).

1. Power RDC Amount

At the beginning of each fiscal year of the rate period (that is, each "applicable year"), BPA will calculate Power Accumulated Calibrated Net Revenue (Power ACNR) and BPA Accumulated Calibrated Net Revenue (BPA ACNR) for the fiscal year preceding the applicable year. If Power ACNR is greater than the Power RDC Threshold for that applicable year by at least $5 million, and BPA ACNR is greater than the BPA RDC Threshold for that applicable year by at least $5 million, the Administrator will determine a Power RDC Amount. If the Administrator determines that part of the Power RDC Amount will be applied to a Power DD, the resulting rate decrease will go into effect for the period of December 1 through September 30 of the applicable year.

(a) Calculating the Power ACNR and BPA ACNR

The Power ACNR calculation is described in GRSP II.O.1(a). The BPA ACNR is the sum of the Transmission ACNR and the Power ACNR. *See* Transmission GRSP II.G.1(a) and Power GRSP II.O.1(a).

(b) Calculating the Power RDC Amount

The Power RDC can trigger only if (1) Power ACNR exceeds the Power RDC Threshold, measured in Power ACNR, and (2) BPA ACNR exceeds the BPA RDC Threshold, measured in BPA ACNR.

The Power RDC Amount is the amount of financial reserves for risk attributed to Power that the Administrator will consider applying to reduce debt, incrementally fund capital projects, decrease rates through a Power DD, distribute to customers, or any other Power-specific purposes determined by the Administrator. The Power RDC Amount will be the smallest of Power ACNR minus the Power RDC Threshold, BPA ACNR minus the BPA RDC Threshold, or the Power RDC Cap.

Table D.1
Power RDC Annual Thresholds and Caps
(dollars in millions)

ACNR Calculated from CNR for Fiscal Year(s)	***RDC Applied to Fiscal Year***	***Threshold Measured in Power ACNR***	***Threshold Measured in Power Reserves for Risk***	***Maximum RDC Amount (Cap)***
2019	2020	$513	$601	$500
2019 + 2020	2021	$558	$601	$500

Table D.2
BPA RDC Annual Thresholds
(dollars in millions)

ACNR Calculated from CNR for Fiscal Year(s)	***RDC Applied to Fiscal Year***	***Threshold Measured in BPA ACNR***	***Threshold Measured in BPA Reserves for Risk***
2019	2020	$294	$597
2019 + 2020	2021	$424	$597

2. Power DD Credit Rate

If the Administrator elects to apply all or a portion of a Power RDC Amount to reduce Power rates, then the following Power DD Credit rate shall apply:

(a) Calculating the Power DD Credit Rate

The Power DD Credit rate in mills per kilowatthour shall be:

$$\frac{\text{Power RDC Amount being used for a Power DD}}{\sum \text{BD}}$$

Where:

∑ *BD* (*Sum of Billing Determinants*) is the sum of the following December through September forecasts, made on or about the beginning of each applicable year, in kilowatthours:

- service under the PF Melded, IP, and NR rates, and
- PF System Shaped Loads.

(b) Billing

For customers taking service at the PF Melded, IP, and NR rates, the Power DD Credit rate will be subtracted from the December through September monthly/diurnal PF Melded, IP and NR energy rates for the applicable year.

For PF customers with a System Shaped Load, the Power DD Credit rate will be applied to the sum of each customer's HLH and LLH PF System Shaped Load, multiplied by -1, for December through September of the applicable year. A customer's Low Density Discount shall be applied to the Power DD, which will be a charge.

(c) Adjustment to the PF Tier 1 Equivalent Energy Rates

The Power DD Credit rate will be subtracted from each of the monthly/diurnal PF Tier 1 Equivalent energy rates (GRSP II.AA) for December through September of the applicable year.

(d) Annual Power DD Credit Rate

An Annual Power DD Credit rate, in mills per kilowatthour, will be calculated so that the Load Shaping Charge True-up rate and PF Melded Equivalent Energy Scalar can be adjusted. The Annual Power DD Credit rate is calculated by dividing the Power RDC Amount being used for a Power DD by the annual forecast, made around the beginning of each Fiscal Year, of service under the PF Melded, IP, and NR rates and the sum of the PF System Shaped Loads for the applicable year, in kilowatthours. The Annual Power DD Credit rate will be:

(1) Added to the Load Shaping Charge True-Up rate (GRSP II.E, Section 1); and

(2) Added to the PF Melded Equivalent Energy Scalar rate (GRSP II.R, Section 1(c)).

3. Power RDC Notification Process

BPA shall follow these notification procedures:

(a) Financial Performance Status Reports

Each quarter, BPA shall post to its external website (www.bpa.gov) preliminary, unaudited, year-to-date aggregate financial results for the generation function.

For the Second and Third Quarter Reviews, BPA shall post to its external website (www.bpa.gov) a preliminary forecast of the Power RDC Amount.

(b) Notification of Power RDC

By November 30, 2019, BPA shall complete the calculation of Power ACNR and BPA ACNR through the end of FY 2019, for use in calculating the Power RDC applicable to rates for December through September of FY 2020. By November 30, 2020, BPA shall complete the calculation of Power ACNR and BPA ACNR through the end of FY 2020, for use in calculating the Power RDC applicable to rates for December through September of FY 2021.

If the Power RDC triggers, BPA will notify customers of the preliminary Power RDC Amount and whether the amount will be used to reduce debt, incrementally fund capital projects or other high-value Power purposes, or reduce rates, as soon as practicable, but in no case later than November 30 of each applicable year. BPA will make available to customers the preliminary data relied upon to calculate the Power RDC Amount, including the calculation of Power ACNR.

BPA will hold at least one public meeting to discuss the calculations of Power ACNR, the Power RDC Amount, and if applicable, the Power DD Credit rate and Annual Power DD Credit rate. BPA will provide customers an opportunity for comment on the preliminary data. BPA will issue the final Power RDC Amount as soon as practicable, but in no case later than December 15 of each applicable year.

Q. Power Financial Reserves Policy (Power FRP) Surcharge

1. Suspension of Power FRP Surcharge

The Power FRP Surcharge is suspended as of the effective date of the confirmation and approval of this rate schedule by the Federal Energy Regulatory Commission (Commission); *provided, however,* if the effective date given by the Commission is on any day other than the first day of the month, then this rate schedule shall go into effect the first day of the following month. *See* Administrator's Record of Decision, BP-20E-A-01.

2. Adjustments to Load Shaping Charge True-up Rate and PF Melded Equivalent Scalar for Fiscal Year 2020

Prior to suspension, the Power FRP Surcharge triggered and was billed to customers during FY 2020 on a monthly basis. To recognize this FY 2020 charge for the months prior to suspension, the Load Shaping Charge True-up Rate and PF Melded Equivalent Energy Scalar shall be adjusted as follows:

$$\text{Annual Power FRP Surcharge rate} = \frac{\$30{,}000{,}000 \times \dfrac{\text{Applicable months}}{10}}{44{,}625{,}581\ \text{MWh}}$$

Where:

"Applicable months" is the number of months in Fiscal Year 2020 that the Power FRP Surcharge was applied prior to suspension as described in Section Q.1.

