BENTON P·U·D

COMPREHENSIVE ANNUAL FINANCIAL REPORT

2018 ANNUAL REPORT

Your trusted energy partner

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Benton PUD Linemen Joe Garner and Shawn Heibert

Public Utility District No. 1 of Benton County, Washington
for the fiscal years ended December 31, 2018 and 2017

Your trusted energy partner

COMPREHENSIVE ANNUAL FINANCIAL REPORT

Public Utility District No. 1 of Benton County, Washington
for the fiscal years ended December 31, 2018 and 2017

2018

Prepared by Financial & Business Services and Communications & Governmental Relations of Benton PUD

OUR PURPOSE

To improve the quality of life in our community through leadership, cooperation and stewardship.

OUR MISSION

We contribute high value to our community and customers by providing energy and related services using reliable and efficient delivery systems.

OUR VALUES

Safety
Excellence
Forward Focus
Integrity
Mutual Respect
Teamwork

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INTRODUCTORY SECTION

2018

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Government Finance Officers Association

Certificate of Achievement for Excellence in Financial Reporting

Presented to

Public Utility District No. 1

of Benton County, Washington

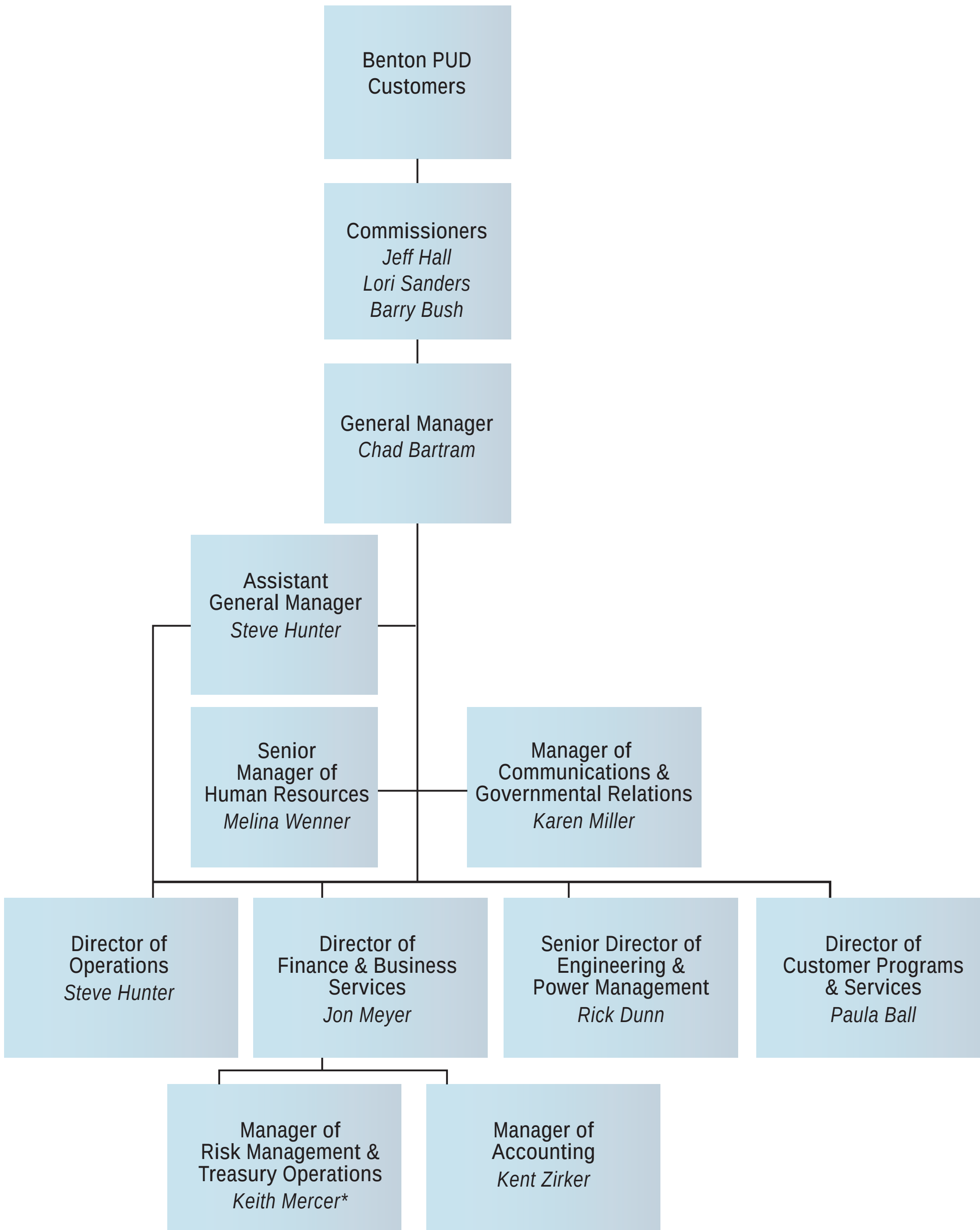
For its Comprehensive Annual
Financial Report
for the Fiscal Year Ended

December 31, 2017

Christopher P. Morrill

Executive Director/CEO

ORGANIZATION CHART



*replaced Kevin White July 23, 2018

COMMISSION MESSAGE

The Commissioners of Benton PUD salute Joe Garner and Shawn Heibert. The Benton PUD Lineman, featured on the cover, partnered with Benton REA to assist Sheriff Deputies and the Washington State Patrol (WSP) in rescuing stranded motorists during blizzard conditions. They received a WSP Commendation Award and Coin Challenge. We honor Joe and Shawn and are grateful for these heroes. While not every employee experiences such extreme working conditions, all play an important role in providing our customers safe and reliable service. We commend all Benton PUD employees for their dedication during challenging times.

Charging forward for our community: Our community continues to experience significant growth. With growth comes the challenge of providing reliable service. Over the past year we made significant investments in our electric system to ensure its reliability. We constructed a new transmission line, partnered with a neighboring utility to complete a new substation, and invested in upgrades to existing infrastructure to support future development.

Even with these capital-intensive projects, we maintained our low-cost rates. This was achieved by managing our operation and maintenance costs, making strategic investments in technology, and preserving our low debt ratio.

Benton PUD again received the sought after American Public Power Association RP3 Diamond level designation for our excellence in reliability, safety, workforce development, and system improvement.

Charging forward for our customers: Several years ago, Benton PUD launched a Customer Engagement Strategic Plan. Our objective is to provide technology that allows our customers to interact with us in new ways. In 2017, we introduced SmartHub®, an online customer portal. The success of this new platform far exceeded our expectation. Over half of our customers are now enrolled in Smarthub. These customers are now exploring all the benefits SmartHub has to offer.

In 2018, we launched two payment kiosks and an immediate restore of service initiative, made possible by leveraging the technology of our advanced meters. If a customer has a remote meter, we can now restore service immediately when the reconnect balance is paid through one of our many self-service payment options.

In 2019 we will begin offering our "pay as you go" service. Similar to buying minutes for a cell phone, or adding fuel to the gas tank in a car, a customer can prepay their electricity in smaller more frequent payments eliminating the need for a deposit.

Charging forward for our environment: Our commitment to the environment is reflected in our power purchases. Our fuel mix is 97% carbon free. We continue to support our clean hydro power and the regions well thought out fish and wildlife recovery efforts.

Since 1982, our energy efficiency programs have resulted in energy savings equivalent to that of powering 9,500 homes annually. As a result of generous state incentives, participants of our first community solar project saw a payback on their initial investment while at the same time we saw an increase in applications from those interested in rooftop solar.

We installed the first non-Tesla fast charging station in our community. This was made possible by a Washington State grant and our partnership with the Electric Vehicle Transportation Infrastructure Alliance (EVITA).

Jeff Hall, Commissioner — Barry Bush, Commissioner — Lori Sanders, Commissioner

LETTER OF TRANSMITTAL

May 1, 2019
To the Board of Commissioners and Customers
Public Utility District No. 1 of Benton County, Washington

The Comprehensive Annual Financial Report (CAFR) of the Public Utility District (District) No. 1 of Benton County, Washington for the year ended December 31, 2018 is hereby submitted. The report is designed to assess the District's financial position, educate readers about District services, examine current challenges facing the District, and fulfill legal reporting requirements.

State law requires that every local government submit financial reports to the State Auditor within 150 days after the close of each fiscal year. The District's bond covenants require financial information be provided to each nationally recognized municipal securities information repository in accordance with Section (b)(5) of Securities and Exchange Commission Rule 15c2-12 under the Securities and Exchange Act of 1934. This report is published to fulfill both requirements for the fiscal year ended December 31, 2018.

Management assumes full responsibility for the completeness and reliability of the information contained in this report, based upon a comprehensive framework of internal control that is established for this purpose. Because the cost of internal control should not exceed anticipated benefits, the objective is to provide reasonable, rather than absolute, assurance that the financial statements are free of any material misstatements.

The certified public accounting firm of Moss Adams has issued an unmodified ("clean") opinion on the District's financial statements for the years ended December 31, 2018 and 2017. The independent auditor's report is located at the front of the financial section of this report.

Management's discussion and analysis (MD&A) immediately follows the independent auditor's report and provides a narrative introduction, overview, and analysis of the basic financial statements. MD&A complements this transmittal letter and should be read in conjunction with it.

Profile of the District

The District is a municipal corporation of the State of Washington established in 1934 for the purpose of engaging in the purchase, generation, transmission, distribution and sale of electric energy. Additionally, the District is authorized under state law to provide wholesale telecommunication services. The District is governed by an elected three-member board and maintains its administrative offices in Kennewick, WA.

The District is a statutory preference customer of the Bonneville Power Administration (BPA) and purchases most of its power from BPA. The District's remaining power supply requirements are supplied by various contract purchases (see Note 8). The District's contracted power supply is projected to be surplus for most months of the year. The District purchases and sells power within the wholesale markets to balance resources to load.

The District's properties include 38 substations, approximately 98 miles of 115 kV transmission lines, 1,699 miles of distribution lines, and other buildings, equipment, stores and related facilities.
The District is located in southeastern Washington, encompassing approximately 939 square miles of Benton County and includes the incorporated cities of Kennewick, Benton City, and Prosser (the Benton County seat). The District's largest city, Kennewick, as well as the City of Richland in Benton County (outside the District service territory), and the City of Pasco in adjacent Franklin County, make up what is known as the Tri-Cities.

LETTER OF TRANSMITTAL

The District records financial transactions within a single proprietary fund. The District has no governmental funds with legally adopted budgets that carry the force of law. Accordingly, the District's budget is not contained within this report.

The District adopts an annual budget for purposes of planning and management control. The budget process involves preparation of a proposed operating and capital budget by District staff for the ensuing year that is presented to the Board of Commissioners. During workshop sessions that are open to the public, the staff and Board review and revise the proposed budget. A public hearing is conducted to obtain ratepayer comments. The budget is approved by the Board and becomes the basis for operations for the next calendar year.

Local Economy

Benton County's economy is based on the following major industries: Government, healthcare, administrative and waste services, agriculture, manufacturing, and retail trade. These industries comprise 62.5% of employment; other notable industries include professional and technical services, and hospitality and food services.

Government employment, which includes both public education and healthcare, is the largest employing industry in the County at 15.1%. State and local government employers provide a variety of services including, education, public safety, health and social services, and utilities. Large employers in this segment include Kennewick and Richland school districts, and Energy Northwest.
The Hanford Reservation, encompassing 560 square miles within Benton County, has evolved into one of the largest nuclear industrial centers in the United States. Today the focus is on energy research, environmental cleanup, and related technology. The major employers in Benton County are Battelle, PNNL, Bechtel National, and the Department of Energy and its contractors associated with the Hanford Project.

Farmland comprises the majority of Benton County's land area. Many corporate farms are located in the District encompassing over 100,000 acres of irrigated and dry land crops. Irrigation has led to increased production of a wide variety of crops including potatoes, apples, sweet corn, onions, grapes, cherries, wheat, hay, and hard and soft fruits. These crops are shipped to both domestic and export markets.

Manufacturing activities within the county include a large fertilizer and agricultural products plant which distributes its products throughout the Northwest and California. The Tri-Cities is home to the world's largest crane manufacturer, as well as a manufacturer of zirconium and titanium alloy tubing used for the aerospace industry (hydraulic landing gear), the medical industry (human bone surgery), golf clubs, bicycles, ski poles, and tennis racquets. Other industries in the region include paper, cardboard container plants, and production of nuclear fuel pellets and rods.

The local economy continues to be strong and steady. Tri-Cities nonfarm employment was up 2.6 percent in December 2018 as compared to December 2017. The Tri-Cities gained approximately 2,900 jobs during the year primarily as a result of expanding construction, educational and health services, and leisure and hospitality. In addition, private service industries such as food services and professional and business services continued to be strong. The Tri-Cities is a regional shopping destination for communities throughout southeastern Washington and northeastern Oregon leading to continued growth in the retail service industry.

LETTER OF TRANSMITTAL

Long-Term Financial Planning

The District's Leadership Team meets at least quarterly to review an updated five-year financial forecast. The forecast includes both operating (including power supply costs) and capital activity with a focus on reserve levels, debt service coverage levels, and potential rate action. The forecast is then reviewed with the Board of Commissioners on a quarterly basis.

The District has adopted a comprehensive set of financial policies for purposes of managing the District's finances. The policies cover such issues as liquidity, debt service coverage, debt financing, retail rates, enterprise risk management, power supply risk, credit risk, investment policies and practices, insurance, integrated planning, budgetary and procurement controls, and financial reporting.

The financial policies call for the development of financial plans to achieve a minimum debt service coverage ratio of 2.0 times annual debt service including capital contributions and 1.75 times annual debt service excluding capital contributions and provide for maintaining a debt ratio at 38% or less. The financial policies related to reserve levels call for minimum operating reserves to be no less than 90 days cash on hand. In addition, the policies establish financial plans to maintain total unrestricted reserves that are expected to achieve or maintain the targeted bond rating that is the median for public power utilities. The Commission periodically reviews these policies.

Relevant Financial Policies

As a result of rising wholesale net power costs during the period and future years, the District increased retail rates an average of 1.9% effective October 1, 2017. The District will continue to evaluate the need for future retail rate increases in order to meet targets established in financial policies

Major Initiatives

The District completed installation and testing of two self-serve kiosks for customers to make payments. One is located at each of the District offices in Kennewick and Prosser. District staff continues to work on the implementation of a prepay option to provide another option to customers. This is expected to be operational mid-year 2019.

The District, in conjunction with the City of Richland, finished constructing a new substation along Leslie Road in early 2019. This substation is being utilized by both utilities to improve system reliability for an area with substantial growth in recent years with more growth expected to come.

The District also has substantial transmission, substation, and distribution projects planned over the next several years to continue to ensure reliable electric service while accommodating growth. This includes nearly $5.4 million in the 2019 budget for substation projects that include construction of a new substation, adding additional capacity to another, and replacing two transformers at other substations. In addition, replacing equipment that has reached the end of its useful life, and installing or upgrading equipment with more advanced, reliable, and safe technology. Additional 115 kilovolt transmission lines are planned for the southern part of the county to improve reliability for agricultural customers. In addition, a new line is being constructed to improve reliability for rapidly expanding residential areas.

The District is proactively planning projects to meet the needs of expanding growth in its service territory which include expanding substations and increasing distribution reliability to these areas.

LETTER OF TRANSMITTAL

Awards and Acknowledgments

The Government Finance Officers Association of the United States and Canada (GFOA) awarded a Certificate of Achievement for Excellence in Financial Reporting to the District for its comprehensive annual financial report for the fiscal year ended December 31, 2017. This was the sixteenth consecutive year the District has achieved this prestigious award. In order to be awarded a Certificate of Achievement, a government must publish an easily readable and efficiently organized comprehensive annual financial report. This report must satisfy both generally accepted accounting principles and applicable legal requirements.

A Certificate of Achievement is valid for a period of one year only. We believe that our current comprehensive annual financial report continues to meet the Certificate of Achievement Program's requirements and we are submitting it to the GFOA to determine its eligibility for another certificate. Preparation of the Comprehensive Annual Financial Report was made possible by the dedicated service of the entire staff of the Finance and Business Services and the Communications and Governmental Relations departments. We wish to express our appreciation to these staff members for their contributions to the development of this report. Further appreciation is extended to the Board of Commissioners for their leadership and support in planning and conducting the financial operations of the District in a responsible and enterprising manner.

Respectfully submitted,

Chad B. Bartram	*Jon L. Meyer*
Chad B. Bartram	Jon L. Meyer
General Manager	Director of Finance and Business Services

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FINANCIAL SECTION

2018

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INDEPENDENT AUDITOR'S REPORT

MOSS ADAMS

The Commissioners
Public Utility District No. 1
of Benton County, Washington

Report on the Financial Statements

We have audited the accompanying financial statements of Public Utility District No. 1 of Benton County, Washington (the "District"), which comprise the statements of net position as of December 31, 2018 and 2017, and the related statements of revenues, expenses, and changes in net position and cash flows for the years then ended, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

MOSS ADAMS

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the District as of December 31, 2018 and 2017, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Other Matter
Required Supplementary Information

Accounting principles generally accepted in the United States of America require that the accompanying management's discussion and analysis preceding the financial statements and the schedules of proportionate share of net pension liability and schedules of employer contributions subsequent to the notes to the financial statements be presented to supplement the financial statements. Such information, although not a part of the financial statements, is required by the Governmental Accounting Standards Board, who considers it to be an essential part of financial reporting for placing the financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the financial statements, and other knowledge we obtained during our audit of the financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

Other Information

Our audit was conducted for the purpose of forming an opinion on the financial statements that collectively comprise the District's financial statements. The statistical section is presented for purposes of additional analysis and is not a required part of the financial statements.
The statistical section has not been subjected to the auditing procedures applied in the audit of the financial statements, and accordingly, we do not express an opinion or provide any assurance on it

Moss Adams LLP

Portland, Oregon
March 29, 2019.

MANAGEMENT'S DISCUSSION & ANALYSIS

This section provides an overview and analysis of key data presented in the basic financial statements for the years ended December 31, 2018 and 2017, with additional comparative data for 2016. Information within this section should be used in conjunction with the basic financial statements and accompanying notes.

Overview of the Financial Statements

Public Utility District No. 1 of Benton County (District) accounts for its financial activities within a single proprietary fund titled the Electric System. The Electric System is used to account for the purchase, generation, transmission, distribution, and sale of electric energy, as well as the sale of wholesale telecommunication services.

In accordance with requirements set forth by the Governmental Accounting Standards Board (GASB), the District's financial statements employ the accrual basis of accounting in recognizing increases and decreases in economic resources. Accrual accounting recognizes all revenues and expenses incurred during the year, regardless of when cash is received or paid.

The basic financial statements, presented on a comparative format for the years ended December 31, 2018 and 2017, consist of:

Statement of Net Position: The District presents its Statement of Net Position using the balance sheet format. The Statement of Net Position reflects the assets, liabilities, deferred outflows and inflows of resources, and net position (equity) of the District at year-end. The net position section is separated into three categories: net investment in capital assets, net position - restricted, and net position - unrestricted.

