REVISED DRAFT REPORT

City of Bainbridge Island
Electric Utility Municipalization
Feasibility Study

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Prepared for

City of Bainbridge Island
Bainbridge Island, Washington

by

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Electric Utility Municipalization Feasibility Study
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Executive Summary

Introduction

The City of Bainbridge Island, Washington (City) retained D. Hittle & Associates, Inc. (DHA) in 2016 to conduct an electric utility municipalization feasibility study. The study is intended to provide a review of the technical and economic issues related to the establishment of an electric utility owned and operated by the City or another public entity. Electric service is presently provided to the residents and businesses on Bainbridge Island by Puget Sound Electric (PSE), a privately-owned electric utility headquartered in Bellevue, Washington. This report summarizes the results and findings of the feasibility study. The law firm of Gordon Thomas Honeywell assisted DHA in the preparation of certain portions of this report.

In general, the concept of establishing a municipal electric utility would involve acquisition of the existing distribution and transmission system in the City, contracting for a supply of electric power and establishing the capability to operate and maintain the electric system. Although most electric utilities retain their own staff to operate their respective systems many operation and maintenance functions can be performed by contractors if desired.

Consumer-Owned Electric Utility Options

Consumer-owned electric utilities, often referred to as public power utilities, are common in the Pacific Northwest and across the United States. They provide all functions of electric service and are directed by board members, commissioners or city council members generally elected from within the service area of the utility. As such, local control is a significant element of public power utilities.

Public power utilities provide electric service at cost and are not-for profit and do not pay federal income taxes. They generally have access to loans at tax-exempt interest rates or to loans provided by the federal government at low interest rates. Public power utilities also have preference over private utilities in purchasing power generated at federal hydroelectric resources. In the Pacific Northwest, this is a significant benefit in that most public power utilities, other than those with significant generating resources of their own, purchase all, or nearly all, of their power supply requirement from the Bonneville Power Administration (BPA), a federal power marketing agency. BPA's wholesale price of power is relatively low compared to the cost of power from new generating resources.

The three primary forms of consumer-owned electric utilities are municipal utilities, cooperative utilities and public utility districts (PUDs). Each of these utility types have certain benefits and drawbacks. For the purpose of this analysis, the municipal electric utility option has primarily been evaluated.

Electric Facilities on Bainbridge Island

The electric facilities located within the City include transmission lines, substations, overhead and underground distribution lines, poles, transformers, vaults, service drops, meters, streetlights, right-of-ways and ancillary distribution system facilities. There are three substations on the island that transform power from transmission voltage to the primary distribution voltage. PSE's transmission system on Bainbridge Island consists of approximately 14 miles of 115-kilovolt (kV) overhead transmission lines that connect to PSE's transmission system on the Kitsap Peninsula side of Agate Pass.

PSE indicates that there are 307 miles of distribution lines on Bainbridge Island of which 165 miles are underground. The overhead and underground lines are a mixture of three, two and single phase. In addition, 22 miles of overhead distribution lines use insulated tree wire. Overhead distribution and transmission lines are generally built with typical wood-pole construction and in some areas the distribution lines are underbuilt on transmission poles.

There are several options that the City could take in defining the electric facilities that would be acquired to establish a new electric utility system. It is expected that the substations, distribution lines, transformers, services and meters would be needed for the City to own the distribution system as required by BPA. All of the transmission lines, however, would not necessarily need to be acquired. Instead, PSE could continue to own some or all of the transmission lines on the island and BPA would make arrangements with PSE to deliver power over the lines to the City's substations.

For the purpose of this analysis, we have assumed that PSE would continue to own the transmission lines north of the Port Madison substation. A metering system would be installed at the Port Madison substation and this is where the new utility would take delivery of power from BPA. From this point the new electric utility would own the substations, the radial transmission lines between the substations, all overhead and underground distribution lines, distribution transformers, customer services, and meters.

Estimated Cost of Acquiring Facilities

An appraisal of the value of electric facilities to be acquired by the City for its electric system has not been conducted. Such an appraisal would rely upon a detailed description of the facilities to be acquired and will potentially be needed if the City proceeds towards acquisition of the PSE system on Bainbridge Island.

For the purpose of this analysis, the cost the City would pay for the acquired facilities is estimated to be between the original cost less depreciation (OCLD) value and the reproduction cost new less depreciation (RCNLD) value of the electric facilities, based on our knowledge of other utility acquisitions. OCLD is defined as the original cost of the property when it was first put into service as a public utility, less accrued depreciation. The OCLD value is an estimate of the net book value of property. The actual purchase price will be either negotiated or established in a court proceeding but should reasonably be expected to be in the range between the OCLD and RCNLD values. We have estimated the RCNLD value of the facilities proposed to be acquired at $52.1 million. The OCLD value is estimated to be $24.0 million. These costs are for the system as it currently exists. Any additions or improvements made to the system by PSE or required by City policy before acquisition would need to be factored into the acquisition cost.

Estimated Number of Customers and Load Forecast

The number of customers in the City's service territory has been estimated to serve as the basis for estimating energy sales and overall power requirements of the municipal electric system. PSE has indicated that approximately 12,300 electric customers are presently served on Bainbridge Island and that the total number of electric customers served has increased about 0.7% on average per year between 2010 and 2016.

The total annual energy requirement of the City electric system is estimated to be 220,600 MWh, or 26.9 average MW, at present levels. The peak demand is estimated to be 67 MW based on the assumed relationship between average and peak demand considered to be representative of an electric utility with higher levels of electric space heat. The peak demand will potentially vary significantly from year to year based on weather conditions and customer usage characteristics.

Financing Options and Estimated Cost of Financing

Municipally-owned electric utilities and PUD's generally use tax-exempt revenue bonds and loans to fund the capital costs associated with their systems. Federal tax laws generally prohibit the use of tax-exempt loans for the funding of municipal acquisition of electric systems owned by investor-owned or privately owned utilities. Alternatively, low interest rate financing may be available through the federal Rural Utility Service (RUS).

For the purpose of the base case of this analysis, it is assumed that the acquisition cost of the new utility will be financed with revenue bonds. The estimated initial financing requirement is based on the assumption that the cost to acquire the electric facilities from PSE is two times the estimated OCLD value of the facilities. Other costs we have included in the initial financing requirement are the costs of installing equipment to meter wholesale power purchases at the substations, purchase necessary vehicles and equipment, purchase materials and supplies, pay the costs of additional warehouse and maintenance facilities that the City may need and pay initial legal, engineering and consulting fees.

In addition to the initial costs, the fees associated with issuing revenue bonds and the establishment of a debt service reserve fund are included. For the base case of this analysis assuming initial acquisition at two times the OCLD value, the initial financing requirement is estimated to be $62.4 million.

Estimated Cost of Operations

Publicly-owned electric utilities generally establish rates to recover revenues through the sale of power sufficient to pay all operating expenses, taxes, and debt service as well as provide a margin from which to fund renewals, replacements and additions to the system. The total of all these cost obligations on an annual basis are referred to as the annual revenue requirement. Operating expenses of the electric system will include purchased power, purchased transmission services, transmission and distribution system operations and maintenance (O&M), customer accounting, and administrative and general expenses. It is expected that the City will initially either contract for O&M services and/or hire its own staff to perform some or all of these functions.

The most significant annual operating expense that the City's electric system will incur is the cost of wholesale power. Upon fulfillment of certain criteria primarily related to establishing ownership of its distribution system, the new utility will be entitled to purchase power from BPA as a preference customer. The City electric system can reasonably expect to purchase a significant portion, if not all, of its power supply from BPA at the priority firm power rate, also referred to as the Tier 1 power rate.

The annual revenue requirements have been projected for the first twenty years of City electric system operation. Electric system operation is assumed to begin in 2021. Annual costs include the costs of power and transmission, transmission and distribution O&M, customer accounting, administrative and general expenses, taxes, debt service and an amount for renewals, replacements and additions to the system. Debt service is estimated to be a significant cost component of the overall revenue requirement.

For the base case, the first year annual revenue requirement is estimated to be 11.8 cents per kWh. This is the average unit revenue needed to pay all costs of the system. Average revenue requirements are not specific rates. Rates will need to be adopted by the governing board of the City electric system. Rates would need to be established that would reflect the actual cost to serve certain customer classifications (i.e. residential, small commercial, large commercial).

Estimated Net Benefits

The estimated annual revenue requirements for the City electric system have been compared to the estimated charges for electric service from PSE to evaluate the net benefits that electric consumers on Bainbridge Island would realize with the City electric system. With a public power utility the benefits are long-term in that they are realized far into the future. For a new utility with a fairly high initial investment, the full level of benefits may not be realized until the initial loans are repaid, paid down or refinanced. Although an estimation of net benefits in the first twenty years of new utility operation are presented in this analysis it is important to acknowledge that benefits would typically be greater in the future.