The Annual Power FRP Surcharge rate will be:

(1) Subtracted from the Load Shaping Charge True-up Rate (GRSP II.E, Section 1)

(2) Subtracted from the PF Melded Equivalent Energy Scalar Rate (GRSP II.R, Section 1(c)).

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R. Slice True-Up Adjustment

Pursuant to Section 2.7 of the TRM, BP-12-A-03, Slice customers shall have an annual Slice True-Up Adjustment for expenses, revenue credits, and adjustments allocated to the Composite cost pool and to the Slice cost pool. The annual Slice True-Up Adjustment shall be calculated for each fiscal year as soon as BPA's audited actual financial data are available (usually in November).

1. Calculation of the Annual Composite Cost Pool True-Up

(a) Calculation of the Slice True-Up Adjustment Charge for the Composite Cost Pool

Following the end of each fiscal year of the rate period, BPA shall:

(1) subtract:

(i) the forecast annual expenses, revenue credits, and adjustments allocated to the Composite cost pool for the applicable fiscal year of the rate period,

from

(ii) the actual expenses, revenue credits, and adjustments in the applicable fiscal year of the rate period that are allocable to the Composite cost pool;

(2) divide the difference determined in (1) above by the sum of TOCAs for that fiscal year adjusted in accordance with TRM Section 5.1.1 and the Load Shaping True-Up methodology set forth in TRM Section 5.2.4.1 for Load Following customers; and

(3) multiply the dollar amount in (2) above by each Slice customer's Slice percentage for the applicable fiscal year.

For each Slice customer, the dollar amount calculated, which may be positive or negative, constitutes its Slice True-Up Adjustment charge for the Composite cost pool.

The Composite Cost Pool True-Up Table (Table F) contains the forecast expenses, revenue credits, and adjustments that will be the basis, when compared to actual expenses, revenue credits, and adjustments, for the Slice True-Up Adjustment calculation for the Composite cost pool for the applicable fiscal year. Included in these adjustments and credits are the actual Firm Surplus and Secondary Adjustment from Unused RHWM and the actual DSI Revenue Credit described in (b) and (c) below.

(b) Calculation of the Actual Firm Surplus and Secondary Adjustment from Unused RHWM

For purposes of the annual Composite Cost Pool True-Up, the actual Firm Surplus and Secondary Adjustment from Unused RHWM for the applicable fiscal year shall be calculated as the sum of:

(1) the forecast Firm Surplus and Secondary Adjustment from Unused RHWM for the applicable fiscal year developed in the BP-20 7(i) process; and

(2) the Change in PF Composite Customer Charge Revenue for the applicable fiscal year (change can be positive or negative);

Where:

Change in PF Composite Customer Charge Revenue = (sum of actual TOCAs – sum of forecast TOCAs) × monthly Composite Customer rate × 12 months.

TOCAs are expressed as a percentage, *e.g.*, 95 percent.

Sum of actual TOCAs is calculated after the fiscal year and is equal to the forecast sum of TOCAs for Slice/Block and Block customers, adjusted based on the Annual Net Requirement process in accordance with TRM Section 5.1.1. For Load Following customers, sum of actual TOCAs is adjusted based on TRM Section 2.7.1 using information from the Load Shaping True-Up methodology set forth in TRM Section 5.2.4.1.

Sum of forecast TOCAs is the sum of TOCAs used to set the PF-20 Composite Customer rate; and

(3) the Change in Unused RHWM Revenue for the applicable fiscal year (change can be positive or negative).

Where:

Change in Unused RHWM Revenue = (Actual Unused RHWM – Forecast Unused RHWM) × 24.17 mills/kWh.

Actual Unused RHWM = (1.00 – sum of actual TOCAs, expressed as a decimal) × RHWM Tier 1 System Capability for the applicable fiscal year (expressed in aMW) × 8,760 hours (8,784 hours if a leap year).

Forecast Unused RHWM = (1.00 – sum of forecast TOCAs, expressed as a decimal) × RHWM Tier 1 System Capability for the applicable fiscal year (expressed in aMW) × 8,760 hours (8,784 hours if a leap year).

(c) Calculation of the Actual DSI Revenue Credit

For purposes of the annual Composite Cost Pool True-Up, the Actual DSI Revenue Credit for the applicable fiscal year shall be calculated as the sum of:

(1) the forecast DSI Revenue Credit for the applicable fiscal year developed in the BP-20 7(i) process;

(2) (i) the forecast MWh amount used to calculate (1) above for the applicable fiscal year *minus* (ii) the actual MWh amount of DSI sales for the applicable fiscal year, the result multiplied by –22.56 mills/kWh; and

(3) DSI Take-or-Pay revenues

Where:

Actual kWh amount of DSI sales and DSI Take-or-Pay revenues shall be obtained from BPA data sources.

–22.56 mills/kWh is calculated by the equation:

PFMEES – 7.72 mills/kWh

Where:

PFMEES is the PF Melded Equivalent Energy Scalar of –14.84 mills/kWh and is subject to adjustment during the Rate Period by the Power CRAC (GRSP II.O); the Power RDC (GRSP II.P); and the Power FRP Surcharge (GRSP II.Q).

See GRSP Appendix A, Supplemental Information, for adjusted PF Melded Equivalent Energy Scalars.

2. Calculation of the Annual Slice Cost Pool True-Up

The Slice Cost Pool True-Up Table (Table G) contains the forecast expenses, revenue credits, and adjustments that will be the basis, when compared to actual expenses, revenue credits, and adjustments, for the Slice True-Up Adjustment calculation for the Slice cost pool for the applicable fiscal year.

Following the end of each fiscal year and pursuant to TRM Section 2.7.2, BPA shall:

(a) subtract:

(1) the forecast annual expenses, revenue credits, and adjustments allocated to the Slice cost pool for the applicable fiscal year of the rate period

from

(2) the actual expenses, revenue credits, and adjustments that are allocated to the Slice cost pool for the applicable fiscal year of the rate period;

and

(b) for each Slice customer, multiply the resulting difference from (a) above by the ratio of (i) the customer's Slice percentage for the fiscal year in Exhibit K of the Slice/Block Contract to (ii) the sum of all customers' Slice percentages for the fiscal year in all Exhibits K of the Slice/Block CHWM Contracts.

For each Slice customer, the dollar amount calculated, which may be positive or negative, constitutes its Slice True-Up Adjustment charge for the Slice cost pool.

