Fiscal Year 2019 **Budget**

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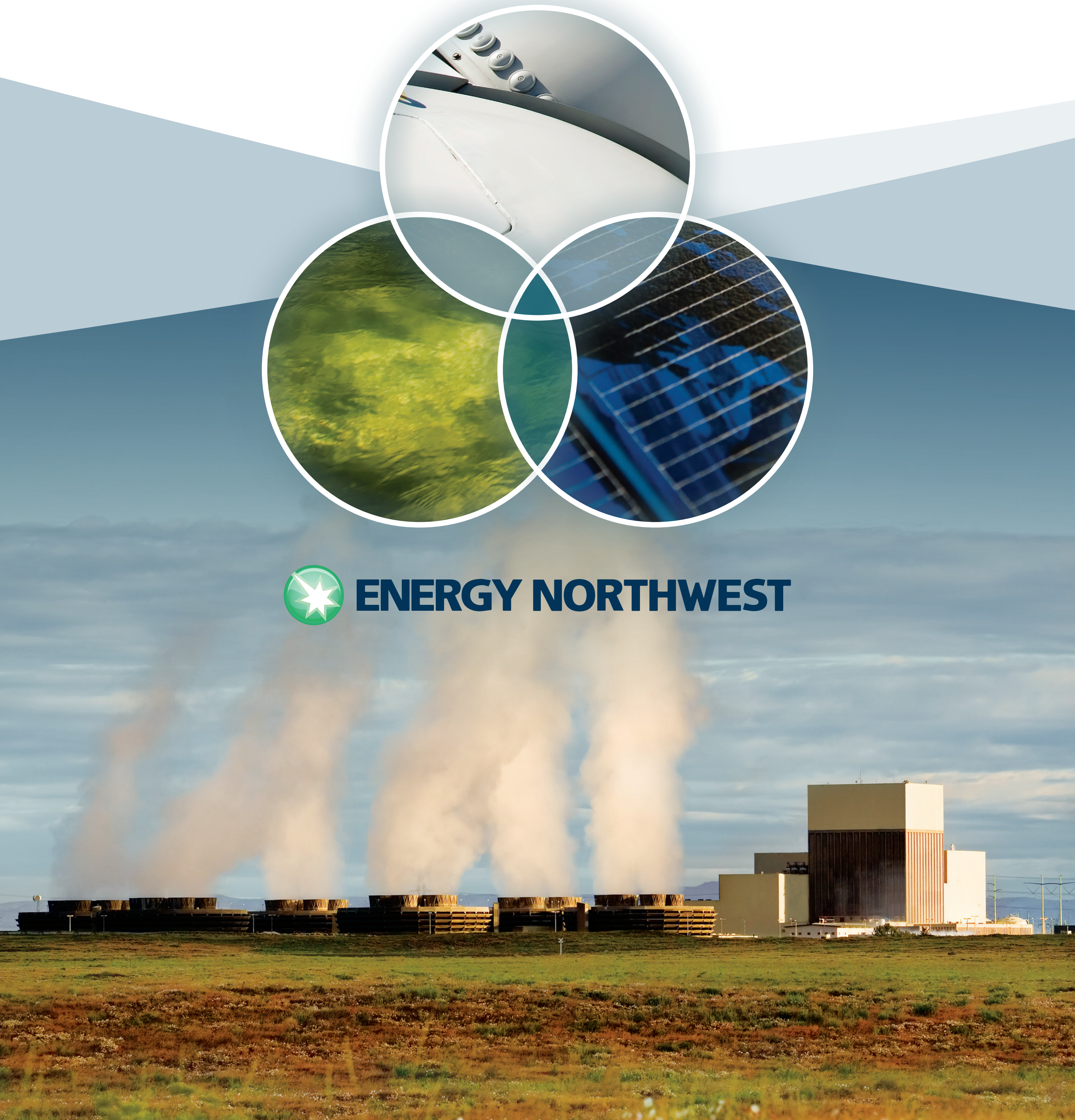

M.E. Reddemann
Chief Executive Officer
P.O. Box 968
Richland, WA 99352-0968
Ph. 509-377-8031
mereddemann@energy-northwest.com

March 13, 2018

TO: Reviewers

SUBJECT: **DRAFT Energy Northwest Fiscal Year 2019 Budget**

We are pleased to submit the Fiscal Year 2019 **Draft** Budget for your review. The budgets will be presented at a workshop on Tuesday, March 20, 2018 in the Holiday Inn Express, 4525 Convention Place, Pasco, WA.

This budget, when approved, will provide the necessary resources to meet our Fiscal Year 2019 objectives and achieve our long term vision.

Respectfully,

M.E. Reddemann
Chief Executive Officer

E-files: **Draft** Fiscal Year 2019 Budget

ELECTRONIC DISTRIBUTION LIST:

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Energy Northwest Executive Board
Energy Northwest Board of Directors
Participant's Review Board
Bonneville Power Administration
Energy Northwest Senior Staff

Fiscal Year 2019
Energy Northwest
Budget Summary

DRAFT

Prepared 3/20/18

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Summary

This document contains a summary of budgets for all Energy Northwest business units. This section has been prepared for information purposes only.

Energy Northwest operates six business units under various contractual agreements and Energy Northwest Board Resolutions. These business units include Columbia Generating Station, Project 1, Project 3, Packwood Hydroelectric Project, The Business Development Fund, and the Nine Canyon Wind Project. Energy Northwest also manages an Internal Service Fund which acts as an agency clearing account for disbursing agency-wide costs such as employee benefits and corporate programs to the various business units.

Table 1
Funding Requirements
(Dollars in Thousands)

Funding Requirements	FY 2019 Budget	Original FY 2018 Budget	Variance
Columbia (1)	$ 1,106,747	$ 1,097,804	$ 8,943
Packwood (2)	3,136	2,960	176
Nine Canyon Wind Project (3)	18,516	18,709	(193)
Project 1 (4)	44,101	86,872	(42,771)
Project 3 (5)	41,751	115,883	(74,132)
Business Development Fund (6)	10,703	8,849	1,854
General Business Unit (7)	42	6	36
Total Funding Requirements	**$ 1,224,996**	**$ 1,331,083**	**$ (106,087)**

Funding Sources	FY 2019 Budget	FY 2018 Budget	Variance
Net Billing Revenues/Direct Pay	$ 516,403	$ 786,073	$ (269,670)
Note/Line of Credit Draws	168,000	236,000	(68,000)
Bond Proceeds from Capital Financing	109,722	111,682	(1,960)
Fuel Revenue	161,150	161,100	50
Revenues	31,058	28,857	2,201
Line of Credit/Fuel Revenue	230,420	-	230,420
Columbia Decommissioning Trust Funds	500	-	500
Working Capital/Receipts from Participants	4,002	3,774	228
BPA Decommissioning	3,741	3,597	144
Total Funding Sources	**$ 1,224,996**	**$ 1,331,083**	**$ (106,087)**

(1) See Table 8 on Page 14 of CGS's Budget Documents
(2) See Table 5 on Page 9 of Packwood's Budget Documents
(3) See Table 4 on Page 9 of Nine Canyon's Budget Documents
(4) See Table 5 on Page 9 of Project 1's Budget Documents
(5) See Table 4 on Page 7 of Project 3's Budget Documents
(6) See Table 5 on Page 10 of Business Development's Budget Documents
(7) See Table 8 on Page 12 of General Business Unit's Budget Documents

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Table 2
Operating & Capital Costs
(Dollars in Thousands)

Operating Costs	FY 2019 Budget	Original FY 2018 Budget	Variance
Columbia (1)	$ 555,021	$ 491,723	$ 63,298
Packwood (2)	2,442	2,468	(26)
Nine Canyon Wind Project (3)	15,871	16,344	(473)
Project 1 (4)	25,585	30,116	(4,531)
Project 3 (5)	34,113	43,531	(9,418)
Business Development Fund (6)	10,549	8,782	1,767
Total Operating Costs	**$ 643,581**	**$ 592,964**	**$ 50,617**

Capital Costs	FY 2019 Budget	FY 2018 Budget	Variance
Columbia (1)	$ 109,715	$ 99,825	$ 9,890
Packwood (2)	819	603	216
Nine Canyon Wind Project (3)	60	53	7
Business Development Fund (7)	424	349	75
Total Capital Costs	**$ 111,018**	**$ 100,830**	**$ 10,188**

(1) See Table 3 on Page 7 of CGS Budget's Document
(2) See Table 1 on Page 5 of Packwood Budget's Document
(3) See Table 1 on Page 5 of Nine Canyon Budget's Document
(4) See Table 1 on Page 4 of Project 1's Budget Document
(5) See Table 1 on Page 4 of Project 3's Budget Document
(6) See Table 1 on Page 5 of Business Development's Budget Document
(7) See Table 3 on Page 7 of Business Development's Budget Document

Table 3
Summary of Full Time Equivalent Positions by Business Unit(1)(2)

Business Unit	FY 2019 Budget	FY 2018 Budget	Variance
Columbia	1,036	1,036	-
Packwood	4	4	-
Nine Canyon Wind Project	12	12	-
Project 1	7	7	-
Project 3	1	1	-
Business Development Fund	24	23	1
Total Full Time Equivalent Positions	**1,084**	**1,083**	**1**

(1) Includes Full Time Equivalent positions for transition of new employees taking positions of retiring employees.

(2) Corporate Programs (A&G) Full Time Equivalent positions of 71 in Fiscal Year 2019 and 71 in Fiscal Year 2018 have been allocated and are included in the Business Units above.

Fiscal Year 2019
Columbia Generating Station
Annual Operating Budget

Prepared 3/20/18

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Summary

Energy Northwest's Columbia Generating Station (Columbia) is a 1,174 megawatt boiling water nuclear power station utilizing a General Electric nuclear steam supply system. The project is located on the Department of Energy's Hanford Reservation near Richland, Washington. The project began commercial operation in December 1984.

This Columbia Generating Station Fiscal Year 2019 Annual Operating Budget has been prepared by Energy Northwest pursuant to the requirements of Board of Directors Resolution No. 640, the Project Agreement, and the Net Billing Agreements. This document includes all capitalized and non-capitalized costs associated with the project for Fiscal Year 2019. In addition this document includes all funding requirements.

The total cost budget for Fiscal Year 2019 for Expense and Capital related costs are estimated at $664,736,000 (Table 3), with associated total funding requirements of $1,106,747,000 (Table 8). Using the Memorandum of Agreement basis for measuring Columbia's costs, budget requirements for Fiscal Year 2019 have been established at $427,195,000 (Table 1) including escalation. In Fiscal Year 2019, Bonneville Power Administration will be directly paying the funding requirements on a monthly basis under the provisions of the Direct Pay Agreements. This will take the net billing requirements to zero, for the statements which are normally sent to participants in the project, and will be paid in accordance with the terms of the Net Billing Agreements. The Net Billing Agreements are still in place, but the direct cash payments from Bonneville Power Administration will simply take the participant payment amounts to zero. In the Direct Pay Agreements, Energy Northwest agreed to promptly bill each participant its share of the costs of the project under the Net Billing Agreements, if Bonneville fails to make a payment when due under the Direct Pay Agreements. Fiscal Year 2019 Capital costs will be funded by bond proceeds and are not included in the Fiscal Year 2019 direct pay requirements. Total direct pay requirements of $433,214,000 (Table 8) will be the basis for billing directly to Bonneville Power Administration.

This budget is presented on a cost basis and includes a cost to cash reconciliation (Table 7) converting cost data to a cash basis. The Columbia Generating Station's Annual Budget (Table 8) is required by the various project agreements.

Comparison of the Fiscal Year 2019 Budget to the Fiscal Year 2018 Long Range Plan for Fiscal Year 2019 is included (Table 1). Comparison of the Fiscal Year 2019 Budget is made to the original budget for Fiscal Year 2018, dated April 27, 2017.

Key Assumptions/Qualifications

This budget is based upon the following key assumptions and qualifications:

- Fiscal Year 2019 cost of power is based on net generation of 8,777 GWh.

- There is a refueling outage planned for Fiscal Year 2019.

- Risk reserves consist of a total of $10.4 million.

- Unknown NRC mandates are excluded.

- All assumptions associated with Nuclear Fuel are referenced in the Columbia Fuel Plan Section.

- Other Specific Inclusions:
  - Sales tax calculated at 8.6 percent for appropriate items

- All Fiscal Year 2019 Capital expenses have been financed from the 2018AB transaction that priced in February 2018 or will be funded by cash held as a result of Independent Spent Fuel Storage Installation Facility settlements with the Department of Energy.

- Fuel Revenue of $230.42 million is expected to be received by September 30, 2019 from the Tennessee Valley Authority (TVA) related to the Depleted Uranium Enrichment Program (DUEP). Under the TVA Agreement, TVA is obligated to pay prior to September 30, 2019. However, to ensure the benefits are achieved in the appropriate rate period as originally contemplated under the DUEP, revenues will be received or line of credit proceeds will be received to fund the maturing debt prior to July 1, 2019.

- Note / Line of Credit draws for a portion of Operations and Maintenance and interest expense associated with the acceleration of the Regional Cooperation Debt initiative are anticipated throughout Fiscal Year 2019.

Table 1
Memorandum of Agreement (MOA) (1)
(Dollars in Thousands)

Description	FY 2019 Budget	FY 2018 (2) LRP for FY 2019 (2)	Variance
Baseline	$ 145,233	$ 142,991	$ 2,242
Indirect Allocations O&M	76,314	77,585	(1,271)
Expense Projects	41,458	43,338	(1,880)
Risk Reserve	2,938	2,041	897
Operations & Maintenance Total	**$ 265,943**	**$ 265,955**	**$ (12)**
Capital Projects	$ 85,462	$ 81,357	$ 4,105
Indirect Allocations Capital	16,752	19,002	(2,250)
Risk Reserve	7,501	9,367	(1,866)
Capital Total	**$ 109,715**	**$ 109,726**	**$ (11)**
Nuclear Fuel Related Costs	$ 51,537	$ 51,761	$ (224)
Fuel Total	**$ 51,537**	**$ 51,761**	**$ (224)**
Total	**$ 427,195**	**$ 427,442**	**$ (247)**
Net Generation (GWh)	**8,777**	**8,716**	**61**
Cost of Power ($/MWh)	**$ 48.67**	**$ 49.04**	**$ (0.37)**

(1) Columbia costs as defined by the Memorandum of Agreement between Energy Northwest and BPA. This measure includes operations and maintenance, capital additions and fuel related costs as well as an appropriate allocation of indirect costs (such as employee benefits, A&G, and information technology expenses).
(2) Fiscal Year 2018 Long Range Plan for Fiscal Year 2019.

Table 2
Columbia Station Costs - Memorandum of Agreement Comparison (1)
(Dollars in Thousands)

Description	FY 2019 Budget	Original FY 2018 Budget	Variance
Controllable Costs			
Energy Northwest Labor	$ 83,022	$ 78,469	$ 4,553
Baseline Non-Labor	56,559	55,785	774
Incremental Outage	22,600	-	22,600
Expense Projects Non-Labor	38,731	6,867	31,864
Capital Projects Non-Labor	71,241	59,001	12,240
Indirect Allocations	93,066	89,995	3,071
Risk Reserve	10,439	9,167	1,272
Subtotal Controllable	**$ 375,658**	**$ 299,284**	**$ 72,031**
Nuclear Fuel Related Costs			
Nuclear Fuel Amortization	$ 51,537	$ 57,709	$ (6,172)
Subtotal Nuclear Fuel Related	**$ 51,537**	**$ 57,709**	**$ (6,172)**
Total	**$ 427,195**	**$ 356,993**	**$ 65,859**
Net Generation (GWh)	**8,777**	**9,769**	**(992)**
Cost of Power ($/MWh)	**$ 48.67**	**$ 36.54**	**$ 12.13**

(1) Columbia Costs as defined by the Memorandum of Agreement between Energy Northwest and BPA. This cost measure includes operations and maintenance and capital additions, fuel related costs as well as an appropriate allocation of indirect costs (such as employee benefits, and corporate programs).

Table 3
Summary of Costs
(Dollars in Thousands)

Description	FY 2019 Budget	Original FY 2018 Budget	Variance
Controllable Expense			
Energy Northwest Labor	$ 68,801	$ 64,367	$ 4,434
Base Non-Labor	56,559	55,785	774
Expense Projects Non-Labor (1)	38,731	6,867	31,864
Incremental Outage	22,600	-	22,600
Indirect Allocations	76,314	72,440	3,874
Risk Reserve	2,938	-	2,938
Subtotal Controllable	**$ 265,943**	**$ 199,459**	**$ 66,484**
Incremental			
Nuclear Fuel Amortization	$ 51,537	$ 57,709	$ (6,172)
Generation Taxes	5,117	5,568	(451)
Subtotal Incremental	**$ 56,654**	**$ 63,277**	**$ (6,623)**
Fixed			
Treasury Related Expenses (2)	$ 134,347	$ 143,215	$ (8,868)
Decommissioning (3)	8,588	8,164	424
Depreciation	89,489	77,608	11,881
Subtotal Fixed	**$ 232,424**	**$ 228,987**	**$ 3,437**
Total Operating Expense	**$ 555,021**	**$ 491,723**	**$ 63,298**
Capital			
Energy Northwest Labor	$ 14,221	$ 14,102	$ 119
Capital Projects Non-Labor (4)	71,241	59,001	12,240
Indirect Allocations	16,752	17,555	(803)
Capital Risk Reserve	7,501	9,167	(1,666)
Total Capital	**$ 109,715**	**$ 99,825**	**$ 9,890**
Total Expense and Capital	**$ 664,736**	**$ 591,548**	**$ 73,188**

(1) See Table 5B (page 10).
(2) See Table 6 (page 11).
(3) Includes ISFSI Decommissioning.
(4) See Table 5A (page 10).