The estimation of revenue requirements for the new City electric system have been developed based on the assumptions and variables defined in this report. We are unaware of any detailed projections of future PSE electric rates so for the purpose of this analysis, an estimate of PSE's charges for electric service has been made based on a review of historical changes in PSE rates.

The estimated cost of electric service with the City electric system is estimated to be slightly lower than the cost of service from PSE. In the assumed first year of operation, 2021, it is estimated that the average cost of electric service from the City system would be about 0.07 cents per kWh or 0.6% less than would be charged by PSE in that year. By 2030, the annual savings are estimated to be about 1.4%.

Over the first ten years of operation, electric consumers in the City are estimated to pay in total approximately $358,000 less per year on average for electric service with the City system than they would with continued service from PSE. Over the second ten years of operation (years 11-20), the average annual reduction in total electricity payments is estimated to be $1,021,000. Over the first twenty years of operation of the City electric system, the average annual savings in payments for electricity is estimated to be 1.8% less when compared to the estimated costs of service from PSE.

Alternative assumptions to the analysis would result in different results. Key variables include the estimated cost of acquisition, the estimated cost of financing and assumed increases in the number of electric customers served and load growth on Bainbridge Island. The net benefits of City service using alternative assumptions have been estimated and indicate that the purchase price and the cost of financing are significant variables. As an example of the results of one of the alternative cases evaluated, if the initial acquisition price of the facilities was 1.35 times OCLD and low-cost financing was obtained through the federal RUS, the first year average revenue requirement of the City electric system is estimated to be 11.0 cents per kWh and the net savings in the cost of electricity over the first ten years of operation are estimated to average $2,126,000 per year.

It is important to note that if so desired, a public power utility can set its rates to recover additional revenue to fund investments in expanded energy efficiency programs, development of alternative generating resources and improvements to the electric system, among other things.

Other Factors

An important advantage of a City electric utility is local control. This is especially true when it comes to socially responsible initiatives. That is, the City will be in better touch with the needs of its residents than almost any other organization and can adjust programs for the unique mix and needs of Bainbridge Island residents and businesses.

A number of opportunities related to a municipal electric utility exist such as the potential to develop and finance a City-owned high-speed broadband network to serve residents and businesses. There are also many opportunities for promoting and assisting in the expansion of energy efficiency programs in the community. A variety of non-economic benefits and synergies are presented in this report.

Reliability of electric service is a critical issue for electric consumers in the City. Tree-trimming and vegetation management are significant issues and will continue to be important activities for either PSE or a City electric system in the future. Undergrounding of certain overhead distribution lines can also be used to improve reliability of service. PSE has indicated that it is planning to install additional tree wire and place sections of overhead line underground in certain locations on Bainbridge Island to improve reliability.

PSE offers a green power program and several energy efficiency programs. Residents and businesses in the City have taken advantage of these programs and it will be important for the City electric system to continue with such measures. The City electric system can enhance programs of this type and structure them to the best interests of the community. Public power utilities throughout the Pacific Northwest offer energy efficiency programs funded partly by BPA and partly through their own revenues. The City electric system can pursue development of renewable energy projects either on its own or jointly with other utilities. As such, the type of renewable energy projects developed can be more focused on the needs of the community and the location of renewable resources can potentially be established to be close to the City.

The greenhouse gas (GHG) emissions intensity attributed to full requirements customers of BPA are significantly less than the GHG emissions intensity attributed to PSE. This is due to BPA's fuel mix being about 85% hydroelectric. A significant portion of PSE's GHG emissions are produced by the Colstrip coal-fired power plant in Montana. PSE plans to close Colstrip Units 1 and 2 by 2022. It is not known what resources will be obtained by PSE to replace the output of the Colstrip plant, but some of the replacement generation may be from natural gas-fired power plants. Serving the City load with BPA power would reduce the amount of additional power generation PSE would need to acquire to replace Colstrip output.

Some of the risks associated with pursuing a City electric system would initially include uncertainty with regard to facility acquisition costs and potential increases in interest rates before long-term financing is obtained. Once in operation, the new utility would need to establish electric rates that would produce revenues sufficient to pay the costs of operation. All electric utilities are subject to changing conditions in regulations, power costs, labor costs and the costs of materials and equipment that can put upward pressure on rates over time. Changing demographic and economic conditions as well as customer demands for power can affect the revenues of an electric utility as well, both positively and negatively. Also, the risks associated with natural disasters could have more of an impact on a local City electric system. The City electric system would need to acknowledge all of these factors, among others, in its ongoing governance of its electric system.

Next Steps

The primary actions to be taken at this time include reviewing and revising the feasibility report, and determining if further action towards establishment of a consumer owned utility is desired. Public discussion and input to the decision should be encouraged. The type of consumer-owned utility will need to be defined as well. Discussions with the City's legal and financial advisors should also be conducted.

If a decision is made to pursue establishment of a utility it will be necessary to prepare for a public referendum. For a PUD a vote must be taken in an even numbered year. For a municipal utility the vote can be in any year. It may be necessary to prepare additional analytical materials and information for voters. Informational meetings in the community should be conducted.

Activities that will follow public approval will include conducting detailed discussions with BPA regarding power supply, transmission and interconnection contracts and issues. Discussions with PSE will also need to be conducted regarding the negotiations for acquiring the electric facilities. As the process progresses, discussions with vendors, contractors and others that will be needed to assist the new utility in its initial operation will need to be conducted.

Changed Conditions

This report summarizes the information, methodologies and assumptions used in the development of our analysis. Alternative assumptions could provide different results. The underlying factors from which the basic information and assumptions are derived are subject to change. In addition, the issues associated with the ownership, operation, administration and regulation of electric utilities in the United States are constantly changing. As such, the results of this study are subject to change and adjustments to the analysis may be needed in the future to determine the impact of changing conditions.

Section 1
Introduction

Introduction

Background

The City of Bainbridge Island, Washington (City) retained D. Hittle & Associates, Inc. (DHA) in 2016 to conduct an electric utility municipalization feasibility study. The study is intended to provide a preliminary review of the technical and economic issues related to the establishment of an electric utility owned and operated by the City. The content of this study addresses issues defined in the scope of work agreed to between the City and DHA. This report summarizes the results and findings of the feasibility study. The law firm of Gordon Thomas Honeywell assisted DHA in the preparation of certain portions of this report.

Although the primary focus of the study has been to evaluate the feasibility of establishing a municipal utility, other forms of consumer-owned utilities such as a public utility district or an electric cooperative have been evaluated. Additional information has been provided regarding whether or not establishing a municipal utility would open up currently unavailable opportunities for local control over energy sources serving Bainbridge Island that could foster economic development, decrease greenhouse gas emissions, increase system reliability and improve power quality.

Electric service is presently provided to the residents and businesses on Bainbridge Island by Puget Sound Electric (PSE), a privately-owned electric utility headquartered in Bellevue, Washington. PSE has indicated that approximately 12,300 electric customers are served in the City. Electric facilities on Bainbridge Island include about 14 miles of 115-kilovot (kV) overhead transmission lines, three distribution substations and 307 miles of distribution lines of which 165 miles are underground. Power is delivered to Bainbridge Island from PSE's transmission network in Kitsap County and beyond by means of overhead transmission lines at Agate Pass. This overhead transmission crossing is essentially new having been rebuilt in 2014. PSE provides electric service in the City pursuant to a fifteen year franchise agreement that expires in 2022 (Ordinance No. 2007-11).

In general, the concept of establishing a municipal electric utility would involve acquisition of the existing distribution and transmission system in the City, contracting for a supply of electric power and establishing the capability to operate and maintain the electric system. Although most electric utilities retain their own staff to operate their respective systems many operation and maintenance functions can be performed by contractors if desired. PSE uses a contractor to perform most of the maintenance work on its system.

As a "publicly-owned" electric utility, if established and after meeting certain criteria, the City's municipal electric utility would be able to purchase electric power from the Bonneville Power Administration (BPA) at BPA's most favorable rate. BPA is a federal agency that markets the power from the federal Columbia River power system. Most of the publicly-owned electric utilities in the Pacific Northwest purchase most or all of their power supply from BPA. BPA also operates an extensive transmission system in the Pacific Northwest and delivers power to its customers.

In preparing this feasibility study we have reviewed the existing electric facilities in the City, identified the facilities that the City would need to establish electric service as a City electric system, estimated the costs to acquire these facilities and estimated that costs to operate, maintain, manage and administer an electric utility. Total power requirements in the City were estimated to determine how much power would need to be purchased. The annual revenues that the City electric system would need to collect for electric service to pay the costs of electric service have been estimated for several years into the future. This revenue requirement has been used to provide an estimate of electric rates the City system would charge. Comparing these estimated rates to those estimated for PSE provides an estimate of the net benefits or costs of the City electric system.