Table F
Composite Cost Pool True-Up Table

		Actual Data ($000)	FY 2020 forecast ($000)	FY 2021 forecast ($000)
1	**Operating Expenses**			
2	**Power System Generation Resources**			
3	**Operating Generation**			
4	COLUMBIA GENERATING STATION (WNP-2)		262,471	319,462
5	BUREAU OF RECLAMATION		153,609	151,623
6	CORPS OF ENGINEERS		252,557	252,557
7	LONG-TERM CONTRACT GENERATING PROJECTS		12,709	13,250
8	**Sub-Total**		**681,345**	**736,892**
9	**Operating Generation Settlement Payment and Other Payments**			
10	COLVILLE GENERATION SETTLEMENT		22,997	22,997
11	SPOKANE LEGISLATION PAYMENT		-	-
12	**Sub-Total**		**22,997**	**22,997**
13	**Non-Operating Generation**			
14	TROJAN DECOMMISSIONING		1,200	1,200
15	WNP-1&3 DECOMMISSIONING		431	331
16	**Sub-Total**		**1,631**	**1,531**
17	**Gross Contracted Power Purchases**			
18	PNCA HEADWATER BENEFITS		3,100	3,100
19	OTHER POWER PURCHASES (omit, except Designated Obligations or Purchases)		-	-
20	**Sub-Total**		**3,100**	**3,100**
21	**Bookout Adjustment to Power Purchases (omit)**			
22	**Augmentation Power Purchases (omit - calculated below)**			
23	AUGMENTATION POWER PURCHASES		-	-
24	**Sub-Total**		**-**	**-**
25	**Exchanges and Settlements**			
26	RESIDENTIAL EXCHANGE PROGRAM (REP)		250,570	250,370
27	OTHER SETTLEMENTS		-	-
28	**Sub-Total**		**250,570**	**250,370**
29	**Renewable Generation**			
30	RENEWABLES (excludes KIII)		26,475	24,711
31	**Sub-Total**		**26,475**	**24,711**
32	**Generation Conservation**			
33	CONSERVATION ACQUISITION (Purchases)		67,000	67,000
34	CONSERVATION INFRASCTRUCTURE		27,296	27,296
35	LOW INCOME WEATHERIZATION & TRIBAL		5,739	5,853
36	REIMBURSABLE ENERGY EFFICIENCY DEVELOPMENT		8,000	8,000
37	DR & SMART GRID		855	855
38	LEGACY		590	590
39	MARKET TRANSFORMATION		12,050	12,050
40	**Sub-Total**		**121,530**	**121,644**
41	**Power System Generation Sub-Total**		**1,107,648**	**1,161,245**
42	**Power Non-Generation Operations**			
43	**Power Services System Operations**			
44	EFFICIENCIES PROGRAM		-	-
45	INFORMATION TECHNOLOGY		6,714	6,775
46	GENERATION PROJECT COORDINATION		6,059	6,205
47	SLICE IMPLEMENTATION		555	575
48	**Sub-Total**		**13,329**	**13,555**
49	**Power Services Scheduling**			
50	OPERATIONS SCHEDULING		8,806	9,148
51	OPERATIONS PLANNING		5,643	5,839
52	**Sub-Total**		**14,449**	**14,987**
53	**Power Services Marketing and Business Support**			
54	POWER R&D		2,662	2,666
55	SALES & SUPPORT		23,191	23,954
56	STRATEGY, FINANCE & RISK MGMT		16,103	16,470
57	EXECUTIVE AND ADMINISTRATIVE SERVICES		3,879	3,967
58	CONSERVATION SUPPORT		8,399	8,699
59	**Sub-Total**		**54,235**	**55,756**
60	**Power Non-Generation Operations Sub-Total**		**82,012**	**84,298**
61	**Power Services Transmission Acquisition and Ancillary Services**			
62	TRANSMISSION and ANCILLARY Services - System Obligations		32,028	32,028
63	3RD PARTY GTA WHEELING		96,200	96,200
64	POWER 3RD PARTY TRANS & ANCILLARY SVCS (Composite Cost)		2,338	2,384
65	TRANS ACQ GENERATION INTEGRATION		13,577	13,671
66	TELEMETERING/EQUIP REPLACEMT		-	-
67	**Power Services Trans Acquisition and Ancillary Serv Sub-Total**		**144,143**	**144,283**
68	**Fish and Wildlife/USF&W/Planning Council/Environmental Req**			
69	**Fish & Wildlife**		249,603	250,031
70	**USF&W Lower Snake Hatcheries**		30,483	30,483
71	**Planning Council**		11,725	11,956
72	**Environmental Requirements**		-	-
73	**Fish and Wildlife/USF&W/Planning Council Sub-Total**		**291,811**	**292,470**

Table F, continued
Composite Cost Pool True-Up Table

74		Actual Data	FY 2020 forecast	FY 2021 forecast
75		($000)	($000)	($000)
76	**BPA Internal Support**			
77	**Additional Post-Retirement Contribution**		19,577	20,831
78	**Agency Services G&A (excludes direct project support)**		57,859	57,644
79	**BPA Internal Support Sub-Total**		**77,436**	**78,475**
80	**Bad Debt Expense**		-	-
81	**Other Income, Expenses, Adjustments**		-	(20,000)
82	**Depreciation**		138,968	141,050
83	**Amortization**		379,327	384,364
84	**Total Operating Expenses**		**2,221,345**	**2,266,186**
85	**Other Expenses and (Income)**			
86	Net Interest Expense		270,654	202,407
87	LDD		38,505	39,107
88	Irrigation Rate Discount Costs		20,905	20,905
89	Other Expense and (Income)		-	-
90	**Sub-Total**		**330,064**	**262,418**
91	**Total Expenses**		**2,551,409**	**2,528,604**
92	**Revenue Credits**			
93	Generation Inputs for Ancillary, Control Area, and Other Services Revenues		119,815	119,815
94	Downstream Benefits and Pumping Power revenues		19,364	19,364
95	4(h)(10)(c) credit		86,250	86,852
96	Colville and Spokane Settlements		4,600	4,600
97	Energy Efficiency Revenues		8,000	8,000
98	PF Load Forecast Deviation Liquidated Damages		9,499	9,458
99	Miscellaneous revenues		12,362	12,397
100	Renewable Energy Certificates		-	-
101	Net Revenues from other Designated BPA System Obligations (Upper Baker)		353	347
102	RSS Revenues		2,728	2,813
103	Firm Surplus and Secondary Adjustment (from Unused RHWM)		68,746	61,756
104	Balancing Augmentation Adjustment		1,213	4,273
105	Transmission Loss Adjustment		30,066	30,308
106	Tier 2 Rate Adjustment		510	615
107	NR Revenues		1	1
108	**Total Revenue Credits**		**363,507**	**360,598**
109				
110	**<u>Augmentation Costs (not subject to True-Up)</u>**			
111	Tier 1 Augmentation Resources (includes Augmentation RSS and Augmentation RSC adders)		12,367	12,477
112	Augmentation Purchases		-	-
113	**Total Augmentation Costs**		**12,367**	**12,477**
114				
115	**DSI Revenue Credit**			
116	Revenues 12 aMW @ IP rate		4,303	4,291
117	**Total DSI revenues**		**4,303**	**4,291**
118				
119	**Minimum Required Net Revenue Calculation**			
120	Principal Payment of Fed Debt for Power		173,072	518,065
121	Repayment of Non-Federal Obligations (EN Line of Credit)		227,000	-
122	Repayment of Non-Federal Obligations (CGS, WNP1, WNP3, N. Wasco, Cowlitz Falls)		41,581	22,871
123	Irrigation assistance		24,331	14,747
124	**Sub-Total**		**465,984**	**555,683**
125	Depreciation		138,968	141,050
126	Amortization		379,327	384,364
127	Capitalization Adjustment		(45,937)	(45,937)
128	Non-Cash Expenses		-	-
129	Customer Proceeds		-	-
130	Cash freed up by DSR refinancing		16,590	15,885
131	Prepay Revenue Credits		(30,600)	(30,600)
132	Non-Federal Interest (Prepay)		9,826	8,863
133	Contribution to decommissioning trust fund		(4,100)	(4,300)
134	Gains/losses on decommissioning trust fund		(5,052)	(5,220)
135	Interest earned on decommissioning trust fund		(8,818)	(9,112)
136	**Sub-Total**		**450,204**	**454,993**
137	Principal Payment of Fed Debt and Non-Fed Debt plus Irrigation assistance exceeds non cash expenses		15,780	100,690
138	Minimum Required Net Revenues		**15,780**	**100,690**
139				
140	Annual Composite Cost Pool (Amounts for each FY)		**2,211,745**	**2,276,882**
141				
142	**SLICE TRUE-UP ADJUSTMENT CALCULATION FOR COMPOSITE COST POOL**			
143	TRUE-UP AMOUNT (Diff. between actual Comp. Cost Pool and forecast Comp. Cost Pool for applicable FY)			
144	Adjustment of True-Up Amount when actual TOCAs < 100 percent (divide by sum of TOCAs, expressed as a decimal, 100 percent = 1.0)			
	TRUE-UP ADJUSTMENT CHARGE BILLED (22.3627 percent)			