Table 4
Summary of Full Time Equivalent (FTE) Positions*

Organization	Direct Charge	Corporate Allocation**	Laboratories Support	FY 2019 Budget	FY 2018 Budget	Variance
Chief Executive Officer	1	11	-	12	12	-
General Counsel	5	6	-	11	11	-
Chief Operating Officer/Chief Nuclear Officer***	799	-	-	799	799	-
General Manager Energy Services & Development****	50	-	19	69	69	-
Vice President Corporate Services/Chief Financial Officer/Chief Risk Officer	94	51	-	145	145	-
Total	**949**	**68**	**19**	**1,036**	**1,036**	**-**

Note: FY 2018 Staffing has been reclassified for comparison purposes
* Includes project positions
* Includes employees supporting Capital Projects
* Excludes temporary positions
** Includes allocation of Corporate FTE Positions (95% in FY 2019 and FY 2018)
*** Includes employment "pipeline" for Operations and Security
**** Includes Environmental and Calibrations Laboratories support (19 FTE in FY 2019 and 19 FTE in FY 2018)

Table 5
Projects Non-Labor
(Dollars in Thousands)

Description	FY 2019 Budget	Original FY 2018 Budget	Variance
Capital Projects			
Plant Modifications	$ 62,436	$ 48,939	$ 13,497
Facilities Modifications	624	623	1
Information Technology	8,181	9,439	(1,258)
Subtotal Capital Projects	**$ 71,241**	**$ 59,001**	**$ 12,240**
Expense Projects			
Plant Modifications	$ 37,950	$ 5,935	$ 32,015
Facilities Modifications	781	932	(151)
Subtotal Expense Projects	**$ 38,731**	**$ 6,867**	**$ 31,864**
Total	**$ 109,972**	**$ 65,868**	**$ 44,104**

Table 5A
Capital Projects Non-Labor Over $1.25 Million
(Dollars in Thousands)

Plant Modifications and Information Technology		FY 2019 Budget
Low Pressure Turbine Rotor Replacement	$	6,602
Control Rod Drive Repair/Refurbishment		6,597
Fukushima Project		6,266
Reactor Water Clean-up Heat Exchanger Replacement		3,077
Asset Suite Upgrade		3,000
Main Turbine Valve Inspection		2,587
Replace Obsolete Safety Related 480V Starters		2,446
Rector Recirculation Pump 1A/1B Replacement		2,062
License Renewal Implementation		2,054
Dehalogenation Chemical Feed		1,959
Local Power Range Monitor Replacement		1,890
Plant Fire Detection Upgrade		1,579
Condenser Expansion Joint/Piping Replacement		1,470
Main Steam Isolation Valve Disassemble/Inspection		1,375
All Other Projects < $1.25 Million		28,277
Total Capital Projects Non-Labor	**$**	**71,241**

Table 5B
Expense Projects Non-Labor Over $750 Thousand
(Dollars in Thousands)

Plant Modifications & Major Maintenance(MM)		FY 2019 Budget
In-Service Inspection Programs	$	8,490
Reactor Vessel Services		4,920
Main Turbine Inspection		4,880
Plant Valve Project		4,800
Cooling Tower Preventative Maintenance		2,740
Main Generator Maintenance		2,032
Flow Accelerated Corrosion Program		2,000
Outage Temporary Power		1,292
Condenser Eddy Current Support		1,250
Service Water Pond and System Cleaning		909
All Other Projects < $750 Thousand		5,418
Total Expense Projects Non-Labor	**$**	**38,731**

Table 6
Treasury Related Expenses
(Dollars in Thousands)

Description	FY 2019 Budget	Original FY 2018 Budget	Variance
Interest Expense (1)	$ 150,326	$ 155,946	$ (5,620)
Build America Bond Subsidy (2)	(4,098)	(4,085)	(13)
Interest on Note (3)	4,736	6,388	(1,652)
Amortized Financing Cost (4)	(16,011)	(14,337)	(1,674)
Investment Income (5)	(1,336)	(1,444)	108
Treasury Svcs/Paying Agent Fees (6)	730	747	(17)
Total	**$ 134,347**	**$ 143,215**	**$ (8,868)**

Assumptions

(1) Budget assumes approximately $243.9 million in principal will be refunded in FY 2018 and approximately $222.3 million during FY 2019.

(2) Build America Bonds were expected to receive a subsidy from the Treasury for 35% of the interest payments. Reductions have been implemented as part of the Congressional budget cuts.

(3) A portion of Columbia Operations and Maintenance and bond interest expenses will be funded by lines of credit that enable the acceleration of Bonneville federal debt repayments as part of the regional cooperation debt initiative.

(4) The amortized financing costs are driven by the amortization of the premiums on bond issues.

(5) Includes income on investment of monies held in the Interest and Principal Accounts and the Capital Fund which can be transferred periodically to the Revenue Fund.
Projected investment income earning rates are forecasted to average 1.25%.

(6) Includes all non-interest costs of banking, debt and internal labor and overheads.

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Table 7
Cost-to-Cash Reconciliation
(Dollars in Thousands)

Description	FY 2019 Total Cost	Non-Cash Items	Non-Cost Items	Deferred Cash Requirements	Prior Year Commitments	FY 2019 Total Cash
Operating						
Controllable - Expense	$ 265,943	$ -	$ -	$ -	$ -	$ 265,943
Controllable - Capital	109,715	-	332	-	-	110,047
Nuclear Fuel	51,537	(51,298)	64,460	-	-	64,699
Fuel Litigation	-	-	185	-	-	185
Spares/Inventory Growth	-	-	6,900	-	-	6,900
Generation Taxes	5,117	-	1,131	-	-	6,248
Subtotal Operating	**$ 432,312**	**$ (51,298)**	**$ 73,008**	**$ -**	**$ -**	**$ 454,022**
Fixed Expenses						
Treasury Related Expense						
Interest on Bonds	$ 150,326	$ -	$ -	$ -	$ -	$ 150,326
Build America Bond Subsidy	(4,098)	-	-	-	-	(4,098)
Interest on Note Payable	4,736	-	-	-	-	4,736
Payoff of Note Principal	-	-	302,050	-	-	302,050
Bond Retirement	-	-	194,965	-	-	194,965
Amortized Cost	(16,011)	16,011	-	-	-	-
Investment Income-Revenue Fund	(1,336)	-	-	906	-	(430)
Treasury Services	730	-	-	-	-	730
Decommissioning(1)	8,429	(8,429)	3,741	-	-	3,741
Asset Retirement Obligation (ARO) Estimate	-	-	500	-	-	500
ISFSI Decommissioning	159	(159)	205	-	-	205
Depreciation	89,489	(89,489)	-	-	-	-
Subtotal Fixed Expenses	**$ 232,424**	**$ (82,066)**	**$ 501,461**	**$ 906**	**$ -**	**$ 652,725**
Total	**$ 664,736**	**$ (133,364)**	**$ 574,469**	**$ 906**	**$ -**	**$ 1,106,747**

(1) Decommissioning paid directly by the Bonneville Power Administration

Note: Controllable cost and cash is equal due to BPA decision to Direct Pay and the institution of contractor time & labor.

Table 8
Annual Budget
Statement of Funding Requirements (Revenue Fund)
(Dollars in Thousands)

Description	FY 2019 Budget	Original FY 2018 Budget	Variance
Operating			
Controllable Expense	$ 265,943	$ 199,459	$ 66,484
Controllable Capital	110,047	111,734	(1,687)
Nuclear Fuel	64,699	26,058	38,641
Fuel Litigation	185	255	(70)
Spares/Inventory Growth	6,900	5,500	1,400
Generation Taxes	6,248	5,452	796
Subtotal Operating Requirements	**$ 454,022**	**$ 348,458**	**$ 105,564**
Fixed			
Treasury Related Expenses			
Interest on Bonds	$ 150,326	$ 155,946	$ (5,620)
Build America Bond Subsidy	(4,098)	(4,085)	(13)
Interest on Note	4,736	6,388	(1,652)
Payoff of Note Principal	302,050	405,000	(102,950)
Bond Retirement (1)	194,965	181,705	13,260
Investment Income-Revenue Fund	(430)	(141)	(289)
Treasury Services/Paying Agent Fees	730	747	(17)
Decommissioning Costs (2)	3,741	3,597	144
Asset Retirement Obligation (ARO) Estimate	500	-	500
ISFSI Decommissioning Costs	205	189	16
Subtotal Fixed	**$ 652,725**	**$ 749,346**	**$ (96,621)**
Total Funding Requirements	**$ 1,106,747**	**$ 1,097,804**	**$ 8,943**
Funding Sources			
Direct Pay from BPA / Net Billing (3)	$ 433,214	$ 585,425	$ (152,211)
Note / Line of Credit Draws (4)	168,000	236,000	(68,000)
Bond Proceeds (5)	109,722	111,682	(1,960)
Fuel Revenue	161,150	161,100	50
Line of Credit / Fuel Revenue (6)	230,420	-	230,420
Columbia Decommissioning Trust Funds	500	-	500
Bonneville Direct Funding Decommissioning	3,741	3,597	144
Total Funding Sources	**$ 1,106,747**	**$ 1,097,804**	**$ 8,943**

(1) $222.3 million of maturing July 2019 bonds are expected to be extended while $195.0 will be repaid.
(2) BPA directly funds the requirements for the Decommissioning Fund on behalf of Energy Northwest.
(3) Bonneville will direct pay the monthly funding requirements under the provisions of the Direct Pay Agreement.
(4) Draws against Note / Line of Credit for O&M / Interest Expense through June 2019.
(5) Bond Proceeds do not include funding of approximately $325k related to the Energy Northwest Office Complex.
(6) Line of Credit / Fuel Revenue includes proceeds related to the scheduled TVA revenue to be received by 9/30/19.

Table 9
Monthly Statement of Funding Requirements
(Dollars in Thousands)

Description	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	FY 2019 Total
Beginning Balance	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**
Disbursements													
Operating													
Controllable Expense	$ 24,318	$ 18,161	$ 15,189	$ 19,323	$ 14,941	$ 16,939	$ 20,154	$ 15,455	$ 19,039	$ 23,217	$ 40,119	$ 39,088	$ 265,943
Controllable Capital	8,461	6,488	6,605	7,877	6,824	8,039	6,333	8,988	10,254	9,009	10,332	20,837	110,047
Nuclear Fuel In Process	25,482	544	544	544	544	544	544	544	544	544	34,132	189	64,699
Fuel Litigation	-	-	-	-	35	75	75	-	-	-	-	-	185
Spares/Inventory Growth	-	1,725	-	-	1,725	-	-	1,725	-	-	1,725	-	6,900
Generation Taxes	-	-	-	-	-	-	-	-	-	-	-	6,248	6,248
Subtotal Operating	**$ 58,261**	**$ 26,918**	**$ 22,338**	**$ 27,744**	**$ 24,069**	**$ 25,597**	**$ 27,106**	**$ 26,712**	**$ 29,837**	**$ 32,770**	**$ 86,308**	**$ 66,362**	**$ 454,022**
Fixed													
Treasury Related Expenses													
Interest on Bonds	$ -	$ -	$ -	$ -	$ -	$ 75,000	$ -	$ -	$ -	$ -	$ -	$ 75,326	$ 150,326
BABs Subsidy	-	-	-	-	-	(2,043)	-	-	-	-	-	(2,055)	(4,098)
Interest on Note	-	-	1,000	-	-	-	-	-	-	-	-	3,736	4,736
Payoff of Note Principal	-	-	161,050	-	-	-	-	-	-	-	-	141,000	302,050
Bond Retirement (1)	-	-	-	-	-	-	-	-	-	-	-	194,965	194,965
Investment Income	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(40)	(40)	(430)
Treasury Services	60	60	60	60	60	60	61	61	61	62	62	63	730
Decommissioning	-	-	3,741	-	-	-	-	-	-	-	-	-	3,741
Asset Retirement Obligation	-	-	500	-	-	-	-	-	-	-	-	-	500
ISFSI Decommissioning	205	-	-	-	-	-	-	-	-	-	-	-	205
Subtotal Fixed	**$ 230**	**$ 25**	**$ 166,316**	**$ 25**	**$ 25**	**$ 72,982**	**$ 26**	**$ 26**	**$ 26**	**$ 27**	**$ 22**	**$ 412,995**	**$ 652,725**
Total Disbursements	**$ 58,491**	**$ 26,943**	**$ 188,654**	**$ 27,769**	**$ 24,094**	**$ 98,579**	**$ 27,132**	**$ 26,738**	**$ 29,863**	**$ 32,797**	**$ 86,330**	**$ 479,357**	**$ 1,106,747**
Funding Sources													
BPA Direct Pay (2)	$ 30,005	$ 455	$ -	$ -	$ -	$ 16,435	$ 20,774	$ 17,750	$ 19,609	$ 23,763	$ 75,998	$ 228,425	$ 433,214
Note / Line of Credit Draws	20,000	20,000	16,758	19,867	17,270	74,105	-	-	-	-	-	-	168,000
Bond Proceeds	8,461	6,488	6,605	7,877	6,824	8,039	6,333	8,988	10,254	9,009	10,332	20,512	109,722
Fuel Revenue	25	-	161,050	25	-	-	25	-	-	25	-	-	161,150
Line of Credit / Fuel Revenue	-	-	-	-	-	-	-	-	-	-	-	230,420	230,420
Columbia Decommissioning Trust	-	-	500	-	-	-	-	-	-	-	-	-	500
BPA - Decommissioning	-	-	3,741	-	-	-	-	-	-	-	-	-	3,741
Total Funding Sources	**$ 58,491**	**$ 26,943**	**$ 188,654**	**$ 27,769**	**$ 24,094**	**$ 98,579**	**$ 27,132**	**$ 26,738**	**$ 29,863**	**$ 32,797**	**$ 86,330**	**$ 479,357**	**$ 1,106,747**
Ending Balance	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**

(1) $222.3 million of 7/1/2019 maturing bonds are expected to be refunded. The remaining $195.0 are expected to be paid off.

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Fiscal Year 2019
Columbia Generating Station
Long Range Plan