Statement of Revenues, Expenses, and Changes in Net Position: This statement reflects the transactions and events that have increased or decreased the District's total economic resources during the period. Revenues are presented net of allowances and are summarized by major source. Revenues and expenses are classified as operating or nonoperating based on the nature of the transaction.

Statement of Cash Flows: The Statement of Cash Flows reflects the sources and uses of cash separated into four categories of activities: operating, noncapital financing, capital and related financing, and investing.

The notes to the financial statements, presented at the end of the basic financial statements, are considered an integral part of the District's presentation of financial position, results of operations, and changes in cash flows.

Condensed Comparative Financial Information

Provided below is a 3-year comparison of key financial information:

Statement of Net Position *(in thousands)*

	2018	2017	Increase (Decrease) 2018-2017	% Change 2018-2017	2016
Assets and Deferred Outflows of Resources					
Current & Noncurrent Assets	$94,030	$92,286	$1,744	2%	$92,043
Utility Plant	132,198	125,666	6,532	5%	123,470
Subtotal Assets	226,228	217,952	8,276	4%	215,513
Deferred Outflows of Resources	5,951	2,552	3,399	133%	3,937
Total Assets and Deferred Outflows of Resources	232,179	220,504	11,675	5%	219,450
Liabilities and Deferred Inflows of Resources					
Current Liabilities	22,815	20,875	1,940	9%	20,515
Noncurrent Liabilities	69,964	72,448	(2,484)	-3%	80,576
Subtotal Liabilities	92,779	93,323	(544)	-1%	101,091
Deferred Inflows of Resources	5,500	3,026	2,474	82%	2,323
Total Liabilities and Deferred Inflows of Resources	98,279	96,349	1,930	2%	103,414
Net Position					
Net Investment in Capital Assets	74,962	64,407	10,555	16%	58,672
Restricted for Debt Service	1,108	1,108	-	0%	1,108
Unrestricted	57,830	58,640	(810)	-1%	56,256
Total Net Position	$133,900	$124,155	$9,745	8%	$116,036

Statement of Revenues, Expenses, and Changes in Net Position *(in thousands)*

	2018	2017	Increase (Decrease) 2018-2017	% Change 2018-2017	2016
Operating Revenues					
Retail Energy Sales	$129,792	$130,811	($1,019)	-1%	$120,439
Secondary Market Sales	26,070	15,828	10,242	65%	15,723
Other	4,007	3,504	503	14%	3,700
Nonoperating Revenues					
Interest Income	1,144	605	539	89%	326
Other Income	447	562	(115)	-20%	321
Unrealized Gain/(Loss) on Investments	51	(33)	84	-255%	(4)
Total Revenues	161,511	151,277	10,234	7%	140,505
Operating Expenses					
Power Supply	106,171	96,775	9,396	10%	94,193
Operations, Maintenance and A&G	21,674	21,760	(86)	0%	19,966
Taxes/Depreciation/Amortization	23,667	24,197	(530)	-2%	25,261
Nonoperating Expenses					
Interest Expense	2,832	2,910	(78)	-3%	2,665
Debt Premium Amortization & (Gain) on Defeased Debt	(454)	(493)	39	-8%	(144)
Total Expenses	153,890	145,149	8,741	6%	141,941
Income/(Loss) before Contributions	7,621	6,128	1,493	24%	(1,436)
Capital Contributions	2,124	1,991	133	7%	1,165
Change in Net Position	9,745	8,119	1,626	20%	(271)
Beginning Net Position	$124,155	$116,036	$8,119	7%	$116,307
Ending Net Position	$133,900	$124,155	$9,745	8%	$116,036

Financial Analysis

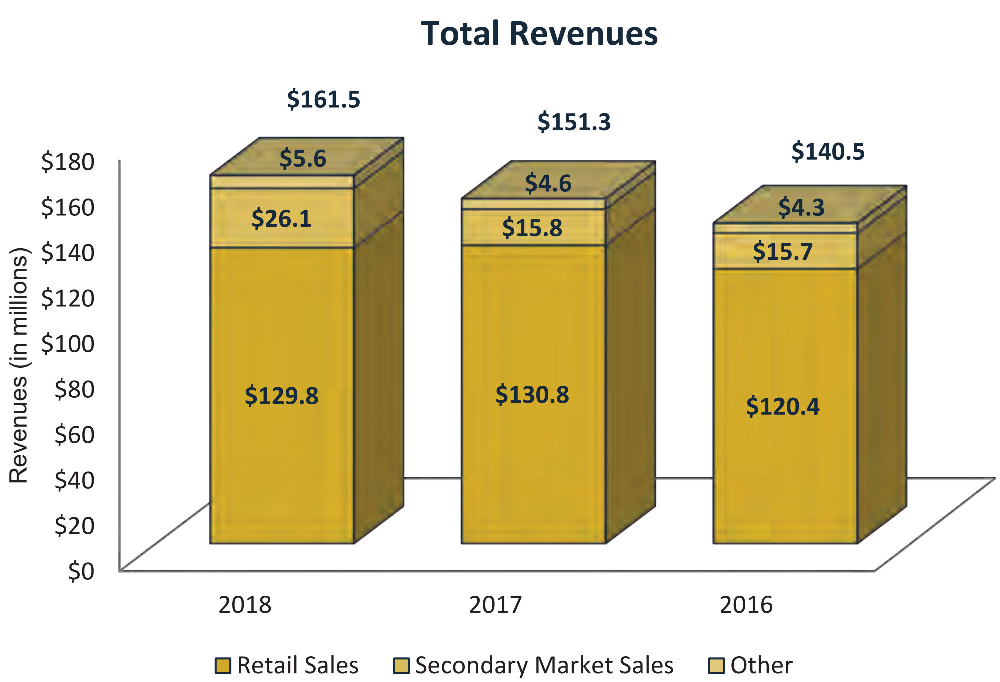
During 2018, the District's overall financial position and results of operations improved over last year. The District's net position increased by $9.7 million compared to an increase of $8.1 million in 2017. Provided below is a year-over-year analysis of the change in net position by major component of income, with a primary focus on changes between 2018 and 2017.

Operating Revenues
2017 to 2018:
Revenues from sales to retail customers (retail energy sales) in 2018 decreased $1.0 million (1%) from 2017. Warmer winter months contributed to a decrease in kilowatt hours (kWh) sold to customers of 2.5%, the effects of which were partially offset by an increase in retail rates of 1.9% effective October 1, 2017. Active service agreements increased by 1.3%.

Revenues from secondary market energy and natural gas sales increased by $10.2 million (64.7%), primarily as a result of financial hedges and an increase in secondary market prices of about 29%.

2016 to 2017:
Revenues from sales to retail customers (retail energy sales) in 2017 increased $10.4 million (9%) from 2016. Colder than average winter and warmer than average summer weather contributed to an increase in kilowatt hours (kWh) sold to customers of 5.4%. In addition, active service agreements increased by 1.2% and the District had rate increases of 1.9% effective October 1, 2017 and 4.9% effective September 1, 2016.

Revenues from secondary market energy and natural gas sales increased by $105,000 (0.7%), primarily as a result of increased sales despite a decrease in wholesale prices of about 7%.



Operating Expenses
2017 to 2018:
Power supply expense increased by $9.4 million (9.7%), primarily as a result of financial hedges, higher market prices, and increased purchase transactions by The Energy Authority (TEA) to manage daily loads. In addition, net power expense (power supply expense less secondary market sales) decreased by $846,000 (1.0%), primarily attributable to effective use of financial hedges. The District uses net power expense as a means to measure overall financial performance related to power supply management.

Total operations, maintenance and administrative and general (A&G) expenses decreased by $86,000 (0.4%). The decrease was primarily due to a reduction in pension expense which offset other increases. The District charges internal labor to operations, maintenance, A&G activities, and capital projects. In 2018, the internal labor required for operations and maintenance activities increased $127,000 from 2017 and internal labor performed on capital projects increased $21,000.

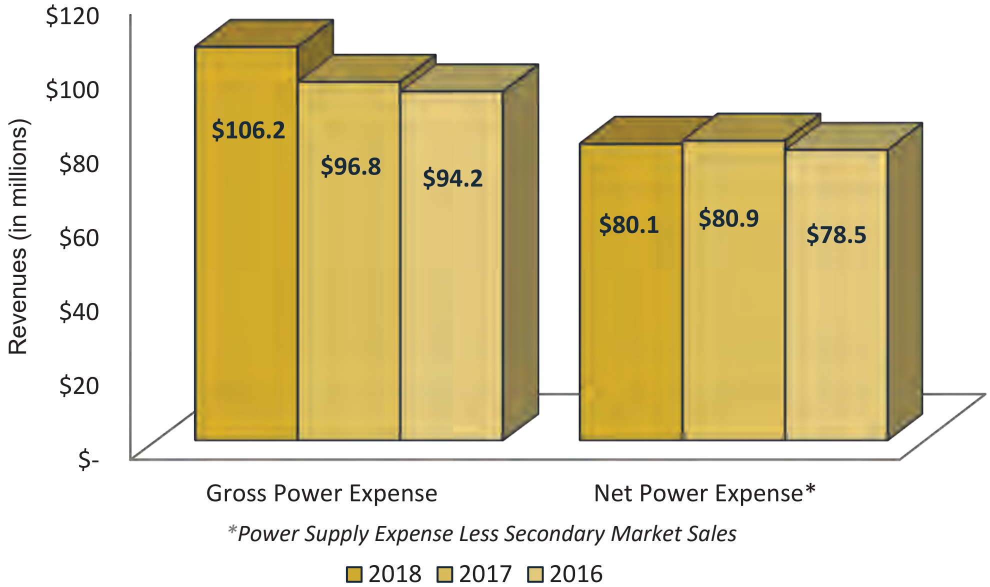
Taxes assessed by state and municipal governments decreased by $206,000 (1.5%), primarily as a result of lower retail sales. Depreciation and amortization decreased $323,000 (3.2%) as a result of assets becoming fully depreciated and updating useful lives to better match the service life of certain assets.

2016 to 2017:
Power supply expense increased by $2.6 million (2.7%), primarily as a result of weather and increased purchase transactions by The Energy Authority (TEA) to manage daily loads. In addition, net power expense (power supply expense less secondary market sales) increased by $2.5 million (3.2%), primarily attributable to increased retail energy sales and a rate increase from BPA that became effective October of 2017. The District uses net power expense as a means to measure overall financial performance related to power supply management.

Total operations, maintenance and administrative and general (A&G) expenses increased by $1.8 million (9.0%). The increase was primarily due to 2016 had included $700,000 in temporary budget reductions, and 2017 labor and benefits charged to operations and maintenance expense from resources previously dedicated to capital projects The District charges internal labor to operations, maintenance, A&G activities, and capital projects. In 2017, the internal labor required for operations and maintenance activities increased $1.1 million from 2016 while internal labor performed on capital projects decreased $777,000.

Taxes assessed by state and municipal governments increased by $1.4 million (11%), primarily as a result of higher retail sales. Depreciation and amortization decreased $2.5 million as a result of assets becoming fully depreciated and updating useful lives to better match the service life of certain assets.

Gross and Net Power Expenses



**Power Supply Expense Less Secondary Market Sales*

Other Income & Expense

During 2018, interest income increased by $539,000 (89%) due to higher interest rates on investments with the Washington State Treasurer's Local Government Investment Pool (LGIP). The average investment rate of the LGIP increased from 0.97% in 2017 to 1.90% in 2018. At year-end, the District's investments had an unrealized gain of $51,000.

During 2017, interest income increased by $279,000 (86%) due to higher interest rates on longer term investments as compared to previous investment purchases. In addition, the average investment rate of the LGIP increased from 0.47% in 2016 to 0.97% in 2017. At year-end, the District's investments had an unrealized loss of $33,000.

There were no significant restrictions, commitments, or other limitations that would affect the availability of resources for future use in 2018, 2017, and 2016.

Capital Contributions

During 2018, capital contributions increased by $133,000 (6.7%), primarily due to increased customer requested line extensions.

During 2017, capital contributions increased by $826,000 (71%), primarily due to a few larger distribution projects.

Summary of Financial Position

The overall financial position of the District increased $9.7 million. Other financial areas of the District remained stable as the District maintained solid cash and investment reserves and achieved a debt service coverage ratio well above policy limits. With rising power costs over the past several years, the District had an average rate increase of 1.9% effective October 1, 2017. Prior to that, it was an average rate increase of 4.9% effective September 1, 2016.

District financial policies require that financial plans be developed to maintain minimum end-of-year cash and investment balances contained within unrestricted accounts sufficient to provide funding for a specified amount of operating expenses, power supply expenses, catastrophic loss, debt service, and capital improvements. The District's unrestricted cash and investment balances totaled $57.3 million, $56.8 million, and $54.2 million at December 31, 2018, 2017, and 2016, respectively. Actual balances exceeded the minimum required level per District financial policies for each year.

In accordance with District financial policies and covenants established within the District's bond resolutions, the District is required to maintain and collect rates and charges sufficient to provide net revenues (defined as net position less depreciation, amortization, and interest expense) in each fiscal year in an amount at least equal to 1.25 times the annual debt service. For the years ended 2018, 2017, and 2016, the District was in compliance with such policies and covenants.

Capital Asset and Long-Term Debt Activity

During 2018, gross capital additions totaled $16.6 million. Capital contributions associated with these additions totaled $2.1 million. Major capital additions included completion of additions and improvements to existing distribution infrastructure and substations, additions to broadband infrastructure, and a 1.3% growth in customers served by the District, as well as internal capital expenditures to meet District needs. Construction work-in-progress totaled $6.9 million at year-end, a net increase of $2.3 million from 2017.

During 2017, gross capital additions totaled $13.2 million. Capital contributions associated with these additions totaled $2.0 million. Major capital additions included completion of additions and improvements to existing distribution infrastructure and substations, installation of electric facilities along new major road expansions, and a 1.2% growth in customers served by the District, as well as internal capital expenditures to meet District needs. Construction work-in-progress totaled $4.6 million at year-end, a net decrease of $1.1 million from 2016.

In September 2016, the District issued $22,470,000 of Electric Revenue and Refunding Bonds, Series 2016. The bond proceeds were used to fund $15.1 million of improvements and replacements of the District's electric utility system and to refund the 2011 bonds maturing on or after November 1, 2023. (See Note 5)

The 2016 Bonds, as well as the District's credit ratings, were affirmed by three rating agencies: Standard & Poor's at A+, Fitch Ratings at A+, and Moody's at Aa3. Fitch Ratings re-affirmed the District's A+ rating in 2018.

Debt service payments totaled $6.5 million in 2018, $6.2 million in 2017, and $5.4 million in 2016.

Further information about the District's capital assets and long-term debt is presented in Notes 2 and 5.

STATEMENT OF NET POSITION

As of December 31, 2018 and 2017

ASSETS AND DEFERRED OUTFLOWS OF RESOURCES	2018	2017
ASSETS		
CURRENT ASSETS		
Unrestricted Cash & Cash Equivalents	$46,652,499	$44,190,936
Investments (Note 3)	10,668,115	12,616,525
Accounts Receivable, Net	9,355,672	8,579,629
BPA Prepay Receivable (Note 8)	600,000	600,000
Accrued Interest Receivable	181,517	59,654
Wholesale Power Receivable	1,699,439	1,407,401
Accrued Unbilled Revenues	4,500,000	4,800,000
Inventory - Materials & Supplies	5,674,743	5,544,372
Prepaid Expenses & Option Premiums	353,585	491,064
Total Current Assets	**79,685,570**	**78,289,581**
NONCURRENT ASSETS		
Restricted Bond Reserve Fund	1,107,865	1,107,865
BPA Prepay Receivable (Note 8)	5,250,000	5,850,000
Other Receivables (Note 1)	163,010	96,778
Other Charges (Note 4)	7,822,857	6,941,230
Subtotal Noncurrent Assets	14,343,732	13,995,873
Utility Plant (Note 2)		
Land and Intangible Plant	3,531,698	3,493,641
Electric Plant in Service	318,902,899	305,931,426
Construction Work in Progress	6,911,759	4,599,287
Less: Accumulated Depreciation	(197,148,521)	(188,357,607)
Net Utility Plant	132,197,835	125,666,747
Total Noncurrent Assets	**146,541,567**	**139,662,620**
TOTAL ASSETS	**226,227,137**	**217,952,201**
DEFERRED OUTFLOWS OF RESOURCES		
Pension Deferred Outflow (Note 6)	1,180,507	1,429,022
Accumulated Decrease in Fair Value of Hedging Derivatives	4,770,996	1,122,842
Total Deferred Outflows of Resources	**5,951,503**	**2,551,864**
TOTAL ASSETS AND DEFERRED OUTFLOWS OF RESOURCES	**$232,178,640**	**$220,504,065**

LIABILITIES, DEFERRED INFLOWS OF RESOURCES, AND NET POSITION		
LIABILITIES		
CURRENT LIABILITIES		
Accounts Payable	$11,460,839	$9,922,995
Customer Deposits	2,035,979	1,667,840
Accrued Taxes Payable	3,666,006	3,652,731
Other Accrued Liabilities	1,440,221	1,569,509
Accrued Interest Payable	461,914	491,664
Revenue Bonds, Current Portion (Note 5)	3,750,000	3,570,000
Total Current Liabilities	**22,814,959**	**20,874,739**
NONCURRENT LIABILITIES		
Revenue Bonds (Note 5)	53,454,777	57,671,311
Pension Liability (Note 6)	6,852,561	9,884,887
BPA Prepay Incentive Credit	1,572,277	1,733,533
Other Credits & Liabilities (Note 4)	8,083,917	3,158,625
Total Noncurrent Liabilities	**69,963,532**	**72,448,356**
TOTAL LIABILITIES	**92,778,491**	**93,323,095**
DEFERRED INFLOWS OF RESOURCES		
Unamortized Gain on Defeased Debt	31,212	18,389
Pension Deferred Inflow (Note 6)	2,930,225	1,866,603
Accumulated Increase in Fair Value of Hedging Derivatives	2,539,134	1,140,955
Total Deferred Inflows of Resources	**5,500,571**	**3,025,947**
NET POSITION		
Net Investment in Capital Assets	74,961,846	64,407,047
Restricted for Debt Service	1,107,865	1,107,865
Unrestricted	57,829,867	58,640,111
Total Net Position	**133,899,578**	**124,155,023**
TOTAL LIABILITIES, DEFERRED INFLOWS OF RESOURCES, AND NET POSITION	**$232,178,640**	**$220,504,065**

The accompanying notes are an integral part of the financial statements.