Table G
Slice Cost Pool True-Up Table

		Audited Actual Data ($000)	FY 2020 forecast ($000)	FY 2021 forecast ($000)
1	**Slice Expenses**			
2				
3				
4	**Total Slice Expenses**		$ -	$ -
5				
6	**Slice Credits**			
7				
8	**Total Slice Credits**		$ -	$ -
9				
10	Annual Slice Cost Pool (Amounts for each FY)		$ -	$ -
11				
12	**SLICE TRUE-UP ADJUSTMENT CALCULATION FOR SLICE COST POOL**			
13	TRUE UP AMOUNT (Diff. between actual Slice Cost Pool and forecast Slice COST Pool for applicable FY)			
14				
15	TRUE-UP ADJUSTMENT CHARGE BILLED (100 percent)			

S. Residential Exchange Program Residential Load

Residential Loads of investor-owned utilities for the rate period are shown in Table H below. These loads are applicable to each year of the rate period, FY 2020 and FY 2021, and are established pursuant to Section 2 of the 2012 REP Settlement Agreement, REP-12-A-02A (misfiled as REP-12-A-02-AP01) (2012 REP Settlement).

Table H
Residential Load for the BP-20 Rate Period (in kWh)

Month	*Avista*	*Idaho*	*NorthWestern*
October	250,016,994	455,396,562	50,567,544
November	305,575,577	425,971,623	54,946,271
December	401,987,435	526,910,480	66,836,555
January	497,120,436	684,421,016	80,582,405
February	405,183,431	613,207,645	68,644,239
March	374,163,589	537,238,828	65,532,435
April	315,687,321	427,318,024	55,061,547
May	262,906,040	456,028,908	48,967,394
June	245,752,042	533,302,515	46,872,757
July	275,401,209	693,792,859	50,761,107
August	323,491,046	775,280,099	60,860,523
September	278,352,264	631,238,357	52,544,371

Month	*PacifiCorp*	*Portland General*	*Puget Sound*
October	576,332,767	532,635,733	781,401,544
November	692,983,134	581,131,246	966,099,755
December	947,062,234	746,597,931	1,207,552,439
January	1,107,581,861	1,026,819,502	1,447,257,197
February	881,734,848	865,449,531	1,272,447,236
March	816,242,411	808,601,529	1,266,523,700
April	677,011,323	671,918,724	1,013,046,112
May	603,411,392	560,527,214	854,074,176
June	632,962,988	551,487,026	758,339,658
July	739,061,360	591,163,110	742,772,085
August	805,265,615	613,550,137	796,095,611
September	692,334,537	618,208,981	763,849,027

T. Residential Exchange Program 7(b)(3) Surcharge Adjustment

The 7(b)(3) Surcharge is a utility-specific addition to the Base PF Exchange rate that recovers each REP participant's allocated share of the rate protection provided pursuant to the 2012 REP Settlement. As determined in the BP-20 7(i) process, each REP participant's 7(b)(3) Surcharge is based on its Base PF Exchange rate, its Average System Cost (ASC), and its contract exchange loads. Each REP participant's 7(b)(3) Surcharge is displayed in the table in Section 6.1 of the PF-20 rate schedule and is subject to modification under this GRSP.

In implementing the REP, BPA has identified circumstances where a utility's ASC may be modified during the BPA rate period (*e.g.*, new resource additions, new NLSLs, changes in service territory). Subject to limitations in the 2008 ASC Methodology, when BPA modifies a utility's ASC during a BPA rate period, the modified ASC shall be effective on the date specified in BPA's notice to the participating utility confirming the modification of its ASC. Therefore, if a participating utility's ASC differs from the ASC used in establishing rates in Section 6.1 of the PF-20 rate schedule, BPA shall adjust the 7(b)(3) Surcharges of all participating utilities to reflect the new ASC.

Such adjustment of 7(b)(3) Surcharges shall be accomplished by substituting all modified ASCs and recomputing the rates in Section 6.1 of the PF-20 rate schedule. This recomputation shall be accomplished by:

1. Inserting the participating utility's revised ASC, expressed in mills/kWh (equivalent to $/MWh).

2. Retaining the forecast exchange load for the participating utility, expressed in gigawatthours, as adopted in the BP-20 7(i) proceeding.

3. Multiplying the difference between the ASC and the applicable Base PF Exchange rate by the forecast exchange load to compute the unconstrained benefits for each participant.

4. Summing the unconstrained benefits for each participant to compute total unconstrained benefits.

5. Computing the difference between the total unconstrained benefits and $499,513,518 (the total REP benefits adopted for the two-year rate period in the BP-20 7(i) proceeding).

6. Recomputing the IOU adjustments specified in Section 6.2 of the 2012 REP Settlement.

7. Dividing the recomputed allocated dollars by exchange loads to determine the revised 7(b)(3) Surcharge and adding each revised 7(b)(3) Surcharge to the appropriate Base PF Exchange rate to compute the revised utility-specific PF Exchange rates.