ENERGY NORTHWEST

Prepared 3/20/18

BPA Rate Case	RC		RC		RC		RC		RC		
Columbia Fiscal Year	**FY19 (R24)**	**FY20**	**FY21 (R25)**	**FY22**	**FY23 (R26)**	**FY24**	**FY25 (R27)**	**FY26**	**FY27 (R28)**	**FY28**	**FY29 (R29)**
Operations & Maintenance (O&M) Costs											
Baseline Costs	$ 122,633	$ 121,018	$ 122,762	$ 121,183	$ 117,202	$ 112,732	$ 112,336	$ 107,508	$ 104,179	$ 101,403	$ 98,028
Outage Costs (Incremental)	22,600	-	22,952	-	20,334	-	18,632	-	18,632	-	18,632
Indirect Allocations ▼	$ 76,314	$ 82,612	$ 80,579	$ 82,713	$ 82,410	$ 80,820	$ 80,088	$ 79,400	$ 82,770	$ 84,176	$ 85,728
Plant Projects	$ 40,474	$ 7,239	$ 37,465	$ 12,533	$ 38,533	$ 7,243	$ 40,408	$ 7,343	$ 50,235	$ 9,532	$ 50,235
Facilities Projects	$ 983	$ 999	$ 1,002	$ 1,002	$ 1,002	$ 1,002	$ 1,002	$ 1,002	$ 1,002	$ 1,002	$ 1,002
Risk Reserve	2,938	1,500	2,000	1,500	2,000	1,500	2,000	1,500	2,000	1,500	2,000
Subtotal O&M Costs	$ 265,943	$ 213,369	$ 266,760	$ 218,931	$ 261,481	$ 203,297	$ 254,466	$ 196,752	$ 258,817	$ 197,613	$ 255,624
Escalation (3% Labor / 2% Non-Labor)	-	4,546	12,182	15,502	24,367	24,689	36,492	34,072	50,193	44,614	63,697
Total O&M Costs (escalated)	**$ 265,943**	**$ 217,915**	**$ 278,942**	**$ 234,433**	**$ 285,847**	**$ 227,985**	**$ 290,958**	**$ 230,824**	**$ 309,010**	**$ 242,227**	**$ 319,321**
Plant Projects *	$ 75,299	$ 36,505	$ 59,088	$ 34,947	$ 42,336	$ 46,244	$ 61,097	$ 35,064	$ 48,076	$ 51,051	$ 83,727
Risk Reserve	7,500	5,057	9,004	5,367	6,694	7,345	10,047	8,486	10,529	10,931	17,625
Facilities Projects	716	619	621	621	621	621	621	621	621	621	621
Information Technology Projects	9,448	12,032	10,025	9,415	10,075	10,846	10,336	10,443	9,414	9,414	10,075
Indirect Allocations ▼	16,752	10,747	14,651	9,377	11,352	12,314	14,747	14,836	13,197	11,223	11,435
Subtotal Capital Costs	$ 109,715	$ 64,960	$ 93,388	$ 59,726	$ 71,078	$ 77,370	$ 96,847	$ 69,449	$ 81,837	$ 83,240	$ 123,482
Escalation (3% Labor / 2% Non-Labor)	-	1,253	4,011	3,931	6,264	8,650	13,026	11,139	15,031	17,526	28,844
Total Capital Costs (escalated)	**$ 109,715**	**$ 66,212**	**$ 97,400**	**$ 63,657**	**$ 77,342**	**$ 86,020**	**$ 109,873**	**$ 80,588**	**$ 96,868**	**$ 100,766**	**$ 152,326**
Fuel Costs											
Nuclear Fuel Amortization **	51,537	58,224	52,580	58,942	53,848	58,813	53,949	60,251	55,313	61,390	56,228
Subtotal Fuel Costs	**$ 51,537**	**$ 58,224**	**$ 52,580**	**$ 58,942**	**$ 53,848**	**$ 58,813**	**$ 53,949**	**$ 60,251**	**$ 55,313**	**$ 61,390**	**$ 56,228**
Total Un-escalated Budget	**$ 427,195**	**$ 336,552**	**$ 412,729**	**$ 337,598**	**$ 386,406**	**$ 339,480**	**$ 405,261**	**$ 326,452**	**$ 395,967**	**$ 342,243**	**$ 435,334**
Total Escalation	**-**	**5,798**	**16,193**	**19,434**	**30,631**	**33,339**	**49,518**	**45,210**	**65,224**	**62,139**	**92,541**
Total Cost - Industry Basis	**$ 427,195**	**$ 342,350**	**$ 428,922**	**$ 357,032**	**$ 417,037**	**$ 372,819**	**$ 454,779**	**$ 371,663**	**$ 461,191**	**$ 404,382**	**$ 527,875**
Generation/Cost of Power											
Total Net Generation (Gwh)	8,777	9,884	8,777	9,857	8,777	9,884	8,777	9,857	8,777	9,884	8,777
Outage Days	40		40		40		40		40		40
Cost of Power (Cents per kWh)	$ 4.87	$ 3.41	$ 4.70	$ 3.43	$ 4.40	$ 3.43	$ 4.62	$ 3.31	$ 4.51	$ 3.46	$ 4.96
Cost of Power (Cents per kWh, escalated)	$ 4.87	$ 3.46	$ 4.89	$ 3.62	$ 4.75	$ 3.77	$ 5.18	$ 3.77	$ 5.25	$ 4.09	$ 6.01

Key Assumption/Qualifications (Revision - 3/08/18)
Escalation Rate = Labor 3% and Non-labor 2% (FY19-20 non-labor at 1.75% to align with Cost Effective Operations Model)
Net Generation 1160 Mwe; assumes 1% unplanned/ 2% planned loss
▼ Potential Financial Risk; *Includes moveable capital and FY19 Fukushima project funding ** Does not include fuel costs associated with generation increase
Every fourth year, generation increases slightly due to leap year
DRAFT - Pending Board Approval

Energy Northwest
Columbia Generating Station

FY 2019
Fuel Management Plan

Rev. 0

March 2018

S. M. Praetorius
Program Mgr. Nuclear Fuel Procurement

Table of Contents

Section
1

Introduction

The Project Agreement between Energy Northwest and Bonneville Power Administration (BPA) for Columbia Generating Station requires Energy Northwest to submit with each annual budget a Ten-Year Fuel Management Plan.

This Fuel Management Plan for fiscal year (FY) 2019 covers the period from July 1, 2018, through June 30, 2028. This plan includes a cash flow analysis for expenditures and credits for each major component of the fuel cycle by month for the first five (5) years. In addition, the contracts for each component of the fuel cycle are discussed. The tables and figures are located at the end of the text.

Section

2

Assumptions

Economic

Table 1 gives the predicted market prices for uranium concentrates (U_3O_8), conversion and enrichment services. As expected, prices for U_3O_8 and enrichment continued to fall but remain within the assumptions for the Depleted Uranium Enrichment Program transaction. Forward market price data was taken from the *2017 Nuclear Fuel Cycle Supply and Price Report*, provided by Energy Resources International. Over the past year, the spot price for uranium has cycled between lows of $19.25 per lb. U_3O_8 to highs of $26.50 per lb. according to TradeTech, www.uranium.info, historical uranium prices. Spot price is a reflection of very near term inventory supply and demand dynamics. The 2011 accident at the Fukushima Daiichi reactors in Japan continues to affect the current market today because only five reactors out of fifty-four have returned to service as of January 2018. The prolonged shutdowns continue to add to the oversupply in the market and the downward pressure on the uranium and SWU prices. Current spot demand is limited, as utilities have continued to build inventories as prices have come down. Over the past year, the term price continued its decline from the prior year dropping from $35.00 per lb. U_3O_8 to $30.00 per lb. Term price is more closely tied to cost of production and does not exhibit the volatility seen with the spot price but does tend to follow the overall trend of the spot price. In any event, forward price projections predict the price to increase steadily as reactors in Japan are assumed to be returned to service, new plants come online, existing inventories are exhausted and newer higher cost mines begin production to meet demand.

The spot enrichment price has seen continued decline in the last year dropping from a high of $47/SWU to a low of $38/SWU. Over the past year, the term price continued its decline from the prior year dropping from $53/SWU to a low of $45/SWU. The forward price projections for enrichment services have seen a significant decline as centrifuge based production is unable to scale back to meet the reduced worldwide demand and inventories are building up.

Energy Northwest's significant uranium inventory and the long-term enrichment contracts continue to minimize the impact of volatility in the nuclear fuel market prices. The prices from the uranium and enrichment contracts are factored into the cash flow requirements but are not reflected in the prices in Table 1.

Fuel Cycle

Table 2 shows the assumptions for the fuel cycles used in this plan. The planned energy requirements are consistent with the energy requirements supplied by BPA in accordance with the Project Agreement.

Both Final Feedwater Temperature Reduction (FFTR) and Thermal Power Level Coast-Down are planned for cost optimization during the final five to seven weeks of the operating run. During FFTR, the operation of the plant is extended at 100% thermal power level for 8-10 days while the electrical power level gradually decreases by about 1%. During coast-down, the power level is expected to decrease at a rate of 0.30% per day. The Fuel Management Plan assumes 9 days of FFTR and 30 days of coast-down for a total of 39 days of cycle extension for Cycle 25. Future cycles assume a total of 39 days of cycle extension.

The generation factor refers to the amount of energy that is expected to be generated relative to the maximum potential generation from when the generator is synchronized to the grid to when the reactor is shut down for the refueling outage.

The generation factor and outage length are the critical parameters that determine the cycle energy from which the fuel requirements and ultimately the fuel budget is derived. Strong plant performance resulting in an increase in capacity factor, coupled with a planned 1.5% uprate associated with the Measurement Uncertainty Reduction (MUR) project are assumed to require at least eight additional fuel assemblies for Cycle 24 and beyond.

Section
3

Nuclear Fuel Market

Uranium Market

The uranium market has experienced dramatic fluctuations in price over the years. In January 2003, the price of uranium was $10.20 per lb. U_3O_8. The market price peaked in June 2007 at $135 per lb. U_3O_8. The spot price stands at $23.75 per lb. U_3O_8 at the end of December 2017. At the time of the dramatic price increase, utilities moved to place their uncommitted requirements for the next three to six years under contract in an attempt to mitigate supply disruptions and limit their vulnerability to further price increases. Utilities have taken advantage of the low cost of money and falling prices to build inventory resulting in historically high inventory levels. As a result, spot demand is very limited leading to market volatility when significant new supply or demand enters the market.

A number of investment funds had also entered the market buying uranium, which placed additional demand on already short supplies contributing to the rapid rise in price in 2006-2007. Although this demand contributed to the price rise, it also provided a source of liquidity to the market since the investors were solely looking for a return-on-investment. The economic credit crisis in 2008-2010 resulted in the majority of funds liquidating their inventories to raise cash leading to a softening of price. The funds have not been quick to return to the market as the price continues to decline and not forecasted to recover very quickly. The uranium trading operations of Goldman Sachs will be closed once the current portfolio of deliveries is completed in 2019. Deutsche Bank's book of business for uranium trading was sold to Macquarie Bank who has expanded the book and is also providing a needed source of financing to the market.

Price projections indicate a close relationship between the projections and the current term price and show a steady increase in price over the next ten (10) years. The following table lists known factors affecting price:

SECTION 3 – NUCLEAR FUEL MARKET

Push Price Up	**Push Price Down**
New demand from India	Possible short term over-production
Increased worldwide demand for reactors: • China • Russia • Middle East • India	• Kazakhstan push for increased production
Production problems at mines	Production Expansion • Underfeeding at enrichment plants
Low cost uranium mined first • McArthur River • Kazakhstan in situ leach mines	Decreased demand due to reactor shutdowns: • Japan • Germany • United States
Development of uranium mines delayed • Olympic Dam expansion • New mines delayed in Africa	Delay in new plant construction • United States • Asia
Overall decrease in availability of secondary supplies • Currently secondary supplies provide for 35% of world-wide requirements	Increased secondary supplies due to reactor shutdowns. • German utility sales • Japanese utility sales • Enrichment over-supply
Interest/exchange rates	
Government Policies • New Tariff or Duties Imposed on uranium	Government Policies • Increased DOE sales

Conversion Services

Spot conversion prices are currently at $5.85 per KgU relative to the term price of $12.50 per KgU as reported by TradeTech at the end of December 2017. Similar to U_3O_8, the price projections for conversion services indicate a close relationship between the projections and the current term price. However, DOE sales and enrichment supplier sales due to underfeeding will continue to suppress spot conversion prices as these sales are in the form of UF_6. ConverDyn has elected to shutdown operations of their facility for the next two years or until prices recover.

Enrichment Market

The enrichment market has seen drastic price decreases over the past few years as the reactor shutdowns significantly reduced demand and the centrifuge based production is not able to be reduced resulting in inventories growing proportionally. The spot price in January 2006 was $118 per Separative Work Unit (SWU) and has risen to a high of $165 per SWU in January 2010 with current market price reported by TradeTech at $38 per SWU at the end of December 2017, another historic low. Near term, enrichment prices have continued to decline due to surplus capacity being available due to delayed deliveries because of the extended reactor shutdowns in Japan and Germany following the accident at Fukushima Daiichi. Prices would have declined even further without the removal of more than 8 million SWU capacity with the permanent shutdown of both Georges Besse located in France and USEC Gaseous Diffusion Plant located in Paducah, Kentucky. All current commercial production is performed with centrifuges, which cannot effectively be adjusted to meet demand the way the GDP's could resulting in significant amounts of enriched uranium being produced and placed into inventory. The higher the tails assay, the more uranium feed is required and the less enrichment services. The lower the tails assay, the more enrichment services are required and less uranium feed. At the current prices for uranium and enrichment services, the optimum tails assay has reduced to 0.18% from historical levels of 0.30%. The result is an increase in enrichment demand and reduction in uranium requirements.

Louisiana Enrichment Services, LLC (a limited liability company owned by Urenco) halted the expansion of operations at its enrichment facility in New Mexico using centrifuge technology. In addition, Urenco has also halted increasing the capacity at their European plants. AREVA commenced operations at their new centrifuge plant and shutdown the GDP facility at Tricastin in France but halted construction efforts on a centrifuge plant that would have been built near Idaho Falls, Idaho because of poor market conditions. General Electric has received a construction and operating license from the NRC for their laser enrichment facility in North Carolina, but has made the decision to defer building a commercial plant until the market allows. General Electric has also announced that it is seeking to sell their portion of the enrichment company.

The Russian suspension agreement was re-negotiated to allow 20 percent of the US market requirements to be supplied through in 2020, when the suspension would be lifted. Louisiana Enrichment Services has files with the Department of Commerce to extend the suspension agreement beyond 2020. The impact of the supply has contributed to the lower prices in the market.

Fuel Fabrication

Currently, three fabricators supply fabricated fuel to the US BWR community: Global Nuclear Fuel Americas, LLC (GNF), AREVA NP Inc., dba AREVA Inc. and Westinghouse Electric Company, LLC. Westinghouse currently does not have any domestic BWR customers following fabrication of the last Quad Cities reload in February 2016. Westinghouse is seeking new domestic customers. AREVA and GNF share the BWR fuel fabrication market in the United States with GNF refueling the majority of the BWR reactors.

Section
4

Fuel Management Strategy

Fuel Cycle Designs

During FY2019, Columbia will be in the second half of Cycle 24. This is the second reload of the GNF2 fuel design. The current bundle and core design contain a batch size of 272 GNF2 assemblies with an average enrichment of ~3.88 wt% U^{235}. The Cycle 24 core has energy available to be able to operate at 100% power for 670 days plus an additional 47 days of cycle extension (9 days of FFTR and 38 days of coast-down).

Fuel Procurement Strategy

Energy Northwest has established a fuel procurement strategy to 1) achieve the long-term goal of a secure and consistently low cost fuel supply, and 2) be flexible enough to take advantage of cost saving opportunities as they arise.

Typically, Energy Northwest strives to maintain a minimum strategic inventory of one reload worth of enriched uranium and approximately half a reload of natural uranium.

Fuel Procurement Activities

There is no new fuel procurement activities planned in FY2019. The primary focus will be on the management of the existing inventories.

Fabrication Services

A fabrication services contract for Columbia Generating Station for the fuel supply for three reloads was awarded to GNF in June 2007. Energy Northwest elected to extend the existing contract for two reloads and signed a new contract with GNF in December 2015 extending the supply through the 2027 refueling.

Other Fabrication Costs

A number of costs in addition to vendor fabrication costs for the fuel bundles and analytical services are included as fabrication costs. These costs address the following types of activities:

- Fuel receipt & inspection
- Fuel procurement
- Fuels' staff
- Fuel consultants
- Fuels' work-station and code fees
- Fuels' travel and training

Fuel Management Physical Requirements

The assumed cycle energies and fuel designs are used to develop multi-cycle reload material requirement projections. The projected reload material requirements are integrated with the existing inventory levels to project procurement requirements into the future. Tables 3 and 4 summarize those requirements over the next ten years.

Table 3 assumes uranium is purchased as uranium concentrates (U_3O_8). Conversion services must then be purchased to convert the concentrates to uranium hexafluoride (UF_6). Enrichment services are then purchased to convert the natural UF_6 to enriched UF_6. The enriched UF_6 is transferred to the fabrication facility and used to fabricate the necessary quantity of fuel assemblies. Table 4 shows the total material of each form existing as of the end of each fiscal year. Typically, the processing time from concentrates to fabricated fuel assemblies is one year, allowing for the necessary material lead times at each step in the process. Therefore, the majority of the material in Table 4 is considered working stock with a lesser portion considered the strategic inventory.

Spent Fuel Storage and Disposal

DOE Spent Fuel Contract

While the courts have now ruled that DOE had a binding obligation to begin acceptance of spent nuclear fuel no later than January 31, 1998, DOE has suspended all work on the license application for the Yucca Mountain underground storage repository. Energy Northwest has been successful in its legal action on DOE's failure to meet its obligations for spent fuel and DOE has agreed to reimburse Energy Northwest for the cost incurred by Energy Northwest for its failure to meet its obligations. In December 2013, the U.S. Court of Appeals issued a mandate that DOE must adjust the fee being collected; the Court's order relieves standard contract holders of the obligation to pay annual fees until DOE complies with the Nuclear Waste Policy Act. The collection of the fee by DOE was discontinued in May 2014. The cash plan has been updated to remove the Waste Disposal Fee.

On-Site Spent Fuel Storage

Columbia Generating Station operates an Independent Spent Fuel Storage Installation (ISFSI) using NRC-approved dry storage casks to supplement wet storage in the fuel pool. The ISFSI, located just north of the Deschutes Building, is capable of being expanded to hold the lifetime spent fuel requirements of Columbia Generating Station. Thirty-six (36) storage casks have been loaded to date, moving 2,448 assemblies from the fuel pool to the ISFSI. In preparation of the next loading campaign, the ISFSI storage pad was expanded to hold an additional eighteen (18) storage casks. The next loading campaign is planned for March of 2018 and nine (9) storage casks will be loaded.

The costs for the inner storage canister (called a multi-purpose canister or MPC) and closure welds are included in this Fuel Management Plan in the category of Casks. The costs of the overpacks, facility, and common equipment are treated as plant capital. The Fiscal Years 2018 campaign cost of a multi-purpose canister is currently estimated to be $1,291,829 and welding costs are estimated to be $231,434 per MPC. This equates to a per bundle cost of $22,401. The future costs have been escalated.

Active Contracts

Appendix A contains descriptions of the currently active fuel management contracts for nuclear material and fabrication services.

Section
5

Nuclear Fuel Budgets

Nuclear Fuel Costs

A measure of nuclear fuel cost is the Fuel-in-Process costs, or the costs to fabricate finished fuel assemblies. The estimated costs for the reload batch for Cycle 25 are shown in Table 5. Reload batch costs are amortized over the life of the fuel. Typically, fuel resides in the reactor core for three (3) cycles (equivalent to six years). Energy Northwest has achieved top quartile industry performance on the cost of nuclear fuel on an individual plant comparison and at the company level, even though large fleet operators have advantages of scale.