There will be many decision points if the City moves toward establishing an electric utility. Changes in the basic economic and technical factors and assumptions used in this analysis should be evaluated as they become known. Public input to the concept is also important. If it is determined that the City wants to proceed towards establishment of an electric utility, the next major steps will be to conduct discussions with BPA regarding a power purchase and transmission services contract, determine through negotiation or litigation what facilities will be acquired from PSE and what price will be paid for the facilities, determine what additional facilities should be constructed, arrange for financing, implement an organizational start-up plan and retain necessary staff, equipment and materials to provide service.

A key schedule constraint to providing electric service will be BPA's notice period related to obtaining a power sales contract for a new utility. A full requirements purchase of BPA wholesale power at BPA's lowest Tier 1 rate would normally take approximately three years depending on when the application is made relative to the BPA rate cycle. Tier 2 power could be purchased prior to that, however.

As a point of reference on the time required to establish an electric utility the experience of the most recently formed electric utility in the state, Jefferson County PUD, can be considered. The voters of Jefferson County authorized the Jefferson County PUD to provide electric service in November 2008. Jefferson County PUD negotiated with PSE on the purchase of assets and began providing electric service in April 1, 2013. This represents a planning and implementation period of approximately 53 months. Of this time approximately 19 months elapsed prior to the signing of an asset purchase agreement with PSE. The City of Hermiston, Oregon undertook an initial feasibility study related to providing municipal electric service in 1996. The acquisition of electric facilities from PacifiCorp was negotiated and the City began providing electric service on October 1, 2001, representing about a five year period in preparation of providing service.

Study Methodology

Most of the data used in the study is from publicly available reports and other sources. The City requested certain information from PSE in October 2016 and a limited amount of requested data was provided by PSE. Other information comes from public records associated with PSE, Kitsap County, the State of Washington Department of Revenue, the Washington Utilities and Transportation Commission, and selected statistics on electric utilities compiled by the Washington PUD Association and the Northwest Public Power Association, BPA, etc. Information regarding financing options and costs was obtained from financial advisors involved with the financing of electric utility systems.

PSE provided an estimate of the total number of customer accounts served in the City. The total power requirements of the electric customers in the City at the present time have been estimated based on typical energy consumption values for PSE customers as found in recent FERC Form 1 filings for PSE.

For the purpose of this study, the determination of electric facilities to be acquired was based on a cursory field examination of PSE's transmission and distribution system in the City. The length of transmission lines and the number and capacity of substations were derived from observations and maps of the City. The estimated costs of transmission lines, distribution lines, service drops, meters and other distribution facilities, were developed using estimated unit costs based on our experience with similar utility systems.

Should the City decide to move forward in the development of a municipal utility, a much more detailed assessment of electric facility quantities and costs would need to be derived in subsequent studies and analyses. If the development of the City's electric utility proceeds and access to PSE's customer sales and facility inventory records can be obtained, a detailed inventory and age identification of various PSE assets within the City would potentially be developed.

The estimated costs the City would experience for power purchases, system operation and maintenance, customer accounting and administration included in the analysis have been based on representative costs experienced by other publicly-owned electric utilities in the Pacific Northwest. It is assumed that the City would conduct its own billing and accounting activities and would provide in-person customer service for bill paying, hookup requests and other services. These billing and accounting functions could be integrated with other City functions. In addition to operating expenses, annual debt service payments and funds for annual capital improvement expenditures were included in the projected revenue requirements

Section 2
Electric Utility Options and Other Significant Issues

Consumer-Owned Electric Utility Options

Consumer-owned electric utilities, often referred to as public power utilities, are common in the Pacific Northwest and across the United States. They provide all functions of electric service and are directed by board members, commissioners or city council members generally elected from within the service area of the utility. As such, local control is a significant element of public power utilities[1].

Public power utilities provide electric service at cost and are not-for profit, and with the exception of cooperatives do not pay federal income taxes. They generally have access to loans at tax-exempt interest rates or to loans provided by the federal government at low interest rates. Public power utilities also have preference over private utilities in purchasing low cost power generated at federal hydroelectric resources. In the Pacific Northwest, this is a significant benefit in that most public power utilities, other than those with significant generating resources of their own, purchase all, or nearly all, of their power supply requirement from the Bonneville Power Administration (BPA), a federal power marketing agency.

Rates for electric service for public power utilities are established by each utility's governing board to collect revenues sufficient to pay operating costs, pay interest and principal on debt, and pay for the renewal, replacement and additions to its facilities. Generally, public power utilities are not regulated by their respective state utility commissions. In the Pacific Northwest there is significant coordination among public power utilities to assist each other with training, group equipment purchases, representation in wholesale rate and other regulatory issues and in emergency repairs. Public power utilities often work together to develop jointly-owned or joint-power purchaser generating facilities that in themselves would be too large for smaller systems.

The three primary forms of consumer-owned electric utilities are municipal utilities, cooperative utilities and public utility districts (PUDs). Each of these utility types have certain benefits and drawbacks. They are discussed in more detail in the following subsections.

Municipal Electric Utility

Municipally-owned electric utilities are common in Washington as well as around the country. With a municipal electric utility, the city or town council typically serves as the governing board for the utility and provides oversight and approval of the utility operation, establishes rates for electric service and approves various policies and procedures. The financing authority of the municipality is used to provide funding for the acquisition and construction of necessary electric facilities; however, security for repayment of loans can be specifically limited to the revenues of

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[1] The American Public Power Association (APPA) provides an overview of the benefits of municipalization in the booklet, Public Power for Your Community, available at:
http://www.publicpower.org/files/PDFs/Summary_of_Public_Power_for_Your_Community.pdf

the electric utility operation. Various administrative functions of the municipal utility, such as billing, accounting, human resources, and financial management, are often integrated with other municipal activities. The service area of most municipal electric utilities is reasonably consistent with the municipal boundary. Examples of municipally-owned electric utilities include: City of Seattle, City of Blaine, City of Sumas, City of Ellensburg, City of Tacoma, City of Ruston, Town of Steilacoom, City of Port Angeles, City of Centralia, and the City of Richland.

Municipal utilities have condemnation authority. Some cities, such as first class or code cities, have authority to provide retail telecommunication services.

For a municipal electric utility, planning, engineering and construction can be coordinated within the municipality as a joint effort among the various municipal operations. This can be very helpful with regard to comprehensive planning and in building and maintaining the electric system to address a municipality's broader goals. For example, undergrounding of electric lines can be effectively coordinated with street construction or water and sewer system improvements.

An advantage of a municipal electric utility is the ability to obtain financing for most capital expenditures at tax-exempt interest rates. A municipal utility does not pay federal income taxes and its revenues can be used to pay the costs of certain services provided to the utility through the municipal government. Municipal utilities are required to pay the state public utility tax and most municipal utilities collect a local tax on power sales as well.

Although the city council serves as the governing board of a municipal electric utility, some municipal utilities establish boards to provide more of the regular oversight of the electric utility and formulate recommendations for the city council. These boards in some instances have been delegated authority for certain defined decision-making, and in other instances are solely advisory in nature. City councils are responsible for much more than the oversight of utility operations and the use of a utility advisory or other board can be of significant assistance. More information on the function of advisory boards is provided in the subsection entitled "Alternative Municipal Governing and Advisory Concepts" in this report.

The time required to establish a municipal electric utility could be relatively short; however, it may require an extended period of discussion before the city council. The time required is very much dependent on the willingness of the incumbent utility to sell the existing electric facilities. In Washington, RCW 35.92.070 requires approval of a majority vote of the voters of the city if the governing body of the city deems it advisable to acquire a public utility. The vote can be conducted at any general or special election, requires thirty days prior notice and requires a simple majority for approval. In addition, the ordinance submitted to the voters for approval or rejection is required to specify the proposed plan and declare its estimated cost. As such, it would be necessary to have a fairly well established plan for the new municipal utility operation before conducting the vote.

A new municipal electric utility would need to qualify for the purchase of BPA power pursuant to BPA's requirements for new preference customers.

Public Utility District

Public utility districts (PUDs) are nonprofit, consumer-owned utilities that provide electricity, water, wholesale telecommunications and sewer service. The citizens in each Washington county have the right to form a PUD. In Washington, there are 28 operating PUDs in 27 counties which in total provide electric service to approximately 1,003,000 customers and water service to approximately 122,000 customers in their respective service areas. Counties can have more than one PUD as is exemplified with two PUDs in Mason County.

Kitsap County PUD was organized in 1940 and provides water service to approximately 14,000 customers in various locations within Kitsap County including Bainbridge Island. In 2000, Kitsap County PUD began providing wholesale broadband telecommunication services in the county. Kitsap County PUD does not presently provide electric service but has considered the possibility of doing so in the past.