The specific computations that will be performed are displayed on Tables 2.4.11 and 2.4.12 of the Power Rates Study Documentation, BP-20-E-BPA-01A. Table 2.4.11 shall be updated as specified above to perform the actual 7(b)(3) Surcharge adjustments. The adjusted 7(b)(3) Surcharges shall take effect on the day that the utility's modified ASC takes effect. This adjustment shall occur as frequently as ASCs are modified during the two-year rate period the PF Exchange rate herein is in effect.

The adjustment of 7(b)(3) Surcharges shall be updated and published as ASCs are modified. The table can be accessed through BPA's Residential Exchange Program website.

U. Conservation Surcharge

The Conservation Surcharge, if implemented, shall be applied in accordance with relevant provisions of the Northwest Power Act, BPA's current Conservation Surcharge policy, and the customer's power sales contract with BPA. The Conservation Surcharge applies to the PF-20 (including Slice purchasers), NR-20, and IP-20 rate schedules.

V. [Reserved for Future Use]

W. Flexible Priority Firm Power (PF) Rate Option

The Flexible PF rate option will be offered at BPA's discretion to a customer that makes a contractual commitment to purchase under this option. The rates and billing determinants under this option shall be specified by BPA at the time the Administrator offers to make power available to a customer under this option. The customer under the Flexible PF rate option shall purchase the same set of power products and services that it would otherwise purchase under the PF-20 rate schedule. The flexible rates and billing determinants will be mutually agreed to by BPA and the customer, subject to satisfying the following conditions:

- Equivalent NPV Revenue: Forecast revenue from a customer under the Flexible PF rate option must be equivalent, on a net present value basis, to the revenue BPA would have received had the appropriate rates specified in Sections 2, 3, 4, and 5 of the PF-20 rate schedule been applied to the same sales.

- The Flexible PF rate contract may establish a limit on the amount of power purchased at the Flexible PF rate. In this case, purchases beyond the contractual limit will be billed at the rates specified in Sections 2, 3, 4, and 5 of the PF-20 rate schedule, unless such power would be charged as an Unauthorized Increase.

Notwithstanding the effective dates of the PF-20 rate and associated GRSPs, any rights and obligations of BPA and a customer arising out of the customer's election to participate in the

Flexible PF Rate program by purchasing under the Flexible PF Rate Option shall survive and be fully enforceable until such time as they are fully satisfied.

X. Priority Firm Power (PF) Shaping Option

Prior to the beginning of the rate period, BPA and a customer purchasing Firm Requirements Power charged under Section 2.1 of the PF-20 rate schedule may agree to a PF-20 Tier 1 Customer charge payment schedule for the rate period that differs from the flat monthly charge specified in the PF-20 rate schedule. BPA will, to the maximum extent practicable while ensuring timely BPA cost recovery, accommodate individual customer requests to "shape" certain PF-20 Tier 1 Customer charges within the fiscal year to mitigate adverse cash flow effects on the customer. The shaped payments at PF-20 Tier 1 Customer rates will be mutually agreed to by BPA and the customer. Requests to shape Customer charges during the rate period must be received by BPA no later than September 1, 2019.

This Shaping Option analysis will take into account the cash-flow impacts to the customer of the Tier 1 charges: the Customer charges; a forecast of monthly Load Shaping charges; a forecast of monthly demand charges; and any applicable rate discounts. BPA and the customer may agree to 12 monthly Composite Customer charges that the customer shall pay in each year of the rate period. If further shaping is requested to mitigate a customer's cash-flow impacts, BPA may also agree to shape the Non-Slice Customer charge.

BPA will accommodate requests to shape Customer charges if the following conditions are met:

1. Equivalent Net Present Value: Forecast revenue from the shaped charges must be equivalent, on a net present value basis, to the revenue BPA would have received for each fiscal year without shaping.

2. No Material Adverse Impacts on BPA's Cash Flow: The aggregate shaping requests do not have a material adverse impact on BPA's overall cash flow, as determined solely by BPA. In order to accommodate multiple shaping requests, BPA will take into account the potential offsetting impacts of all shaping requests. If BPA is not able to accommodate all requests in total due to material adverse impacts on BPA's cash flow, BPA may limit the shaping for individual requests.

Y. Flexible New Resource Firm Power (NR) Rate Option

The Flexible NR rate option will be offered at BPA's discretion to a customer that makes a contractual commitment to purchase under this option. The rates and billing determinants under this option shall be specified by BPA at the time the Administrator offers to make power available to a customer under this option. The customer under the Flexible NR rate option shall purchase the same set of power products and services that it would otherwise purchase under the NR-20 rate schedule. The flexible rates and billing determinants will be mutually agreed to by BPA and the customer, subject to satisfying the following conditions:

- Equivalent NPV Revenue: Forecast revenue from a customer under the Flexible NR rate option must be equivalent, on a net present value basis, to the revenue BPA would have received had the appropriate rates specified in Sections 2, 3, 4 and 5 of the NR-20 rate schedule been applied to the same sales.

- The Flexible NR rate contract may establish a limit on the amount of power purchased at the Flexible NR rate. In this case, purchases beyond the contractual limit will be billed at the rates specified in Sections 2, 3, 4 and 5 of the NR-20 rate schedule, unless such power would be charged as an Unauthorized Increase.

Notwithstanding the effective dates of the NR-20 rate and associated GRSPs, any rights and obligations of BPA and a customer arising out of the customer's election to participate in the Flexible NR Rate program by purchasing under the Flexible NR Rate Option shall survive and be fully enforceable until such time as they are fully satisfied.

Z. Cost Contributions

Pursuant to Section 7(j) of the Northwest Power Act (16 U.S.C. § 839e(j)), BPA has made the following resource cost determinations:

1. The approximate cost contribution of different resource categories to each rate schedule is:

Table I
Resource Cost Contribution

Rate Schedule	***Federal Base System***	***Exchange Resources***	***New Resources***
PF	38.14%	61.86%	0%
IP	0%	67.42%	32.58%
NR	0%	67.42%	32.58%
FPS	0%	70.27%	29.73%

2. The cost of resources acquired to meet load growth within the region is estimated to be 31.76 mills/kWh, and the forecast average cost of resources available to BPA under average water conditions is 47.50 mills/kWh.

AA. Priority Firm Power (PF) Tier 1 Equivalent Rates

The PF Tier 1 Equivalent rates are an expression of the Non-Slice PF Public Tier 1 rates in a traditional HLH and LLH energy form. These rates can be used as a reference when a need arises for Tier 1 rates to be expressed in this manner.

	Energy Rate in mills/kWh		***Demand Rate in $/kW***
Month	***HLH***	***LLH***	***HLH***
October	39.03	34.07	11.42
November	40.38	37.03	12.07
December	43.28	38.75	13.45
January	40.43	34.40	12.10
February	39.55	34.47	11.66
March	34.38	31.30	9.19
April	33.17	29.59	8.61
May	26.90	21.74	5.60
June	25.71	16.87	5.04
July	36.64	30.50	10.27
August	40.43	35.40	12.10
September	40.05	35.17	11.91

These rates are subject to adjustment during the Rate Period by the Power CRAC (GRSP II.O); the Power RDC (GRSP II.P); and the Power FRP Surcharge (GRSP II.Q). See GRSP Appendix A, Supplemental Information, for adjusted PF Tier 1 Equivalent rates.