Fuel Revenue

There will be cash revenue from Fuels activities in FY2019-FY2023 from sales and reimbursed expenses from TVA under the Depleted Uranium Enrichment Program. The TVA agreement is summarized in Appendix A and the revenue is shown in Table 6.

Nuclear Fuel Cash Flows

A summary of cash flows by fuel component and fiscal year for the next ten years is given in Table 7. Cash flows for nuclear fuel by month for each component for the next five years are shown in Tables 8 through 12.

Section
6

Tables and Figures

Table 1

Projected Market Fuel Prices

Year	Uranium* $/lb. U3O8	Conversion* $/ KgU UF_6	Enrichment* $/SWU
2019	$30.50	$10.20	$50.00
2020	$32.00	$11.70	$53.00
2021	$33.50	$12.00	$57.00
2022	$34.00	$12.00	$65.00
2023	$35.00	$12.10	$72.00
2024	$35.50	$12.10	$74.00
2025	$35.50	$11.90	$76.00
2026	$36.50	$11.60	$76.00
2027	$39.50	$11.30	$78.00
2028	$44.50	$11.20	$80.00

* Source: Energy Resources International
* All Prices are in Constant Dollars

Table 2

Fuel Cycle Assumptions

Fiscal Year	Outage Length (Days)	Cycle	Energy FPD	Generation Factor %
2019	40	25	661	96%
2020				
2021	40	26	661	96%
2022				
2023	40	27	667	96%
2024				
2025	40	28	661	96%
2026				
2027	40	29	661	96%
2028				
2029	40	30	667	96%

Energy FPD = Operating Calendar Days x GF – (Days lost during startup and coastdown)
Fuel plan estimates based on equilibrium cycles and may not reflect year-to-year shifts in refueling outage lengths per Long Range Plan (LRP). The reload batch estimates shown in Table 3 are within +/- 8 fuel assemblies based on equilibrium cycle energies.

Table 3

Planned Purchases of Nuclear Material and Fuel Fabrication Requirements

	Purchases			Fabrication		
Fiscal Year	Lbs. U_3O_8	KgU UF_6 Conversion	SWU	KgU Enriched UF_6	SWU	# Bundles
2019			182,800	435,013	259,153	268
2020			100,000			
2021				435,296	259,369	268
2022			300,000			
2023				436,684	260,463	268
2024			300,000			
2025				436,684	260,463	268
2026			300,000			
2027	261,285	100,000		436,684	260,463	268
2028	261,285	100,000	200,000			

Table 4

Nuclear Material Totals

Fiscal Year	TVA UF_6 Deliveries[1]	Natural UF_6 KgU	Enriched Uranium Product	
			UF_6	SWU
2019		400,074	1,871,276	662,958
2020		293,651	2,000,816	744,261
2021		402,296	1,456,875	484,892
2022	108,645	731,624	1,196,896	728,801
2023	648,598	1,218,073	273,763	468,337
2024	486,449	898,803	662,382	712,246
2025		898,803	225,698	451,783
2026		302,697	951,284	647,056
2027		402,697	514,600	386,593
2028		289,851	773,679	549,199

[1] Return of natural UF_6 from TVA SWU only sales under the DUEP.

Table 5

Predicted Reload Batch Costs ($1,000)

Component	CGS1-25
# of Assemblies	268
Fuel Cost:	
Uranium	$26,313
Conversion	$2,566
Enrichment	$30,690
Fabrication	$36,228
Sales Tax	$7,405
Fuels' Projects	$0
TOTAL Cost	$103,202

Per Assembly Cost
($)

Total Cost	$385,080

Table 6

Planned Revenue From TVA Sales [1] ($1,000)

Fiscal Year	Uranium	Enrichment	Services	Storage Fees	Total
2019	$85,000	$76,050	$100		$161,150
2020	$147,000	$83,420	$100		$230,520
2021		$67,760	$100		$67,860
2022		$85,920	$100		$86,020
2023		$65,880	$100		$65,980

1) TVA revenue from the sales of Uranium and SWU from the DUEP.

SECTION 6 – TABLES AND FIGURES

Table 7

10-Year Cash Flow for Nuclear Fuel ($1,000)

FY	Uranium	Conversion	Enrichment	Staff	Fabrication	Tax	Casks	Fuel Cash	Disposal[1]	Gen Tax
2019	$0	$0	$24,978	$1,956	$30,121	$7,405	$0	$64,460	$0	$6,248
2020	$0	$0	$10,233	$1,980	$2,160	$0	$5,069	$19,442	$0	$5,921
2021	$0	$0	$0	$2,076	$31,104	$7,507	$4,436	$45,123	$0	$7,100
2022	$0	$0	$31,365	$2,100	$2,064	$0	$9,011	$44,540	$0	$6,748
2023	$0	$0	$0	$2,208	$31,583	$7,539	$1,631	$42,961	$0	$8,105
2024	$0	$0	$32,046	$2,220	$2,184	$0	$4,892	$41,342	$0	$7,725
2025	$0	$0	$0	$2,340	$33,796	$7,675	$5,707	$49,518	$0	$9,305
2026	$0	$0	$32,751	$2,364	$2,316	$0	$12,300	$49,731	$0	$8,845
2027	$10,321	$1,130	$0	$2,484	$36,161	$6,881	$0	$56,977	$0	$10,624
2028	$11,627	$1,120	$16,000	$2,508	$2,460	$0	$0	$33,715	$0	$10,126
Total	$21,948	$2,250	$147,373	$22,236	$173,949	$37,007	$43,046	$447,809	$0	$80,747

(1) Court's order relieves standard contract holders of the obligation to pay annual Waste Disposal fees until DOE complies with the Nuclear Waste Policy Act. The collection of the fee by DOE was discontinued in May 2014.

Table 8

Fiscal Year 2019 Monthly Cash Flow ($1,000)

Date	Uranium	Conv.	Enrich	Staff	Fab	Tax	Casks	Fuel Cash	Disposal	Gen Tax
Jul-18			24,978	163	358			25,499		
Aug-18				163	358			521		
Sep-18				163	358			521		
Oct-18				163	358			521		
Nov-18				163	358			521		
Dec-18				163	358			521		
Jan-19				163	358			521		
Feb-19				163	358			521		
Mar-19				163	358			521		
Apr-19				163	358			521		
May-19				163	26,541	7,405		34,109		
Jun-19				163				163		6,248
Total			24,978	1,956	30,121	7,405		64,460		6,248

SECTION 6 – TABLES AND FIGURES

Table 9

Fiscal Year 2020 Monthly Cash Flow ($1,000)

Date	Uranium	Conv.	Enrich	Staff	Fab	Tax	Casks	Fuel Cash	Disposal	Gen Tax
Jul-19			10,233	165	180		1,267	11,845		
Aug-19				165	180			345		
Sep-19				165	180			345		
Oct-19				165	180			345		
Nov-19				165	180			345		
Dec-19				165	180			345		
Jan-20				165	180		3,802	4,147		
Feb-20				165	180			345		
Mar-20				165	180			345		
Apr-20				165	180			345		
May-20				165	180			345		
Jun-20				165	180			345		5,921
Total			10,233	1,980	2,160		5,069	19,442		5,921

SECTION 6 – TABLES AND FIGURES

Table 10

Fiscal Year 2021 Monthly Cash Flow ($1,000)

Date	Uranium	Conv.	Enrich	Staff	Fab	Tax	Casks	Fuel Cash	Disposal	Gen Tax
Jul-20				173	335			508		
Aug-20				173	335			508		
Sep-20				173	335			508		
Oct-20				173	335			508		
Nov-20				173	335			508		
Dec-20				173	335			508		
Jan-21				173	335			508		
Feb-21				173	335			508		
Mar-21				173	335		4,436	4,944		
Apr-21				173	335			508		
May-21				173	27,754	7,507		35,434		
Jun-21				173				173		7,100
Total				2,076	31,104	7,507	4,436	45,123		7,100

SECTION 6 – TABLES AND FIGURES

Table 11

Fiscal Year 2022 Monthly Cash Flow ($1,000)

Date	Uranium	Conv.	Enrich	Staff	Fab	Tax	Casks	Fuel Cash	Disposal	Gen Tax
Jul-21			31,365	175	172		276	31,988		
Aug-21				175	172			347		
Sep-21				175	172		3,168	3,515		
Oct-21				175	172		600	947		
Nov-21				175	172			347		
Dec-21				175	172		2,366	2,713		
Jan-22				175	172			347		
Feb-22				175	172			347		
Mar-22				175	172		867	1,214		
Apr-22				175	172		867	1,214		
May-22				175	172		867	1,214		
Jun-22				175	172			347		6,748
Total			31,365	2,100	2,064		9,011	44,540		6,748

SECTION 6 – TABLES AND FIGURES

Table 12

Fiscal Year 2023 Monthly Cash Flow ($1,000)

Date	Uranium	Conv.	Enrich	Staff	Fab	Tax	Casks	Fuel Cash[1]	Disposal	Gen Tax
Jul-22				184	346			530		
Aug-22				184	346			530		
Sep-22				184	346			530		
Oct-22				184	346			530		
Nov-22				184	346			530		
Dec-22				184	346			530		
Jan-23				184	346			530		
Feb-23				184	346			530		
Mar-23				184	346			530		
Apr-23				184	346			530		
May-23				184	28,123	7,539		35,846		
Jun-23				184			1,631	1,815		8,105
Total				2,208	31,583	7,539	1,631	42,961		8,105

Appendix A
Active Nuclear Material Contracts

Contract	Vendor	Scope
324350	Global Nuclear Fuel	Energy Northwest contracted with GNF in June 2007 to supply fuel design, licensing, and fabrication services for three consecutive reloads for Columbia Generating Station. The first reload under this contract was delivered in the spring of 2009. The scope of this contract will meet the needs of Columbia Generating Station for reload fabrication services through 2013. In August 2012, Energy Northwest extended the existing fabrication services contract one additional reload to 2015. In December of 2013, Energy Northwest again extended the contract through 2017 to allow additional time for the fabrication bid and implementation of other plant modifications.
313337	Urenco	In January 2006, Energy Northwest issued RFP 640137 for SWU to be delivered between calendar years 2010 to 2015. Urenco was awarded the procurement and the contract extended through 2015. The contract has been amended two additional times to move deliveries to meet the needs of both Urenco and Energy Northwest extending the contract through 2018.
345715	Global Nuclear Fuel	Energy Northwest contracted with GNF in December 2015 to supply fuel design, licensing, and fabrication services for five firm reloads and two optional reloads for Columbia Generating Station. The first reload under this contract will be delivered in the spring of 2019. The scope of this contract will meet the needs of Columbia Generating Station for reload fabrication services through 2027.
335901	TVA	Energy Northwest established a contract with TVA in May 2012 for the sale of 2.9 million SWU and 1,675 MTU of feed contained in EUP produced by Depleted Uranium Enrichment Program for $730.2 million over TVA fiscal years 2015 to 2023.
342639	Urenco USA	Energy Northwest awarded a contract to Urenco USA in December 2014 for the purchase of 1 million SWU and transportation, storage and management of 290 type 30B enriched uranium cylinders.
350925	AREVA Nuclear Materials	Exchange of 175,000 KgU of UF_6 natural for 260,127 SWU in December 2017. Free storage of UF_6 natural and SWU through December 2025.

Appendix A
Active Nuclear Material Contracts – Delivery Schedules

Contract	Vendor	Scope
324350	Global Nuclear Fuel	Spring 2017 – Fabrication Services
313337	Urenco	2017 – 132,000 SWU 2018 – 182,800 SWU
345715	Global Nuclear Fuel	Spring 2019, 2021, 2023, 2025 & 2027 – Fabrication Services
335901	TVA	FY2019 – 625,000 KgU UF_6 and 450,000 SWU FY2020 – 1,050,000 KgU UF_6 and 485,000 SWU FY2021 – 385,000 SWU FY2022 – 480,000 SWU FY2023 – 360,000 SWU
342639	Urenco USA	FY2020 – 100,000 SWU FY2022 – 300,000 SWU FY2024 – 300,000 SWU FY2026 – 300,000 SWU

Fiscal Year 2019
Packwood Lake Hydroelectric Project
Annual Operating Budget

Energy Northwest

Prepared 3/20/18

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Summary

The Packwood Lake Hydroelectric Project (Packwood), the first electrical generating project undertaken by Energy Northwest, began commercial operation in June 1964. Occupying 660 acres of the Gifford Pinchot National Forest in south central Washington, Packwood consists of a dam at Packwood Lake; a five mile long system of pipeline, tunnels and Penstock; and a 27,500 kilowatt-rated, underground powerhouse located 1,800 feet below the lake elevation. The reservoir is fed by Upper Lake Creek and several small tributaries that rely exclusively on direct rainfall and snow melt for their water supply.

The total net Fiscal Year 2019 operating and capital cost combined is estimated to be $3,261,000 (Table 1), with associated funding requirements of $3,136,000 (Table 5). The difference between total program cost and net funding requirements is due to depreciation (Table 4).

Key Assumptions/Qualifications

- The Project budget has been reviewed and approved by the participants.
- Generation is estimated at 93,520 MWh, which reflects 5-year average of the plant output and further reduced by approximately 10% due to impacts of actions required under the new operating license.
- The Fiscal Year 2019 Budget includes costs for mitigation activities required under the new operating license which is expected to become effective during the year.

Table 1
Summary of Operating and Capital Costs
(Dollars in Thousands)

Description	**FY 2019 Budget**	**Original FY 2018 Budget**	**Variance**
Operating Costs			
Operating & Support Services	$ 2,310	$ 2,340	$ (30)
Generation Taxes	22	22	-
Depreciation	125	111	14
Subtotal Operating Costs	$ 2,457	$ 2,473	$ (16)
Interest/Financing (Net)	(15)	(5)	(10)
Total Cost	**$ 2,442**	**$ 2,468**	**$ (26)**
Total Net Generation (MWh)	**93,520**	**93,840**	**(320)**
Cost of Power ($/MWh) (1)	**$ 26.11**	**$ 26.30**	**$ (0.19)**
Total Capital Cost	**$ 819**	**$ 603**	**$ 216**
Total Operating and Capital Cost	**$ 3,261**	**$ 3,071**	**$ 190**

(1) Cost of Power includes Operating & Support Services, Generation Taxes, Depreciation, and Net Interest/Financing costs.

Table 2
Summary of Revenues
(Dollars in Thousands)

Description	FY 2019 Budget	Original FY 2018 Budget	Variance
Revenues			
Participant Billings	$ 2,758	$ 2,678	$ 80

Variance - ( ) Unfavorable

Table 3
Summary of Full Time Equivalent Positions *

Description	FY 2019 Budget	FY 2018 Budget	Variance
Operations & Maintenance	4	4	-

*** Includes Allocations of Corporate Full Time Equivalent Positions**

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Table 4
Cost-to-Cash Reconciliation
(Dollars in Thousands)

Description	FY 2019 Total Cost	Non-Cash Items	Non-Cost Items	Deferred Cash Requirements	Prior Year Commitments	FY 2019 Total Cash
Operating						
O&M and Support Services	$ 2,310	$ -	$ -	$ -	$ -	$ 2,310
Generation Taxes	22	-	-	-	-	22
Depreciation	125	(125)	-	-	-	-
Subtotal Operating	$ 2,457	$ (125)	$ -	$ -	$ -	$ 2,332
Licensing						
Maintain License & Permits		$ -	$ -	$ -	$ -	$ -
Subtotal Licensing	$ -	$ -	$ -	$ -	$ -	$ -
Interest/Financing						
Interest Income	$ (29)	$ -	$ -	$ -	$ -	$ (29)
Treasury Services	14	-	-	-	-	14
Loan Repayment	-	-	-	-	-	-
Subtotal Net Interest/Financing	$ (15)	$ -	$ -	$ -	$ -	$ (15)
Capital	$ 819	$ -	$ -	$ -	$ -	$ 819
Refund to Members	-	-	-	-	-	-
Total Disbursements	$ 3,261	$ (125)	$ -	$ -	$ -	$ 3,136
Funding Sources						
Participants Billings	$ 2,758	$ -	$ -	$ -	$ -	$ 2,758
Beginning Packwood Funds	-	-	2,262	-	-	2,262
Total Funding Sources	$ 2,758	$ -	$ 2,262	$ -	$ -	$ 5,020
Ending Working Capital	$ (503)	$ (125)	$ 2,262	$ -	$ -	$ 1,884

Table 5
Statement of Funding Requirements
(Dollars in Thousands)

Description	FY 2019 Budget	Original FY 2018 Budget	Variance
Beginning Packwood Funds Balance	**$ 2,262**	**$ 2,131**	**$ 131**
Funding Requirements			
Operating			
Operating & Support Services	$ 2,310	$ 2,340	$ (30)
Generation Taxes	22	22	-
Subtotal Operating	**$ 2,332**	**$ 2,362**	**$ (30)**
Interest/Financing			
Interest Income	$ (29)	$ (15)	$ (14)
Treasury Services	14	10	4
Subtotal Net Interest/Financing	**$ (15)**	**$ (5)**	**$ (10)**
Capital	$ 819	$ 603	$ 216
Total Funding Requirements	**$ 3,136**	**$ 2,960**	**$ 176**
Funding Sources			
Participants Billings	2,758	2,678	80
Total Funding Sources	**$ 2,758**	**$ 2,678**	**$ 80**
Ending Packwood Funds Balance	**$ 1,884**	**$ 1,849**	**$ 35**