PUDs are governed by a board of commissioners typically consisting of three commissioners elected from the residents of the county in which the PUD is located.

The formation of a new PUD in Kitsap County could be undertaken in conjunction with the county government. RCW 54.08.010 provides that at any general election in an even-numbered year, the county legislative authority may conduct an election (and on petition of 10% of the qualified voters is required to conduct an election) to approve formation of a PUD coextensive with the boundary of the county.[2] The petition must be filed with the county auditor not less than four months before the election. Further, the form of the petition has to be submitted to the county auditor within ten months prior to the election.

It is also permissible to establish a PUD that covers less than the entire county. In this circumstance, a petition is filed with the county legislative authority and a hearing is held after public notice and boundaries of the PUD will be established. If the county finds the petition includes lands improperly or which will not be benefited by the PUD, it will change the boundaries of the proposed PUD and fix them as it deems reasonable and that are "just and conducive to the public welfare".[3] The partial county area cannot divide any voting precincts. The election is confined to the area of the proposed PUD. RCW 54.08.010 prohibits any PUD created after September 1, 1979 from including any other PUD in its boundaries. As such, the existing Kitsap County PUD would need to be reformed if a partial county PUD were to be formed for only a portion of the county.

At the same election requesting approval to form a new PUD, there will also be held an election of three commissioners. If the proposition to form the PUD does not receive approval by a majority of the voters, the election of the new commissioners is declared null and void.

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[2] Under RCW 54.08.060, the county legislative authority may also call a special election for this purpose at the earliest practicable time, and at the request of the petitioners must do so.
[3] RCW 54.08.010, Districts including the entire county or less – Procedure (Effective January 1, 2007.)

Another PUD option would be to pursue electric service through the existing Kitsap County PUD. Pursuant to RCW 54.08.070, any PUD which has been in existence for at least ten years and does not currently provide electric service must conduct an election in the PUD service area to obtain voter approval to do so. The election must be held in an even-numbered year and may be submitted to the voters of the district by PUD commission resolution, and must be submitted to a vote based on a petition of 10% of the voters in the PUD area submitted to the county legislative authority at least four months prior to the election date and within 10 months before the election.

The acquisition of electric facilities from PSE by a PUD would be accomplished similar to that of a new municipal utility, although there are a few differences outlined in RCW 54. The PUD would have condemnation authority and could exercise this authority if an acceptable sale of the facilities could not be negotiated. Electric service through the PUD would not need to be provided to all county residents. A plan would need to be developed to assure reliable, cost effective service to all county residents.

An existing PUD that establishes electric service would be viewed by BPA as a new electric utility as far as access to preference power is concerned. As a result, the issues and timing associated with access to BPA power would be the same for a new municipal electric utility or the existing PUD. The PUD would also need to start a new electric utility operation similar to that of the municipal electric utility.

Electric Cooperative

An electric cooperative is a non-profit corporation tasked with providing electric service to its members residing in a specific service area. Revenues in excess of expenses are either reinvested in the system for improvements and replacements or are distributed to members in the form of "capital credits". There are fifteen electric cooperatives[4] in Washington providing electric service to approximately 158,000 member-customers. Generally, electric cooperatives provide service in rural areas. This was the intent of the Rural Electrification Administration (REA) which was created in 1935 to promote the extension of reasonably priced electricity to farms in areas not served by existing electric utilities. Under the Department of Agriculture Reorganization Act of 1994 the REA was absorbed by the Rural Utilities Service (RUS). It is noted, however, that several smaller towns and cities in Washington, including West Richland, North Bend and Gig Harbor, are within the service areas of electric cooperatives.

Most electric cooperatives obtain low interest loans from the federal government through the Rural Utilities Service (RUS), a government agency within the U.S. Department of Agriculture. The low interest loans are generally only available to fund costs related to the rural portions of the utility. This means that the costs of the urban portions of the system may need to be funded with other sources. Electric cooperatives do not have access to tax-exempt financing like municipal utilities and PUDs and, as a result, the average cost of capital for electric cooperatives can be

[4] Includes mutual and cooperative utilities, which function much the same, headquartered in Washington. There are also three other electric cooperatives that serve member-customers in Washington that are headquartered in Idaho.

higher than for PUDs and municipalities. In addition to loans through the federal RUS, there are also two lending entities, CFC and Cobank that offer lower cost loans to electric cooperatives. Cooperatives are exempt from paying federal income tax under Section 501(c)12 of the Internal Revenue Code.

Cooperatives are governed by a board of directors elected from the membership. The board of directors sets policies and procedures that are implemented by the cooperative's professional staff. Membership in the cooperative is voluntary. An electric cooperative could be established in Kitsap County by any group interested in doing so. To provide electric service in the area however, a sufficient number of members would need to be identified and committed to form the base for acquiring electric facilities, contracting for power and starting a utility operation. A cooperative does not have condemnation authority and would need to negotiate with PSE to acquire the PSE electric facilities.

Another alternative is to request to become part of an existing cooperative. Cooperatives do not need to have a contiguous service territory. For example Tanner Electric Cooperative has three service territories near Ames Lake, North Bend and Anderson Island.

Electric cooperatives, like municipal utilities and PUDs, are not regulated by the Washington Utilities and Transportation Commission (WUTC). The WUTC has no jurisdiction over a cooperative; however, it would be expected that the WUTC will provide some review of the proposed transfer of electric service from a regulated utility such as PSE to the cooperative on behalf of electric consumers.

There are no particular time requirements related to establishing a cooperative. Schedule requirements related to acquiring a power supply would be similar to a municipal utility and a PUD. A membership campaign would be needed and it is expected that approximately one to two years would be needed to negotiate the purchase of electric facilities and conduct various engineering studies.

Comparison of Consumer-Owned Utility Options

The following table summarizes the primary differences of utility ownership options.

TABLE 1
Comparison of Consumer-Owned Electric Utility Options

	Municipal Electric Utility	Public Utility District (PUD)	Electric Cooperative	Investor Owned Utility
Governing Board elected by local voters?	Yes	Yes	Yes†	No
Governed locally?	Yes	Yes	Yes	No
Board meetings generally open to the public?	Yes	Yes	Yes‡	No
Access to tax-exempt financing?	Yes*	Yes*	No	No**
Non-profit entity?	Yes	Yes	Yes	No
Rates generally established at cost?	Yes	Yes	Yes	Cost plus allowed return
Required to pay income taxes?	No	No	No	Yes
Equity in electric facility assets generally accrue to customer-owners?	Yes	Yes	Yes	No
Access to BPA Tier 1 power at preference rates?	Yes	Yes	Yes	No
Regulated by Washington Utility and Transportation Commission?	No	No	No	Yes

* Tax-exempt financing is generally not available to pay the costs of acquiring electric facilities of an existing utility.

** Some tax-exempt financing may be available through industrial development bonds within the state volume cap.

† Governing Board is elected by Cooperative members.

‡ Board meetings are generally open to cooperative members.

Alternative Municipal Governing and Advisory Concepts

As previously mentioned, the governing body for a municipal electric utility is the city council. As such, the city council provides general oversight of the utility, retains competent management, makes policy decisions and sets the rates and charges for utility service. City council members are elected by the citizens within the municipality and as a result, the governing board of the electric utility is elected by the citizens.

Some city councils have established utility boards or utility advisory committees to provide a more specialized oversight of the utility operation, review recommendations of utility management and staff and advise the city council with regard to various issues related to utility policy, operation and administration. Typically the members of a utility board are appointed by the city council.

The advisory boards have a variety of functions to perform but generally they are expected to have regular contact with the electric utility management and the general public and assist the city council in administering the utility, establishing policy and addressing utility-related issues of concern to electric consumers and the community as a whole. Serving as the utility governing board is just one of many tasks performed by a city council and a utility board or advisory committee can remain focused on the utility business and provide significant coordination between the utility and the city council.

Examples of utility advisory boards in Washington and Oregon include:

Tacoma Public Utilities (TPU), Public Utility Board

The five-member board oversees the operations of Tacoma's electric and water utilities, the Click! communications operations, and industrial freight-switching railroad. The Tacoma City Council appoints the board members and they serve five-year terms, unpaid. The board meets twice monthly and board meetings are open to the public for public comment.

Seattle City Light, City Light Review Panel

The Seattle City Light Review Panel was created in 2010 as the successor to the City Light Advisory Board/Committee and the Rate Advisory Committee, and combines the duties of both groups.

The nine panel members come from City Light's customer groups. Five members are nominated by the mayor and four members are nominated by the city council, serving staggered three-year terms. In 2010, the focus of the panel was to help develop a six year strategic plan for Seattle City Light.