STATEMENT OF REVENUES, EXPENSES AND CHANGES IN NET POSITION

For the years ended December 31, 2018 and 2017

	2018	2017
OPERATING REVENUES		
Retail Energy Sales	$129,792,002	$130,811,427
Secondary Market Sales	24,618,712	14,542,756
Transmission of Power for Others	1,450,552	1,284,536
Broadband Revenue	2,250,450	2,164,500
Other Revenue	1,756,987	1,338,933
Total Operating Revenues	**159,868,703**	**150,142,152**
OPERATING EXPENSES		
Power Supply (Includes Prepaid Power Amortization, See Note 8)	106,171,090	96,774,565
Transmission Operation & Maintenance	163,952	199,419
Distribution Operation & Maintenance	9,645,034	9,799,347
Broadband Expense	936,989	844,688
Customer Accounting, Collection & Information	4,267,684	3,735,098
Administrative & General Expense	6,660,053	7,181,596
Taxes	13,812,993	14,018,894
Depreciation	9,854,391	10,177,574
Total Operating Expenses	**151,512,186**	**142,731,181**
OPERATING INCOME	**8,356,517**	**7,410,971**
NONOPERATING REVENUES & EXPENSES		
Interest Income	1,144,102	605,664
Other Income	446,903	562,073
Interest Expense, net of amounts capitalized	(2,832,268)	(2,910,007)
Debt Premium Amortization & Gain on Defeased Debt	453,711	492,959
Unrealized Gain/(Loss) on Investments	51,590	(33,130)
Total Nonoperating Revenues & Expenses	**(735,962)**	**(1,282,441)**
INCOME BEFORE CAPITAL CONTRIBUTIONS	**7,620,555**	**6,128,530**
CAPITAL CONTRIBUTIONS	2,124,000	1,990,641
CHANGE IN NET POSITION	**9,744,555**	**8,119,171**
TOTAL NET POSITION, BEGINNING OF YEAR	**124,155,023**	**116,035,852**
TOTAL NET POSITION, END OF YEAR	**$133,899,578**	**$124,155,023**

The accompanying notes are an integral part of the financial statements.

STATEMENT OF CASH FLOWS

For the years ended December 31, 2018 and 2017

	2018	2017
CASH FLOWS FROM OPERATING ACTIVITIES		
Cash Received from Customers and Counterparties	$159,455,334	$150,946,386
Cash Paid to Suppliers and Counterparties	(111,194,170)	(104,413,811)
Cash Paid to Employees for Services	(14,330,905)	(14,331,940)
Taxes Paid	(13,799,716)	(13,748,825)
Net Cash Provided by Operating Activities	**20,130,543**	**18,451,810**
CASH FLOWS FROM NONCAPITAL FINANCING ACTIVITIES		
Other Interest Expense	(77,891)	(40,556)
Net Cash Used by Noncapital Financing Activities	**(77,891)**	**(40,556)**
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES		
Acquisition of Capital Assets	(16,613,340)	(12,572,630)
Reimbursement of Bond Expense	-	10,205
Bond Principal Paid	(3,570,000)	(3,045,000)
Bond Interest Paid	(2,598,737)	(2,831,526)
Capital Contributions	2,124,000	1,990,641
Proceeds from Sale of Assets	44,749	76,766
Net Cash Used by Capital and Related Financing Activities	**(20,613,328)**	**(16,371,544)**
CASH FLOWS FROM INVESTING ACTIVITIES		
Interest Income	1,022,239	578,112
Proceeds from Sale of Investments	2,000,000	8,008,658
Purchase of Investments	-	(8,742,193)
Net Cash Provided (Used) by Investing Activities	**3,022,239**	**(155,423)**
NET INCREASE (DECREASE) IN CASH	**2,461,563**	**1,884,287**
CASH & CASH EQUIVALENTS BALANCE, BEGINNING OF YEAR	**$45,298,801**	**43,414,514**
CASH & CASH EQUIVALENTS BALANCE, END OF YEAR	**$47,760,364**	**$45,298,801**
RECONCILIATION OF OPERATING INCOME TO NET CASH PROVIDED (USED) BY OPERATING ACTIVITIES		
Operating Income	$8,356,517	$7,410,971
Adjustments to reconcile net operating income to net cash provided by operating activities:		
Depreciation	9,854,391	10,177,574
BPA Prepaid & Power Contracts Amortization	1,178,400	1,178,400
(Increase) Decrease in Unbilled Revenues	300,000	600,000
Misellaneous Other Revenue & Receipts	91,516	216,086
Pension Expense/(Credit)	(1,371,215)	(593,733)
Decrease (Increase) in Accounts Receivable	(771,908)	194,030
Decrease (Increase) in Inventories	(130,371)	116,293
Decrease (Increase) in Wholesale Power Receivable	(292,038)	(536,965)
Decrease (Increase) in Miscellaneous Assets	(128,081)	(13,884)
Decrease (Increase) in Prepaid Expense & Option Premiums	137,478	(56,391)
Increase (Decrease) in Accounts Payable	1,537,844	(388,195)
Increase (Decrease) in Accrued Taxes Payable	13,277	270,069
Increase (Decrease) in Customer Deposits	368,139	190,383
Increase (Decrease) in BPA Prepay Incentive Credit	(161,256)	(161,256)
Increase (Decrease) in Other Current Liabilities	1,493,150	(474,658)
Increase (Decrease) in Other Credits	(345,300)	323,086
Net Cash Provided by Operating Activities	**$20,130,543**	**$18,451,810**

NONCASH OPERATING, INVESTING, CAPITAL, AND FINANCING ACTIVITIES

The District's investments had an unrealized gain of $51,590 at December 31, 2018 and an unrealized loss of $33,130 at December 31, 2017.

Bond Interest Paid does not include subsidy payments on Series 2010 Revenue Build America Bonds made directly by the US Treasury to the Fiscal Paying Agent of $355,387 in 2018 and $345,985 in 2017 (see Note 5).

The net effect of accumulated increases and decreases in the fair value of hedging derivates had no effect on cash flows for 2018 and 2017. For accumulated decreases in fair value, $4,770,996 and $1,122,842 in 2018 and 2017 respectively, the District records an offsetting liability. For accumulated increases in fair value, $2,539,134 and $1,140,955 in 2018 and 2017 respectively, the District records an offsetting asset.

The deferred inflows and outflows relating to GASB 68 had no effect on cash flows for 2018 and 2017. The pension deferred outflow was $1,180,507, and $1,429,022 as of December 31, 2018 and 2017 respectively. The pension deferred inflow was $2,930,225, and $1,866,603 as of December 31, 2018 and 2017, respectively.

The accompanying notes are an integral part of the financial statements.

NOTES TO FINANCIAL STATEMENTS

Note 1 - Summary of Operations and Significant Accounting Policies

Public Utility District No. 1 of Benton County, Washington (the District) is a municipal corporation of the State of Washington established in 1934 for the purpose of engaging in the purchase, generation, transmission, distribution, and sale of electric energy. Additionally, the District is authorized under state law to provide wholesale telecommunication services.

The District serves Benton County exclusive of most of the City of Richland, the U.S. Department of Energy's operations on the Hanford Reservation, the City of West Richland and those rural areas of the County that are served by the Benton Rural Electric Association. Cities in the District's service area include Kennewick, population 81,850, Prosser, population 6,125, and Benton City, population 3,405. The District maintains its administrative offices in the City of Kennewick. The District is governed by an elected three-member board.

The District's service area comprises approximately 939 square miles of Benton County. The District's properties include 38 substations, approximately 98 miles of 115kV transmission lines, 1,699 miles of distribution lines, and other buildings, equipment, stores, and related facilities.

As required by generally accepted accounting principles (GAAP), management has considered all potential component units in defining the reporting entity and has no component units. The following is a summary of the more significant policies:

a) Basis of Accounting and Presentation: The accounting policies of the District conform to GAAP applicable to governmental units. The Governmental Accounting Standards Board (GASB) is the accepted standard-setting body for establishing governmental accounting and financial reporting principles. In 2017, the District implemented GASB statement No. 82 Pension Issues – an amendment of GASB Statements No. 67, No. 68, and No. 73. In 2018, the District implemented GASB statement No. 86 Certain Debt Extinguishment Issues.

Accounting records are maintained in accordance with methods prescribed by the Washington State Auditor's Office under the authority of Revised Code of Washington (RCW) 43.09 and the Uniform System of Accounts prescribed for public utilities and licensees by the Federal Energy Regulatory Commission (FERC). The financial statements are reported using the economic resources measurement focus and the accrual basis of accounting where revenues are recognized when incurred, regardless of the timing of the related cash flows. Revenues and expenses related to the District's principal operations are considered to be operating revenues and expenses; while revenues and expenses related to capital, financing, and investing activities are considered to be nonoperating revenues and expenses.

b) Utility Plant and Depreciation: Utility plant is recorded at original cost, which includes both direct costs of construction or acquisition and indirect costs. The District's capitalization threshold is $5,000 for noninfrastructure capital. All costs related to infrastructure are capitalized. The cost of maintenance and repairs is charged to expense as incurred, while the cost of replacements and improvements is capitalized.

Property, plant, and equipment are depreciated using the straight-line method over these estimated useful lives:

Buildings and Improvements	33 - 40	years
Generation Plant	20	years
Electric Plant - Transmission	25 – 33	years
Electric Plant - Distribution	10 – 33	years
Electric Plant/Equipment - Broadband	5 – 20	years
Transportation Equipment	16	years
General Plant & Equipment	4 – 14	years

Initial depreciation on utility plant is recorded in the month subsequent to purchase or completion of construction. Composite rates are used for asset groups and, accordingly, no gain or loss is recorded on the disposition of an asset unless it represents a major retirement. The composite depreciation rate was approximately 3.1% in 2018 and 3.4% in 2017. When operating plant assets are retired, their original cost together with removal costs, less salvage, is charged to accumulated depreciation.

Preliminary survey and investigation costs incurred for proposed projects are deferred pending a final decision to develop the project. Costs relating to projects ultimately constructed are reclassified to utility plant. If the project is abandoned, the costs are expensed.

c) Allowance for Funds Used During Construction (AFUDC): AFUDC represents the estimated costs of financing construction projects and is computed using the District's long-term borrowing rate. The allowance totaled $165,860 and $207,413 in 2018 and 2017, respectively, and is capitalized as part of the cost of the project and reflected as a reduction of interest expense.

d) Restricted Assets: In accordance with bond resolutions, related agreements, and laws, separate restricted accounts have been established. These assets are restricted for specific uses including bond reserve and capital additions and are classified as current or noncurrent assets, as appropriate. When both restricted and unrestricted resources are available for use, it is the District's practice to use restricted resources first, then unrestricted resources as needed.

e) Cash and Cash Equivalents: For purposes of the statement of cash flows, the District considers all short-term highly liquid investments with a maturity of 3-months or less when purchased to be cash equivalents.

f) Accounts Receivable: Receivables are considered past due after 30 days and are written off 210 days after the respective billing dates. The percentage-of-sales allowance method is used to estimate uncollectible accounts. The reserve is then reviewed for adequacy against an aging schedule of accounts receivable. Accounts deemed uncollectible are transferred to the provision for uncollectible accounts on a monthly basis. The reserve for uncollectible accounts totaled $388,999 and $553,178 in 2018 and 2017, respectively.

g) Other Receivables: Other receivables include a Rural Economic Development Revolving Fund, which was established during 2008 pursuant to RCW 82.16.0491. The District contributed to the fund in 2008 and 2009. Each contribution to the fund was partially offset by a public utility tax credit. The District appointed Benton-Franklin Council of Governments to oversee and direct activities of the fund. The District does not have a reserve for uncollectible accounts related to Other Receivables as it expects to fully collect these amounts.

h) Inventories: Inventories are valued at average cost, which approximates the market value.

i) Derivative Instruments: The District has adopted GASB Statement No. 53, *Accounting and Financial Reporting for Derivative Instruments*. Subject to certain exceptions, GASB Statement No. 53 requires every derivative instrument be recorded on the statement of net position as an asset or liability measured at its fair value, and changes in the derivative's fair value be recognized in earnings unless such derivatives meet specific hedge accounting criteria to be determined as effective. Effective hedges qualify for hedge accounting and such changes in fair values are deferred.

It is the District's policy to document and apply as appropriate the normal purchase and normal sales exception under GASB Statement No. 53. The District has reviewed its various contractual arrangements to determine applicability of these standards. Purchases and sales of forward electricity, natural gas, and option contracts that require physical delivery and which are expected to be used or sold by the reporting entity in the normal course of business are generally considered "normal purchases and normal sales." These transactions are excluded under GASB Statement No. 53 and therefore are not required to be recorded at fair value in the financial statements. Certain put and call options and financial swaps for electricity and natural gas are considered to be derivatives under GASB Statement No. 53, but do not generally meet the "normal purchases and normal sales" criteria.

As of December 31, 2018, the District had the following derivative instruments outstanding:

	Changes in Fair Value		Fair Value at December 31, 2018		Notional
	Classification	Amount	Classification	Amount	(MWh/MMBtu)
Cash Flow Hedges:					
Financial Swap Forward	Deferred Inflow	($2,539,134)	Derivative Asset	$2,539,134	3,023,250
Financial Swap Forward	Deferred Outflow	$4,770,996	Derivative Liability	($4,770,996)	920,225

These derivative instruments were entered into between November 2016 and December 2018 with maturities between January 2019 and September 2020. The District paid or received no cash to enter into these transactions.

As of December 31, 2017, the District had the following derivative instruments outstanding:

	Changes in Fair Value		Fair Value at December 31, 2017		Notional
	Classification	Amount	Classification	Amount	(MWh/MMBtu)
Cash Flow Hedges:					
Financial Swap Forward	Deferred Inflow	($1,140,955)	Derivative Asset	$1,140,955	936,975
Financial Swap Forward	Deferred Outflow	$1,122,842	Derivative Liability	($1,122,842)	2,612,120

These derivative instruments were entered into between July 2016 and December 2017 with maturities between January 2018 and December 2019. The District paid or received no cash to enter into these transactions.

The fair values of the commodity swap contracts were based on the futures price curve for the Mid-Columbia Intercontinental Exchange (ICE) index for electricity and the Sumas index for natural gas; additionally, all instruments close at the same index, respectively. The fair value of the options was calculated using the Black-76 options pricing model. The District categorizes its fair value measurements within the fair value hierarchy established by GAAP. The hierarchy is based on the valuation inputs used to measure the fair value of the asset. Level 1 inputs are quoted prices in active markets for identical assets; Level 2 inputs are significant other observable inputs; Level 3 inputs are significant unobservable inputs. All of the District's fair market measurements are classified as Level 2.

Objective & Strategies:

The District enters into derivative energy transactions to hedge its known or expected positions within its approved Risk Management policy. Decisions are made to enter into forward transactions to protect its financial position, specifically to deal with expected long and short positions as determined by projected load and resource balance positions. Generally, several strategies are employed to hedge the District's resource portfolio, including:

- *Combustion Turbine* - The District purchases gas for future periods to generate electricity when the Frederickson Plant (see Note 8) is economically viable on a marginal basis for that period based on parameters set by the Risk Management Committee. If load projections indicate the District does not require the electricity to serve its customers, an equivalent quantity of power will concurrently be sold or otherwise hedged for the same period.

- *Surplus Purchased Power Resources* - The District hedges projected surpluses in future periods by selling power or by purchasing put options. Surplus power is generally sold forward at a fixed price, either physically or financially, when the probability of surplus is very high; surplus power is hedged through the purchase of physical or financial put options when the projected surplus is less certain, but nevertheless expected to be available under expected scenarios. From time to time, the District will sell physical power forward in the next calendar month at a price based on the Mid-Columbia ICE index to perfect financial forward sales that settle based on the same index.

- *Deficit Power Resources* - The District hedges projected power resource deficits in future periods by purchasing power or by purchasing power call options (or if the Frederickson Plant is economically viable for the period, by buying gas). Power is generally purchased to cover projected deficits at a fixed price, either physically or financially, when the probability of the deficit position is very high; such deficit positions are hedged through the purchase of physical or financial call options when the projected deficits are less certain, but nevertheless expected under the approved planning conditions.

Derivatives authorized under the Risk Management policy by the District include:
- Physical power and natural gas forward purchases and sales
- Monthly and daily power and gas physical calls and puts
- Power and natural gas fixed for floating swaps
- Currency swaps relating to managing US/Canadian exchange rate risk resulting from transactions denominated in Canadian dollars
- Quarterly and monthly financial power and gas put and call options
- Financial daily power and gas put and call options
- Quarterly and monthly power and natural gas swaptions
- Financial natural gas swing and basis swaps

Risks

Credit Risk - The District has developed a credit policy that establishes guidelines for setting credit limits and monitoring credit exposure on a continuous basis. The policy addresses frequency of counterparty credit evaluations, credit limits per specific counterparty, and counterparty credit concentration limits. A summary of counterparty credit exposure related to derivatives is provided in Note 8.

Commodity transactions, both physical and financial, are entered into only with counterparties approved by the District's Risk Management Committee for creditworthiness. The District had 43 counterparties with approved credit limits for electric power and natural gas sales and purchases as of December 31, 2018, and 46 counterparties at December 31, 2017. Counterparty credit limits are based on The Energy Authority's (TEA) (see Note 8) proprietary credit rating system and other factors. Credit ratings for counterparties range from "not-rated" to AAA, with a majority of counterparties rated between BBB- and AAA. Not-rated counterparties either provide additional security or are assigned credit limits of $25,000 or less.

The District's counterparty credit limits are scaled against TEA credit limits with a maximum credit limit of $3 million. This mitigates the District's credit exposure by netting and setting off the District's sales with purchases made by other TEA clients. Credit concentration limits based on market conditions and available qualified counterparties are established by the Risk Management Committee.

The District has entered into master enabling agreements with various counterparties, which enable hedging transactions. Such agreements include the Western Systems Power Pool (WSPP) form of agreement for physical power transactions, various forms of enabling agreements for physical gas transactions, and International Swaps and Derivatives Association Agreements (ISDA) for financial transactions. All of the enabling agreements have provisions addressing credit exposure and provide for various remedies to assure financial performance, including the ability to call on additional collateral as conditions warrant, generally as determined by the exposed party. The District also uses netting provisions in the agreements to diffuse a portion of the risk.

Forward transactions under the physical enabling agreements are used to deal with long and short physical positions under the direction of the Risk Management Committee and pursuant to the Risk Management policy. Transactions under the ISDA agreements are used to financially hedge long or short positions so that the District will pay or receive the equivalent of a fixed or known price for energy purchased or sold. The agreements also permit the District to hedge the risk of an underlying physical position by using call options, put options, runoff insurance, and weather insurance.

The aggregate fair value of hedging derivative instruments in asset positions was $2,539,134 and $1,140,955 at December 31, 2018 and 2017, respectively. There was no collateral held or liabilities included in the netting arrangements.

Although the District executes hedging derivative instruments with various counterparties, three counterparties comprise 100% of the net exposure to credit risk as of December 31, 2018. These counterparties are rated BBB+/Baa1 (98 contracts comprising 97% of net exposure), BBB/Baa2 (6 contracts comprising 2% of net exposure), and BBB+/A3 (47 contracts comprising 1% of net exposure). At December 31, 2017, four counterparties comprise 99% of the net exposure to credit risk. These counterparties are rated BBB+/Baa1 (19 contracts comprising 23% of net exposure), Not Rated/Baa2 (11 contracts comprising 25% of net exposure), A/A2 (18 contracts comprising 30% of net exposure, and BBB+/A3 (9 contracts comprising 21% of net exposure).