Table 6
Monthly Statement of Funding Requirements
(Dollars in Thousands)

Description	Jul	Aug	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	FY 2019 Total
Beginning Balance	**$ 2,262**	**$ 2,301**	**$ 2,339**	**$ 2,378**	**$ 1,666**	**$ 1,705**	**$ 1,740**	**$ 1,779**	**$ 1,818**	**$ 1,858**	**$ 1,897**	**$ 1,916**	**$ 2,262**
Receipts													
Participants Billings	$ 230	$ 230	$ 230	$ 230	$ 230	$ 229	$ 230	$ 230	$ 230	$ 230	$ 230	$ 229	$ 2,758
Total Receipts	**$ 230**	**$ 230**	**$ 230**	**$ 230**	**$ 230**	**$ 229**	**$ 230**	**$ 230**	**$ 230**	**$ 230**	**$ 230**	**$ 229**	**$ 2,758**
Disbursements													
Operations Disbursements													
O&M and Support Services	$ 193	$ 192	$ 193	$ 192	$ 193	$ 192	$ 193	$ 192	$ 193	$ 192	$ 192	$ 193	$ 2,310
Generation Taxes	-	-	-	-	-	-	-	-	-	-	22	-	22
Subtotal Operations	**$ 193**	**$ 192**	**$ 193**	**$ 192**	**$ 193**	**$ 192**	**$ 193**	**$ 192**	**$ 193**	**$ 192**	**$ 214**	**$ 193**	**$ 2,332**
Interest/Financing													
Investment Income	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(3)	(3)	(3)	(3)	(3)	(29)
Treasury Services	-	2	-	2	-	4	-	2	-	2	-	2	14
Subtotal Interest/Financing Related	**$ (2)**	**$ -**	**$ (2)**	**$ -**	**$ (2)**	**$ 2**	**$ (2)**	**$ (1)**	**$ (3)**	**$ (1)**	**$ (3)**	**$ (1)**	**$ (15)**
Capital	$ -	$ -	$ -	$ 750	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 69	$ 819
Total Disbursements	**$ 191**	**$ 192**	**$ 191**	**$ 942**	**$ 191**	**$ 194**	**$ 191**	**$ 191**	**$ 190**	**$ 191**	**$ 211**	**$ 261**	**$ 3,136**
Ending Balance	**$ 2,301**	**$ 2,339**	**$ 2,378**	**$ 1,666**	**$ 1,705**	**$ 1,740**	**$ 1,779**	**$ 1,818**	**$ 1,858**	**$ 1,897**	**$ 1,916**	**$ 1,884**	**$ 1,884**

Table 7
Long Range Plan
(Dollars in Thousands)

Description	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028
Operating Costs										
Operating & Support Services	$ 2,227	$ 2,326	$ 2,384	$ 2,444	$ 2,504	$ 2,567	$ 2,630	$ 2,696	$ 2,763	$ 2,832
Mitigation	83	160	163	549	361	55	50	50	55	45
Escalation on Select Program Costs	-	120	182	286	337	360	425	492	562	629
Subtotal Operating Costs	**$ 2,310**	**$ 2,606**	**$ 2,729**	**$ 3,279**	**$ 3,202**	**$ 2,982**	**$ 3,105**	**$ 3,238**	**$ 3,380**	**$ 3,506**
Capital & Other Costs										
Capital Costs	$ 819	$ 440	$ 85	$ 505	$ 650	$ 140	$ 875	$ 329	$ 85	$ 15
Generation Taxes	22	20	20	20	20	20	20	20	20	20
Interest/Financing (Net)	(15)	(3)	(5)	(5)	(6)	(6)	(6)	(6)	(6)	(6)
Escalation on Capital Costs	-	8	13	57	47	9	9	11	14	13
Subtotal Capital & Other Costs	**$ 826**	**$ 465**	**$ 113**	**$ 577**	**$ 711**	**$ 163**	**$ 898**	**$ 354**	**$ 113**	**$ 42**
Total Escalated Program Costs	**$ 3,136**	**$ 3,071**	**$ 2,842**	**$ 3,856**	**$ 3,913**	**$ 3,145**	**$ 4,003**	**$ 3,592**	**$ 3,493**	**$ 3,548**
Total Un-escalated Costs	**$ 3,136**	**$ 2,943**	**$ 2,647**	**$ 3,513**	**$ 3,529**	**$ 2,776**	**$ 3,569**	**$ 3,089**	**$ 2,917**	**$ 2,906**
Total Escalation	**$ -**	**$ 128**	**$ 195**	**$ 343**	**$ 384**	**$ 369**	**$ 434**	**$ 503**	**$ 576**	**$ 642**
Total Escalated Costs	**$ 3,136**	**$ 3,071**	**$ 2,842**	**$ 3,856**	**$ 3,913**	**$ 3,145**	**$ 4,003**	**$ 3,592**	**$ 3,493**	**$ 3,548**
Participants Billings	**$ 2,758**	**$ 2,841**	**$ 2,926**	**$ 3,014**	**$ 3,105**	**$ 3,198**	**$ 3,294**	**$ 3,392**	**$ 3,494**	**$ 3,599**
Total Net Generation (MWh)	93,520	93,520	93,520	93,520	93,520	93,520	93,520	93,520	93,520	93,520
Participant Billing Cost ($/MWh) (1)	$ 29.49	$ 30.38	$ 31.29	$ 32.23	$ 33.20	$ 34.19	$ 35.22	$ 36.27	$ 37.36	$ 38.48

Key Assumptions/Qualifications:

Escalation Rate = 2.50%; FY 2019 = Base Year.

(1) Participant Billing Cost reflects actual funding from participants to meet expected cash requirements.

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Fiscal Year 2019
Nine Canyon Wind Project
Annual Operating Budget

Prepared 3/20/18

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Summary

The Nine Canyon Wind Project is located in the Horse Heaven Hills area southeast of Kennewick, Washington.

Phase I of the project, which began commercial operation in September 2002, consists of 37 wind turbines, each with a maximum generating capacity of approximately 1.3 megawatts of electricity, for a total wind capacity of 48.1 megawatts. Phase II of the project, which was declared operational December 31, 2003, included an additional 12 wind turbines with an aggregate generating capacity of approximately 15.6 megawatts. Phase III of the project, which was declared operational April 1, 2008, included an additional 14 wind turbines, each with a maximum generating capacity of approximately 2.3 megawatts of electricity, for a total wind capacity of 32.2 megawatts. The total project generating capability is approximately 95.9 megawatts.

For Phase I and II the turbines are installed in rows with about 500 feet between turbines. Each three-blade turbine consists of a tubular steel tower 200 feet in height, three 100-foot turbine blades attached to a rotor, and a nacelle that houses a generator, gear box and braking mechanisms.

For Phase III the turbines are installed in rows with about 600 feet between turbines. Each three-blade turbine consists of a tubular steel tower 262 feet in height, three 147-foot turbine blades attached to a rotor, and nacelle that houses a generator, gear box and braking mechanisms.

Electricity generated by the project is purchased by Pacific Northwest Public Utility Districts whose customers have expressed an interest in purchasing at least a portion of their electricity from green power sources. Phase I, II, and III participants have signed a power purchase agreement with Energy Northwest through 2030. The project is connected to the Bonneville Power Administration transmission grid via a substation and transmission lines constructed by the Benton County Public Utility District.

For Fiscal Year 2019, the total funding requirements equal $18,516,000 (Table 4) with revenue of $18,723,000 (Table 1) resulting in a net cash deposit of $207,000 (Table 4).

The Fiscal Year 2019 Budget is presented on a cost basis and includes a cost to cash reconciliation (Table 3) illustrating the conversion of the cost data to a cash basis.

A comparison of the Fiscal Year 2019 Budget is made to the original budget issued for Fiscal Year 2018.

Key Assumptions/Qualifications

This budget will provide funding for continued operation and maintenance of the project. This is based upon the key assumptions and qualifications stated below.

- The Project budget has been reviewed and approved by the participants.

- Billing Price for electrical output is estimated to be $79.01 per MWh (Table 1) for Fiscal Year 2019. The difference between billing price and cost of power is due to depreciation and debt repayment. Billing price per MWh increase is driven solely by reduced estimated net generation.

- Estimated Generation is set at 224,300 MWh (Table 1) which is based off of the most recent five year average.

- Turbine manufacturer Bonus A/S provided O&M services and training. Their support of Phase I was completed in August 2005. Phase II support was completed in December 2006. Siemens is currently providing support for Phase III with the Long Term Service Agreement that was extended for a fifteen year term beginning in August 2013.

Table 1
Summary of Operations
(Dollars in Thousands)

Description		FY 2019 Budget		Original FY 2018 Budget		Variance
Revenue						
Billings	$	17,723	$	17,723	$	-
BPA Transmission Revenue		1,000		1,000		-
Total Revenue	**$**	**18,723**	**$**	**18,723**	**$**	**-**
Operating Costs						
Labor & Overheads	$	1,940	$	1,953	$	(13)
Equipment/Materials/Services		1,312		1,415		(103)
Insurance		220		204		16
Site Maintenance & Warranty		1,114		1,114		-
Benton County PUD		189		114		75
Lessee Payments		700		741		(41)
Risk Reserve		100		100		-
Subtotal Operating Costs	**$**	**5,575**	**$**	**5,641**	**$**	**(66)**
Generation Taxes	$	54	$	54	$	-
Capital		60		53		7
BPA Transmission Costs		1,000		1,000		-
Decommissioning		98		95		3
Depreciation		6,839		6,817		22
Subtotal Operating, Taxes & Capital Cost	**$**	**13,626**	**$**	**13,660**	**$**	**(34)**
Net Financing						
Interest/Financing (Net)		2,305		2,737		(432)
Subtotal Net Financing	**$**	**2,305**	**$**	**2,737**	**$**	**(432)**
Total Cost	**$**	**15,931**	**$**	**16,397**	**$**	**(466)**
Total Net Generation (MWh)		**224,300**		**231,431**		**(7,131)**
Cost of Power ($/MWh) (1)	**$**	**66.30**	**$**	**66.30**	**$**	**(0.00)**
Billing Price to Participants ($/MWh) (2)	**$**	**79.01**	**$**	**76.58**	**$**	**2.43**

(1) Cost of Power excludes BPA Transmission and Capital related costs.

(2) Billing Price is the cash requirements for O&M, Capital, and Debt Service of the Project.

Table 2
Summary of Full Time Equivalent Positions *

Description	FY 2019 Budget	Original FY 2018 Budget	Variance
Project Manager / Supervisor	1	1	-
O&M Technicians	9	9	-
Admin & Technical Support	2	2	-
Total	**12**	**12**	**-**

* Includes Allocations of Corporate Full Time Equivalent Positions

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Table 3
Cost-to-Cash Reconciliation
(Dollars in Thousands)

Description	FY 2019 Total Cost	Non-Cash Items	Non-Cost Items	Deferred Cash Requirements	Prior Year Commitments	FY 2019 Total Cash
Operating Costs						
Operating Costs	$ 5,575	$ -	$ -	$ -	$ -	$ 5,575
Generation Tax	54	-	-	-	-	54
Capital	60	-	-	-	-	60
BPA Transmission	1,000	-	-	-	-	1,000
Decommissioning (1)	98	(98)	-			
Depreciation	6,839	(6,839)	-	-	-	-
Subtotal Operating, Taxes & Capital	**$ 13,626**	**$ (6,937)**	**$ -**	**$ -**	**$ -**	**$ 6,689**
Net Debt Service						
Interest Expense	$ 3,705	$ -	$ -	$ -	$ -	$ 3,705
Bond Retirement	-	-	8,425	-	-	8,425
Amortized Cost	(1,097)	1,097	-	-	-	-
Interest Income	(367)	-	-	-	-	(367)
Treasury Services	64	-	-	-	-	64
Subtotal Net Debt Service	**$ 2,305**	**$ 1,097**	**$ 8,425**	**$ -**	**$ -**	**$ 11,827**
Total Disbursements	**$ 15,931**	**$ (5,840)**	**$ 8,425**	**$ -**	**$ -**	**$ 18,516**
Revenue						
Billings	$ 17,723	$ -	$ -	$ -	$ -	$ 17,723
BPA Transmission	1,000					1,000
Total Revenue	**$ 18,723**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 18,723**
Cash (Withdrawal) / Deposit						**$ 207**

(1) Decommissioning costs through FY2018 have not been funded. Estimated Asset Retirement Obligation liability is $1.6 million in 2019 dollars.

Table 4
Statement of Funding Requirements
(Dollars in Thousands)

Description	**FY 2019 Budget**	**Original FY 2018 Budget**	**Variance**
Operating Costs			
Labor/Benefits/Overhead	$ 1,940	$ 1,953	$ (13)
Equipment/Materials/Services	1,312	1,415	(103)
Insurance	220	204	16
Site Maintenance & Warranty	1,114	1,114	-
Benton PUD	189	114	75
Lessee Payments	700	741	(41)
Risk Reserve	100	100	-
Subtotal Operating Costs	**$ 5,575**	**$ 5,641**	**$ (66)**
Generation Taxes	$ 54	$ 54	$ -
Capital	60	53	7
BPA Transmission	1,000	1,000	-
Subtotal Operating, Taxes & Capital Costs	**$ 6,689**	**$ 6,748**	**$ (59)**
Net Debt Service			
Interest Expense	$ 3,705	$ 4,105	$ (400)
Bond Retirement	8,425	8,010	415
Interest Income	(367)	(214)	(153)
Treasury Services	64	60	4
Subtotal Net Debt Service	**$ 11,827**	**$ 11,961**	**$ (134)**
Total Funding Requirements	**$ 18,516**	**$ 18,709**	**$ (193)**
Funding Sources			
Billings	$ 17,723	$ 17,723	$ -
Participants for BPA Transmission	1,000	1,000	-
Cash Withdrawal / (Deposit)	(207)	(14)	(193)
Total Funding Sources	**$ 18,516**	**$ 18,709**	**$ (193)**

Monthly Statement of Funding Requirements
(Dollars in Thousands)

Description	Jul	Aug	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	FY 2019 Total
Beginning Balance	**$ 13,151**	**$ 14,075**	**$ 15,219**	**$ 16,093**	**$ 17,238**	**$ 18,381**	**$ 17,337**	**$ 18,492**	**$ 19,644**	**$ 20,520**	**$ 21,673**	**$ 22,774**	**$ 13,151**
Receipts													
Billings	$ 1,477	$ 1,477	$ 1,477	$ 1,477	$ 1,477	$ 1,477	$ 1,477	$ 1,477	$ 1,477	$ 1,477	$ 1,477	$ 1,477	$ 17,723
BPA Transmission	83	83	83	83	83	83	83	83	83	83	83	83	1,000
Total Receipts	**$ 1,560**	**$ 1,560**	**$ 1,560**	**$ 1,560**	**$ 1,560**	**$ 1,560**	**$ 1,560**	**$ 1,560**	**$ 1,560**	**$ 1,560**	**$ 1,560**	**$ 1,560**	**$ 18,723**
Disbursements													
Operations Disbursements													
Labor & Overheads	$ 162	$ 162	$ 162	$ 161	$ 162	$ 161	$ 162	$ 162	$ 161	$ 162	$ 161	$ 162	$ 1,940
Equipment/Materials/Services	109	109	110	109	110	109	109	110	109	109	110	109	1,312
Insurance	220	-	-	-	-	-	-	-	-	-	-	-	220
Site Maintenance & Warranty	-	-	269	-	-	275	-	-	280	-	-	290	1,114
Other	82	83	82	83	82	83	82	83	82	83	82	82	989
Generation Taxes	-	-	-	-	-	-	-	-	-	-	54	-	54
Capital	-	-	-	-	-	60	-	-	-	-	-	-	60
BPA Transmission	83	83	83	83	83	83	83	83	83	83	83	83	1,000
Subtotal Operations	**$ 656**	**$ 437**	**$ 706**	**$ 436**	**$ 437**	**$ 771**	**$ 436**	**$ 438**	**$ 715**	**$ 437**	**$ 490**	**$ 726**	**$ 6,689**
Debt Service													
Interest Expense	$ -	$ -	$ -	$ -	$ -	$ 1,853	$ -	$ -	$ -	$ -	$ -	$ 1,852	$ 3,705
Bond Retirement	-	-	-	-	-	-	-	-	-	-	-	8,425	8,425
Investment Income	(25)	(25)	(25)	(25)	(25)	(25)	(36)	(36)	(36)	(36)	(36)	(37)	(367)
Treasury Services	5	4	5	4	5	5	4	6	5	6	5	10	64
Subtotal Debt Service	**$ (20)**	**$ (21)**	**$ (20)**	**$ (21)**	**$ (20)**	**$ 1,833**	**$ (32)**	**$ (30)**	**$ (31)**	**$ (30)**	**$ (31)**	**$ 10,250**	**$ 11,827**
Total Disbursements	**$ 636**	**$ 416**	**$ 686**	**$ 415**	**$ 417**	**$ 2,604**	**$ 404**	**$ 408**	**$ 684**	**$ 407**	**$ 459**	**$ 10,976**	**$ 18,516**
Ending Balance	**$ 14,075**	**$ 15,219**	**$ 16,093**	**$ 17,238**	**$ 18,381**	**$ 17,337**	**$ 18,492**	**$ 19,644**	**$ 20,520**	**$ 21,673**	**$ 22,774**	**$ 13,358**	**$ 13,358**