City of Ellensburg, Utility Advisory Committee

There are seven Utility Advisory Committee members consisting of two city council members, one representative from Central Washington University, two customers of one or more city utility systems, one representative of KITTCOM and one customer of the telecommunications utility. Committee members serve three-year terms and are not paid. The committee meets monthly.

The Utility Advisory Committee operates under the authority of the Ellensburg city code and was created for the purpose of providing a mechanism for the city council to obtain benefits of recommendations, advice, and opinions on those matters affecting City energy policy and operations from a committee which may devote the resources necessary for careful consideration of such matters and which will increase citizen participation and input to local government.

City of Port Angeles, Utility Advisory Committee

The Utility Advisory Committee gives advisory recommendations to the City Council on matters relating to city utility policy and operation.

The Utility Advisory Committee is comprised of three City Council members, one industrial representative, and two community representatives. The members are appointed to four-year terms, with a limit of two consecutive terms. Members are residents of the city, except the member representing the licensed care facilities need not be a city resident but must own or manage a licensed care facility in the city.

Eugene Water and Electric Board (EWEB)

EWEB is chartered by the City of Eugene, Oregon to serve as the electric and water utility providing service to the homes, businesses, schools and other customers in Eugene. In accordance with the Eugene city charter, the citizens of Eugene elect a five-member Board of Commissioners for EWEB. Four board members represent specific wards within the city; the fifth member is elected "at-large" by all city voters. Each commissioner's term is four years and commissioners volunteer their time for their work on the commission.

Commissioners hold regularly scheduled public board meetings on the first Tuesday of each month. The opportunity for public comment is provided at each board meeting.

The EWEB example is unique in that the Board of Commissioners has governing authority typically found with the city council for a municipal utility. Although a city council in Washington could rely upon an advisory board for significant input, policy and operating decisions would still need to be made by the city council.

Acquiring Electric Facilities

If a new public power utility were to be established on Bainbridge Island it would be necessary for the new utility to own its electric distribution system in order to purchase power from BPA as a preference customer. It is expected that the existing electric facilities currently owned by PSE on Bainbridge Island would be acquired or replaced by the new utility. PSE would need to be paid a fair value for the electric facilities. To establish the value of the existing facilities the facilities will need to be inventoried, assessed and quantified and a valuation estimate will be developed. Engineering analysis will be needed to determine how the new utility will operate its facilities separate from the surrounding PSE system and determine where wholesale power deliveries will be received.

A separation plan must be prepared that could include the specification of new transmission, distribution and operation facilities. In some cases the separation plan is implemented by agreement over a period of time that extends beyond the ownership transfer date[5].

The purchase of the electric facilities by the new utility can be relatively straightforward if both parties are cooperative. Without cooperation, condemnation could be utilized for acquisition. A condemnation process can be time consuming and costly, but could provide a path to municipal electric utility formation with an unwilling seller. Overall, based on our experience with other acquisitions we would estimate that the time needed to acquire the electric facilities would require between one and three years, with the shorter time reflective of a relatively simple negotiated sale and the longer period reflective of an aggressive condemnation proceeding that includes appeals.

Prior to establishing electric service in Jefferson County in 2013, Jefferson County PUD negotiated with PSE to purchase the electric facilities in the county owned by PSE. The PUD chose to negotiate a purchase price rather than pursue acquisition through the condemnation process. The condemnation process could have potentially produced a lower purchase price but most likely would have taken longer to complete. With condemnation, the price to purchase the electric facilities is specified by the court proceedings.

The City of Hermiston, Oregon is an example of a new public power utility established in 2001 that pursued its option to condemn the electric facilities owned by PacifiCorp but eventually agreed to a negotiated acquisition settlement.

The City has the authority to condemn the property of PSE within the City municipal boundaries. If the City elects to condemn the property prior to forming a PUD, its authority is pursuant to RCW 35.92.050. If the City elects to form a PUD first, the PUD has authority to condemn pursuant to RCW 54.16.020. Eminent domain proceedings are entirely statutory and the procedures for such proceedings are set forth in Washington Revised Code Sections 8.04.005 to -8.28.070.

[5] Emerald PUD in Springfield, Oregon had a net billing arrangement with Pacific Power & Light that allowed certain customers to be served off the other utility's lines while new facilities were constructed. The arrangement was in effect for well over 20 years.

There are two circumstances in which the City or a PUD might undertake to condemn PSE's facilities. If PSE is not willing to voluntarily sell the facilities, then it will be necessary to invoke its power of eminent domain to compel the acquisition. Even if PSE is willing to negotiate and sell voluntarily, the City may still elect to commence a condemnation action if the parties cannot reach agreement with regard to a purchase price. Through the condemnation process the City may or may not achieve a lower acquisition cost than it could through a negotiated sale. The City should consider the costs, time frame, and risks of litigation when evaluating acquisition costs in the context of a condemnation proceeding.

The estimated cost for the City or a PUD to condemn the PSE electric facilities in Bainbridge Island is difficult to predict. But if litigation is pursued, the City should expect that the cumulative attorneys' fees and expert costs can be expected to be in excess of $1 million. More discussion of attorney and consulting fees is presented in the section in this report entitled "Estimated Initial Financing Requirements"..

Discussions with attorneys indicates that the estimated time needed to reach conclusion of acquiring PSE's facilities through condemnation from the date of filing the petition through trial is between 12 and 24 months. This is exclusive of appeals. An appeal will not delay obtaining possession of PSE's property, provided that the City or PUD pays in full the judgment as awarded by the jury or judge pending appeal.

Examples of Recent Public Power Utility Acquisitions in the Pacific Northwest

As previously indicated, in 2010 Jefferson County PUD negotiated to purchase the PSE electric facilities in Jefferson County thereby avoiding the condemnation process. The negotiated purchase price for the facilities was $103 million[6]. In WUTC's order[7] regarding the matter of PSE's petition for accounting of the proceeds from the sale of assets to Jefferson County PUD, the WUTC indicated that the net book value or original cost less depreciation (OCLD) of the assets was $46.7 million. Based on this net book value amount, the negotiated purchase price was approximately 2.2 times the net book value. At the time, the negotiated purchase price represented approximately $5,600 per electric customer account in the PUD service area.

In 2001, the City of Hermiston, Oregon negotiated to purchase the electric facilities in Hermiston from PacifiCorp. The estimated purchase price was $8.1 million, estimated to be about two times the net book value of the electric facilities. At the time, the purchase price represented approximately $1,670 per electric customer account in Hermiston.

In 2000, the Columbia River People's Utility District headquartered in St. Helens, Oregon, acquired certain service territory and electric facilities owned by Portland General Electric Company (PGE). The service area acquired in 2000 included portions in the incorporated towns

[6] Actual proceeds of the sale were $109.3 million.
[7] Washington Utilities and Transportation Commission, Docket UE-132027, Order 04, Service Date September 11, 2014.

of St. Helens, Scappoose, Rainier and Columbia City that PGE had continued to serve after the PUD began electric service in 1984. The PUD paid PGE approximately $9.5 million for the electric distribution facilities in the acquired area in 2000, estimated to be about 1.8 times the net book value and representing about $1,580 per electric customer account in the acquired area.

Power Supply Overview

As with most Pacific Northwest electric utilities, the most significant annual operating expense that the City's electric system will incur is the cost of wholesale power. For many public power distribution electric utilities, purchased power and transmission expense typically represents 40-60% of the annual budget. Upon fulfillment of certain criteria primarily related to establishing ownership of its distribution system, the new utility will be entitled to purchase power from the Bonneville Power Administration (BPA) as a preference customer. BPA principally markets the power generated by the Federal Columbia River Power System (FCRPS), which is comprised mostly of the hydropower generated at federal dams. The City electric system can reasonably expect to purchase a significant portion, if not all, of its power supply from BPA at BPA's lowest cost of power, which is the priority firm power rate, also referred to as the Tier 1 power rate.

In addition to BPA, a number of other opportunities for near-term power supply could be available to the City including power purchases from other utilities, independent generating facilities or power marketers. In the future, it is expected that the City will most likely continue to purchase power from BPA but will also be able to participate jointly with other utilities in new generation facilities, contract to purchase power from other suppliers and construct new generating facilities of its own including solar, wind and other renewable resources. For our initial analysis, we have assumed that the full power requirement of the new utility is supplied by BPA wholesale power.

BPA Power Supply Contract Issues

BPA is a federal agency within the Department of Energy that markets electric power from federal hydroelectric projects and certain other facilities to the region's utilities. Most of the publicly-owned electric utilities in the Pacific Northwest rely upon BPA for a significant portion of their power supply needs. As a municipal electric utility, the City's electric system would be able to contract with BPA to purchase its power supply from BPA provided certain criteria are met. Further, the City's system should qualify to purchase the majority of its power requirement at BPA's lowest wholesale power rate.