Basis Risk - The District proactively works to eliminate or minimize basis risk on energy transactions by entering into derivative transactions that settle pursuant to an index derived from market transactions at the point physical delivery is expected to take place. There are no derivative transactions outstanding that carry basis risk as of December 31, 2018 or 2017. As applicable, all power related transactions are to be settled on the relevant Mid-Columbia index, and all gas transactions are to be settled on the relevant Sumas/Huntingdon index or be converted to the Sumas/Huntingdon index within 6 months of delivery. The District has ready access to electric transmission and natural gas transportation capacity at those respective trading points.

Termination Risk - As of December 31, 2018 and 2017, no termination events have occurred, and there are no outstanding transactions with material risk. None of the outstanding transactions have early termination provisions except in the event of default by either counterparty. Events of default are generally related to (i) failure to make payments when due, (ii) failure to provide and maintain suitable credit assurances as required, (iii) bankruptcy or other evidence of insolvency, or (iv) failure to perform under any material provision of the agreement. Failure to provide or receive energy or natural gas under physical commodity transactions generally does not fall under the events of default provisions, unless the nonperforming party fails to pay the resulting liquidated damages when due.

There is no rollover, interest rate, or market access risk for these derivative products at December 31, 2018 or 2017.

j) Debt Premium Amortization and Gain on Defeased Debt: Original issue and reacquired bond premiums relating to revenue bonds are amortized over the terms of the respective bond issues using the bonds outstanding method. Premiums are reported with revenue bonds on the Statement of Net Postion. In accordance with GASB Statement No. 23*, Accounting and Financial Reporting for Refundings of Debt Reported by Proprietary Activities*, gains on debt refundings have been deferred and amortized over the shorter of the remaining life of the old or new debt. Gains are reported as deferred inflows of resources on the Statement of Net Position. Effective with GASB 65, bond issuance costs are expensed in the period incurred.

k) Revenue Recognition: Revenues from retail sales of electricity are recognized when occurred and reported net of bad debt expense of $213,000 and $219,000 at December 31, 2018 and 2017, respectively. Revenues include an estimate for energy delivered to customers between the last billing date and the end of the year. This amount is reflected in the accompanying financial statements as Accrued Unbilled Revenue in the amount of $4.5 million and $4.8 million at December 31, 2018 and 2017, respectively.

l) Capital Contributions: Capital contributions for the District consist mainly of line extension fees. Line extension fees represent amounts collected to recover the costs of installing new lines. Capital contributions are recorded as deferred revenues when received and reclassified to revenue when the related project is completed. Deferred revenues are reported as Other Credits & Liabilities on the Statement of Net Position, see also Note 4.

m) Pensions: For purposes of measuring the net pension liability, deferred outflows/inflows of resources and pension expense, information about the fiduciary net position of the Public Employees Retirement System (PERS) and additions to/deductions from PERS' fiduciary net position have been determined on the same basis as they are reported by PERS. For this purpose, plan contributions are recognized as of employer payroll paid dates and benefit payments and refunds are recognized when due and payable in accordance with the benefit terms. Investments held by PERS are reported at fair value.

n) Compensated Absences: The District consolidated its vacation and sick leave program to a personal leave program May 1, 1993. Accrued unused sick leave balances for active employees as of April 30, 1993, were frozen and converted to a supplemental leave benefit (SLB). The SLB may be used by employees to make up the difference between short-term disability benefit payments and 100% of gross, straight-time pay. Additionally, an employee may restore work hours required for short-term disability eligibility one-time per Collective Bargaining Agreement Contract cycle (3 years). At death, the District is obligated to pay 100% of the SLB cash value to the employee's beneficiary. At retirement, the

District is obligated to deposit 30% of the SLB cash value into the retiring employee's Voluntary Employee Beneficiary Association Trust account. The liability for unpaid supplemental leave benefits was $15,110 and $14,663 at December 31, 2018 and 2017, respectively.

Employees earn personal leave in accordance with length of service. The District accrues the cost of personal leave in the year when earned. Personal leave may accumulate to a maximum of 1,200 hours for employees hired prior to April 1, 2011, and is payable upon separation of service, retirement, or death. For employees hired on or after April 1, 2011, personal leave may accumulate to a maximum of 700 hours.

The liability for unpaid leave, benefits, and related payroll taxes was $2,797,147 and $2,680,529 at December 31, 2018 and 2017, respectively. Of the liability for unpaid leave, $1,351,064 and $1,493,553 at December 31, 2018 and 2017, respectively, were classified as a current liability and the remainder as a long-term liability (see Note 4).

o) Use of Estimates: The preparation of the financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results may differ from those estimates.

p) Investments: It is the District's policy to record investments at fair value. For various risks related to the investments see Note 3.

q) Significant Risk and Uncertainty: The District is subject to certain business risks that could have a material impact on future operations and financial performance. These risks include prices on the wholesale market for short-term power, interest rates, water conditions, weather and natural disaster-related disruptions, collective bargaining labor disputes, fish and other Endangered Species Act issues, Environmental Protection Agency and other federal government regulations, or orders concerning the operation, maintenance, and/or licensing of facilities, other governmental regulations, and the deregulation of the electrical utility industry.

The District's accounts receivable are concentrated with a diverse group of customers and counterparties who have purchased energy or other products and services. These customers generally do not represent a significant concentration of credit risk. The District mitigates credit risk by requiring large customers to provide an acceptable means of payment assurance and by an ongoing financial review of counterparties and establishment of credit limits based on the results of that review.

r) Bonneville Power Administration Prepay Program: In March 2013, the District participated in BPA's Prepay Program making a lump-sum up-front payment of $6.8 million. The District will receive $9.3 million in credits which started in April 2013 and continue until September 2028. (See Note 8)

Note 2 - Utility Plant

Utility plant activity for the years ended December 31 was as follows:

Activity for 2018

Electric Plant Assets	Balance Dec. 31, 2017	Increase	Decrease	Balance Dec. 31, 2018
Capital Assets Not Being Depreciated:				
Land and Intangible Plant	**$3,493,641**	**$38,057**	**$0**	**$3,531,698**
Construction Work in Progress	**4,599,287**	**13,816,163**	**(11,503,691)**	**6,911,759**
Capital Assets Being Depreciated:				
Transmission	9,827,655	309,075	-	10,136,730
Generation	1,912,370	-	-	1,912,370
Distribution	221,865,956	11,474,772	(882,705)	232,458,023
General	72,325,445	2,834,317	(763,986)	74,395,776
Subtotal	**305,931,426**	**14,618,164**	**(1,646,691)**	**318,902,899**
Less Accumulated Depreciation for:				
Transmission	(6,335,928)	(252,187)	-	(6,588,115)
Generation	(1,112,187)	(78,416)	-	(1,190,603)
Distribution	(140,932,217)	(6,817,182)	1,149,061	(146,600,338)
General	(39,977,275)	(2,854,103)	61,913	(42,769,465)
Total Accumulated Depreciation	**(188,357,607)**	**(10,001,888)**	**1,210,974**	**(197,148,521)**
Net Utility Plant	***$125,666,747***	***$18,470,496***	***($11,939,408)***	***$132,197,835***

Activity for 2017

Electric Plant Assets	Balance Dec. 31, 2016	Increase	Decrease	Balance Dec. 31, 2017
Capital Assets Not Being Depreciated:				
Land and Intangible Plant	**$3,474,031**	**$47,761**	**($28,151)**	**$3,493,641**
Construction Work in Progress	**5,697,524**	**10,466,791**	**(11,565,028)**	**4,599,287**
Capital Assets Being Depreciated:				
Transmission	8,085,187	1,742,468	-	9,827,655
Generation	1,912,370	-	-	1,912,370
Distribution	214,115,465	8,327,425	(576,934)	221,865,956
General	78,606,899	4,158,979	(10,440,433)	72,325,445
Subtotal	**302,719,921**	**14,228,872**	**(11,017,367)**	**305,931,426**
Less Accumulated Depreciation for:				
Transmission	(6,119,943)	(215,985)	-	(6,335,928)
Generation	(1,026,504)	(85,683)	-	(1,112,187)
Distribution	(134,983,313)	(6,440,954)	492,050	(140,932,217)
General	(46,291,568)	(3,540,517)	9,854,810	(39,977,275)
Total Accumulated Depreciation	**(188,421,328)**	**(10,283,139)**	**10,346,860**	**(188,357,607)**
Net Utility Plant	***$123,470,148***	***$14,460,285***	***($12,263,686)***	***$125,666,747***

Note 3 - Deposits and Investments

As of December 31, 2018, the District had the following investments:

Investment Type	Maturities	Fair Value
Federal Home Loan Mortgage Corp	2/28/2019	3,993,800
US Treasury	5/15/2019	1,982,180
Federal Home Loan Bank	11/15/2019	1,978,340
Federal Farm Credit Bank	12/19/2019	741,555
Federal National Mortgage Assn	3/30/2020	1,972,240
Total		**$10,668,115**

As of December 31, 2017, the District had the following investments:

Investment Type	Maturities	Fair Value
Federal National Mortgage Assn	5/21/2018	$1,995,700
Federal Home Loan Mortgage Corp	2/28/2019	3,977,040
US Treasury	5/15/2019	1,950,480
Federal Home Loan Bank	11/15/2019	1,979,940
Federal Farm Credit Bank	12/19/2019	742,845
Federal National Mortgage Assn	3/30/2020	1,970,520
Total		**$12,616,525**

Fair Market Value - Investments have been adjusted to reflect available market values as of December 31 of 2017 and 2018 obtained from available financial industry valuation services. The District categorizes its fair value measurements within the fair value hierarchy established by GAAP. The hierarchy is based on the valuation inputs used to measure the fair value of the asset. Level 1 inputs are quoted prices in active markets for identical assets; Level 2 inputs are significant other observable inputs; Level 3 inputs are significant unobservable inputs. All of the District's fair market measurements are classified as Level 2.

Interest Rate Risk - In accordance with its investment policy, the District manages its exposure to declines in fair values by matching investment maturities to meet anticipated cash flow requirements. The policy limits investment maturities to less than 5-years from the date of the purchase, unless the maturities coincide as nearly as practicable with the expected use of the funds.

Credit Risk - The District's investment policy conforms with state law, which restricts investments of public funds to debt securities and obligations of the U.S. Treasury, U.S. Government agencies, and certain other U.S. Government sponsored corporations, certificates of deposit, and other evidences of deposit at financial institutions qualified by the Washington Public Deposit Protection Commission (PDPC), bankers' acceptances, investment-grade general obligation debt of state and local governments and public authorities, and the Washington State Treasurer's Local Government Investment Pool (LGIP). The LGIP portfolio meets the requirements set forth in GASB 79 to report the investment at amortized cost. The reported value of the pool is the same as the fair value of the pool shares. There is no formal withdrawal transaction limit; however, the LGIP requests a one day notice for transaction sizes of ten million dollars or more. The LGIP is governed by the State Finance Committee and is administered by the

State Treasurer. The District's investments in the Federal National Mortgage Association, Federal Home Loan Bank, and Federal Home Loan Mortgage Corporation were rated Aaa by Moody's Investor Services and AA+ by Standard & Poor's. The District has a third-party safekeeping agreement for investments through Wells Fargo Bank, N.A.

Concentration of Credit Risk - The District's investment policy limits investments at the time of purchase to a percentage of the total investment portfolio in the following manner:

- Direct obligations of the U.S. Government, up to 100%
- Washington State Treasurer's Local Government Investment Pool, up to 100%
- U.S. Government agency debt, up to 30% for any single agency
- Certificate of Deposit, up to 50% from any single bank provided they are PDPC approved

Custodial Credit Risk Deposits - For a deposit, this is the risk that in the event of a bank failure, the District's deposits may not be returned. The District's deposits and certificates of deposit are held by public depositaries authorized by the PDPC and are not subject to custodial credit risk. State law requires public depositaries to fully collateralize their uninsured public deposits with approved third-party safekeeping agents and provides for independent oversight of this program.

Note 4 - Other Charges and Other Credits

As of December 31, other charges consisted of the following:

Other Charges	2018	2017
Derivative Asset (Note 1)	$2,539,134	$1,140,955
White Creek Wind Project (Note 8)	5,157,868	5,736,268
Preliminary Surveys	125,855	64,007
Total	**$7,822,857**	**$6,941,230**

During the year ended December 31, 2018, the following changes occurred in other credits:

Other Credits & Other Liabilities	Balance Dec. 31, 2017	Increase	Decrease	Balance Dec. 31, 2018
Unclaimed Property	$37,125	$8,616	$8,330	$37,411
Bio Fuel Deposit	148,968	20,940	-	169,908
Derivative Liability (Note 1)	1,122,842	4,770,996	1,122,842	4,770,996
Deferred Revenue	473,595	3,396,294	2,365,341	1,504,548
Finley CT Site Clean Up	189,119	-	34,148	154,971
Personal Leave and Benefits*	1,186,976	1,875,022	1,615,915	1,446,083
Total	**$3,158,625**	**$10,071,868**	**$5,146,576**	**$8,083,917**

** In addition to this amount, $1,351,064 is reported as a current liability for personal leave and related benefits.*

During the year ended December 31, 2017, the following changes occurred in other credits:

Other Credits & Other Liabilities	Balance Dec. 31, 2016	Increase	Decrease	Balance Dec. 31, 2017
Unclaimed Property	$35,542	$9,379	$7,796	$37,125
Bio Fuel Deposit	114,541	96,881	62,454	148,968
Derivative Liability (Note 1)	1,919,445	1,122,842	1,919,445	1,122,842
Deferred Revenue	462,210	1,769,913	1,758,528	473,595
Finley CT Site Clean Up	180,113	9,006	-	189,119
Personal Leave and Benefits*	1,199,411	1,647,902	1,660,337	1,186,976
Total	**$3,911,262**	**$4,655,923**	**$5,408,560**	**$3,158,625**

** In addition to this amount, $1,493,553 is reported as a current liability for personal leave and related benefits.*

Note 5 - Long-Term Debt

During the year ended December 31, 2018, the following changes occurred in long-term debt:

Issue	Beginning Balance	Additions	Reductions	Ending Balance	Due Within One Year
2010 Revenue Build America Bonds, due in annual installments of $1,645,000 - $2,250,000 beginning November 1, 2022 through November 1, 2030; interest at 5.86% - 6.546%; Original issue amount: $17,345,000	$17,345,000	$ -	$ -	$17,345,000	$ -
2011 Revenue and Refunding Bonds, due in annual installments of $460,000 - $4,135,000 through November 1, 2035; interest at 2.0% - 5.0% Original issue amount: $38,545,000	17,090,000	-	3,570,000	13,520,000	3,750,000
2016 Revenue and Refunding Bonds, due in annual installments of $790,000 - $1,560,000 beginning November 1, 2023 through November 1, 2041; interest at 4.0% - 5.0%; Original issue amount: $22,470,000	22,470,000	-	-	22,470,000	-
Subtotal	56,905,000	-	3,570,000	53,335,000	3,750,000
Plus: Unamortized premium	4,336,311	-	466,534	3,869,777	
Total Long-Term Debt	**$61,241,311**	**$0**	**$4,036,534**	**$57,204,777**	**$3,750,000**

During the year ended December 31, 2017, the following changes occurred in long-term debt:

Issue	Beginning Balance	Additions	Reductions	Ending Balance	Due Within One Year
2010 Revenue Build America Bonds, due in annual installments of $1,645,000 - $2,250,000 beginning November 1, 2022 through November 1, 2030; interest at 5.86% - 6.546%; Original issue amount: $17,345,000	$17,345,000	$ -	$ -	$17,345,000	$ -
2011 Revenue and Refunding Bonds, due in annual installments of $460,000 - $4,135,000 through November 1, 2035; interest at 2.0% - 5.0% Original issue amount: $38,545,000	20,135,000	-	3,045,000	17,090,000	3,570,000
2016 Revenue and Refunding Bonds, due in annual installments of $790,000 - $1,560,000 beginning November 1, 2023 through November 1, 2041; interest at 4.0% - 5.0%; Original issue amount: $22,470,000	22,470,000	-	-	22,470,000	-
Subtotal	59,950,000	-	3,045,000	56,905,000	3,570,000
Plus: Unamortized premium	4,845,315	-	509,004	4,336,311	
Total Long-Term Debt	**$64,795,315**	**$0**	**$3,554,004**	**$61,241,311**	**$3,570,000**

Future debt service requirements on these bonds are as follows:

Year	Principal	Interest	Total
2019	3,750,000	2,771,487	6,521,487
2020	3,940,000	2,583,987	6,523,987
2021	4,135,000	2,386,987	6,521,987
2022	3,340,000	2,180,237	5,520,237
2023	2,500,000	1,999,090	4,499,090
2024-2028	14,710,000	7,774,347	22,484,347
2029-2033	10,310,000	3,596,264	13,906,264
2034-2038	6,190,000	1,996,850	8,186,850
2039-2041	4,460,000	453,250	4,913,250
Total	**$53,335,000**	**$25,742,499**	**$79,077,499**

In March 2010, the District issued $17,345,000 of taxable Electric Revenue Build America Bonds. The proceeds were used to fund capital projects. The U.S. Treasury subsidizes a portion (32.6% after sequestration) of the interest debt service payments which it pays directly to the Fiscal Paying Agent.

In October 2011, the District issued $38,545,000 of Electric Revenue and Refunding Bonds, Series 2011. The bond proceeds were used to fund $10 million of improvements and replacements in the District's electric utility system and to refund all of the 2001A bonds maturing on or after November 1, 2011, and all of the 2002 bonds maturing on or after November 1, 2012. The portion of bond proceeds for the refunding was placed in an irrevocable trust for future debt service on the refunded bonds.

In September 2016, the District issued $22,470,000 of Electric Revenue and Refunding Bonds, Series 2016. The bond proceeds were used to fund $15.1 million of improvements and replacements of the District's electric utility system and to refund the 2011 bonds maturing on or after November 1, 2023. The portion of bond proceeds for the refunding was placed in an irrevocable trust for future debt service on the refunded bonds.

These issuances are subject to certain bond reserve requirements satisfied by bond insurance and a bond reserve fund of $1,107,865.

In prior years, the District defeased certain electric revenue bonds by placing the proceeds of new bonds in an irrevocable trust to provide for all future certain debt service payments on the old bonds. Accordingly, the trust account assets and the liability for the defeased bonds are not included in the District's financial statements. At December 31, 2018, $9,335,000 of bonds outstanding are considered defeased.