SECTION III. DEFINITIONS

A. Power Products and Services Offered By BPA Power Services

1. Block Product

As defined in the TRM, the Block Product is BPA's power product defined in Section 4 of the Block and Slice/Block CHWM Contracts.

2. Capacity Without Energy

Capacity Without Energy is the stand-ready obligation whereby BPA will deliver a contract-specific amount of power upon contract-specific notice provisions. The notice provision may be automated, such as Automatic Generation Control automatic deliveries, phone call schedules, or any other standard utility notice provisions. The notice provision and duration of delivery is contract-specific and will affect the value of the capacity product. No energy is sold with Capacity Without Energy; any energy delivered when the capacity contract is exercised will be returned or paid for under contract terms. The terms of the contract will define all parameters of the required notice provisions and all parameters of the return or payment of any energy delivered when capacity rights are exercised.

3. Construction, Test and Start-Up, and Station Service

Power for the purpose of Construction, Test and Start-Up, and Station Service for a generating resource or transmission facility shall be made available to eligible customers under the Priority Firm Power (PF-20), New Resources Firm Power (NR-20), and Firm Power and Surplus Products and Services (FPS-20) rate schedules. Such power is not available under the PF Exchange rate.

Construction, Test and Start-Up, and Station Service power must be used in the manner specified below:

(a) Power sold for construction is to be used in the construction of the project.

(b) Power sold for test and start-up may be used prior to commercial operation, both to bring the project on-line and to ensure that the project is working properly.

(c) Power sold for station service may be purchased at any time following commercial operation of the project. Once the project has been energized for commercial operation, the customer may use station service power for start-up, shutdown, normal operations, and operations during a shutdown period.

(d) Power sold for Construction, Test and Start-Up, and Station Service is not available for replacement of lost generation for forced or planned outages or resource underperformance.

4. **Energy Shaping Service for NLSL**

   Energy Shaping Service is an optional service for Load Following customers serving a New Large Single Load (NLSL) with a non-Federal resource. ESS includes a capacity component and an energy component. These services shape a customer's resource energy and capacity output amounts to the actual load of a NLSL.

5. **Firm Requirements Power**

   Firm Requirements Power is Federal power that BPA makes continuously available to a customer to meet BPA's obligations to the customer under Section 5(b) of the Northwest Power Act.

6. **Forced Outage Reserve Service (FORS)**

   As defined in the TRM, FORS is a service that provides an agreed-upon amount of capacity and energy to load during the forced outages of a qualifying resource.

7. **Industrial Firm Power (IP)**

   Industrial Firm Power (IP) is electric power that BPA will make available to a DSI customer subject to the terms of the DSI customer's power sales contract with BPA.

8. **Load Following Product**

   As defined in the TRM, the Load Following Product is the BPA firm power service under the Load Following CHWM Contract that meets the customer's Total Retail Load less its Non-Federal Resources obligation on a real-time basis.

9. **Load Shaping**

   BPA provides Load Shaping to customers with CHWM Contracts purchasing the Load Following Product, the Block Product, or the Block portion of the Slice/Block Product. Load Shaping shapes the Tier 1 System Capability to the monthly/diurnal shape of a customer's Actual Monthly/Diurnal Tier 1 Load.

10. **New Resource Firm Power (NR)**

    New Resource Firm Power (NR) is electric power (capacity and energy) that BPA will make continuously available:

    (a) for any NLSL, as defined in the Northwest Power Act;

    (b) for Firm Power purchased by IOUs pursuant to power sales contracts with BPA.

    NR is to be used to meet the customer's firm power load within the Pacific Northwest. Deliveries of NR may be reduced or interrupted as permitted by the terms of the customer's power sales contract with BPA.

NR is guaranteed to be continuously available to the customer during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and force majeure events.

11. NR Resource Flattening Service (NRFS)

NR Resource Flattening Service (NRFS) is applicable to Load Following customers that apply the generation output of a non-dispatchable Specified Resource to serve an NLSL.

12. Priority Firm Power (PF)

Priority Firm Power (PF) is electric power (capacity and energy) that BPA will make continuously available for direct consumption or resale by public bodies, cooperatives, and Federal agencies. Utilities participating in the Residential Exchange Program may purchase PF pursuant to their RPSA or REPSIA with BPA. PF is not available to serve New Large Single Loads. Deliveries of PF may be reduced or interrupted as permitted by the terms of the customer's power sales contract with BPA.

PF is guaranteed to be continuously available to the customer during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and force majeure events.

13. Residential Exchange Program Power

Residential Exchange Program Power is power BPA sells to a customer pursuant to the REP. Under Section 5(c) of the Northwest Power Act, BPA "purchases" power from eligible Pacific Northwest utilities at a utility's Average System Cost (ASC). 16 U.S.C. § 839c(c). BPA then offers, in exchange, to "sell" an equivalent amount of electric power to that customer at BPA's PF rate applicable to exchanging utilities (PF Exchange rate). The amounts of power purchased and sold are both equal to the utility's eligible residential and farm load. Benefits must be passed directly to the utility's residential and farm customers.

14. Resource Remarketing Service (RRS)

Resource Remarketing Service (RRS) is a service that BPA makes available at its discretion to Load Following customers where BPA remarkets non-Federal resources on behalf of customers and provides them with remarketing credits, net of a remarketing fee.

15. Resource Support Services (RSS)

Resource Support Services are used to make resources, either non-Federal or Federal resource acquisitions, financially equivalent to a flat block. RSS are available for all specified non-Federal resources that Load Following customers contractually dedicate to serve their Total Retail Load and for specified new renewable resources Slice/Block and Block customers contractually dedicate to serving their Total Retail Load. RSS includes: Diurnal Flattening Service, Forced Outage Reserve Service, Grandfathered Generation Management Service, Secondary Crediting Service, Transmission Scheduling Service and Transmission Curtailment Management Service.

16. Secondary Crediting Service (SCS)

As defined in the TRM, Secondary Crediting Service (SCS) is the optional service offered by BPA that provides a monetary credit for the secondary output from an existing resource that has a firm critical energy component and a secondary energy component. There are two different options for SCS. Under SCS Option 1, the customer exchanges power generated by its resource with Federal deliveries. Under SCS Option 2, the customer applies its resource directly to load, and Federal deliveries cover the net load.

17. Slice/Block Product

The Slice/Block Product is the customer's purchase obligation under the Slice product and the Block Product to meet the customer's regional consumer load obligation under Section 3.1 of the Slice/Block CHWM Contract.