One of BPA's long standing standards for purchasing Federal power requires a customer to own the distribution facilities necessary and used to serve such customer's retail consumers. This standard applies to public body, cooperative, and privately-owned utilities selling to the general public and to federal agencies.

In July of 2007, BPA published a Long Term Regional Dialogue Final Policy and the Record of Decision on the policy was issued in October 2008[8]. The policy addressed issues necessary to begin negotiating and offering new power sales contracts for service after 2011, defined the products and services BPA would offer in those contracts, and described the process for designing and establishing a tiered Priority Firm (PF) power rate methodology. In particular, the policy stated that BPA intended to execute new long-term power sales contracts with its regional customers and discussed in some detail service to existing and new preference customers.

The current long-term power sales contracts provide for the purchase of BPA power between fiscal year (FY) 2012 (beginning October 1, 2011) and FY 2028. A template for the existing BPA Power Sales Contract can be found on BPA's website[9]. These contracts are complex, but allow for new preference customers, such as the City to be formed and receive power under certain terms and conditions. The Regional Dialogue specifically references new public utilities that serve what were previously privately -owned utility customers. BPA refers to this as "annexed loads" of new preference customers.

A significant element of the long-term contracts BPA entered into with its public power customers provides for tiered rates. Tier 1 power, BPA's lowest cost wholesale firm power product, is limited to the output of the federal system with some augmentation. Each utility has a contract high water mark (CHWM) that is used to establish the allocation of Tier 1 power and the amount of Tier 1 power each utility can receive. The amount of Tier 1 power provided to each utility can change throughout the contract period, which ends in 2028, and if additional power is needed utilities can supplement their Tier 1 power allocations with Tier 2 power, power from other generating facilities, or other power purchases. BPA will also act on behalf of a utility to make other purchases and provide ancillary services to integrate those purchases for the utility.

BPA's policy to serve new public power customers provides (based on current resources) for up to 250 average megawatts of power for new customers during the current long-term contract period. The CWHM for new customers is established as the total net requirement of the new utility in the first year of service. Some limitations do apply, however, in that during any two-year rate period, the amount of power available to new customers is limited to 50 average megawatts. If necessary, individual CHWM amounts for the new utilities will be prorated down to remain within the 50 average MW limit. If this limit is applied, the amounts not provided in the first year will be added in the next rate period.

[8] Bonneville Power Administration, Long-term Regional Dialogue Policy, Administrator's Record of Decision, October 31, 2008.
[9] https://www.bpa.gov/power/pl/regionaldialogue/implementation/Documents/docs/2016-02-25_Conformed_LF_Master_Template.docx

Over time BPA has established certain criteria that must be met before an entity may qualify for service from BPA[10]. For a new preference customer, such as the City to comply with the existing standards for service, it must:

1. Be legally formed in accordance with state and federal laws;
2. Own a distribution system and be ready, willing and able to take power from BPA within a reasonable period of time;
3. Have a general utility responsibility within the service area;
4. Have the financial ability to pay BPA for the federal power it purchases;
5. Have adequate utility operations and structure; and
6. Be able to purchase power in wholesale, commercial amounts.

Upon compliance with these standards for service and upon application to BPA under the provisions of Section 5(b)(1) of the Northwest Power Act, the City will be entitled to purchase power from BPA as a preference customer.

At the present time it is estimated that approximately 200 average MW for new public power customers still remains in the current contract period. The only new public power utility to form and contract with BPA during the contract period has been Jefferson County PUD, with a CHWM just under 50 average MW. If the City were to apply for a contract with BPA and meet the notification requirements and there are no other concurrent new utility applicants, it is expected that the City's full load requirement for the electric system could be established as the CHWM in the first year of service.

The cost of BPA power to the City will be governed by the BPA Power Sales Contract and various other BPA policies established by statute. New large loads, such as a large commercial customer, over 10 average MW that are placed on BPA's system may be subject to a surcharge related to the cost of power supply, potentially at market rates that BPA may need to acquire on behalf of the new load. In the case of the City, there are no anticipated new large loads.

For the purpose of estimating the cost of power to the City in this analysis, it has been assumed that the City would purchase its entire power supply requirement from BPA. Under current BPA policy and past BPA precedents, a power purchase from BPA would entail both Tier 1 power and historically more expensive Tier 2 or market priced power. Currently market priced power is at about the same price or in some cases lower than Tier 1 power from BPA[11]. Since Tier 2 rates have been higher than Tier 1 rates in the past, we have assumed for the analysis that BPA Tier 2 power is 15% more expensive than BPA Tier 1 power. It is estimated that Tier 2 power purchases will represent a small portion of the overall BPA power purchase by the City electric system.

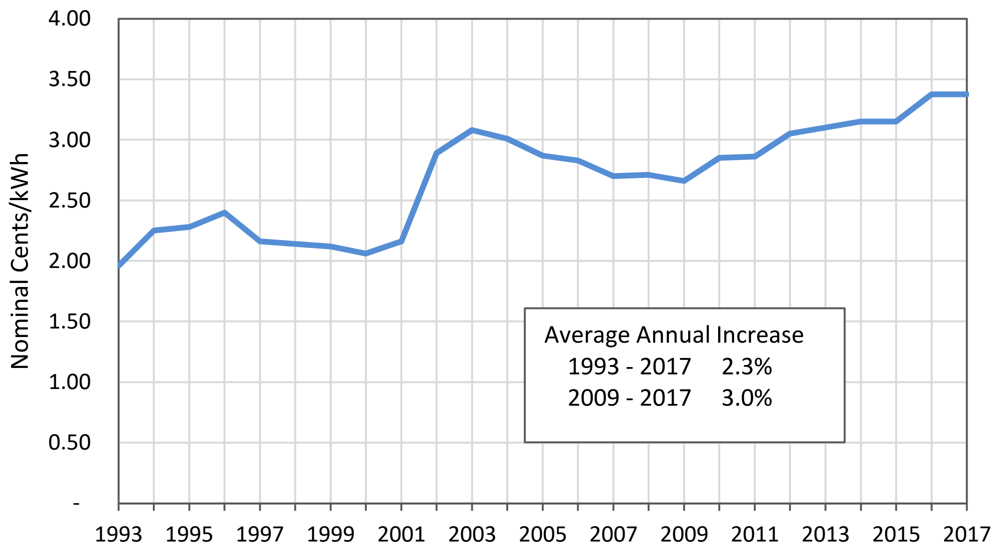
[10] Bonneville Power Administration, Final Policy on Standards for Service – Administrator's Record of Decision, December 22, 1999.

[11] In the current 2016 BPA power rate schedule for Priority Firm power, the price for short-term Tier 2 power is indicated to be 29.72 mills/kWh for FY 2016 and 32.01 mills/kWh for FY 2017.

BPA has indicated that it has begun discussions regarding the next contract period that will begin in 2028. Through "Focus 2028" BPA is endeavoring to prove its cost competitiveness and remain the power supply provider of choice for its customers. The process has involved obtaining customer input with regard to what it means for BPA to be competitive from the customers' perspective. It is envisioned that discussions with regard to the new power sales contracts will begin in the early 2020s.

The following chart shows BPA's average PF rate over the past 25 years. The average annual increase in the PF rate between 1993 and 2017 was 2.3%. Between 2009 and 2017 the PF rate has increased at 3.0% per year on an annual average basis. Note that the rates shown in the chart do not include transmission charges.

FIGURE 1
Historical BPA Average Priority Firm (PF) Power Rate[12]
(Fiscal Years Ending September 30)



For its preference power customers, BPA does not identify specific resources for specific sales. Rather, the "mix" of BPA's power resources is used to establish the overall power product. For its fiscal year 2015, BPA indicates that the mix of its resources by generation type was 84.5% hydroelectric, 9.9% nuclear, 0.9% wind, 4.5% non-specified purchases and 0.2% other. Tier 2 power is purchased on the open market by BPA and is not generally identified as to source. The nuclear energy shown in BPA's resource mix is from the Columbia Generating Station (CGS), a 1,190 MW nuclear energy facility located about ten miles north of Richland, Washington. The CGS began operation in 1984 and it is the only commercially operating nuclear facility in the Pacific Northwest. Its output is provided to BPA and BPA pays the costs of operating and maintaining CGS.

[12] Source: https://www.bpa.gov/power/psp/rates/previous/historical_PF.shtml

Other Power Supply Options

Although most of the smaller public power utilities in the Pacific Northwest purchase their full power requirement from BPA, there are many options currently available for short and long-term contract purchases of renewable and traditional power. The City could choose to pursue some of these options on its own or join with other utilities. Organizations such as The Energy Authority[13] (TEA) can be used to assist with acquisition and management of power supply resources. According to TEA there are good opportunities at the present time to purchase energy from wind farms pursuant to longer term, 10-20 year, contracts.