Defeased Bonds	Principal	Call Date
2011	$9,335,000	11/1/2021

In March 2008, the District established a $10 million revolving line of credit, the Electric System Revenue Note, 2008, with Bank of America. In late 2018, the line of credit was extended for an additional two-year term expiring December 31, 2021. The line of credit was established in support of District financial policies that require additional liquidity be maintained above minimum cash and investment reserve levels for the purpose of meeting unforeseen short-term cash needs. Specifically, the line of credit can be used in support of general District operations or for irrevocable letters of credit as may be required to satisfy collateral posting requirements under contracts and agreements within the ordinary course of business. Draws on the Note will bear interest based on a pricing grid and formula using the bank's prime rate or the LIBOR rate. This Note is a special obligation of the District payable solely out of a special fund and has a lien on revenues junior to the payment of operating expenses of the electric system and outstanding electric system bonds. No draws on the line of credit have been made.

Note 6 - Pension Plans

The following table represents the aggregate pension amounts for all plans subject to the requirements of the GASB Statement 68, *Accounting and Financial Reporting for Pensions* for the year 2018 and 2017:

Aggregate Pension Amounts - All Plans		
	2018	2017
Pension liabilities	$6,852,561	$9,884,887
Deferred outflows of resources	$1,180,507	$1,429,022
Deferred inflows of resources	$2,930,225	$1,866,603
Pension expense/(credit)	($10,030)	$758,364

State Sponsored Pension Plans

Substantially all District regular full-time and qualifying part-time employees participate in one of the following statewide retirement systems administered by the Washington State Department of Retirement Systems, under cost-sharing, multiple-employer public employee defined benefit and defined contribution retirement plans. The state Legislature establishes, and amends, laws pertaining to the creation and administration of all public retirement systems.

The Department of Retirement Systems (DRS), a department within the primary government of the State of Washington, issues a publicly available comprehensive annual financial report (CAFR) that includes financial statements and required supplementary information for each plan. The DRS CAFR may be obtained by writing to:

Department of Retirement Systems
Communications Unit
P.O. Box 48380
Olympia, WA 98504-8380

Or it may be downloaded from the DRS website at www.drs.wa.gov.

Public Employees' Retirement System (PERS)

PERS members include elected officials; state employees; employees of the Supreme, Appeals and Superior Courts; employees of the legislature; employees of district and municipal courts; employees of local governments; and higher education employees not participating in higher education retirement programs. PERS is comprised of three separate pension plans for membership purposes. PERS plans 1 and 2 are defined benefit plans, and PERS plan 3 is a defined benefit plan with a defined contribution component.

PERS Plan 1 provides retirement, disability and death benefits. Retirement benefits are determined as 2 percent of the member’s average final compensation (AFC) times the member’s years of service. The AFC is the average of the member’s 24 highest consecutive service months. Members are eligible for retirement from active status at any age with at least 30 years of service, at age 55 with at least 25 years of service, or at age 60 with at least 5 years of service. Members retiring from active status prior to the age of 65 may receive actuarially reduced benefits. Retirement benefits are actuarially reduced to reflect the choice of a survivor benefit. Other benefits include duty and non-duty disability payments, an optional cost-of-living adjustment (COLA), and a one-time duty-related death benefit, if found eligible by the Department of Labor and Industries. PERS 1 members were vested after the completion of 5 years of eligible service. The plan was closed to new entrants on September 30, 1977.

Contributions - The **PERS Plan 1** member contribution rate is established by State statute at 6 percent. The employer contribution rate is developed by the Office of the State Actuary and includes an administrative expense component that is currently set at 0.18 percent. Each biennium, the state Pension Funding Council adopts Plan 1 employer contribution rates.

The PERS Plan 1 required contribution rates (expressed as a percentage of covered payroll) for 2018 were as follows:

PERS Plan 1: January – August 2018

Actual Contribution Rates:		Employer	Employee
PERS Plan 1		7.49%	6.00%
PERS Plan 1 UAAL		5.03%	
Administrative Fee		0.18%	
	Total	12.70%	6.00%

PERS Plan 1: September – December 2018

Actual Contribution Rates:		Employer	Employee
PERS Plan 1		7.52%	6.00%
PERS Plan 1 UAAL		5.13%	
Administrative Fee		0.18%	
	Total	12.83%	6.00%

The PERS Plan 1 required contribution rates (expressed as a percentage of covered payroll) for 2017 were as follows:

PERS Plan 1: January – June 2017

Actual Contribution Rates:		Employer	Employee
PERS Plan 1		6.23%	6.00%
PERS Plan 1 UAAL		4.77%	
Administrative Fee		0.18%	
	Total	11.18%	6.00%

PERS Plan 1: July – December 2017

Actual Contribution Rates:		Employer	Employee
PERS Plan 1		7.49%	6.00%
PERS Plan 1 UAAL		5.03%	
Administrative Fee		0.18%	
	Total	12.70%	6.00%

PERS Plan 2/3 provides retirement, disability and death benefits. Retirement benefits are determined as 2 percent of the member's average final compensation (AFC) times the member's years of service for Plan 2 and 1 percent of AFC for Plan 3. The AFC is the average of the member's 60 highest-paid consecutive service months. There is no cap on years of service credit. Members are eligible for retirement with a full benefit at 65 with at least 5 years of service credit. Retirement before age 65 is considered an early retirement. PERS Plan 2/3 members who have at least 20 years of service credit and are 55 years of age or older, are eligible for early retirement with a benefit that is reduced by a factor that varies according to age for each year before age 65. PERS Plan 2/3 members who have 30 or more years of service credit and are at least 55 years old can retire under one of two provisions:

- With a benefit that is reduced by 3 percent for each year before age 65; or
- With a benefit that has a smaller (or no) reduction (depending on age) that imposes stricter return-to-work rules.

PERS Plan 2/3 members hired on or after May 1, 2013 have the option to retire early by accepting a reduction of 5 percent for each year of retirement before age 65. This option is available only to those who are age 55 or older and have at least 30 years of service credit. PERS Plan 2/3 retirement benefits are also actuarially reduced to reflect the choice of a survivor benefit. Other PERS Plan 2/3 benefits include duty and non-duty disability payments, a cost-of-living allowance (based on the CPI), capped at 3 percent annually and a one-time duty related death benefit, if found eligible by the Department of Labor and Industries. PERS 2 members are vested after completing 5 years of eligible service. Plan 3 members are vested in the defined benefit portion of their plan after 10 years of service; or after 5 years of service if 12 months of that service are earned after age 44.

PERS Plan 3 defined contribution benefits are totally dependent on employee contributions and investment earnings on those contributions. PERS Plan 3 members choose their contribution rate upon joining membership and have a chance to change rates upon changing employers. As established by statute, Plan 3 required defined contribution rates are set at a minimum of 5 percent and escalate to 15 percent with a choice of six options. Employers do not contribute to the defined contribution benefits. PERS Plan 3 members are immediately vested in the defined contribution portion of their plan.

Contributions - The **PERS Plan 2/3** employer and employee contribution rates are developed by the Office of the State Actuary to fully fund Plan 2 and the defined benefit portion of Plan 3. The Plan 2/3 employer rates include a component to address the PERS Plan 1 UAAL and an administrative expense that is currently set at 0.18 percent. Each biennium, the state Pension Funding Council adopts Plan 2 employer and employee contribution rates and Plan 3 contribution rates.

The PERS Plan 2/3 required contribution rates (expressed as a percentage of covered payroll) for 2018 were as follows:

PERS Plan 2/3: January – August 2018

Actual Contribution Rates:	Employer 2/3	Employee 2
PERS Plan 2/3	7.49%	7.38%
PERS Plan 1 UAAL	5.03%	
Administrative Fee	0.18%	
Employee PERS Plan 3		varies
Total	12.70%	7.38%

PERS Plan 2/3: September – December 2018

Actual Contribution Rates:		Employer 2/3	Employee 2
PERS Plan 2/3		7.52%	7.41%
PERS Plan 1 UAAL		5.13%	
Administrative Fee		0.18%	
Employee PERS Plan 3			varies
	Total	12.83%	7.41%

The PERS Plan 2/3 required contribution rates (expressed as a percentage of covered payroll) for 2017 were as follows:

PERS Plan 2/3: January – June 2017

Actual Contribution Rates:		Employer 2/3	Employee 2
PERS Plan 2/3		6.23%	6.12%
PERS Plan 1 UAAL		4.77%	
Administrative Fee		0.18%	
Employee PERS Plan 3			varies
	Total	11.18%	6.12%

PERS Plan 2/3: July – December 2017

Actual Contribution Rates:		Employer 2/3	Employee 2
PERS Plan 2/3		7.49%	7.38%
PERS Plan 1 UAAL		5.03%	
Administrative Fee		0.18%	
Employee PERS Plan 3			varies
	Total	12.70%	7.38%

Both the District and the employees made the required contributions during fiscal years 2018 and 2017. The District's required employer contributions for the years ended December 31 as follows:

	2018	2017
PERS Plan 1	$0	$8,343
PERS Plan 1 UAAL	$689,118	$669,660
PERS Plan 2/3	$1,021,040	$936,046
Total	$1,710,158	$1,614,049

Actuarial Assumptions

The total pension liability (TPL) for each of the DRS plans was determined using the most recent actuarial valuations completed in 2018 and 2017 with a valuation date of June 30, 2017, and June 30, 2016 respectively. The actuarial assumptions used in the valuation were based on the results of the Office of the State Actuary's (OSA) *2007-2012 Experience Study and 2017 and 2015 Economic Experience Study*.

Additional assumptions for subsequent events and law changes are current as of the 2017 and 2016 actuarial valuation reports. The TPL was calculated as of the valuation dates and rolled forward to the measurement dates of June 30, 2018 and June 30, 2017. Plan liabilities were rolled forward from June 30, 2017, to June 30, 2018 and June 30, 2016 to June 30, 2017 for the respective fiscal years, reflecting each plan's normal cost (using the entry-age cost method), assumed interest and actual benefit payments.

- **Inflation:** 2.75% total economic inflation; 3.5% salary inflation
- **Salary increases**: In addition to the base 3.5% salary inflation assumption, salaries are also expected to grow by promotions and longevity.
- **Investment rate of return:** 7.4%

Mortality rates were based on the RP-2000 report's Combined Healthy Table and Combined Disabled Table, published by the Society of Actuaries. The OSA applied offsets to the base table and recognized future improvements in mortality by projecting the mortality rates using 100 percent Scale BB. Mortality rates are applied on a generational basis; meaning members are assumed to receive additional mortality improvements in each future year throughout their lifetimes.

There were changes in methods and assumptions since the last valuation.

For 2018:

- Lowered the valuation interest rate from 7.70% to 7.50% for all systems.
- Lowered the assumed general salary growth from 3.75% to 3.50% for all systems.
- Lowered assumed inflation from 3.00% to 2.75% for all systems.

There were minor changes in methods and assumptions since the last valuation.

For 2017:

- How terminated and vested member benefits are valued was corrected.
- How the basic minimum COLA in PERS Plan 1 is valued for legal order payees was improved.
- For all plans, the average expected remaining service lives calculation was revised.

Discount Rate

The discount rate used to measure the total pension liability for all DRS plans was 7.4 and 7.5 percent for fiscal years 2018 and 2017 respectively. To determine that rate, an asset sufficiency test included an assumed 7.5 percent for 2018 and 7.7 percent for 2017 long-term discount rate to determine funding liabilities for calculating future contribution rate requirements. Consistent with the long-term expected rate of return, a 7.4 percent for 2018 and 7.5 percent for 2017 future investment rate of return on invested assets was assumed for the test. Contributions from plan members and employers are assumed to continue being made at contractually required rates (including PERS 2/3, whose rates include a component for the PERS 1 plan liabilities). Based on these assumptions, the pension plans' fiduciary net position was projected to be available to make all projected future benefit payments of current plan members. Therefore, the long-term expected rate of return of 7.4 percent for 2018 and 7.5 percent for 2017 was used to determine the total liability.

Long-Term Expected Rate of Return

The long-term expected rate of return on DRS pension plan investments of 7.4 percent for 2018 and 7.5 percent for 2017 was determined using a building-block-method. In selecting this assumption, the Office of the State Actuary (OSA) reviewed the historical experience data, considered the historical conditions that produced past annual investment returns, and considered capital market assumptions and simulated expected investment returns provided by the Washington State Investment Board (WSIB). The WSIB uses the capital market assumptions and their target asset allocation to simulate future investment returns over various time horizons.

Estimated Rates of Return by Asset Class

Best estimates of arithmetic real rates of return for each major asset class included in the pension plan's target asset allocation as of June 30, 2018, are summarized in the table below. The inflation component used to create the table is 2.2 percent and represents WSIB's most recent long-term estimate of broad economic inflation.

Asset Class	Target Allocation	% Long-Term Expected Real Rate of Return Arithmetic
Fixed Income	20%	1.70%
Tangible Assets	7%	4.90%
Real Estate	18%	5.80%
Global Equity	32%	6.30%
Private Equity	23%	9.30%
	100%	

Best estimates of arithmetic real rates of return for each major asset class included in the pension plan's target asset allocation as of June 30, 2017, are summarized in the table below. The inflation component used to create the table is 2.2 percent and represents WSIB's most recent long-term estimate of broad economic inflation.

Asset Class	Target Allocation	% Long-Term Expected Real Rate of Return Arithmetic
Fixed Income	20%	1.70%
Tangible Assets	5%	4.90%
Real Estate	15%	5.80%
Global Equity	37%	6.30%
Private Equity	23%	9.30%
	100%	

Sensitivity of NPL

The table below presents the District's proportionate share of the net pension liability/(asset) calculated using the discount rate of 7.4 percent for 2018 and 7.5 percent for 2017, as well as what the District's proportionate share of the net pension liability would be if it were calculated using a discount rate that is 1-percentage point lower or 1-percentage point higher than the current rate.

	1% Decrease	Current Discount Rate	1% Increase
2018	**(6.4%)**	**(7.4%)**	**(8.4%)**
PERS 1	$5,644,624	$4,593,093	$3,682,254
PERS 2/3	$10,334,861	$2,259,468	($4,361,452)
2017	**(6.5%)**	**(7.5%)**	**(8.5%)**
PERS 1	$6,268,626	$5,145,847	$4,173,281
PERS 2/3	$12,767,469	$4,739,040	($1,839,067)

Pension Plan Fiduciary Net Position

Detailed information about the State's pension plans' fiduciary net position is available in the separately issued DRS financial report.

Pension Liabilities, Pension Expense, and Deferred Outflows of Resources and Deferred Inflows of Resources Related to Pensions.

At December 31, 2018, the District reported a total pension liability of $6,852,561 for its proportionate share of the net pension liabilities as follows:

	Liability
PERS 1	$4,593,093
PERS 2/3	$2,259,468

At December 31, 2017, the District reported a total pension liability of $9,884,887 for its proportionate share of the net pension liabilities as follows:

	Liability
PERS 1	$5,145,847
PERS 2/3	$4,739,040

At December 31, the District's proportionate share of the collective net pension liabilities was as follows:

	Proportionate Share 12/31/18	Proportionate Share 12/31/17	Change in Proportion
PERS 1	0.102845%	0.108446%	(0.005601%)
PERS 2/3	0.132333%	0.136394%	(0.004061%)

Employer contribution transmittals received and processed by DRS for DRS' fiscal year ended June 30 are used as the basis for determining each employer's proportionate share of the collective pension amounts reported by DRS in the Schedules of Employer and Nonemployer Allocations for all plans.

Pension Expense

For the year ended December 31, 2018 and 2017, the District recognized pension expense as follows:

2018	Pension Expense/(Credit)	2017	Pension Expense
PERS 1	$125,184	PERS 1	$168,714
PERS 2/3	($135,214)	PERS 2/3	$589,650
Total	($10,030)	Total	$758,364

Deferred Outflows of Resources and Deferred Inflows of Resources

At December 31, the District reported deferred outflows of resources and deferred inflows of resources related to pensions from the following sources:

PERS 1	Deferred Outflows of Resources		Deferred Inflows of Resources	
	2018	2017	2018	2017
Net difference between projected and actual investment earnings on pension plan investments	-	-	$182,527	$192,029
Contributions subsequent to the measurement date	350,709	349,031	-	-
TOTAL	**$350,709**	**$349,031**	**$182,527**	**$192,029**

PERS 2/3	Deferred Outflows of Resources		Deferred Inflows of Resources	
	2018	2017	2018	2017
Differences between expected and actual experience	276,952	480,176	395,591	155,859
Net difference between projected and actual investment earnings on pension plan investments	-	-	1,386,514	1,263,314
Changes of assumptions	26,432	50,338	643,026	-
Changes in proportion and differences between contributions and proportionate share of contributions	$9,203	$32,209	$322,567	$255,401
Contributions subsequent to the measurement date	517,211	517,268	-	-
TOTAL	**$829,798**	**$1,079,991**	**$2,747,698**	**$1,674,574**
TOTAL ALL PLANS	**$1,180,507**	**$1,429,022**	**$2,930,225**	**$1,866,603**

Deferred outflows of resources related to pensions resulting from the District's contributions subsequent to the measurement date will be recognized as a reduction of the net pension liability in the year ended December 31, 2019.

Other amounts reported as deferred outflows and deferred inflows of resources related to pensions will be recognized in pension expense as follows:

Year ended December 31	PERS 1	PERS 2/3
2019	$7,986	($312,913)
2020	($39,901)	(514,147)
2021	($119,733)	(889,324)
2022	($30,878)	(354,920)
2023	-	(156,972)
Thereafter	-	(206,835)
Total	($182,527)	($2,435,112)

Note 7- Deferred Compensation and Health Benefit Plans

Deferred Compensation Plans

The District offers its employees deferred compensation plans created in accordance with Internal Revenue Code Sections 457(b) and 401(a) permitting employees to defer a portion of their salary until future years. The District match was locked at a maximum rate of 2% on January 1, 2007. The deferred compensation is generally not available to employees until separation from service through termination, retirement, death, or unforeseeable emergency. The 457 plan does contain an employee loan provision. Employees may apply with the Plan Administrator; terms of repayment are set by the Administrator. The plan assets are held in trust for the exclusive benefit of plan participants and beneficiaries. The plans are administered by ICMA-RC.

Health Benefit Plans

Health Reimbursement Arrangement (HRA)

The District, effective January 1, 2015, converted the employee incentive for voluntary participation in the employer provided wellness program to a monthly $150 into an HRA. This payment is intended to help employees pay for qualified health care costs and insurance premiums upon retirement. Contributions are held in trust for the exclusive benefit of participants and beneficiaries. The plan is administered by Gallagher VEBA.

Note 8 - Long-Term Purchased Power Commitments

Bonneville Power Administration (BPA)
Contracts Effective October 2011-September 2028

The District has executed a Slice/Block Power Sales Agreement with BPA for the period commencing October 1, 2011, and expiring September 30, 2028. Compared to the previous agreement, the new Slice agreement has changes in operational flexibility and clarification of with-in hour capacity rights as shown below:

- The Slice Product is a system sale of power that includes requirements power, surplus power, and hourly scheduling rights, all of which are indexed to the variable output capability of the FCRPS resources that comprise the Slice System, and to the extent such capability is available to Power Services after System Obligations and Operating Constraints are met. These capabilities are accessed by the District through the Slice Computer Application, which will reasonably represent and calculate the capabilities available to BPA Power Services from such FCRPS resources after System Obligations and Operating Constraints are met, including energy production, peaking, storage and ramping capability, and which the Slice Computer Application applies the District's Selected Slice Percentage to such capabilities.
- No ability to self-supply ancillary services such as operating reserves, energy imbalance, or dynamic scheduling.
- Slice schedules continue to be firm across the hour of delivery.
- The District's Slice percentage is 1.36865%.
- The monthly Block amounts range from 70 aMW to 156 aMW.