Table 6
Bank Accounts
(Dollars in Thousands)

Description	FY 2019 Budget	Original FY 2018 Budget	Variance
Phase I Bond Reserve Account	$ 4,171	$ 4,148	$ 23
Phase II Bond Reserve Account	795	790	5
Phase III Bond Reserve Account	5,136	5,002	134
Operating Reserve Account	752	764	(12)
Reserve and Contingency Account	807	816	(9)
Revenue Fund	13,151	11,742	1,409
Total Beginning Balance	**$ 24,812**	**$ 23,262**	**$ 1,550**
Addition / (Reduction)	398	181	$ 217
Total Ending Balance	**$ 25,210**	**$ 23,443**	**$ 1,767**

Table 7
Operations & Maintenance – Budget & Forecast
Long Range Plan
(Dollars in Thousands)

	Budget	Forecast								
Description	**FY19**	**FY20**	**FY21**	**FY22**	**FY23**	**FY24**	**FY25**	**FY26**	**FY27**	**FY28**
Operating Costs										
Labor & Overheads	$ 1,940	$ 1,989	$ 2,038	$ 2,089	$ 2,141	$ 2,195	$ 2,250	$ 2,306	$ 2,364	$ 2,423
Equipment/Materials/Services	1,312	1,344	1,416	1,413	1,447	1,524	1,521	1,558	1,641	1,638
Insurance	220	226	232	237	243	249	256	262	268	275
Long Term Service Agreement	1,114	1,142	1,170	1,200	1,230	1,260	1,292	1,324	1,357	1,391
Lease Payments	700	700	700	700	700	700	700	700	700	700
Benton County PUD	189	143	146	150	153	157	161	165	169	174
Risk Reserve	100	100	100	100	100	100	100	100	100	100
Subtotal Operating Costs	**$ 5,575**	**$ 5,643**	**$ 5,803**	**$ 5,888**	**$ 6,015**	**$ 6,186**	**$ 6,280**	**$ 6,416**	**$ 6,599**	**$ 6,700**
Taxes & Capital Costs										
Generation Taxes	$ 54	$ 54	$ 54	$ 54	$ 54	$ 54	$ 54	$ 54	$ 54	$ 54
Capital	60	62	63	65	66	68	70	71	73	75
BPA Transmission	1,000	1,025	1,051	1,077	1,104	1,131	1,160	1,189	1,218	1,249
Subtotal Taxes & Capital Costs	**$ 1,114**	**$ 1,141**	**$ 1,168**	**$ 1,196**	**$ 1,224**	**$ 1,253**	**$ 1,283**	**$ 1,314**	**$ 1,346**	**$ 1,378**
Total Operating, Taxes, & Capital Disbursements	**$ 6,689**	**$ 6,783**	**$ 6,970**	**$ 7,084**	**$ 7,239**	**$ 7,439**	**$ 7,563**	**$ 7,730**	**$ 7,945**	**$ 8,078**

Key Assumptions/Qualifications:

Escalation Rate = 2.50%; FY 2019 = Base Year, excluding lease payments and generation taxes.

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Fiscal Year 2019
Project 1
Annual Budget

ENERGY NORTHWEST

Prepared 3/20/18

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Summary

The Project 1 Fiscal Year 2019 Annual Budget is prepared by Energy Northwest pursuant to the provisions and requirements of Board of Directors' Resolution No. 769, the Project Agreement and the Net Billing Agreements. The budget includes all costs associated with the project for Fiscal Year 2019 including reuse funding, fixed and variable costs, and treasury related expenses. In addition, the budget includes all funding requirements identified for the project for Fiscal Year 2019.

The total net cost for Fiscal Year 2019 is estimated to be $25,585,000 (Table 1). Total Funding Requirements of $44,101,000 (Table 5) less revenue from restoration/demolition and leasing totaling $2,663,000 will be direct billed to Bonneville Power Administration. Bonneville Power Administration pays directly the funding requirements on a monthly basis under the provisions of the Direct Pay Agreements. This takes the net billing requirements to zero, for the statements which otherwise would be sent to participants in the project, and paid in accordance with the terms of the Net Billing Agreements. The Net Billing Agreements are still in place, but the direct cash payments from Bonneville Power Administration simply takes the participant payment amounts to zero. In the Direct Pay Agreements, Energy Northwest agreed to promptly bill each participant its share of the costs of the project under the Net Billing Agreements, if Bonneville fails to make a payment when due under the Direct Pay Agreements.

A comparison of the Fiscal Year 2019 budget is made to the original budget issued for Fiscal Year 2018.

Table 1
Summary of Costs
(Dollars in Thousands)

	FY 2019 Budget	Original FY 2018 Budget	Variance
Revenue			
Restoration / Demolition (1)	$ 2,657	$ 2,082	575
Fixed Costs	6	25	(19)
Total Revenue	**$ 2,663**	**$ 2,107**	**$ 556**
Costs			
Site Costs			
Restoration / Demolition	$ 2,657	$ 2,082	575
Variable Costs	16	54	(38)
Fixed Costs	405	391	14
Subtotal Site Costs	**$ 3,078**	**$ 2,527**	**$ 551**
Other			
Treasury Related Expenses	$ 24,873	$ 30,327	$ (5,454)
Decommissioning	297	(631)	928
Subtotal Other Costs	**$ 25,170**	**$ 29,696**	**$ (4,526)**
Total Costs	**$ 28,248**	**$ 32,223**	**$ (3,975)**
Total Net Costs	**$ 25,585**	**$ 30,116**	**$ (4,531)**

(1) Restoration / Demolition receipts from the Bonneville Power Administration restoration trust fund will be used to offset all costs of this initiative.

Table 2
Treasury Related Expenses
(Dollars in Thousands)

Description	FY 2019 Budget	Original FY 2018 Budget	Variance
Interest Expense (1)	$ 39,375	$ 39,417	$ (42)
Interest on Note (2)	0	547	(547)
Amortized Financing Cost (3)	(14,870)	(10,018)	(4,852)
Investment Income (Rev. Fund) (4)	(53)	(32)	(21)
Treasury Services (5)	421	413	8
Total	**$ 24,873**	**$ 30,327**	**$ (5,454)**

Assumptions

(1) Budget assumes all $1.28 million of maturing principal will be repaid by July 1, 2019 and no bonds will be extended in fiscal year 2019.

(2) Project 1 interest expense was funded by a line of credit in FY18 that enabled the acceleration of Bonneville federal debt repayments as part of the regional cooperation debt initiative.

(3) The amortized financing costs are driven by the amortization of the premiums on bond issues.

(4) Includes income on investment of monies held in the interest and principal accounts and the Reserve and Contingency Fund which are transferred periodically to the Revenue Fund. Investment income earnings rates are forecasted to average 1.25%.

(5) Includes all non-interest costs of banking, debt, internal labor and overheads.

Table 3
Summary of Full Time Equivalent Positions *

Description	FY 2019 Budget	FY 2018 Budget	Variance
Restoration / Demolition	3	3	-
Site Support	3	3	-
Treasury	1	1	-
Total Positions	**7**	**7**	**-**

*** Includes Allocations of Corporate Full Time Equivalent Positions**

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Table 4
Cost-to-Cash Reconciliation
(Dollars in Thousands)

Description	FY 2019 Total Cost	Non-Cash Items	Non-Cost Items	Deferred Cash Req'ts	Prior Year's Commitments	FY 2019 Total Cash
Variable Costs	$ 16	$ -	$ -	$ -	$ -	$ 16
Restoration / Demolition (1)	2,657	-	-	-	-	2,657
Fixed Costs	405	-	-	-	-	405
Subtotal Site	**$ 3,078**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 3,078**
Other						
Decommissioning	$297	($297)	$ -	$ -	$ -	$ -
Treasury Related						
Interest Expense	39,375	-	-	-	-	39,375
Bond Retirement (2)		-	1,280	-	-	1,280
Amortized Cost	(14,870)	14,870	-	-	-	-
Invest. Income (Rev.)	(53)	-	-	-		(53)
Treasury Services	421	-	-	-	-	421
Subtotal Treasury Expenses	$ 24,873	$ 14,870	$ 1,280	$ -	$ -	$ 41,023
Subtotal Other	**$ 25,170**	**$ 14,573**	**$ 1,280**	**$ -**	**$ -**	**$ 41,023**
Total Funding Requirements	**$ 28,248**	**$ 14,573**	**$ 1,280**	**$ -**	**$ -**	**$ 44,101**

(1) Funding will be from BPA Restoration Trust Fund
(2) It is assumed that all $1.28 million of the maturing 7/1/2019 bonds will be repaid.
No bonds mature on 7/1/2018.

Table 5
Annual Budget and
Statement of Funding Requirements
(Dollars in Thousands)

Description	FY 2019 Budget	Original FY 2018 Budget	Variance
Programs			
Variable Costs	$ 16	$ 54	(38)
Restoration / Demolition	2,657	2,082	575
Fixed Costs	405	391	14
Subtotal Programs	**$ 3,078**	**$ 2,527**	**$ 551**
Treasury Related Expenses			
Interest Expense	$ 39,375	$ 39,417	$ (42)
Bond Retirement (1)	1,280	-	1,280
Interest on Note (2)	-	547	(547)
Note Retirement	-	44,000	(44,000)
Investment Income (Revenue)	(53)	(32)	(21)
Treasury Services	421	413	8
Subtotal Treasury Related	**$ 41,023**	**$ 84,345**	**$ (43,322)**
Total Funding Requirements	**$ 44,101**	**$ 86,872**	**$ (42,771)**
Funding Sources			
Restoration / Demolition (3)	$ 2,657	$ 2,082	575
Revenue - Fixed Costs	6	25	(19)
Net Billing/BPA Direct Payments	41,438	84,765	(43,327)
Total Funding Sources	**$ 44,101**	**$ 86,872**	**$ (42,771)**

(1) All maturing bonds on 7/1/2019 are expected to be repaid and none planned to be extended.

(2) Project 1 interest expense was funded by a line of credit in FY18 that enabled the acceleration of Bonneville federal debt repayments as part of the regional cooperation debt initiative.

(3) Restoration / Demolition receipts from the Bonneville Power Administration escrow account will be used to offset all costs of this initiative.

Table 6

Monthly Statement of Funding Requirements - Revenue Fund

(Dollars in Thousands)

Description	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	FY 2019 Total
Beginning Balance	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**
Receipts													
BPA Direct Payments (1)	$ 61	$ 61	$ 61	$ 61	$ 62	$ 19,747	$ 66	$ 66	$ 68	$ 68	$ 68	$ 21,049	$ 41,438
Restoration / Demolition (2)	221	221	222	221	221	222	221	222	221	222	221	222	2,657
Revenue - Leasing	-	-	-	-	-	3	-	-	-	-	-	3	6
Total Receipts	**$ 282**	**$ 282**	**$ 283**	**$ 282**	**$ 283**	**$ 19,972**	**$ 287**	**$ 288**	**$ 289**	**$ 290**	**$ 289**	**$ 21,274**	**$ 44,101**
Disbursements													
Treasury Related Expenses													
Interest Expense	$ -	$ -	$ -	$ -	$ -	$ 19,688	$ -	$ -	$ -	$ -	$ -	$ 19,687	$ 39,375
Bond Retirement (3)	-	-	-	-	-	-	-	-	-	-	-	1,280	1,280
Investment Income	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(5)	(5)	(5)	(5)	(5)	(53)
Treasury Services	32	32	32	32	32	32	36	37	39	39	39	39	421
Subtotal Treasury Related	**$ 28**	**$ 28**	**$ 28**	**$ 28**	**$ 28**	**$ 19,716**	**$ 32**	**$ 32**	**$ 34**	**$ 34**	**$ 34**	**$ 21,001**	**$ 41,023**
Variable Costs	-	-	-	-	-	-	-	-	-	-	-	16	16
Restoration / Demolition	221	221	222	221	221	222	221	222	221	222	221	222	2,657
Fixed Costs	33	33	33	33	34	34	34	34	34	34	34	35	405
Total Disbursements	**$ 282**	**$ 282**	**$ 283**	**$ 282**	**$ 283**	**$ 19,972**	**$ 287**	**$ 288**	**$ 289**	**$ 290**	**$ 289**	**$ 21,274**	**$ 44,101**
Ending Balance	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**

(1) BPA is billed, through the Direct Payment Agreements, one month in advance for the following month's expenses.

(2) Funding will be from BPA Restoration Trust Fund

(3) All maturing bonds on 7/1/2019 are expected to be repaid and none planned to be extended.

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Fiscal Year 2019
Project 3
Annual Budget

Prepared 3/20/18

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Summary

Energy Northwest's Project 3 was terminated in June 1994. Transfer of the Project 3 site to the Satsop Redevelopment Project was completed during Fiscal Year 2000.

This Project 3 Fiscal Year 2019 Annual Budget is prepared by Energy Northwest pursuant to the provisions and requirements of Board of Directors' Resolution No. 775 and the Net Billing Agreements. The Budget includes all costs and funding requirements associated with the debt on Project 3. No other costs are incurred on this project.

The total cost for Fiscal Year 2019 is estimated to be $34,113,000 (Table 1). The total net funding requirements for Fiscal Year 2019 are $41,751,000 (Table 4). Bonneville Power Administration pays directly the funding requirements on a monthly basis under the provisions of the Direct Pay Agreements. This takes the net billing requirements to zero, for the statements which otherwise would be sent to participants in the project, and paid in accordance with the terms of the Net Billing Agreements. The Net Billing Agreements are still in place, but the direct cash payments from Bonneville Power Administration simply takes the participant payment amounts to zero. In the Direct Pay Agreements, Energy Northwest agreed to promptly bill each participant its share of the costs of the project under the Net Billing Agreements, if Bonneville fails to make a payment when due under the Direct Pay Agreements.

Table 1
Summary of Costs
(Dollars in Thousands)

Description	FY 2019 Budget	Original FY 2018 Budget	Variance
Interest Expense (1)	$ 44,260	$ 53,263	$ (9,003)
Interest on Note (2)	0	634	(634)
Amortized Financing Cost (3)	(10,474)	(10,695)	221
Investment Income (4)	(99)	(96)	(3)
Treasury Services (5)	426	425	1
Total	**$ 34,113**	**$ 43,531**	**$ (9,418)**

Assumptions

(1) Budget assumes all $1.35 million in principal will be repaid in FY2019 and none will be extended.

(2) Project 3 interest expense was funded by a line of credit in FY18 that enables the acceleration of Bonneville federal debt repayments as part of the regional cooperation debt initiative.

(3) The amortized financing costs are driven by the amortization of the premiums on bonds.

(4) Includes income on investment of monies held in the Interest and Principal accounts and the Reserve & Contingency Fund which are transferred periodically to the Revenue Fund. Investment income earnings rate is forecasted to average 1.25%

(5) Includes all non-interest costs of banking, debt, internal labor and overheads.

Table 2
Summary of Full Time Equivalent Positions *

Description	FY 2019 Budget	FY 2018 Budget	Variance
Treasury Related	1	1	-

* Includes Allocations of Corporate Full Time Equivalent Positions

Table 3
Cost-to-Cash Reconciliation
(Dollars in Thousands)

Description	FY 2019 Total Cost	Non-Cash Items	Non-Cost Items	Deferred Cash Req'ts	Prior Year's Commitments	FY 2019 Total Cash
Treasury Related Expenses						
Interest Expense	$ 44,260	$ -	$ -	$ -	$ -	$ 44,260
Bond Retirement (1)	-	-	1,350	-	-	1,350
Amortized Financing Cost	(10,474)	10,474	-	-	-	-
Investment Income	(99)	-	-	-		(99)
Treasury Services	426	-	-	-	-	426
Prior Year's R&C Surplus	-	-	(4,186)	-	-	(4,186)
Subtotal Treasury Related	**$ 34,113**	**$ 10,474**	**$ (2,836)**	**$ -**	**$ -**	**$ 41,751**
Total Funding Requirements	**$ 34,113**	**$ 10,474**	**$ (2,836)**	**$ -**	**$ -**	**$ 41,751**

(1) Budget assumes all $1.35 million in prinicpal will be repaid in FY2019 and none will be extended.