18. Transfer Service

As defined in the CHWM Contracts, Transfer Service means the transmission, distribution and other services provided by a third party transmission provider to deliver electric energy and capacity over its transmission system**.**

B. Definition of Rate Schedule Terms

1. Above-RHWM Load

As defined in the TRM, Above-RHWM Load is the forecast annual Total Retail Load, less Existing Resources, New Large Single Loads, and the customer's Rate Period High Water Mark, as determined in the RHWM Process.

2. Actual Monthly/Diurnal Tier 1 Load

As defined in the TRM, the Actual Monthly/Diurnal Tier 1 Load is the amount of the customer's electric load (measured in kilowatthours) that was served at Tier 1 rates during the relevant monthly/diurnal period.

3. Billing Determinant

(a) A measure of electric power usage at a customer's metered point of delivery used in the computation of a customer's bill.

(b) As defined in the TRM, a unit of measure for sales of a product or service for which a customer is billed by BPA.

4. Charge

A charge is the product of a billing determinant and a rate.

5. Contract Demand

The customer's Contract Demand is the maximum amount of capacity that the customer agrees to purchase and BPA agrees to make available, subject to any limitations included in the applicable contract between BPA and the customer.

6. Contract Demand Quantity (CDQ)

As defined in the TRM, the Contract Demand Quantity is the monthly quantity of demand (expressed in kilowatts) included in each customer's CHWM Contract that is subtracted from the Customer System Peak (CSP) as part of the process of determining the customer's demand charge billing determinant, as calculated in accordance with TRM Section 5.3.5.

7. Contract Energy

Contract Energy is the maximum amount of energy that the customer agrees to purchase and BPA agrees to make available, subject to any limitations included in the applicable contract between BPA and the customer.

8. **Contract High Water Mark (CHWM)**

   As defined in the TRM, the Contract High Water Mark is the amount (expressed in average megawatts) computed for each customer in accordance with TRM Section 4. For each customer with a CHWM Contract, the CHWM is used to calculate each customer's RHWM in the RHWM Process for each applicable rate period. The CHWM Contract specifies the CHWM for each customer.

9. **CHWM Contract**

   As defined in the TRM, the CHWM Contract is the power sales contract between a customer and BPA that contains a Contract High Water Mark (CHWM) and under which the customer purchases power from BPA at rates established by BPA in accordance with the TRM.

10. **Customer**

    Pursuant to the terms of an agreement and applicable rate schedule(s), a customer is the entity that contracts to pay BPA for providing a product or service.

11. **DSI Reserve**

    A DSI Reserve is any interruption right in addition to the Minimum DSI Operating Reserve – Supplemental, consistent with the DSI Reserves Adjustment standards and criteria described in GRSP II.H, that is provided by a DSI in a contract with BPA.

12. **Energy Efficiency Incentive**

    The Energy Efficiency Incentive is a funding mechanism that establishes a budget from which BPA funds energy efficiency incentive payments and associated qualified performance payments for customers with a CHWM Contract.

13. **Flat Annual Shape**

    As defined in the CHWM Contracts, Flat Annual Shape means a distribution of energy having the same average megawatt value of energy in each month of the year.

14. **Heavy Load Hours (HLH)**

    Heavy Load Hours (HLH) are all hours in the on-peak period – the hour ending 7 a.m. through the hour ending 10 p.m., Monday through Saturday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable) – except for the six holidays specified in NERC Standards. See also Light Load Hours definition.

15. **Intercontinental Exchange (ICE) Mid-C Day Ahead Power Price Index**

    Average HLH (or on-peak) and average LLH (or off-peak) price indices for firm power sales of electricity at delivery points along the Mid-Columbia River, as published by Intercontinental Exchange, Inc.

16. Light Load Hours (LLH)

Light Load Hours (LLH) are all those hours in the off-peak period – the hour ending 11 p.m. through the hour ending 6 a.m., Monday through Saturday, and all hours Sunday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable). BPA recognizes six holidays classified according to NERC Standards as LLH. Memorial Day, Labor Day, and Thanksgiving Day occur on the same day each year: Memorial Day is the last Monday in May; Labor Day is the first Monday in September; and Thanksgiving Day is the fourth Thursday in November. New Year's Day, Independence Day, and Christmas Day fall on predetermined dates each year. In the event that the predetermined dates fall on a Sunday, the holiday is recognized as the Monday immediately following that Sunday, so that Monday is also LLH all day. If the predetermined dates fall on a Saturday, the holiday is recognized as that Saturday, and that Saturday is classified as LLH.

17. Metered Demand

The Metered Demand, in kilowatts, shall be the largest of the 60-minute clock hour integrated demands at which electric energy is delivered to a customer:

(a) at each point of delivery for which the Metered Demand is the basis for determination of the measured demand;

(b) during each time period specified in the applicable rate schedule; and

(c) during any billing period.

Such largest integrated demand shall be determined from measurements made in accordance with the provisions of the applicable contract and these GRSPs. This amount shall be adjusted as provided herein and in the applicable agreement between BPA and the customer.

18. Metered Energy

The Metered Energy for a customer shall be the number of kilowatthours recorded on the appropriate metering equipment, adjusted as specified in the applicable agreement and delivered to a customer:

(a) at all points of delivery for which metered energy is the basis for determination of the measured energy; and

(b) during any billing period.

19. New Public

As defined in the TRM, a New Public is a Public that is not an Existing Customer. (As defined in the TRM, an Existing Customer is a Public that has a CHWM Contract at the time there is an annexation of some portion of its service territory.)

20. NR Hourly Load

The actual hourly amount (measured in kilowatthours) of (1) a customer's New Large Single Load that is recorded on the metering equipment and adjusted for any applicable resource amounts, as defined in the CHWM Contract; or (2) an investor-owned utility's NR Block amounts as specified in its NR Block Contract.

21. Powerdex Hourly Mid-C Price Index

Average hourly price index for hourly firm power sales of electricity at delivery points along the Mid-Columbia River, as published by Powerdex, Inc.

22. Public

As defined in the TRM, a Public is a public body or cooperative utility or Federal agency eligible to purchase requirements power from BPA pursuant to Section 5(b) of the Northwest Power Act. 16 U.S.C. § 839c(b).

23. Rate Period High Water Mark (RHWM)

As defined in the TRM, the Rate Period High Water Mark is the amount, calculated by BPA in each RHWM Process pursuant to the formula in TRM Section 4.2.1, and expressed in average megawatts, that BPA establishes for each customer based on the customer's CHWM and the RHWM Tier 1 System Capability. The maximum planned amount of power a customer may purchase under Tier 1 rates each fiscal year of the rate period is the RHWM for Load Following customers and the lesser of RHWM or Annual Net Requirement for Block and Slice/Block customers.