In addition to purchasing power from energy resources owned by others, public power utilities can jointly develop, own and operate generation projects. Energy Northwest is an example of a joint operating agency owned by 27 public power utilities in Washington. Among other projects, Energy Northwest owns and operates, the Packwood hydroelectric project near Yelm, Washington, the 1,190 MW Columbia Generating Station nuclear facility, near Richland, Washington, the 64 MW Nine Canyon Wind Project located near Kennewick, Washington and the White Bluffs Solar Station, a solar photovoltaic demonstration project near Richland, Washington.

Transmission Requirements

The new electric utility will also require a transmission contract to transmit the power it purchases to its distribution system. A typical public power utility would have a BPA transmission contract. BPA offers both network integration (NT) and point to point transmission contracts. It is expected that the new utility will obtain a network integration transmission contract with BPA, similar to most small to medium sized BPA customers, and that in conjunction with the power sales contract, BPA will deliver power over BPA's and PSE's transmission systems to a delivery point at a substation on Bainbridge Island.

Provisions within BPA's transmission and power sales contracts allow for a utility to transmit power from non-federal generation resources used to meet the utility's load above the CHWM level over BPA's transmission system. BPA also indicates that it regularly assists its customers with transmission to help bring non-federal generating sources onto the system.

[13] The Energy Authority is a public power owned non-profit corporation with offices in Jacksonville, Florida and Bellevue, Washington. As a national portfolio management company they assist clients in obtaining and managing power supply resources.

Operational Reliability

Reliability of electric service has been indicated to be a key issue of concern to the residents and businesses of Bainbridge Island. Based on outage statistics provided to the City by PSE, it can be seen that tree related issues are the cause of the vast majority of customer outage minutes on Bainbridge Island. The data indicates that there were on average, 270 distribution outages per year between 2004 and 2015 of which approximately 50% are indicated to be caused by trees. Unknown causes and equipment failure represents the second and third largest causes of distribution outages. During the same period, there were about 2.5 transmission outages per year on average, most caused by trees.

The total number of distribution customer outage minutes for all Bainbridge Island customers between 2004 and 2015 averaged about 10.5 million minutes per year of which about 9.2 million minutes, or 92% were tree related.

In looking at the detailed reliability information associated with Bainbridge Island, tree caused outages dominate the amount of time that customers are without power. The biggest potential gains in reliability will be through looking carefully at the primary cause of outages which is trees and tree branches touching overhead power lines. Even if there are no changes in tree and vegetation management programs, there are other things that can be done to improve reliability.

The five-year system average interruption duration index (SAIDI) benchmark is a defined term by the WUTC. The WUTC service quality index #3 or "SAIDI-total 5-year average" is based on all customer minutes of interruptions that occurred during the current and previous 4 years, except for extreme weather or unusual events, divided by the average annual number of electric customers. PSE annually reports this information to the WUTC by county. While an important statistic for an electric utility, a more meaningful measure of service from a customer perspective includes extreme weather or unusual events.

The outage data for Bainbridge Island provided to the City by PSE can be used to develop an estimated "all in" tree related SAIDI-type of index for Bainbridge Island. Adding the "all-in" customer minutes of distribution tree outage to the "all-in" customer minutes of transmission tree outage and dividing by the number of customers provides a representative SAIDI-like statistic related to tree outages. This "all-in" statistic does not exempt major storms or events. Performing such a calculation yields the following:

Average Annual Bainbridge Island Customer Outage Minutes per Customer

	2009	2010	2011	2012	2013	2014	2015	2016 (partial year)
Distribution Tree related “all-in”	517	1,844	212	115	286	494	1,082	694
Transmission Tree related “all-in”	31	483	95	168	151	214	1,084	294
Total Tree related annual average	548	2,327	307	282	437	708	2,166	989
Total all causes “all in” annual average	655	2,497	384	392	510	819	2,336	1,110

The analysis in the above table shows that both distribution and transmission tree related outages are significant and need to be addressed if reliability is to be improved. A further evaluation of reported outage statistics in Kitsap County was also conducted for comparison.

In the March 29, 2016, PSE Service Quality and Electric Service Reliability filed with the WUTC various PSE SAIDI statistics by county for the years 2013, 2014, and 2015 are shown in Appendix K of that report. Kitsap County had the highest $SAIDI_{Total}$ value of any county in PSE’s system in 2015 (1,715 minutes), third highest county value in 2014 (607 minutes) and highest county value in 2013 (324 minutes). This report shows that in 2015 the $SAIDI_{Total}$ for all outages in PSE’s system was 760 minutes. Bainbridge Island tree-related outages appear to be at or higher in total average minutes of outage than Kitsap County total average minutes of outages for each of these years.

This identifies a number of reliability issues. First, tree-related outages in 2015 are the most significant reliability issue on Bainbridge Island and the tree outages appear to be much higher in terms of customer outage minutes per customer than the system-wide PSE $SAIDI_{Total}$ for 2015 reported in the WUTC reliability report. It should also be noted that $SAIDI_{Total}$ in Kitsap County during the years 2013, 2014, 2015 seems to have been higher than average $SAIDI_{Total}$ outages for PSE customers in other counties.

An obvious question is what can be done to reduce tree-related or tree-initiated outages. In 2015 transmission outages were a very large number and about half the total outage minutes (few in number but many customers and long time span) in that year. In other years transmission outage minutes were still significant when compared to distribution outage minutes. Tree related transmission outage minutes are also a function of the amount of tree/vegetation management that removes both danger trees and heavy branch growth.

Providing a looped 115-kV transmission line closing the segment between the Murden Cove substation and the Winslow substation would improve transmission reliability, especially if either automatic or SCADA controlled 115-kV circuit switchers or circuit breakers were used to close or open the existing line segments. This would reduce the time that a substation would be without power if one of the 115-kV lines south of the Port Madison substation were faulted. PSE has studied and defined alternatives for a new transmission connection between the Murden Cove and Winslow substations. This transmission line was proposed to improve reliability of service and also to expand the capacity of the Winslow substation to meet increasing power demands. The estimated length of this line is between five and six miles. In 2010, an early estimate of the cost of this line was indicated by PSE to be $3-$4 million. PSE estimated that the installation of this transmission line would save 1.15 million customer outage minutes per year.

Another reliability issue related to transmission is that the two 115-kV transmission feeds from the Kitsap Peninsula to Bainbridge Island cross over Agate Pass at the same location which could allow for common mode failures. This limitation in power delivery to the island would be difficult to overcome in that the cost of installing an alternative, underwater 115-kV transmission line would be prohibitively expensive, based on our experience with the installation of submarine power cables.

Another factor is the amount of time it takes for a maintenance crew to reach a faulted transmission line and then patrol the line to establish the location of the fault and determine the extent of damage. This means that the distance that the line crew travels from their service center and the time it takes to drive that distance to get to the source of the outage can significantly increase the customer minutes of outage. Similarly, once the crew reaches the de-energized line or substation, it needs to visually inspect the power line to determine if other problems would prevent safely reenergizing the overhead power line.

If there is structural damage to the line, the outage will continue for at least some customers until repair materials and heavy equipment can be transported to the damage location. Having crews, equipment, repair materials and heavy equipment on or near Bainbridge Island would reduce the customer minutes of outage time. Even if the City does not form an electric utility, it might be able to have some equipment and materials staged within the City. Traditionally most electric utilities require their line and engineering employees to live within certain distances of their service territory or service centers as a way of enhancing reliability. Most Pacific Northwest municipal electric utilities have not found this to be a problem when hiring electrical workers.

Still another option is to underground power lines. While PSE does have limited underground 115-kV transmission in its system, as do other utilities in the state, it is very expensive to install underground transmission lines. Another complication beyond expense is that underground transmission right of ways also need to have trees and roots removed from the transmission path. Therefore, undergrounding of transmission could result in more trees being cut than even a more aggressive vegetation management plan for overhead transmission. Most Pacific Northwest electric utilities try to avoid undergrounding transmission due to the high expense and instead focus transmission reliability improvements on vegetation management and quick response to outages. Most utilities also periodically patrol their transmission lines with thermal imaging equipment to detect any hot spots that are indicative of an insulation problem associated with equipment breakage. Also most utilities have aggressive pole testing programs to assess the structural integrity of wood poles.

The other major source of outage minutes has to do with distribution outages. Again tree related outages are a major factor. In our economic analysis, we have included operating costs for an aggressive tree trimming program. As with transmission, distribution reliability can be enhanced with better vegetation management, looped or network distribution systems, undergrounding, and reducing the time to respond and fix the causes of outages.