Table 4
Annual Budget
Statement of Funding Requirements
(Dollars in Thousands)

Description	FY 2019 Budget	Original FY 2018 Budget	Variance
Treasury Related Expenses			
Interest Expense	$ 44,260	$ 52,610	$ (8,350)
Bond Retirement (1)	1,350	11,855	(10,505)
Interest on Note (2)	-	634	(634)
Note Retirement	-	51,000	(51,000)
Reserve & Contingency Fund	-	1,186	(1,186)
Investment Income (Rev)	(99)	(96)	(3)
Prior Year's R&C Surplus	(4,186)	(1,731)	(2,455)
Treasury Services	426	425	1
Total Funding Requirements	**$ 41,751**	**$ 115,883**	**$ (74,132)**
Funding Sources			
Net Billing/BPA Direct Payments	$ 41,751	$ 115,883	$ (74,132)
Total Funding Sources	**$ 41,751**	**$ 115,883**	**$ (74,132)**

(1) Budget assumes all $1.35 million in prinicpal will be repaid in FY2019 and none will be extended.

(2) A line of credit funded the FY18 Interest Expense in order to free up monies that enable the acceleration of Bonneville federal debt repayments as part of the regional cooperation debt initiative.

Table 5
Monthly Statement of Funding Requirements - Revenue Fund
(Dollars in Thousands)

Description	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	FY2019 Total
Beginning Balance	**$ 3,000**	**$ 7,160**	**$ 7,134**	**$ 7,108**	**$ 7,082**	**$ 7,056**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**
Receipts													
BPA Direct Payments (1)	$ -	$ -	$ -	$ -	$ -	$ 18,101	$ 28	$ 29	$ 29	$ 28	$ 28	$ 23,508	$ 41,751
Total Receipts	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 18,101**	**$ 28**	**$ 29**	**$ 29**	**$ 28**	**$ 28**	**$ 23,508**	**$ 41,751**
Disbursements													
Treasury Related													
Interest Expense	$ -	$ -	$ -	$ -	$ -	$ 22,130	$ -	$ -	$ -	$ -	$ -	$ 22,130	$ 44,260
Bond Retirement (2)	-	-	-	-	-	-	-	-	-	-	-	1,350	$ 1,350
Investment Income	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(9)	(9)	(9)	$ (99)
Prior Year R&C Surplus	(4,186)	-	-	-	-	-	-	-	-	-	-	-	$ (4,186)
Treasury Services	34	34	34	34	34	35	36	37	37	37	37	37	$ 426
Total Disbursements	**$ (4,160)**	**$ 26**	**$ 26**	**$ 26**	**$ 26**	**$ 22,157**	**$ 28**	**$ 29**	**$ 29**	**$ 28**	**$ 28**	**$ 23,508**	**$ 41,751**
Ending Balance	**$ 7,160**	**$ 7,134**	**$ 7,108**	**$ 7,082**	**$ 7,056**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**	**$ 3,000**

(1) BPA is billed, through the Direct Payment Agreements, one month in advance for the following month's expenses.
(2) Budget assumes all $1.35 million in prinicpal will be repaid in FY2019 and none will be extended.

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Fiscal Year 2019
Business Development Fund
Annual Budget

Prepared 3/20/18

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Summary

The Business Development Fund (BDF) was created by Executive Board Resolution No. 1006 in April 1997 for the purpose of holding, administering, disbursing, and accounting for Energy Northwest costs and revenues generated from engaging in new energy-related business opportunities.

The BDF is managed as an enterprise fund. The budgets are divided by business sector: Applied Technology and Innovation, Business Services, Facilities, Generation, and Professional Services. Each sector may have one or more programs that are managed as a unique business activity. Revenues, expenses, and margins are reported for each program and sector.

For Fiscal Year 2019, the revenue for the BDF equals $10,672,000 while total funding requirements equal $10,703,000 creating a reduction in fund balance of $31,000 (See Table 5).

A comparison of the Fiscal Year 2019 Budget is made to the original budget issued for Fiscal Year 2018.

Key Assumptions/Qualifications

- Manage, operate, maintain, modify, and support facilities related to power generation.

- Assist members with generation resources, transmission integration, and power management issues.

- Offer cost competitive resource options that manage risk and promote environmental stewardship.

- Invest in key strategic focus areas:

    - Professional / O&M services
    - Electric Vehicle Infrastructure
    - Demand Side Management Resources

Table 1
Summary of Revenues and Expenses by Business Sector
(Dollars in Thousands)

Description	FY 2019 Budget	Original FY 2018 Budget	Variance
Revenues			
Applied Technology & Innovation	$ 167	$ 929	$ (762)
Business Services	5,868	5,557	311
Facilities	7	143	(136)
Generation	474	208	266
Professional Services	4,156	2,190	1,966
Total Revenues	**$ 10,672**	**$ 9,027**	**$ 1,645**
Expenses (1)			
Applied Technology & Innovation	$ 784	$ 1,098	$ (314)
Business Services (2)	5,385	5,192	193
Facilities	4	133	(129)
Generation	663	416	247
Professional Services (3)	3,713	1,943	1,770
Total Expenses	**$ 10,549**	**$ 8,782**	**$ 1,767**
Net Margin	**$ 123**	**$ 245**	**$ (122)**

(1) Does not include capital expenses
(2) Includes $258,000 in depreciation
(3) Includes $12,000 in depreciation

Table 2
Detailed Financial Summary
(Dollars in Thousands)

Description	FY 2019 Revenue	FY 2019 Cost	FY 2019 Margin
Applied Technology & Innovation (ATI)			
Capacity Markets	$ -	$ 32	$ (32)
Demand Response - Program	-	195	(195)
Distributed Storage	-	50	(50)
DVRI Capital	95	289	(194)
DVRI/DSM Operations	72	72	-
Energy Storage	-	37	(37)
Power System Services	-	109	(109)
Total ATI	**$ 167**	**$ 784**	**$ (617)**
Business Services			
Columbia Calibration Services	$ 2,377	$ 2,377	$ -
Commercial Calibration Services	1,550	1,098	452
Environmental Laboratory Services	220	213	7
Columbia Environmental Laboratory	1,682	1,682	-
Co-Location Rentals / Other	39	15	24
Total Business Services (1)	**$ 5,868**	**$ 5,385**	**$ 483**
Facilities			
Misc Other	$ 7	$ 4	$ 3
Total Facilities	**$ 7**	**$ 4**	**$ 3**
Generation			
Electric Vehicle Initiatives	$ 280	$ 332	$ (52)
Horn Rapids Solar	-	103	(103)
Neoen Solar	57	41	16
Small Modular Research	-	28	(28)
Solar	-	35	(35)
UAMPS Carbon Free Power	137	124	13
Total Generation	**$ 474**	**$ 663**	**$ (189)**
Professional Services			
Joint Procurement	$ -	$ 18	$ (18)
Portland Hydro Project	1,684	1,464	220
Roving Work Force	96	96	-
Special Coatings	-	1	(1)
Technical Services	307	307	-
Tieton O&M Services	2,068	1,815	253
White Bluffs Solar (2)	1	12	(11)
Total Professional Services	**$ 4,156**	**$ 3,713**	**$ 443**
Total	**$ 10,672**	**$ 10,549**	**$ 123**

Margin - ( ) Unfavorable

(1) Includes depreciation of $258,000

(2) Includes depreciation of $12,000

Note: $2,194,000 in BDF Business Support is allocated to Energy Services & Development programs.

Table 3
Summary of Capital
(Dollars in Thousands)

Description	FY 2019 Budget	Original FY 2018 Budget	Variance
Business Sector / Project			
Business Services			
Calibration Laboratory Services	$ 352	$ 276	$ 76
Environmental Laboratory Services	72	73	(1)
Total - Capital	**$ 424**	**$ 349**	**$ 75**

Table 4
Summary of Full Time Equivalent Positions *

Description	FY 2019 Budget	Original FY 2018 Budget	Variance
Applied Technology & Innovation	1	1	-
Business Services Sector	25	25	-
Facilities / Leasing Sector	2	2	-
Generation Sector	2	2	-
Indirect Support	10	10	-
Professional Services Sector (1)	3	2	1
Total Positions	**43**	**42**	**1**
Less: FTEs in Labs Supporting Columbia	19	19	-
Total Positions Supporting External Business	**24**	**23**	**1**

* Includes Allocations of Corporate Full Time Equivalent Positions

(1) Project Manger I Position Added in Professional Services.

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Table 5
Statement of Funding Requirements
(Dollars in Thousands)

Description	FY 2019 Budget	Original FY 2018 Budget	Variance
Funding Requirements			
Expense Requirements (1)	$ 10,279	$ 8,500	$ 1,779
Capital Requirements	424	349	75
Total Funding Requirements	**$ 10,703**	**$ 8,849**	**$ 1,854**
Funding Sources			
Revenues	$ 10,672	$ 9,027	$ 1,645
Total Funding Sources	**$ 10,672**	**$ 9,027**	**$ 1,645**
Change in Fund Balance from Operations	**$ (31)**	**$ 178**	**$ (209)**

(1) Expenses exclude $270,000 of depreciation (non-cash item).

Table 6
Business Development Fund - Cash Flow
(Dollars in Thousands)

Description	Jul	Aug	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	FY 2019 Total
Beginning Balance	**$ 8,673**	**$ 8,705**	**$ 8,737**	**$ 8,771**	**$ 8,803**	**$ 8,836**	**$ 8,869**	**$ 8,901**	**$ 8,934**	**$ 8,967**	**$ 8,999**	**$ 9,033**	**$ 8,673**
Receipts													
Revenues	$ 889	$ 889	$ 890	$ 889	$ 890	$ 889	$ 889	$ 890	$ 889	$ 889	$ 890	$ 889	$ 10,672
Total Receipts	**$ 889**	**$ 889**	**$ 890**	**$ 889**	**$ 890**	**$ 889**	**$ 889**	**$ 890**	**$ 889**	**$ 889**	**$ 890**	**$ 889**	**$ 10,672**
Disbursements													
Expense Requirements	$ 857	$ 857	$ 856	$ 857	$ 857	$ 856	$ 857	$ 857	$ 856	$ 857	$ 856	$ 856	$ 10,279
Capital Requirements	-	-	-	-	-	-	-	-	-	-	-	424	424
Total Disbursements	**$ 857**	**$ 857**	**$ 856**	**$ 857**	**$ 857**	**$ 856**	**$ 857**	**$ 857**	**$ 856**	**$ 857**	**$ 856**	**$ 1,280**	**$ 10,703**
Ending Balance	**$ 8,705**	**$ 8,737**	**$ 8,771**	**$ 8,803**	**$ 8,836**	**$ 8,869**	**$ 8,901**	**$ 8,934**	**$ 8,967**	**$ 8,999**	**$ 9,033**	**$ 8,642**	**$ 8,642**

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Fiscal Year 2019
General Business Unit
Annual Budget

Prepared 3/20/18

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Summary

Presented within the General Business Unit Fiscal Year 2019 budget are the costs for Benefits, Corporate Programs, Organizational Overhead and General Purpose Projects.

The total Fiscal Year 2019 General Business Unit cost is estimated to be $99,885,000 (Table 1).

Corporate Program costs and staffing are shown separately to identify the services being provided to each business unit as opposed to employee related benefits. Fiscal Year 2019 Corporate costs are estimated to be $14,974,000 (Table 2).

Benefits which include health care, personal time/holidays, employer portion of social security and Washington State Employees' Retirement System, 401(k) matching, and other related costs are estimated to be $68,646,000 (Table 3).

Organizational Overhead which includes at-risk compensation, tuition and relocation reimbursements as well as other related costs is estimated to be $13,222,000 (Table 4).

General Purpose Projects are composed of Corporate IT Projects and the Capital Development Corporation (CDC) facility. The Corporate IT Projects are estimated to be $2,945,000 (Table 5). The CDC facility is not expected to realize any revenue and is estimated to have $98,000 in costs for a net loss of $98,000 (Table 5). The CDC facility estimated net loss of $98,000 (Table 8) will be funded by the Performance Fee Account.

The General Business Unit costs are allocated to each Business Unit as explained on page 10. Also, the allocation process is depicted in a diagram on Table 7.

The Performance Fee account has been established for the purpose of depositing monies related to fees earned by Energy Northwest. Monies within this account are used to fund start-up expenses related to Business Development Fund projects, and for other purposes as directed by the Chief Executive Officer (Table 8).

The Fiscal Year 2018 Budget has been adjusted to reclassify certain costs for comparison purposes to the Fiscal Year 2019 Budget.

Table 1
Summary of Costs
(Dollars in Thousands)

Description	FY 2019 Budget	Original FY 2018 Budget	Variance
Corporate Programs	$ 14,974	$ 14,700	$ 274
Benefits/Personal Time	68,646	66,672	1,974
Organizational Overhead	13,222	12,863	359
General Purpose Project - O&M	98	40	58
Total O&M Costs	**$ 96,940**	**$ 94,275**	**$ 2,665**
General Purpose Project - Capital	$ 2,945	$ 1,465	**$ 1,480**
Total Costs	**$ 99,885**	**$ 95,740**	**$ 4,145**

Table 2
Corporate Program Costs
(Dollars in Thousands)

Description	FY 2019 Budget	Original FY 2018 Budget	Variance
Information Services	$ 5,705	$ 5,704	$ 1
Public Affairs	2,512	2,506	6
Human Resources	1,825	1,770	55
Asset Management	1,544	1,592	(48)
Senior Management	1,443	1,288	155
Finance/Treasury	737	682	55
Legal	704	752	(48)
Environmental & Regulatory Programs	243	144	99
Training	220	220	-
Other	41	42	(1)
Total	**$ 14,974**	**$ 14,700**	**$ 274**

Table 2A
Corporate Program Full Time Equivalent Positions

Description	FY 2019 Budget	FY 2018 Budget	Variance
Information Services	25	26	(1)
Human Resources	15	15	-
Finance/Asset Management	11	11	-
Public Affairs	10	10	-
Legal	5	4	1
Senior Management	3	3	-
Environmental & Regulatory Programs	2	2	-
Total	**71**	**71**	**-**

Table 3
Employee Benefit Costs
(Dollars in Thousands)

Description	FY 2019 Budget	Original FY 2018 Budget	Variance
Medical Benefits	$ 18,235	$ 17,006	$ 1,229
F.I.C.A.	9,312	9,610	(298)
Retirement:			
WA PERS Contribution	16,805	17,171	(366)
401(k) Match	3,419	3,628	(209)
Personal Time/Holidays	17,425	16,709	716
Unemployment/Disability/Other	2,232	2,547	(315)
Subtotal	**$ 67,428**	**$ 66,671**	**$ 757**
Outage	$ 1,218	$ -	$ 1,218
Total	**$ 68,646**	**$ 66,671**	**$ 1,975**

Table 4
Organizational Overhead
(Dollars in Thousands)

Description	FY 2019 Budget	Original FY 2018 Budget	Variance
At-Risk Compensation/Retention/ Employee Recognition	$ 12,490	$ 12,077	$ 413
Relocations	577	581	(4)
Tuition	155	205	(50)
Total	**$ 13,222**	**$ 12,863**	**$ 359**

Table 5
General Purpose Projects
(Dollars in Thousands)

Description	FY 2019 Budget	Original FY 2018 Budget	Variance
Capital Projects			
Information Technology (1)	$ 2,945	$ 1,465	$ 1,480
Total Capital Projects	**$ 2,945**	**$ 1,465**	**$ 1,480**
Expense Projects			
Information Technology (1)	$ -	$ -	$ -
CDC - Downtown Building (2)	98	40	58
Total Expense Projects	**$ 98**	**$ 40**	**$ 58**
Total General Purpose Projects	**$ 3,043**	**$ 1,505**	**$ 1,538**

(1) Information Technology costs are managed centrally within Energy Northwest for the benefit of all Business Units. Items must have a useful life greater than one year, and have a procurement cost of greater than $1,000. Internally developed software projects must be greater than $250,000 to be capitalized.
(2) CDC Building is an asset of the General Business Unit and is revenue producing. The net revenues or losses are transferred to the Performance Fee Account.

Table 6
Business Unit Allocation of Costs
(Dollars in Thousands)

Business Unit Allocations (Dollars)	FY 2019 Budget	Original FY 2018 Budget	Variance
Project 1	$ 414	$ 452	$ (38)
Columbia	92,162	89,593	2,569
Project 3	90	99	(9)
Packwood	390	401	(11)
Nine Canyon Wind Project	793	820	(27)
Business Development Fund	2,976	2,880	96
Total Allocations	**$ 96,825**	**$ 94,245**	**$ 2,580**

Business Unit Allocations (Percentages)	FY 2018 Budget	FY 2018 Budget	Variance
Project 1	0.43%	0.48%	(0.05%)
Columbia	95.19%	95.05%	0.14%
Project 3	0.09%	0.11%	(0.02%)
Packwood	0.40%	0.43%	(0.03%)
Nine Canyon Wind Project	0.82%	0.87%	(0.05%)
Business Development Fund	3.07%	3.06%	0.01%
Total Allocations	**100.00%**	**100.00%**	**(0.00%)**

Note:
Total Business Unit Allocation dollars shown exclude CDC/Other non-allocated costs, thus, will not agree with Table 1.

Overview of Indirect Cost Pools

Energy Northwest makes use of four indirect cost pools. Allocation of these pools is conducted in four sequential steps. A graphical depiction of allocation steps are provided on the following page (Table 7).

Step 1 - Employee Benefits (Resource Category 703)
All costs incurred by Energy Northwest for medical and dental benefits, employer portion of social security and Washington State Employees' Retirement System, 401(k) matching, and other costs associated with employee wellness. Employee benefit costs are allocated to business units and other intermediate cost pools based on regular labor costs. Overtime, temporary and special pay costs receive a reduced rate.