24. Remarketing Value

The Remarketing Value is the value BPA returns to customers for remarketed Tier 2 and non-Federal energy. This value is also used to calculate the cost of unpurchased amounts of Tier 2 energy. If BPA makes a transaction for a flat annual block of power (between November 1, 2018 and June 1, 2019) to be delivered in a fiscal year in the upcoming Rate Period, then the Remarketing Value for that fiscal year is based on the price of that transaction. If multiple transactions are made, then the Remarketing Value for that fiscal year is based on the weighted-average price of all transactions for the applicable delivery fiscal year. Otherwise, the Remarketing Value for a fiscal year is based on average ICE MID-C settlement prices from two separate five consecutive-business-day periods (the last full week in September 2018 and the last full week March 2019) for a flat block of annual power in the same fiscal year, plus $0.50 per megawatthour.

25. Resource Shaping Charge

As defined in the TRM, the Resource Shaping Charge is the customer-specific charge or credit as described in TRM Section 8.5 that adjusts for the difference in value between a planned resource energy shape that is flat within each monthly/diurnal period (but not necessarily flat when comparing one monthly/diurnal period to another) and an equivalently sized flat annual block (flat for all hours of the fiscal year).

26. Resource Shaping Rate

As defined in the TRM, the Resource Shaping Rate is the rate that is set, as described in TRM Section 8.5, equal to the Load Shaping Rate for each monthly/diurnal period.

27. Retail Access

Retail Access is non-discriminatory retail distribution access mandated either by Federal or state law that grants retail electric power consumers the right to choose their electricity supplier.

28. RHWM Tier 1 System Capability (RT1SC)

As defined in the TRM, RHWM Tier 1 System Capability means the Tier 1 System Firm Critical Output plus RHWM Augmentation. The RT1SC table of values may be found at GRSP II.A, Table A.

29. Super Peak Credit

As defined in the TRM, the Super Peak Credit is the amount of additional HLH energy, as defined in TRM Section 5.3.4, that a customer contractually commits to provide with non-Federal resources during the Super Peak Period. Such notification must occur by October 31 of the Rate Case Year.

30. Super Peak Period

As defined in the TRM, the Super Peak Period is the hours defined pursuant to the CHWM Contract for each rate period into which a customer must reshape its HLH energy from its Specified Resources and Unspecified Resource Amounts to receive a Super Peak Credit. The hours BPA establishes for the Super Peak Period may vary by month and will be either two 3-hour periods each day or a single 6-hour period each day.

The Super Peak Period hours for FY 2020–2021 are as follows (HE = Hour Ending):

October – May	HE 8 through HE 10 and HE 19 through HE 21
June – September	HE 16 through HE 21

31. System Shaped Load

As defined in the TRM, the System Shaped Load is the amount of energy a Load Following or Block customer would receive from BPA under its Tier 1 rates in each of the monthly/diurnal periods in each fiscal year of the rate period if the customer's TOCA Load was delivered in the shape of the RHWM Tier 1 System Capability through such periods.

32. Tier 1 Cost Allocator (TOCA)

As defined in the TRM, the TOCA is the billing determinant for the customer charges for each customer purchasing power at a Tier 1 rate under its CHWM Contract. TOCAs are expressed as percentages and are calculated as specified in TRM Section 5.1.1. TOCAs are posted on BPA's website.

33. Tier 1 Customer System Peak (Tier 1 CSP)

Tier 1 Customer System Peak is equivalent to Customer System Peak as defined in the TRM. As defined in the TRM, Tier 1 CSP is the customer's maximum Actual Hourly Tier 1 Load (measured in kilowatts) during the Heavy Load Hours of each month.

34. Total Customer System Peak (CSP or Total CSP)

Total Customer System Peak is the largest measured HLH Total Retail Load amount, in kilowatts, for the billing period.

35. Total Retail Load (TRL)

All retail electric power consumption, including electric system losses, within a customer's electrical system, excluding (i) those loads BPA and the customer have agreed are nonfirm or interruptible loads; (ii) transfer loads of other utilities served by such customer; and (iii) any loads not on such customer's electrical system or not within such customer's service territory, unless specifically agreed to by BPA.

36. Unanticipated Load

Unanticipated Load is any request by a customer for Firm Requirements Power received by BPA after February 1 of the ratesetting year that (1) results in an increase in the customer's load placed on BPA during the ensuing rate period, and (2) was not requested and thus not forecast when setting the rates for that rate period.

37. Wheel Turning Load

Wheel Turning Load is that portion of Total Plant Load that is not integral to a customer's industrial process and is not a part of a technological allowance. A megawatt amount of Wheel Turning Load shall be defined in the customer's power sales contract with BPA, unless such amount is self-supplied. Wheel Turning Load shall be exempt from reduction or interruption associated with providing Minimum DSI Operating Reserve – Supplemental.

APPENDIX

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Appendix A: Supplemental Information

Adjustments to rates and GRSPs during the Rate Period due to the Power CRAC (GRSP II.O), the Power RDC (GRSP II.P), and the Power FRP Surcharge (GRSP II.Q) are summarized here. Any other adjustments to rates or GRSPs during the Rate Period, made in accordance with these rate schedules and GRSPs, will also be summarized here.

I. Power Financial Reserves Policy (FRP) Surcharge for Fiscal Year 2020

This reflects the Power FRP Surcharge that went into effect on July 1, 2020.

Power FRP Surcharge Rate	0.81 mills/kWh for the months of December 2019 – June 2020
Annual Power FRP Surcharge Rate	0.47 mills/kWh

A. Power FRP Surcharge for Rate Schedules

Rate Schedule/Service	**For December 2019 – June 2020 service, the Power FRP Surcharge rate of 0.81 mills/kWh shall be applied to the following billing determinants:**
PF (Section 2.1.4) • Load Following • Block • Block portion of Slice/Block	Sum of HLH and LLH PF System Shaped Load
PF Melded Rate (Section 3.1.1)	Total hourly energy loads for each diurnal period
NR (Section 2.1.1.2)	Total of NR Hourly Loads for each diurnal period
IP (Section 2.1.1.3)	Energy Entitlement

B. GRSP II.AA. Priority Firm Power (PF) Tier 1 Equivalent Energy Rates for FY 2020 Adjusted by Power FRP Surcharge Rate[1/]

FY 2020	***Energy Rate in mills/kWh***	
	HLH	***LLH***
December	44.09	39.56
January	41.24	35.21
February	40.36	35.28
March	35.19	32.11
April	33.98	30.40
May	27.71	22.55
June	26.52	17.68

1/Power FRP Surcharge Rate of 0.81 mills/kWh is added to December 2019–June 2020 energy rates (shown in chart). All other PF Tier 1 Equivalent rates (energy and demand) remain the same.

C. GRSP Factors Adjusted by Annual Power FRP Surcharge Rate (0.47 mills/kWh)

GRSP	**Adjusted factors for FY 2020**
GRSP II.E, Load Shaping Charge True-Up Adjustment, Section 1	Load Shaping True-Up Rate = -15.66 mills/kWh
GRSP II.R, Slice True-Up Adjustment, Section 1(c)	PF Melded Equivalent Energy Scalar (PFMEES) Rate = -15.31 mills/kWh

Bonneville Power Administration
DOE/BP-4860 • December 2018 (Rev 7-1-2020)