In conjunction with the new Slice/Block agreement, BPA implemented a Tiered Rates Methodology (TRM). Under the TRM and new agreements, BPA has implemented a cap on the amount of power that the District can purchase at the lowest cost based rates (Tier 1). The cap is referred to in the contract as a Contract High Water Mark (CHWM). The District's CHWM is 204.3 aMW. The maximum amount of power the District can purchase in any federal fiscal year (FFY) is referred to as the Rate Period High Water Mark (RHWM), which adjusts the CHWM for changes in Federal System Capability. For FFY 2017 the RHWM was 199.6 aMW, for FFY 2018 it was 198.0, and FFY 2019 it is 198.0. BPA has a fiscal year of October through September. The amount of power the District can purchase in a FFY is the lesser of its Net Requirement (Forecast load less its share of Packwood) or RHWM and is the Tier 1 amount. This amount for FFY 2017 was 199.6, for FFY 2018 was 198.0, and FFY 2019 is 198.0.

The TRM provides for the determination of Tier One Cost Allocators (TOCA) to determine monthly charges. The TOCA is determined by dividing the Tier 1 amount by the sum of all BPA customers' RHWM. For FFY 2017, this value for the District was 2.859%; for FFY 2018, this value was 2.852%, and FFY 2019 is 2.852. The TOCA is multiplied by BPA's monthly Composite Charge to determine that portion of the District's monthly BPA power bill that represents BPA's costs. The nonslice TOCA is the TOCA minus the slice percentage resulting in a FFY 2017 value of 1.489%, FFY 2018 value of 1.483% and FFY 2019 value of 1.483%. The nonslice TOCA is multiplied by BPA's nonslice charge to determine that portion of the District's monthly BPA power bill that represent several BPA revenues, primarily their wholesale sales.

BPA has put in place a Power Cost Recovery Adjustment Clause (Power CRAC) that applies to the District's Block purchases. The Power CRAC will trigger if BPA's forecasted Accumulated Calibrated Net Revenues (ACNR) were lower than a calculated amount. For FFY 2018 and 2019, ACNR represents the power net revenues, modified by certain items, as accumulated since FFY 2016. The amount of the Power CRAC would have been determined by the amount ACNR is forecasted to be less than certain values and is capped at $300 million per year. For FFY 2018, the trigger is based on BPA Power function cash reserves for risk levels. If these levels drop below zero, the CRAC could trigger. It is still capped at $300 million per year. If triggered, the CRAC amount would be converted to a percentage and would increase the Block rates charged to the District. The $300 million per year cap would then be increased if BPA triggered a National Marine Fisheries Service FCRPS BiOp (NFB) adjustment. The NFB adjustment would have been triggered if a court ordered additional expenditures for Fish and Wildlife mitigation, an Endangered Species Act (ESA) litigation settlement occurred which resulted in higher costs, a new, more expensive, Biological Opinion (BiOp) was implemented, or BPA committed to implement a recovery plan under the ESA. The NFB adjustment would have started at the beginning of a fiscal year, or during the fiscal year if an emergency was declared. The CRAC did not trigger for FFY 2017, 2018, or 2019.

The rates also contained a Power Reserves Distribution Clause (RDC), which would operate similar to the CRAC but would have lowered the Block rates charged to the District. The RDC would have been triggered when Power ACNR exceeds the Power RDC threshold, measured in Power ACNR, and BPA ACNR exceeds the BPA RDC threshold, measured in BPA ACNR. In FFY 2018 and 2019, the cap is $500 million. The RDC did not trigger for FFY's 2017, 2018, or 2019.

The rates also contain a spill surcharge created to recover the costs associated with increased spill at the dams as a result of a ruling issued Spring 2017 by the U.S. District Court for the District of Oregon. The court order increased spill at eight Federal Columbia River Power System dams on the lower Columbia and Snake rivers for the 2018 spring fish passage season. The surcharge is in addition to power rates and was implemented once sufficient information was available regarding planned annual spill levels. The District's share of the surcharge for FY 2018 was $207,615.

To obtain needed transmission services, the District entered into a service agreement with BPA for point-to-point transmission services commencing May 31, 1997 and terminating on the earlier of September 30, 2031, or the date of termination established pursuant to BPA's Open Access Transmission Tariff. Effective October 1, 2000, the District obtained transmission demand of 468 MW. It was reduced to 428 MW on October 1, 2003 and 423 MW on October 1, 2005. This service level exceeds requirements needed to meet projected retail loads.

The District, along with over 80% of BPA's Consumer Owned Utility (COU) customers and the region's IOUs entered into an agreement to settle the amount of the residential exchange benefits paid by BPA to the IOUs. The settlement included a provision for BPA to continue to provide COU's a discount on BPA power bills. For the FFY 2017 period, the discount for the District was $182,097/month, and for FFY 2018, the discount was $183,247/month. For FFY 2019, the discount is $183,247/month.

BPA Prepay Program

BPA developed a Prepay Program to help fund hydro system infrastructure and as a means to allow customers to prepay for the future delivery of power consistent with the existing power supply agreements, except that payment provisions would be revised to reflect the prepayment. The District submitted an offer for one block in the amount of $6.8 million that was accepted and, in return, would receive a total of $9.3 million in credits resulting in net present value savings of $1.1 million. The District made a lump-sum up-front payment in March 2013, and began receiving a $50,000 credit each month on its power bill beginning April 2013 and continues until September 2028.

Energy Northwest

The District, Energy Northwest, and BPA have entered into separate agreements with respect to certain Energy Northwest projects. Under these agreements, the District has purchased 4.965%, 5.350%, and 4.295% capability of Project No. 1, Columbia Generating Station, and Energy Northwest's 70% share of Project No. 3, respectively. All project participants, including the District, have assigned their respective rights to the capability of these projects to BPA under contracts referred to as net-billing agreements. Project participants are obligated to pay Energy Northwest their pro rata share of total project costs, and BPA in turn is obligated to pay the participants identical amounts by reducing amounts due to BPA under power sales agreements. The net-billing agreements provide that participants and BPA are obligated to make such payments whether or not the projects are completed, operable, or operating and notwithstanding the suspension, interruption, interference, reduction, or curtailment of the projects' output.

BPA and Energy Northwest received a favorable private letter ruling from the IRS allowing for direct-pay agreements effective June 2006. The ruling assures that the proposed direct-pay agreements do not adversely affect the existing federal income tax-exemption on the BPA-backed bonds issued by Energy Northwest for three nuclear projects. Under the direct-pay agreements, BPA pays amounts directly to Energy Northwest to cover the costs of the projects. This enables Energy Northwest to reduce to zero the amounts it bills to project participants and also reduces to zero the amount of net-billing credits BPA provides. The direct-pay agreements improve BPA's cash flows and provide an opportunity for rate relief for the region. The District began participation in the direct-pay program in June 2006.

Additionally, the District entered into a Nine Canyon Wind Project Power Purchase Agreement with Energy Northwest for the purchase of 3 MW of the project generating capacity (1 aMW) of Phase I through July 1, 2023. The project reached commercial operation in late 2002. The District on October 30, 2006, signed an Amended and Restated Agreement with ENW and the other purchasers, which extended the term of the Agreement through July 1, 2030 (with rights to extend the agreement for 5-year terms) and provided the District with 6 MW (2 aMW) from the Phase III expansion (see Note 12).

Packwood Lake Hydroelectric Project (Packwood)

The District is a 14% participant in Energy Northwest's 27 MW Packwood Project, located in the Cascade Mountains south of Mount Rainier. The Packwood Agreement with Energy Northwest obligates participants to pay annual costs and receive excess revenues. Energy Northwest recognizes revenues equal to expenses for each period. No net revenue or loss is recognized, and no equity is accumulated. Accordingly, no investment for the joint venture is reflected on the District's statement of net position. No distributions were made in 2018 or 2017.

Frederickson Plant

In March 2001, the District entered into a 20-year agreement with Frederickson Power LP for the purchase of 50 MW of contract capacity beginning September 2002 from the 249 MW Frederickson 1 Generating Station combined-cycle natural gas fired combustion turbine plant near Tacoma, Washington. The agreement includes firm gas transportation from the Canadian border to the plant. Power deliveries and variable energy charges are based on a deemed heat rate of 7,100 British thermal units (Btu) per kilowatt-hour (kWh). Up to 40% of the contract capacity may be displaced regardless of the dispatch decisions of other purchasers. Power costs include a capacity charge and fixed and variable operation and maintenance charges indexed to performance and escalation factors. The District receives fuel management services for the Frederickson Plant from The Energy Authority (TEA).

Lakeview Light and Power (LL&P) Wind Energy, Inc.

In April 2007, the District entered into a 20-year Energy and Environmental Attributes Purchase Agreement with LL&P to purchase 3 MW of capacity (1 aMW) at the White Creek Wind Project. This project is a wind generation facility with capacity of 204.7 MW. It is located in Klickitat County and was declared to be in commercial operation in November 2007. The purchase is part of the District's strategy for meeting renewable resource requirements of the Energy Independence Act (EIA) (see Note 12). The District pays for only the energy and associated environmental attributes generated by the project.

White Creek Wind Project

In September 2008, the District entered into an Assignment Agreement with Klickitat PUD under which Klickitat PUD assigned the District a 3% share of its Energy Purchase Agreement with White Creek Wind I, LLC for $11.1 million. The purchase is part of the District's strategy for meeting renewable resource requirements of EIA (see Note 12). The purchase cost is being amortized on a straight-line basis over a 19-year term. In both 2018 and 2017, power supply expense includes $578,400 each year in amortization of the purchase cost. This 3% share of the 204.7 MW project represents 6.14 MW (2 aMW).

BioFuels Washington, LLC Project/Emerald City Renewables LLC

In February 2013, the District entered into a contract with BioFuels Washington, LLC of Encinitas, CA, to purchase 33,000 Renewable Energy Credits (REC) annually, with a contract term of March 1, 2013, through March 31, 2026, with delivery beginning January 1, 2016. This REC purchase counts toward the District's compliance with the EIA target of 9% renewable energy that began in 2016.

Subsequently, on September 18, 2013, the State of Washington Department of Commerce issued an advisory opinion stating that electricity generated by the BioFuels Washington facility qualifies as distributed generation under RCW 19.285.040(2)(b). For purposes of the compliance with EIA, the Renewable Energy Credits purchased from BioFuels will count double. Therefore, for compliance purposes, this contract provides 66,000 RECs annually toward the District's 9% renewable energy target.

In October 2015, the District consented to the assignment of contracts of the facility to Emerald City Renewables LLC. There were no changes to the District's rights or obligations.

Idaho Wind Partners

In December 2014, the District entered into contracts with Payne's Ferry Wind Park, LLC and Yahoo Creek Wind Park, LLC, which are owned by Idaho Wind Partners, to purchase RECs with a contract term starting in 2015 through 2024. This REC purchase counts toward the District's compliance with the EIA target of 9% renewable energy that began in 2016. In 2018, the District received 36,811 REC's and in 2017, the District received 33,693 REC's.

3Degrees Group, Inc.

In September 2018, the District entered into a contract with 3Degrees Group, Inc. of San Francisco CA, to purchase 60,000 firm RECs annually, with a contract term of April 1, 2019 through April 15, 2028, with delivery beginning no earlier than April 1, 2019. This REC purchase counts toward the District's compliance with the EIA target of 15% renewable energy beginning in 2020.

Other Power Supply Contracts and Purchases

The District entered into a Resource Management Agreement (RMA) with TEA on July 1, 2006, to provide scheduling, dispatching, fuel management, and other power management services. The agreement was restated and extended in 2009 and continues until terminated by either party. The District and TEA have the right to terminate the agreement upon 1 years written notice. The agreement also provides for annual consulting task orders to provide for a variety of power management services. Under the agreement, TEA is authorized to trade real time, day-ahead transactions, and forward transactions as principal on behalf of the District. TEA is currently not trading forward transactions as principal. This arrangement allows a financial benefit to the District with TEA trading in aggregated larger power blocks and passing the resulting transaction pricing on to the District. It also provides the advantages of simplified settlement, lower operational and settlement risk, and rigorous documentation and equitable allocation of pricing for like transactions across PUDs. In December 2008, the RMA was amended to allow these transactions to be traded utilizing TEA's credit and contracts as discussed in Note 1(i).

As discussed in Note 1(i), the District entered into other power supply contracts and purchases as follows:

- At December 31, 2018, the District had entered into various short-term financial forward sales and purchase contracts committing the District through September 2020. Financial forward contracts for electricity and gas had a net negative fair value of $2,231,862 at December 31, 2018, and are reflected in the financial statements as deferred inflows of resources and deferred outflows of resources.
- At December 31, 2017, the District had entered into various short-term financial forward sales and purchase contracts committing the District through December 2019. Financial forward contracts for electricity and gas had a net positive fair value of $18,113 at December 31, 2017, and are reflected in the financial statements as deferred inflows of resources and deferred outflows of resources.

Note 9 - Self-Insurance

In the normal course of business, the District is exposed to various risks of loss related to liability claims, property damage, and employee health and welfare programs. The District participates in the following self-insurance programs to protect against such losses.

Public Utility Risk Management Services Self-Insurance Fund
The District is a member of the Public Utility Risk Management Services (PURMS) Self-Insurance Fund. PURMS is a public entity risk pool organized on December 30, 1976, in the State of Washington under RCW 54.16.200 and interlocal governmental agreements. It currently operates under RCW 48.62. Its members include 18 public utility districts and one non-profit mutual corporation. The objectives of PURMS are to formulate, develop, and administer a program of self-insurance in order to obtain lower costs for the various coverages provided to its members and to develop a comprehensive loss control program.

The risks shared by the members are defined in the Self-Insurance Agreement (SIA). The fund consists of three pools for liability, property, and health and welfare coverage. The pools operate independently of one another. All members do not participate in all pools. The District does not participate in the health and welfare pool.

The pools are governed by a Board of Directors which consists of one designated representative from each participating member. The Administrator and an elected Administrative Committee are responsible for conducting the business affairs of the Pool.

PURMS engages an independent qualified actuary on an annual basis to determine the claim financing levels, liabilities for unpaid claims, and claims adjustment expenses for the Liability Pool and the Property Pool. A copy of these reports is provided to the Washington State Risk Manager and to the

Washington State Auditor's Office. Audit reports for the Trust are available from the Washington State Auditor's Office (Report Nos. 1022049 and 1022326 for fiscal year 2017 and 1019718 and 1019719 for fiscal year 2016).

The pools are fully funded by its current and former members. Members that withdraw from PURMS are responsible for their share of contributions to the pools for any unresolved, unreported, and in-process claims for the period they were signatory to the SIA. Claims are filed by members with the Administrator, Pacific Underwriters, Seattle, WA, which serves by contract as the fund's Administrator and provides claims adjustment and loss prevention services.

Settled claims have not exceeded insurance coverage in any of the past 3 fiscal years.

Liability Risk Pool

The liability pool has a $1 million liability coverage limit per occurrence. In addition, the fund maintains $35 million of excess general liability insurance over the $1 million retention. A second layer of excess general liability insurance of $25 million is also maintained over the first layer of $35 million. The fund maintains $35 million in directors and officers liability coverage with a retention level of $500,000. The fund also maintains $10 million in cyber security liability coverage with a retention level of $500,000. The deductible is $250.

The liability pool reserve balance is $3.45 million. Liability assessments are levied at the beginning of each calendar year to replenish the reserves to the designated level and at any time during the year that the actual reserves drop to $500,000 less than the designated level. The minimum reserve balance may be increased above $3.45 million through member assessments to meet legal funding requirements based on annual actuarial reviews.

Property Risk Pool

The majority of the property in the property pool has a self-insured retention of $250,000 per property loss. Certain classes of property have higher retention requirements up to $750,000. In addition, the fund purchases $200 million of excess insurance over the $250,000 (or higher) retention level. The deductible varies but for most classes of property it is $250.

The designated property pool reserve balance is $750,000. Property assessments are levied at the beginning of each calendar year to replenish the reserves to the designated level and at any time during the year that the actual reserves drop below $500,000. The minimum reserve balance may be increased above $750,000 through member assessments to meet legal funding requirements based on annual actuarial reviews.

Central Washington Public Utilities Unified Insurance Program Trust

The District is a member of the Central Washington Public Utilities Unified Insurance Program Trust (Trust). The Trust was organized October 1, 1982, pursuant to the provisions of RCW Title 54 and interlocal governmental agreements. The Trust's general objectives are to provide a central fund for the collection and disbursement of employee benefit premiums and claims involving medical, dental, life, and long-term disability coverage. The Trust is administered by a Board of Trustees consisting of an appointed Trustee and Alternate Trustee from each of the seven member Districts. The Trustees are authorized to negotiate, obtain, maintain insurance policies, and authorize disbursements made from the Trust to Third-Party Administrators or other entities. Effective August 1, 2002, the Trust established a self-insured medical plan. Effective January 1, 2009, the Trust established a self-insured dental plan. Both plans are approved by the State Risk Office. The audit reports for the Trust are available from the Washington State Auditor's Office (Report Nos. 1021910 for fiscal year 2017 and 1019357 and 1019358 for fiscal year 2016).

Unemployment Claims

The District pays unemployment claims on a reimbursement basis with claims administered by the Washington State Department of Employment Security.

Short-Term Disability Insurance

The District self-pays short-term disability benefits through a 70% salary continuation program from the 41st consecutive scheduled hour of inability to work until the employee either recovers and returns to work or completes the waiting period required for long-term disability insurance eligibility, whichever is earlier. Certification of illness or injury by a licensed, competent medical authority is required. The District utilizes a Third-Party Administrator who provides medical oversight and advice-to-pay for disability claims.

Note 10 – Associated Organizations

Participation in Northwest Open Access Network, Inc. (NoaNet)

The District, along with nine other Washington State public entities, is a member of NoaNet, a Washington nonprofit mutual corporation. NoaNet was incorporated in February 2000 to provide a broadband communications backbone over public benefit fibers leased from BPA throughout Washington. The network began commercial operation in January 2001.

As a member of NoaNet and as allowed by RCW 54.16, the District can guarantee certain portions of NoaNet debt based on its proportionate membership share of 20.72%. The District had no guarantees as of December 31, 2018 or 2017. NoaNet reserves the right to assess members to cover deficits from operations. There have been no member assessments since 2011.

NoaNet recorded a decrease in net position of $5,362,412 (unaudited) for 2018 and a decrease of $9,351,838 (audited) for 2017. In accordance with GAAP a proportionate share of these gains/losses has not been recorded by the District.

Financial statements for NoaNet may be obtained by writing to: Northwest Open Access Network, Chief Financial Officer, 7195 Wagner Way, Suite 104, Gig Harbor, WA 98335.