Step 2 – Personal Time (Resource Category 701)
All costs of labor while employees are on Personal Time (e.g., vacation, holiday, sick, etc.) and a pro rata allocation of employee benefits. These costs are allocated to business units and other intermediate cost pools based on regular labor costs.

Step 3 – Organizational Overhead (Resource Category 702)
Contains costs for education reimbursement, new employee relocation, employee labor supporting corporate sponsored initiatives and labor costs determined when goals are evaluated. Also, included is a pro rata allocation of employee benefits and personal time. These costs are allocated to business units and the Corporate Programs cost pool based on regular labor costs.

Step 4 – Corporate Programs (Resource Category 704)
Contains all costs associated with management of Energy Northwest's corporate activities. These costs include costs of finance, legal, administration, human resources, procurement, and information technology. Also, included is a pro rata allocation of employee benefits, personal time, and Organizational Overhead. These costs are allocated over Total Operating and Capital costs.

Table 7
Indirect Cost Allocation Diagram

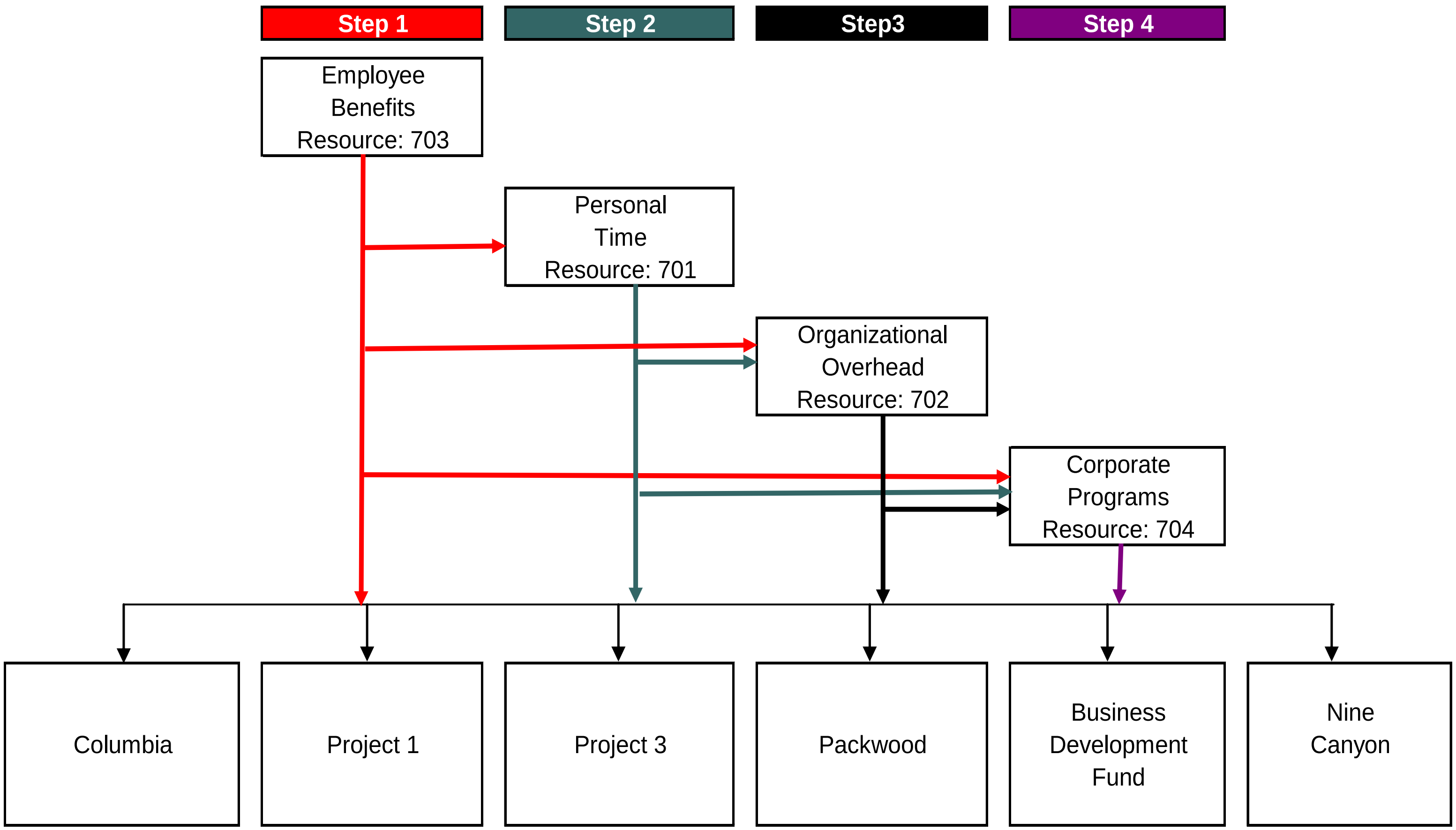

Table 8
Performance Fee Account
Statement of Funding Requirements
(Dollars in Thousands)

	FY 2019 Budget	Original FY 2018 Budget	Variance
Beginning Balance	**$ 4,510**	**$ 4,618**	**$ (108)**
Use of Funds			
Transfer to Bus Dev Fund (BDF)	$ -	$ -	$ -
Total Use of Funds	**$ -**	**$ -**	**$ -**
Source of Funds			
CDC Margin	$ (98)	$ (40)	$ (58)
Transfer from BDF	-	-	-
Investment Income	56	34	22
Total Funding Sources	**$ (42)**	**$ (6)**	**$ (36)**
Ending Balance (1)	**$ 4,468**	**$ 4,612**	**$ (144)**

(1) Internal policy allows portions of the Performance Fee account balance to be either transferred or encumbered by other Business Units.

ALLOCATION: A process to spread indirect overhead costs to other business units based on a common cost pool.

AMORTIZATION: A method of allocating (accruing) costs to fiscal periods to match costs with the revenues or benefits generated from a specific activity.

AMORTIZED FINANCING COSTS: Reflects the capitalized financing costs that were incurred to issue long-term bonds to finance construction of the project or refinance outstanding project bonds, which are being amortized over the life of the bonds.

ANNUAL BUDGET: The amount of resources, expressed in dollars, allocated to a specific project for a given fiscal year.

BASELINE COSTS: Columbia Generating Station (Columbia) direct and indirect costs not associated with projects. Estimated labor associated with projects has been included in the project line item budgets.

BILLING STATEMENTS: A contractual notification to project participants indicating their percentage and dollar share of a net-billed project's annual budget.

BOND PROCEEDS: Monies received from the issuance of bonds.

BOND RESOLUTION: A resolution passed by Energy Northwest's Board of Directors establishing a plan and system for the acquisition and construction of a particular Energy Northwest project. Each of Energy Northwest's projects has a bond resolution. Among other things, the resolution authorizes the issuance of bonds to construct the project and establishes special rules pertaining to the accounting and funding of each project. Each resolution mandates that separate funds and books of accounts be maintained and strictly prohibits the payment of obligations of one project with funds of another project.

BOND RETIREMENT: Funds deposited into the Bond Fund Principal or Bond Fund Retirement accounts used to retire maturing debt or meet sinking fund requirements.

BPA DIRECT PAY AGREEMENTS: Energy Northwest and Bonneville entered into an agreement with respect to each Net Billed Project ("Direct Pay Agreements") pursuant to which, beginning May 2006, Bonneville pays at least monthly all costs for each Net Billed Project, including debt service on the Net Billed Bonds, directly to Energy Northwest. Each Participant pays directly to Bonneville all costs associated with its power sales and other contracts with Bonneville instead of making such payments to Energy Northwest. The Net Billing Agreements provide that Energy Northwest is to bill budgeted costs less amounts payable from sources other than the Net Billing Agreements to Participants. Direct payments received from Bonneville under the Direct Pay Agreements are considered a source other than the Net Billing Agreements and, therefore, the Net Billing Agreements were not amended. In the Direct Pay Agreements, Energy Northwest agrees to promptly bill each Participant its share of the costs of the respective Project under the Net Billing Agreements if Bonneville fails to make a payment when due under the Direct Pay Agreements.

BUSINESS DEVELOPMENT FUND (BDF): A special enterprise fund created for the purpose of holding, administering, disbursing and accounting for Energy Northwest costs and revenues generated from new energy-related business opportunities. Created by Executive Board Resolution Number 1006 in April 1997.

BUSINESS UNIT: A plan and system authorized by Energy Northwest's Board of Directors. Columbia, WNP-1, WNP-3, Packwood, Business Development Fund, Nine Canyon Wind Project, and General Business Unit are all Business Units. The General Business Unit includes indirect costs that are subsequently allocated to all other business units.

CAPITAL ADDITIONS: Includes improvements and modifications that will be made throughout the operating life of the plant that will be necessary to assure plant safety, reliability, efficiency and cost effectiveness.

CAPITAL COSTS/EQUIPMENT: Costs related to improvements and modifications to the plant or the purchase of equipment. Generally, an item is considered to be capital equipment if it exceeds $10K, except computer equipment which is $1K, in value and has a service life of greater than one year. Capital items are depreciated over their estimated service-lives.

CONSTRUCTION FUND: Established pursuant to Bond Fund resolutions, the Construction Fund pays for all costs of construction.

CONTROLLABLE COSTS: Controllable costs include operations, maintenance, capital and overhead costs. They exclude costs related to depreciation, fuel, and financing.

CORPORATE PROGRAMS: The administration, management and general programs that support Energy Northwest as a business entity are accumulated into a Corporate Program indirect cost pool. The Corporate Program costs are distributed based upon total Operating and Capital costs charged to Energy Northwest projects or other final cost objectives. Corporate Programs include, but are not limited to, accounting, human resources, legal services and general management.

COST OF POWER: A measurement, expressed in dollars per megawatt-hour, designed to measure the cost effectiveness of plant operations. Also see Memorandum of Agreement.

COST-TO-CASH RECONCILIATION: A schedule depicting how cost numbers, which are used to manage and control Energy Northwest business units, are converted to cash and funding requirements.

DEBT SERVICE: Amounts paid or required to be paid into the applicable Bond and Reserve & Contingency Fund for purposes of paying the semi-annual coupon interest and annual bond principal redemption.

DECOMMISSIONING: Refers to the plan of dismantlement and site restoration of Columbia. The decommissioning plan for Columbia reflects a 60-year plant life, three years to prepare for protective storage, 60 years of protective storage, and 3.5 years for facility dismantlement and site restoration. A special fund has been established to provide monies necessary to pay for decommissioning.

DEPRECIATION: A systematic and rational basis for allocating capital costs over the service life of an asset. Depreciation may be based on estimated service life in years or production capacity. Depreciation can be viewed as the wear and tear of an asset over time.

ESCALATION: The dollar amount or percentage rate that costs are expected to increase in future periods due to inflation, changes in labor contracts, tax increases, etc.

EXCESS WORKING CAPITAL: The amount in excess of $3 million that has been designated as the required amount of working capital for the Revenue Fund. To the extent that on June 30, there is more than that amount of monies in the Revenue Fund, such amounts for the current fiscal year are excess amounts to be used to reduce the funding requirements for the project for the subsequent fiscal year.

FISCAL YEAR: The twelve-month period July 1 through June 30. Energy Northwest's accounting and budgeting cycle is based on a fiscal year that spans this period.

FIXED COSTS: Includes non-variable costs that will be incurred regardless of plant operations, output or conditions (e.g., bond interest, depreciation, decommissioning, etc.).

FUND: Established by bond resolutions, a fund is a pool of money set aside to pay specified obligations of the projects. Typically, Energy Northwest project bond resolutions call for construction costs to be paid from the Construction Fund, operations and maintenance costs to be paid from the Revenue Fund, bond interest payments to be paid from the Interest Account within the Bond Fund, etc. Fund restrictions were established by bond resolutions as a form of security for bondholders.

FUNDING REQUIREMENTS: Identification of the amount of cash required for a given budget period to meet business unit needs.

GENERAL BUSINESS UNIT (GENERAL FUND): A fund established for accounting purposes to pay multi-project obligations and collect and allocate overhead costs to projects.

GENERATION TAXES: Pursuant to RCW 54.28.025, a tax is assessed on Columbia net generation equal to one and one-half percent of the wholesale value of energy produced. An additional surcharge is also assessed pursuant to RCW 82.02.030 equal to seven percent of the generation tax payable.

INCREMENTAL COSTS: Includes those costs that are variable in nature and are directly related to the amount of power produced (e.g., nuclear fuel amortization spent fuel disposal fees, generation taxes, etc.).

INCREMENTAL OUTAGE COSTS: Includes those costs that are needed to support an outage that are not specific to an individual project (e.g., overtime, supplies and materials).

INDIRECT COSTS: Includes costs charged to intermediate cost pools for later allocation. Includes costs associated with Administrative & General (A&G), Information Technology, Organizational Overhead, Employee Benefits, and Absence (see General Business Unit tab for further definition of these cost pools).

INTEREST EXPENSE: The interest on outstanding bonds. Funds are transferred monthly from the Revenue Funds to the Bond Fund Interest Accounts in order to pay the semi-annual coupon interest.

INVENTORY: Operational spare parts, common stock and general materials and supplies purchased by Energy Northwest and stored in warehouses for later use.

INVESTMENT INCOME: Income earned on investment securities.

MATERIALS: Included in materials is the cost of office supplies, software, fuels, oils, chemicals, gases, support materials, and resins.

NET-BILLING: A payment procedure established by net-billing agreements. More than 100 Northwest utilities have purchased all of the project capability of Nuclear Project No. 1, Columbia and Energy Northwest's 70 percent ownership share of Nuclear Project No. 3. Project Participants have resold such capability to BPA and, in return, BPA is obligated to pay annual costs of these projects, including debt service, by a procedure referred to as net-billing. Project Participants pay Energy Northwest their respective share of annual costs, and BPA pays Project Participants identical amounts by reducing amounts due to BPA by Participants under power sales agreements.

NUCLEAR FUEL AMORTIZATION: Represents the amortization of nuclear fuel costs in a given fiscal year. The cost of nuclear fuel is first capitalized as an asset in order to reflect the value of the unused fuel. At the time the fuel is placed in the reactor, the cost of the fuel is amortized to fiscal periods on the basis of quantity of heat produced.

NUCLEAR FUEL IN PROCESS: The cost of nuclear fuel that is being converted, fabricated, enriched, etc. not having reached a finished state.

OPERATING COSTS: Includes controllable and incremental costs.

ORIGINAL BUDGET: The beginning fiscal year budget for a Business Unit.

OUTSIDE SERVICES: Includes the cost of services provided by outside companies. Energy Northwest uses outside services for various functions including data systems, legal assistance, engineering support, craft support, paying agent and trustee fees, health physics and chemistry, maintenance services and radwaste disposal.

PRIOR YEAR'S RESERVE AND CONTINGENCY FUND SURPLUS: Annually, funds remaining are to be transferred back to the Revenue Fund to be utilized to reduce the funding requirements of the project for the subsequent fiscal year. Monies deposited in the Reserve and Contingency Fund can be expended only for special purposes.

PRIVILEGE TAXES: Pursuant to RCW 54.28.020, a tax is assessed on Packwood and Nine Canyon net generation equal to five percent of the first four mills per kilowatt-hour of revenue obtained from the sale of energy for resale. An additional surcharge is also assessed pursuant to RCW 82.02.030 equal to seven percent of the generation tax payable.

PROJECT PARTICIPANT: Municipalities, public utility districts, investor-owned utilities and electric cooperatives that have purchased a share of project output.

REFINANCING: An Energy Northwest and BPA program to refund higher coupon outstanding debt issued for Projects 1, 3 and Columbia with the goal of reducing total debt service of the projects over the life of the bonds.

RESERVE AND CONTINGENCY FUND REQUIREMENT: Funds equal to 10 to 15 percent of the aggregate required monthly transfers from the Revenue Fund to the Bond Fund Debt Service Accounts are to be transferred monthly from the Revenue Fund to the Reserve and Contingency Fund.

RISK RESERVE: A reserve in the budget set aside for unplanned events.

SPENT FUEL DISPOSAL FEE: The Nuclear Waste Policy Act of 1982 specifies that a waste disposal of one mill be paid to the United States Department of Energy (DOE) for each kilowatt-hour of electricity generated. In return, DOE will accept and dispose of spent nuclear fuel.

STRATEGIC PLANNING: A process undertaken by key managers and staff, approved by the Executive Board, to establish a vision of what Energy Northwest should be in five or more years.

Fiscal Year 2019
EN DRAFT Budget
Internal Route

RA Bates	1040	AN Artzer	Distributed
MA Black	PE30	SJ Mickelson	Distributed
A Corpus	Distributed	SF Mitchell	1035
JK Dittmer	Distributed	SM Praetorius	PE26
SA Vance	Distributed	ME Reddemann	1023
JW Gaston	1035	CM Reyff	Distributed
WG Hettell	PE23	BJ Ridge	Distributed
JE Hicks	Distributed	BJ Sawatzke	PE08
JM Irvan	1040	RE Schuetz	927M
A Javorik	PE23	JJ Smith	PE60
DR Jordan	Distributed	MK Thomas	Distributed
KR Kessler	PE60	JM Windham	1040
J McMann	1040		