Participation in National Information Solutions Cooperative (NISC)

NISC is an information technology company that develops and supports software and hardware solutions for Member-Owners who are primarily utility cooperatives and telecommunications companies across the nation. NISC is an industry leader providing advanced, integrated IT solutions for consumer and subscriber billing, accounting, engineering & operations, as well as many other leading-edge IT solutions.

NISC was formed July 2000 as a consolidation of Central Area Data Processing Cooperative (CADP) and North Central Data Cooperative (NCDC). Both predecessor organizations were formed in the mid 1960s and had a history of serving energy and telecommunications cooperatives with information processing services and accounting and billing software. NISC has 828 energy and telecommunications Members in all 50 states, American Samoa, Palau, and Canada.

The membership interest in NISC is stated at cost, plus patronage capital credits issued, less distributions received, which as of December 31, 2018 was $65,938. This amount is reported in the Other Receivables balance on the Statement of Net Position.

Financial statements for NISC may be obtained by writing to: NISC, One Innovation Circle, Lake Saint Louis, MO 63367.

Note 11 - Telecommunications Services

The District has installed and continues to build out a fiber optic backbone system in its service area to provide wholesale telecommunication services and for internal use by the electric system. The District has connected its fiber optic system to NoaNet’s fiber optic communications system. The District regularly reviews its product offerings and makes adjustments as needed. In 2017, the District began offering an Access Internet service option.

Broadband operations and capital activity for the years ended December 31, 2018 and 2017 follows:

Broadband	2018	2017
Operating Revenues		
Ethernet	$1,413,642	$1,391,655
TDM	36,500	56,463
Internet Transport Service	48,551	50,181
Fixed Wireless	43,098	64,924
Access Internet	177,167	76,323
Other Revenue	531,491	524,954
Total Operating Revenues	***$2,250,449***	***$2,164,500***
Operating Expenses		
General Expenses	$848,046	$769,268
Other Maintenance	88,943	71,666
NoaNet Maintenance Expense	-	3,754
Subtotal before depreciation	936,989	844,688
Depreciation	795,002	777,331
Total Operating Expenses	***$1,731,991***	***$1,622,019***
Nonoperating Expenses	$9,588	$9,675
Capital Investment (Annual)	$1,287,690	$1,040,811
Capital Investment (Cumulative)	$23,047,972	$21,760,282

The above amounts are included in summarized line items on the Statement of Net Position and Statement of Revenues, Expenditures, and Changes in Net Position

NOTE 12 - Other Commitments and Contingent Liabilities

Energy Northwest - Nine Canyon Wind Project

The Nine Canyon Wind Energy Project is owned and operated by Energy Northwest. The District, along with nine other public utilities, is a participant in Phases I and III of the Project. Under its Power Purchase Agreement, the District is obligated to pay its percentage share of the annual debt service of each project Phase and the operation and maintenance costs of the project in return for its percentage share of project output, whether or not the project is operating or capable of operating. Under the agreement, the District is obligated to pay an amended percentage share effective May 2008 when Phase III achieved commercial operation. Under a step-up provision, the District could be required to pay up to a maximum of 125% of its percentage share in the event of default by another purchaser. The Agreement limits Energy Northwest's total annual operation and maintenance cost to $4 million prior to Phase III Commercial Operation and to $7 million post Phase III Commercial Operation. These limits will change annually based on certain inflation indexes.

The agreement terminates July 1, 2030. The District's applicable percentage share obligations are:

Allocation of Cost	District % Share	District % Share under Step-up Provision
Debt Service - Phase I	6.25%	7.81%
Debt Service - Phase III	18.63%	23.29%
O&M Costs - Prior to Phase III Commercial Operation	4.72%	5.90%
O&M Costs - Post Phase III Commercial Operation	9.39%	11.74%

Energy Independence Act (Initiative 937)

With the passage of Initiative 937 by Washington voters in November 2006, all electric utilities with more than 25,000 customers are required to purchase renewable energy in gradually increasing percentages and to establish and meet a minimum biennial energy conservation target. As of December 31, 2012, the District had renewable energy contracts in place that satisfy the Initiative's initial renewable target of 3% by 2012. The renewable requirement increases to 9% of retail load in 2016, and finally to 15% of retail load in the year 2020. Total incremental expenses for qualifying renewable resources plus the cost of renewable energy credits are limited to 4% of the annual retail revenue requirement.

In 2018, the Commission established the minimum Biennial Conservation Target for 2018–2019 of 2.25 aMW. The District is on track to meet or exceed the goal.

In 2015, the Commission established the minimum Biennial Conservation Target for 2016–2017 of 1.97 aMW. The District exceeded the goal with 2.60 aMW.

Operating Leases

The District leases electrical testing equipment on an annual basis. The annual rental cost was $27,910 for 2018 and $27,910 for 2017.

The District has entered into an agreement to lease a parcel of land upon which the District constructed the Finley CT in 2001. The initial agreement was for the period of June 1, 2001, to June 1, 2021. In 2018, the agreement was mutually renegotiated and the lease was canceled.

The annual rental cost for the land was $48,649 and $58,008 for 2018 and 2017, respectively.

Required Supplementary Information

Public Utility District No. 1 of Benton County

Schedule of Proportionate Share of the Net Pension Liability

PERS Plan 1
As of June 30, 2018
Last 10 Fiscal Years

	2018	2017	2016	2015	2014
Employer's proportion of the net pension liability (asset)	0.102845%	0.108446%	0.111198%	0.114841%	0.115142%
Employer's proportionate share of the net pension liability	$4,593,093	$5,145,847	$5,971,856	$6,007,252	$5,800,332
Employer's covered payroll	$13,682,851	$13,503,725	$13,093,469	$12,546,922	$12,460,407
Employer's proportionate share of the net pension liability as a percentage of covered payroll	34%	38%	46%	48%	47%
Plan fiduciary net position as a percentage of the total pension liability	63%	61%	57%	59%	61%

Notes to Schedule:
There are no factors at year-end that significantly affect trends in the amounts reported above.
The ten year information will be provided as it is available.

Public Utility District No. 1 of Benton County

Schedule of Proportionate Share of the Net Pension Liability

PERS Plan 2/3
As of June 30, 2018
Last 10 Fiscal Years

	2018	2017	2016	2015	2014
Employer's proportion of the net pension liability (asset)	0.132333%	0.136394%	0.139973%	0.145674%	0.143243%
Employer's proportionate share of the net pension liability	$2,259,468	$4,739,040	$7,047,530	$5,205,015	$2,895,458
Employer's covered payroll	$13,682,851	$13,371,937	$12,986,531	$12,446,584	$12,271,821
Employer's proportionate share of the net pension liability as a percentage of covered payroll	17%	35%	54%	42%	24%
Plan fiduciary net position as a percentage of the total pension liability	96%	91%	86%	89%	93%

Notes to Schedule:
There are no factors at year-end that significantly affect trends in the amounts reported above.
The ten year information will be provided as it is available.

Public Utility District No. 1 of Benton County

Schedule of Employer Contributions

PERS Plan 1
As of December 31, 2018
Last 10 Fiscal Years

	2018	2017	2016	2015	2014
Statutorily or contractually required contributions	$689,118	$678,004	$636,516	$571,651	$514,217
Contributions in relation to the statutorily or contractually required contributions	(689,118)	(678,004)	(636,516)	(571,651)	(514,217)
Contribution deficiency (excess)	-	-	-	-	-
Covered employer payroll	$13,617,368	$13,751,364	$13,204,856	$12,895,713	$12,475,479
Contributions as a percentage of covered payroll	5%	5%	5%	4%	4%

Notes to Schedule:
There are no factors at year-end that significantly affect trends in the amounts reported above.
The ten year information will be provided as it is available.

Public Utility District No. 1 of Benton County

Schedule of Employer Contributions

PERS Plan 2/3
As of December 31, 2018
Last 10 Fiscal Years

	2018	2017	2016	2015	2014
Statutorily or contractually required contributions	$1,021,040	$936,046	$815,729	$720,845	$612,316
Contributions in relation to the statutorily or contractually required contributions	(1,021,040)	(936,046)	(815,729)	(720,845)	(612,316)
Contribution deficiency (excess)	-	-	-	-	-
Covered employer payroll	$13,617,368	$13,675,514	$13,096,369	$12,790,442	$12,335,880
Contributions as a percentage of covered payroll	7%	7%	6%	6%	5%

Notes to Schedule:
There are no factors at year-end that significantly affect trends in the amounts reported above.
The ten year information will be provided as it is available.

Your trusted energy partner

STATISTICAL SECTION

2018

Your trusted energy partner

STATISTICAL SECTION

This part of the District's comprehensive annual financial report presents detailed information as a context for understanding what the information in the financial statements, note disclosures, and required supplementary information says about the District's overall financial health.

FINANCIAL TRENDS

These schedules contain trend information to help the reader understand how the District's financial performance and well-being have changed over time.

REVENUE CAPACITY

These schedules contain information to help the reader assess the District's most significant revenue source, electric sales.

DEBT CAPACITY

These schedules present information to help the reader assess the affordability of the District's current levels of outstanding debt and the ability of the District to issue additional debt in the future.

DEMOGRAPHIC AND ECONOMIC INFORMATION

These schedules offer demographic and economic indicators to help the reader understand the environment within which the District's financial activities take place.

OPERATING INFORMATION

These schedules contain service and infrastructure data to help the reader understand how the information in the District's financial report relates to the services the District provides and the activities it performs.

STATEMENT OF REVENUES, EXPENSES, AND CHANGES IN NET POSITION

For the years ended December 31 (unaudited)

	2018	2017	2016	2015
OPERATING REVENUES				
Sales of Electric Energy - Retail	$129,792,002	$130,811,427	$120,438,526	$116,820,422
Secondary Market Sales	24,618,712	14,542,756	14,808,281	17,678,932
Transmission of Power for Others	1,450,552	1,284,536	915,169	690,639
Broadband Revenue	2,250,450	2,164,500	2,046,068	2,024,661
Other Revenue	1,756,987	1,338,933	1,653,580	1,670,466
Total Operating Revenues	159,868,703	150,142,152	139,861,624	138,885,120
OPERATING EXPENSES				
Purchased Power	92,569,841	83,025,012	80,889,012	82,340,739
Purchased Transmission & Ancillary Services	13,621,653	13,205,172	12,997,169	12,816,306
Conservation Program	(20,404)	544,381	307,113	417,113
Transmission Operations & Maintenance	163,952	199,419	260,519	81,305
Distribution Operations & Maintenance	9,645,034	9,799,347	9,029,751	9,051,462
Broadband Expense	936,989	844,688	931,789	1,022,025
Customer Accounting, Collection & Information	4,267,684	3,735,098	3,411,338	3,794,832
Administrative & General	6,660,053	7,181,596	6,331,749	7,229,048
Taxes	13,812,993	14,018,894	12,630,500	12,263,706
Depreciation	9,854,391	10,177,574	12,630,490	13,207,539
Total Operating Expenses	151,512,186	142,731,181	139,419,430	142,224,075
OPERATING INCOME/(LOSS)	**8,356,517**	**7,410,971**	**442,194**	**(3,338,955)**
NONOPERATING REVENUES & EXPENSES				
Interest & Other Nonoperating Income	1,591,005	1,167,737	647,361	748,220
Interest Expense & Other Nonoperating Expense	(2,832,268)	(2,910,007)	(2,664,442)	(2,756,755)
Debt Premium Amortization & Loss on Defeased Debt (1)	453,711	492,959	143,522	419,819
Unrealized Gain/(Loss) on Investments	51,590	(33,130)	(4,170)	24,568
Assessments to Joint Venture	-	-	-	-
Total Nonoperating Revenues & Expenses	(735,962)	(1,282,441)	(1,877,729)	(1,564,148)
INCOME/(LOSS) BEFORE CONTRIBUTIONS				
AND EXTRAORDINARY ITEM	**7,620,555**	**6,128,530**	**(1,435,535)**	**(4,903,103)**
CAPITAL CONTRIBUTIONS	2,124,000	1,990,641	1,164,819	2,471,250
EXTRAORDINARY ITEM	-	-	-	-
CHANGE IN NET POSITION	**9,744,555**	**8,119,171**	**-270,716**	**-2,431,853**

NET POSITION

For the years ended December 31 (unaudited)

	2018	2017	2016	2015
Net Investment in Capital Assets	$74,961,846	$64,407,047	$58,672,489	$68,039,579
Restricted for Debt Service	1,107,865	1,107,865	1,107,865	1,083,997
Restricted Settlement Proceeds	-	-	-	-
Unrestricted(2)	57,829,867	58,640,111	56,255,498	47,182,992
Total Net Position	**$133,899,578**	**$124,155,023**	**$116,035,852**	**$116,306,568**

(1) Governmental Accounting Standards Board Statement No. 65 was implemented effective 2012 classifying debt issuance costs as expense when incurred. 2011 was restated for comparative purposes in the financial statements.

(2) Governmental Accounting Standards Board Statement No. 65 was implemented effective 2012 classifying debt issuance costs as expense when incurred. 2010 was restated for comparative purposes and the cumulative effect of $(703,941) for prior years has been applied to the Unrestricted balance.

(3) Governmental Accounting Standards Board Statement No. 68 was implemented effective 2015 recognizing liabilities, deferred outflows of resources, deferred inflows of resources, and expenses relating to pension liabilities. The cumulative effect on net pension for 2014 was $12,217,716.

2014 restated[3]	2013	2012	2011 restated	2010 restated	2009
$117,641,940	$115,079,778	$110,799,843	$105,228,051	$94,137,792	$91,942,100
23,325,872	18,232,140	14,048,971	25,773,429	30,122,467	38,885,352
632,528	776,957	797,837	397,063	230,978	229,429
2,191,287	1,980,605	1,620,054	1,617,919	1,181,892	927,041
1,472,425	1,249,791	1,879,829	1,424,566	1,403,220	1,348,716
145,264,052	137,319,271	129,146,534	134,441,028	127,076,349	133,332,638
84,714,618	77,877,737	68,652,534	75,475,402	78,768,878	75,055,153
12,925,752	11,677,803	11,260,088	10,276,334	9,315,582	10,074,812
89,940	1,315,642	405,589	808,494	1,795,846	679,406
81,220	82,066	12,684	17,575	26,909	30,026
8,540,568	8,092,079	8,191,232	7,499,422	7,163,781	7,092,143
982,869	890,521	696,415	674,581	712,433	577,958
3,788,799	4,026,839	3,954,421	3,388,582	3,773,740	4,011,243
6,909,615	6,444,642	6,276,795	5,384,210	5,396,629	5,557,985
12,394,110	12,144,846	11,814,545	10,890,913	9,513,213	9,956,874
12,894,915	12,671,992	11,642,052	10,769,424	9,751,161	9,367,272
143,322,406	135,224,167	122,906,355	125,184,937	126,218,172	122,402,872
1,941,646	**2,095,104**	**6,240,179**	**9,256,091**	**858,177**	**10,929,766**
525,553	612,901	668,774	602,075	488,924	358,811
(2,844,753)	(2,913,078)	(3,001,895)	(2,958,273)	(2,703,991)	(2,278,184)
445,518	459,652	459,198	(237,799)	(674,641)	(34,128)
173,722	(241,104)	19,862	-	-	-
-	-	-	(70,300)	(129,550)	(236,393)
(1,699,960)	(2,081,629)	(1,854,061)	(2,664,297)	(3,019,258)	(2,189,894)
241,686	**13,475**	**4,386,118**	**6,591,794**	**(2,161,081)**	**8,739,872**
3,834,420	2,706,411	2,368,597	1,394,438	1,271,831	3,072,025
-	-	-	-	-	-
4,076,106	**2,719,885**	**6,754,715**	**7,986,232**	**-889,250**	**11,811,897**

2014[3]	2013	2012	2011	2010	2009
$65,363,895	$62,492,766	$58,085,620	$59,836,918	$61,389,146	$64,930,735
140,017	140,017	140,017	140,017	706,157	-
-	-	-	-	-	86,955
53,234,509	64,247,248	65,934,508	57,428,495	47,323,895	45,848,815
$118,738,421	**$126,880,031**	**$124,160,145**	**$117,405,430**	**$109,419,198**	**$110,866,505**

REVENUES AND CONSUMPTION BY CUSTOMER CLASS

For the years ended December 31 (unaudited)

	2018	2017	2016	2015
AVERAGE NUMBER OF CUSTOMERS				
Residential	44,550	43,870	43,157	42,375
General Service	5,937	5,919	5,840	5,737
Industrial	5	5	5	3
Irrigation	983	987	790	794
Miscellaneous	2,269	2,330	1,850	1,853
Total	53,744	53,111	51,642	50,762
RETAIL ELECTRIC SALES (IN THOUSANDS) (1)				
Residential	$59,461	$62,861	$53,643	$51,402
General Service	37,236	36,690	34,223	33,706
Industrial	3,438	3,440	3,214	3,051
Irrigation	23,517	21,825	22,348	22,283
Miscellaneous	678	673	656	616
Total	$124,330	$125,489	$114,084	$111,058
RETAIL ELECTRIC SALES IN MWh				
Residential	697,107	759,634	661,742	665,505
General Service	546,595	545,884	525,603	530,283
Industrial	65,997	67,084	64,612	66,942
Irrigation	424,610	405,805	435,186	468,202
Miscellaneous	6,540	6,691	6,935	7,090
Total	1,740,849	1,785,098	1,694,078	1,738,022
AVERAGE REVENUE PER kWh (CENTS) (1)				
Residential	8.53	8.28	8.11	7.72
General Service	6.81	6.72	6.51	6.36
Industrial	5.21	5.13	4.97	4.56
Irrigation	5.54	5.38	5.14	4.76
Miscellaneous	10.37	10.05	9.46	8.69
Average - All Classes	7.14	7.03	6.73	6.39

(1) Includes total retail revenue (per kWh charge and base charge); excludes city utility occupation tax, bad debt expense, and accrued unbilled revenue.

2014	2013	2012	2011	2010	2009
41,758	41,322	40,645	40,201	39,687	39,220
5,643	5,572	5,499	5,421	5,356	5,289
3	3	3	3	3	3
788	772	721	722	736	746
1,861	1,852	1,842	1,850	1,834	1,816
50,053	49,521	48,710	48,197	47,616	47,074
$52,862	$52,924	$50,678	$49,258	$43,707	$43,704
33,829	32,959	32,416	29,864	27,575	25,605
3,250	3,176	3,223	2,780	2,167	1,483
22,794	19,630	18,817	17,602	15,642	16,290
616	622	821	790	762	733
$113,351	$109,311	$105,955	$100,294	$89,853	$87,815
696,804	697,887	668,018	687,953	654,775	721,720
533,008	519,493	512,797	503,471	503,037	530,255
71,869	69,803	70,575	65,411	55,365	38,909
472,643	402,619	385,738	381,999	371,321	427,269
6,998	6,972	8,148	9,528	8,304	8,188
1,781,322	1,696,774	1,645,276	1,648,362	1,592,802	1,726,341
7.59	7.58	7.59	7.16	6.68	6.06
6.35	6.34	6.32	5.93	5.48	4.83
4.52	4.55	4.57	4.25	3.91	3.81
4.82	4.88	4.88	4.61	4.21	3.81
8.81	8.92	10.08	8.29	9.17	8.95
6.36	6.44	6.44	6.08	5.64	5.09

RETAIL RATES [1]

For the years ended December 31 (unaudited)

	2018	2017	2016	2015
Residential				
Daily System Charge[2]	$0.62	$0.62	$0.55	$0.52
Monthly Base Charge (single phase)	-	-	-	-
Energy Charge (cents/kWh)	7.18	7.18	7.18	6.84
Small General Service				
Daily System Charge[2] (Single-Phase)	$0.54	$0.54	$0.46	$0.44
Daily System Charge[2] (Multi-Phase)	$0.80	$0.80	$0.68	$0.65
Monthly Base Charge (single phase)	-	-	-	-
Energy Charge Effective 2010 (cents/kwh)	6.44	6.44	6.44	6.14
Prior to 2010				
First 20,000 kwh	-	-	-	-
Over 20,000 kwh	-	-	-	-
Medium General Service				
Daily System Charge[2] (Single-Phase)	$1.08	$1.08	$0.92	$0.88
Daily System Charge[2] (Multi-Phase)	$1.61	$1.61	$1.38	$1.32
Monthly Base Charge (single phase)	-	-	-	-
Energy Charge (cents/kwh)				
Summer (Effective 2011)	5.09	5.09	5.09	4.85
Winter (Effective 2011)	5.97	5.97	5.97	5.69
Summer (Prior to 2011)				
First 20,000 kwh	-	-	-	-
Over 20,000 kwh	-	-	-	-
Winter (Prior to 2011)				
First 20,000 kwh	-	-	-	-
Over 20,000 kwh	-	-	-	-
Demand Charge	$9.55	$9.55	$8.77	$8.36
Large General Service				
Daily System Charge[2] (Multi-Phase)	$1.96	$1.96	$1.38	$1.32
Monthly Base Charge (multi phase)	-	-	-	-
Energy Charge - Non Time of Use (cents/kwh)				
Summer (Effective 2010)	4.11	4.11	4.11	3.92
Winter (Effective 2010)	4.92	4.92	4.92	4.69
Summer (Prior to 2010)				
First 20,000 kwh	-	-	-	-
Over 20,000 kwh	-	-	-	-
Winter (Prior to 2010)				
First 20,000 kwh	-	-	-	-
Over 20,000 kwh	-	-	-	-
Demand Charge	$7.93	$7.93	$7.45	$7.10

(1) These rates represent the typical customer. Other monthly charges may apply.
Other rate schedules also in effect are small irrigation, large irrigation, industrial, and miscellaneous.

(2) The Daily System Charge was effective 9/1/2015 and replaced the Monthly Base Charge.
The rate is per day and applied to the number of days in the billing period.

2014	2013	2012	2011	2010	2009
-	-	-	-	-	-
$11.05	$11.05	$11.05	$10.50	$9.20	$8.80
6.84	6.84	6.84	6.49	6.05	5.78
-	-	-	-	-	-
-	-	-	-	-	-
$11.95	$11.95	$11.95	$11.45	$11.45	$10.70
6.14	6.14	6.14	5.88	5.47	-
-	-	-	-	-	5.13
-	-	-	-	-	3.35
-	-	-	-	-	-
-	-	-	-	-	-
$17.55	$17.55	$17.55	$16.30	$14.25	$13.20
4.85	4.85	4.85	4.51	-	-
5.69	5.69	5.69	5.29	-	-
-	-	-	-	4.45	4.46
-	-	-	-	3.55	2.74
-	-	-	-	5.29	5.24
-	-	-	-	4.19	3.33
$8.36	$8.36	$8.36	$7.77	$7.13	$6.60
-	-	-	-	-	-
$26.10	$26.10	$26.10	$24.15	$18.60	$17.40
3.89	3.89	3.89	3.59	3.31	-
4.65	4.65	4.65	4.30	3.97	-
-	-	-	-	-	4.33
-	-	-	-	-	2.89
-	-	-	-	-	4.72
-	-	-	-	-	3.56
$7.00	$7.00	$7.00	$6.48	$5.99	$5.60

PRINCIPAL RATEPAYERS

For the years ended December 31 (unaudited)

2018

Ratepayer's Rate Class [1]	Rank	Retail Sales[2]	Percentage of Total Retail Electric Sales	kWh	aMW	Percentage of Total kWh
Large Irrigation Customer 1	1	$9,945,880	8.0%	178,271,990	20.4	10.2%
Large Irrigation Customer 2	2	4,071,651	3.3%	76,009,652	8.7	4.4%
Large Industrial Customer 1	3	3,446,457	2.8%	66,128,348	7.5	3.8%
Large Irrigation Customer 3	4	3,146,155	2.5%	56,702,161	6.5	3.3%
Large General Customer 1	5	2,038,563	1.6%	26,868,841	3.1	1.5%
Large Irrigation Customer 4	6	1,930,766	1.6%	34,674,552	4.0	2.0%
Large Irrigation Customer 5	7	1,838,172	1.5%	32,010,717	3.7	1.8%
Large General Customer 2	8	1,698,403	1.4%	23,178,513	2.6	1.3%
Large Irrigation Customer 6	9	1,384,273	1.1%	26,830,661	3.1	1.5%
Large General Customer 3	10	1,249,998	1.0%	18,521,311	2.1	1.1%
Large General Customer 4	-	-	-	-	-	-
		$30,750,318	24.8%	539,196,746	61.7	30.9%
Total All Ratepayers		**$124,330,782**		**1,740,949,265**		

(1) To preserve confidentiality, individual ratepayer names are not disclosed.
(2) Retail sales are before bad debt expense and unbilled revenue.

2009

Rank	Retail Sales[(2)]	Percentage of Total Retail Electric Sales	kWh	aMW	Percentage of Total kWh
1	$6,829,342	7.4%	188,534,878	21.5	10.9%
2	2,581,574	2.8%	71,045,636	8.1	4.1%
3	1,478,543	1.6%	38,899,317	4.4	2.3%
4	1,390,527	1.5%	39,863,383	4.6	2.3%
9	1,172,963	1.3%	23,156,692	2.6	1.3%
6	1,177,696	1.3%	33,573,722	3.8	1.9%
5	1,310,959	1.4%	35,467,244	4.0	2.1%
10	1,006,737	1.1%	21,564,477	2.5	1.2%
8	814,742	0.9%	22,788,000	2.6	1.3%
-	-	-	-	-	-
7	1,096,953	1.2%	25,646,657	2.9	1.5%
	$18,860,036	20.5%	500,540,006	57.0	28.9%
	$91,942,100		**1,726,340,980**		

RATIOS OF OUTSTANDING DEBT

For the years ended December 31 (unaudited)

	2018	2017	2016	2015
Revenue Bonds	$53,335,000	$56,905,000	$59,950,000	$49,735,000
Unamortized Premium & Discount	3,869,777	4,336,311	4,845,315	3,099,629
Total Outstanding Revenue Debt	$57,204,777	$61,241,311	$64,795,315	$52,834,629
Total Revenue Debt to Operating Revenues	36%	41%	46%	38%
Total Revenue Debt to Total Assets	26%	28%	30%	26%
Total Revenue Debt per Ratepayer	$1,064	$1,153	$1,255	$1,041

DEBT MARGIN INFORMATION (1)

For the year ended December 31, 2018 (unaudited)

Net Revenues January 2018 - December 2018(2)	$22,994,646
Maximum Future Annual Debt Service (2020)	$6,523,987
Maximum Allowable Annual Debt Service per Bond Covenants (2)	$18,395,717
Allowable Additional Annual Debt Service	$11,871,730

(1) As a proprietary fund, the District does not have a legal debt limitation. However, the District's bond resolutions establish restrictions on the issuance of additional debt based on a defined formula.

(2) The bond covenants state that new parity bonds may be issued if the amount of net revenue for any twelve consecutive months in the prior 24 month period divided by the maximum annual debt service in any future year is not less than 125%.

(3) With implementation of GASB 65 in 2012, bond issuance costs are expensed in the year incurred. The District restated 2011 for comparative purposes to match the financial statements. In addition, prior to 2011, the unamortized loss on defeasance is included in Total Outstanding Revenue Debt.

2014 restated	2013	2012	2011[3]	2010	2009
$53,600,000	$56,635,000	$59,575,000	$62,330,000	$59,165,000	$50,865,000
3,572,728	4,072,098	4,597,935	5,134,338	452,684	597,829
$57,172,728	$60,707,098	$64,172,935	$67,464,338	$59,617,684	$51,462,829
39%	44%	50%	50%	47%	39%
27%	29%	31%	34%	32%	29%
$1,142	$1,226	$1,317	$1,400	$1,252	$1,093

DEBT SERVICE COVERAGE

For the years ended December 31 (unaudited)

	2018	2017	2016	2015
DEBT SERVICE CALCULATION				
Change in Net Position	$9,744,555	$8,119,171	($270,716)	($2,431,853)
Adjustments to (from) Change in Net Position				
Depreciation	9,854,391	10,177,574	12,630,490	13,207,539
Prepaid Power (1)	1,017,144	1,017,144	1,017,144	1,017,144
Interest Expense	2,832,268	2,910,007	2,664,442	2,756,755
Debt Discount/Premium Amortization & Bond Issue Costs	(453,711)	(492,959)	(143,522)	(419,819)
GASB 68 Pension noncash entry	(1,371,215)	(593,733)	(308,366)	(157,447)
Transfer (to) from Rate Stabilization	-	-	-	-
REVENUE AVAILABLE FOR DEBT SERVICE	**$21,623,432**	**$21,137,204**	**$15,589,472**	**$13,972,319**
DEBT SERVICE	**$6,519,987**	**$6,226,648**	**$5,351,412**	**$4,767,944**
DEBT SERVICE COVERAGE RATIO	**3.32**	**3.39**	**2.91**	**2.93**

(1) White Creek Wind Project amortization and Bonneville Power Administration prepaid power.

2014 restated	2013	2012	2011	2010	2009
$4,076,106	$2,719,886	$6,754,715	$7,986,232	($889,251)	$11,811,897
12,894,915	12,671,992	11,642,052	10,769,424	9,751,161	9,367,272
1,017,144	907,457	578,400	578,400	578,400	578,400
2,844,753	2,913,078	3,001,895	2,958,273	2,683,991	2,259,809
(445,518)	(459,652)	(459,198)	237,799	674,641	34,128
(245,062)	-	-	-	-	-
-	-	-	(2,369,920)	-	-
$20,142,338	**$18,752,761**	**$21,517,864**	**$20,160,208**	**$12,798,942**	**$24,051,506**
$5,966,784	**$5,965,509**	**$5,969,064**	**$5,002,221**	**$5,445,961**	**$5,131,680**
3.38	**3.14**	**3.60**	**4.03**	**2.35**	**4.69**

PRINCIPAL EMPLOYERS - TRI-CITIES METROPOLITAN STATISTICAL AREA

For the years ended December 31 (unaudited)

		2018		
Employer	**Product/Service**	**Employees**	**Rank**	**Percentage of Total MSA Nonfarm Employment**
Battelle/Pacific NW National Laboratory	Research/National Laboratory	4,500	1	3.9%
Kadlec Medical Center	Health Care	3,532	2	3.1%
ConAgra/Lamb Weston Inc.	Food Processing	3,000	3	2.6%
Bechtel National, Inc.	Engineering & Construction	2,943	4	2.6%
Kennewick School District	Education	2,336	5	2.0%
Washington River Protection Solutions	Environmental Remediation	2,129	6	1.9%
Pasco School District	Education	2,015	7	1.8%
Mission Support Alliance, LLC	Support Services Hanford	1,902	8	1.7%
CH2MHill Hanford Group Inc./CHG	Environmental Engineering	1,682	9	1.5%
Richland School District	Education	1,500	10	1.3%
Fluor Hanford Inc./URS	Environmental Engineering	-	-	-
Tyson Fresh Meats/Iowa Beef	Meat Packing	-	-	-
Total		25,539		22.4%

Source: Tri-City Development Council

2009		
Employees	Rank	Percentage of Total MSA Nonfarm Employment
4,033	1	4.2%
1,535	8	1.6%
2,128	4	2.2%
2,130	3	2.2%
1,750	7	1.8%
-	-	-
1,900	5	2.0%
-	-	-
1,170	10	1.2%
1,350	9	1.4%
3,630	2	3.7%
1,800	6	1.9%
21,426		22.2%

DEMOGRAPHIC STATISTICS

For the years ended December 31 (unaudited)

	2018	2017	2016	2015
Population (1)				
Tri-Cities Metropolitan Statistical Area	289,960	283,830	279,170	275,740
Benton County	197,420	193,500	190,500	188,590
City of Kennewick	81,850	80,280	79,120	78,290
Prosser	6,125	5,965	5,940	5,845
Benton City	3,405	3,360	3,325	3,285
Total Personal Income - Benton County (000's) (2)	N/A	$9,034,074	$8,700,510	$8,449,267
Per Capita Income - Benton County (2)	N/A	$45,587	$44,968	$44,430
Unemployment Rate - Benton County (3)	5.8%	6.1%	7.0%	7.1%
Building Permits Issued (4)				
Kennewick	2,409	2,064	2,211	2,005
Benton County (Unincorporated)	1,014	997	919	784
Taxable Retail Sales - All of Benton County (5)	N/A	$3,905,643,498	$3,789,869,697	$3,612,773,217

(1) Source: Washington State Office of Financial Management. 2010 was restated with census numbers.
(2) Source: U.S. Bureau of Economic Analysis. 2008-2015 revised estimates from BEA in 2017.
(3) Source: December 2018 Unemployment Rates, Washington Employment Security Department
(4) Source: City of Kennewick and Benton County Building Departments
(5) Source: Washington State Department of Revenue

2014	2013	2012	2011	2010	2009
273,100	268,200	262,500	258,400	253,340	242,000
186,500	183,400	180,000	177,900	175,177	169,300
77,700	76,410	75,160	74,665	73,917	67,180
5,815	5,810	5,785	5,780	5,714	5,110
3,255	3,240	3,295	3,145	3,038	2,955
$7,774,240	$7,484,079	$7,559,526	$7,633,386	$7,216,864	$6,586,643
$41,699	$40,591	$41,447	$42,311	$40,898	$38,491
7.7%	7.9%	9.0%	9.2%	7.1%	7.4%
2,054	1,989	1,918	2,123	2,161	1,868
713	728	588	711	753	674
$3,284,581,847	$3,189,855,069	$2,937,655,298	$2,959,959,724	$2,731,890,939	$2,623,845,560

OPERATING INDICATORS

For the years ended December 31 (unaudited)

	2018	2017	2016	2015
Operating Expenses / Revenues	94.8%	95.1%	99.7%	102.4%
Total Electric Sales in MWh				
Retail Sales	1,740,849	1,785,098	1,694,078	1,738,022
Secondary Market Sales	558,160	609,721	576,289	662,886
Total MWh Sales	2,299,009	2,394,819	2,270,367	2,400,908
Average Annual kWh per Customer				
Residential	15,648	17,316	15,333	15,692
General Service	92,066	92,226	90,004	92,432
Industrial	13,199,344	13,416,822	12,922,400	22,313,962
Irrigation	431,954	411,150	550,578	589,675
Miscellaneous	2,882	2,872	3,749	3,826
Average Annual kWh per Customer - All Classes	32,392	33,611	32,804	34,239
Average Revenue per Customer				
Residential	$1,335	$1,433	$1,243	$1,213
General Service	6,272	6,199	5,860	5,875
Industrial	687,644	687,927	642,800	1,016,944
Irrigation	23,924	22,112	28,274	28,065
Miscellaneous	299	289	355	332
Average Revenue per Customer - All Classes	$2,313	$2,363	$2,209	$2,188
Additions to Electric Plant, excluding work-in-progress	$14,307,247	$14,248,483	$12,707,389	$10,795,807
Net Electric Utility Plant	$132,197,835	$125,666,747	$123,470,148	$120,791,227
Capitalized Payroll	$2,456,252	$2,435,631	$3,213,042	$2,201,618
Total Payroll Expense	$14,008,828	$13,864,893	$13,630,457	$12,967,615
Full Time Equivalent Employees (1)	149	152	153	152
Cooling Degree Days (2)	1,221	1,347	1,099	1,534
Heating Degree Days (2)	4,668	5,618	4,392	4,228
Annual Precipitation (inches) (2)	6.43	8.60	7.66	6.48
Peak Load (MW's) (3)	419	426	425	429

(1) Includes regular and temporary employees. In 2017, all years employee counts were reduced to account for shared employees billed

(2) Source: Hanford Meteorological Station
Heating degree days are indicators of household energy consumption for space heating. When the average outdoor temperature is less than 65 degrees Fahrenheit, most buildings require heat to maintain a temperature of 70 degrees inside. Similarily, when the average outdoor temperature is 65 degrees or more, most buildings require air-conditioning to maintain a temperature of 70 degrees inside.

(3) Source: The Energy Authority, Inc.

2014 restated	2013	2012	2011	2010	2009
98.7%	98.5%	95.2%	93.1%	99.3%	91.8%
1,781,322	1,696,774	1,645,277	1,648,362	1,592,802	1,726,341
717,847	580,417	687,098	929,688	693,299	667,758
2,499,169	2,277,191	2,332,375	2,578,050	2,286,101	2,394,099
16,687	16,889	16,435	17,113	16,498	18,402
94,455	93,233	93,253	92,874	93,920	100,256
23,956,495	23,267,593	23,525,055	21,803,603	18,454,887	12,969,692
599,801	521,528	535,005	529,085	504,513	572,747
3,760	3,764	4,423	5,150	4,528	4,509
35,589	34,264	33,777	34,201	33,451	36,673
$1,266	$1,281	$1,247	$1,225	$1,101	$1,114
5,995	5,915	5,895	5,509	5,148	4,841
1,083,292	1,058,609	1,074,442	926,683	722,372	494,424
28,926	25,428	26,098	24,380	21,253	21,836
331	336	446	427	415	403
$2,265	$2,207	$2,175	$2,081	$1,887	$1,865
$14,325,929	$14,261,262	$11,658,180	$16,575,853	$17,203,386	$10,736,615
$122,400,363	$123,009,752	$122,002,258	$121,789,048	$120,302,889	$115,807,257
$2,289,991	$2,344,440	$2,550,126	$2,858,449	$2,677,911	$2,363,236
$12,674,072	$12,573,298	$12,401,390	$11,637,285	$11,672,710	$11,585,291
152	153	150	152	154	158
1,426	1,318	1,057	884	870	1,235
4,611	5,320	4,940	5,466	4,896	5,679
6.53	5.38	8.18	4.45	10.19	5.47
431	415	394	380	392	402

BENTON P·U·D

RELIABLE PUBLIC POWER PROVIDER
American Public Power Association

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BentonPUD.org