Distribution is also traditionally where additional causes of outages, such as animals, car-pole accidents, and equipment failures become a noticeable portion of the outage minutes. The most spectacular distribution outages are usually when either poles fail or when underground conductors fail. PSE, like most utilities, has an extensive pole testing and cable injection/replacement program to help avoid these kinds of spectacular equipment failures.

Unlike transmission, there are two other ways that some utilities will try to reduce distribution tree related outages. Some east coast utilities use compact messenger spacer insulated cable in their overhead distribution construction. The nearest example of spacer cable distribution construction is on the Bangor Trident base. Spacer cable is about 20% to 40% more expensive than open bare wire distribution lines, but has two major benefits. The first is that the messenger wire is usually more rugged than typical tree wire and more capable of supporting tree branches. The second is that the compact spacing of the conductors can allow all phases to be placed farther away from trees on the road side of the pole so that a given amount of tree trimming will reduce the number of outages when compared to standard framing bare wire or tree wire. In addition to higher cost, some view spacer cable construction as a less aesthetically pleasing utility construction method due to the spacers and undulating bundles of conductor. However, in certain locations it could dramatically enhance reliability.

PSE uses tree wire on Bainbridge Island and is planning on additional tree wire installation. Some PSE documents claim that tree wire can reduce the number (not duration) of outages by 70%. While tree wire is used by several Pacific Northwest electric utilities in heavily forested areas, it is not without problems. In particular if the line touches the ground, the partial insulation can prevent typical breakers and fuses from clearing the fault and de-energizing the line. It is also more expensive than open bare wire. Among its 2017-2018 identified improvement projects for Bainbridge Island, PSE has several tree wire installation projects planned. These projects primarily involve the rebuilding of existing overhead distribution segments and the installation of tree wire. PSE has also indicated that it is planning to underground approximately two miles of existing overhead distribution line on Blakely Avenue, estimated to occur in 2017.

Constructing additional distribution feeders to loop and or network the distribution system can also enhance reliability. Most Pacific Northwest network distribution systems are employed only in very high density large central cities. Open looped, operated in a radial means is a more common rural distribution configuration.

Another substation on Bainbridge Island could allow for additional distribution feeders. These feeders could be shorter and as a result the number of customers exposed to outages per feeder will go down. That should reduce some of the outage minutes.

PSE has indicated that nearly 50% of existing distribution lines on Bainbridge Island are underground. Underground distribution lines typically reduce tree and storm outages, but most underground distribution is susceptible to neutral corrosion and water treeing in the cable itself. Modern underground jacketed cable typically has a design life of 40 to 50 years and this can be sometimes extended another 20 years or more through injection of non-conducting silicon oil into the cable to fill internal insulation trees. However, the length of time that is needed to replace damaged underground cables is significant compared to overhead distribution lines. This is especially true for underground cable that is direct buried as opposed to being installed in conduit. Underground feeder construction is estimated to be three or more times as expensive as bare wire overhead construction.

Much of Bainbridge Island's road system is basically a rural style road with a crowned road, drainage ditches on both sides of the road and native vegetation and trees located close in This makes placement of new underground distribution lines difficult, because water, telephone, cable television, and power cables along with power vaults would need to compete for space and fit behind the drainage ditch in the right of way. Undergrounding of overhead utilities could require clearing of trees within the public right of way and adjacent to the drainage ditch. However, the City in its long range road repaving plans, could include conduit runs under the pavement and periodic electrical vaults along the side of the road for future undergrounding of overhead power lines.

Some publicly owned electric utilities set up local improvement districts (LIDs) to pay for the costs of undergrounding distribution lines in certain neighborhoods.

If the City were to establish an electric utility its efforts to improve reliability should be focused. One focal point, vegetation management, will likely be a critical component. PSE has both a tree watch program and periodic tree trimming programs. Collecting outage statistics by feeder and comparing that to tree trimming cycles and distance to trees could help gather data for better reliability. If certain trees are a problem they can either be removed or if that is not possible, rerouting the power lines to another location or looking to a different framing configuration such as tree wire or spacer cable could be pursued.

Another focal point will be the ability to provide quick restoration of power after an outage, which may be enhanced if equipment and crews are located close to or within the City. This would reduce the number of minutes of a typical outage. Still another focal point may be undergrounding of overhead power lines in certain areas to further reduce outages. This does not mean that other forms of maintenance or system design should be neglected. If the City does not form a new electric utility, it may wish to focus its reliability discussions with PSE on what can be done to prevent tree-related outages and/or shortening the amount of time to restore power. To prevent tree related outages may require more information on the types of vegetation management by circuit/location and the outages in those locations.

If a reduction in the SAIDI or minutes of customer outage per customer is a goal, both transmission and distribution tree-related outages will need to be addressed. This is because either can be the majority of the $SAIDI_{all-in}$ minutes in a particular year.

As another point of comparison, we also examined a Snohomish County PUD Electric System Reliability Report that included statistics from 1991 to 2015. Snohomish County is slightly north and east of Bainbridge Island and it includes rural forested areas as well as urban and suburban areas within its service territory.

In Appendix C of the Snohomish County PUD reliability report in Table C-1 of SAIDI, there is data broken out by distribution, transmission, unusual weather events, declared major events and "Overall (Everything)." The Snohomish County PUD "Overall" SAIDI is compared to the PSE Bainbridge Island "all in" total outage minutes in the following table:

Comparison of Snohomish County PUD Overall to Bainbridge Island Total Annual Average Customer Outage Minutes per Customer

	2009	2010	2011	2012	2013	2014	2015
Snohomish County PUD "Overall (Everything)" SAIDI (i.e. Trees and all other causes for both transmission and distribution)	76	114	83	116	85	229	1,390
Bainbridge Island Total All Causes "all-in" (see previous table)	655	2,497	384	392	510	819	2,336

It can be seen from the above table that there are far more average minutes of customer outage on Bainbridge Island than in Snohomish County PUD. Since tree related issues are the most significant cause of outages on Bainbridge Island, vegetation management or tree trimming is the critical reliability factor.

Snohomish County PUD performed a detailed analysis of its outages on the 20 circuits with the greatest number of distribution outages. The PUD determined that the number of tree related distribution outages where trees or branches are farther away than 10 feet from power lines is less than the number of outages (by about a factor of slightly less than two) than where trees and limbs are closer. However, what the PUD also found was that the distant tree caused outage average customer durations (in non-major events or storms) were just slightly less (ratio of about 9 to 10) than average customer durations caused by closer trees. The implication for Bainbridge Island is that to improve SAIDI, trees close to the power lines as well as those more distant need to be addressed, even though tree trimming within 10 feet of power lines is associated with the greater number of outages.

The City should ask PSE to collect similar information by circuit so such information can be factored into the PSE vegetation management and tree trimming programs on Bainbridge Island.

Such information might also identify areas where distribution lines could be rerouted, undergrounded, or constructed with alternate overhead framing techniques such as spacer wire.

Section 3
Estimated Cost of Electric Facilities

Electric System Facilities on Bainbridge Island

Electric service on Bainbridge Island is presently provided by PSE. The electric facilities located within the City include transmission lines, substations, overhead and underground distribution lines, poles, transformers, vaults, service drops, meters, streetlights, right-of-ways and ancillary distribution system facilities. There are three substations on the island that transform power from transmission voltage to the primary distribution voltage.

PSE's transmission system on Bainbridge Island consists of approximately 14 miles of 115-kilovolt (kV) overhead transmission lines that connect to PSE's transmission system on the Kitsap Peninsula side of Agate Passage. There are two transmission circuits that cross Agate Passage by means of an overhead crossing that is essentially new, having been rebuilt in 2014. Once on the island, the two transmission circuits separate and proceed along different routes until Hidden Cove Road and Highway 305. From that point they are near each other along Highway 305 until they reach the Port Madison substation located at the northwest corner of the intersection of Day Road and Highway 305.

The Port Madison substation was originally built in 1980 and serves as a transmission switching station as well as a distribution substation serving approximately 4,000 electric customers. Two radial transmission lines proceed from the Port Madison substation, one to the Murden Cove substation and one to the Winslow substation. The Winslow substation was originally built in 1960 and serves approximately 3,800 customers. The Murden Cove substation was originally built in 1980 and serves approximately 4,500 customers. Each of the three substations has one transformer that provides power at 12.5-kV, the primary distribution voltage, to four distribution feeders.

The transmission connections at the Port Madison substation are indicated by PSE to have been rebuilt in 2000. The underground getaways appear to be older. Two of the feeder getaways at the Murden Cove substation appear to have been rebuilt with new underground cables for each circuit. The Murden Cove substation yard is large and could accommodate a second transformer if needed in the future. The Winslow substation is built using overhead getaways and the poles and wires appear to have been recently replaced. Several overhead spans from the Winslow substation in both directions use tree wire. The Winslow substation yard appears to be smaller making it difficult to expand in the future.

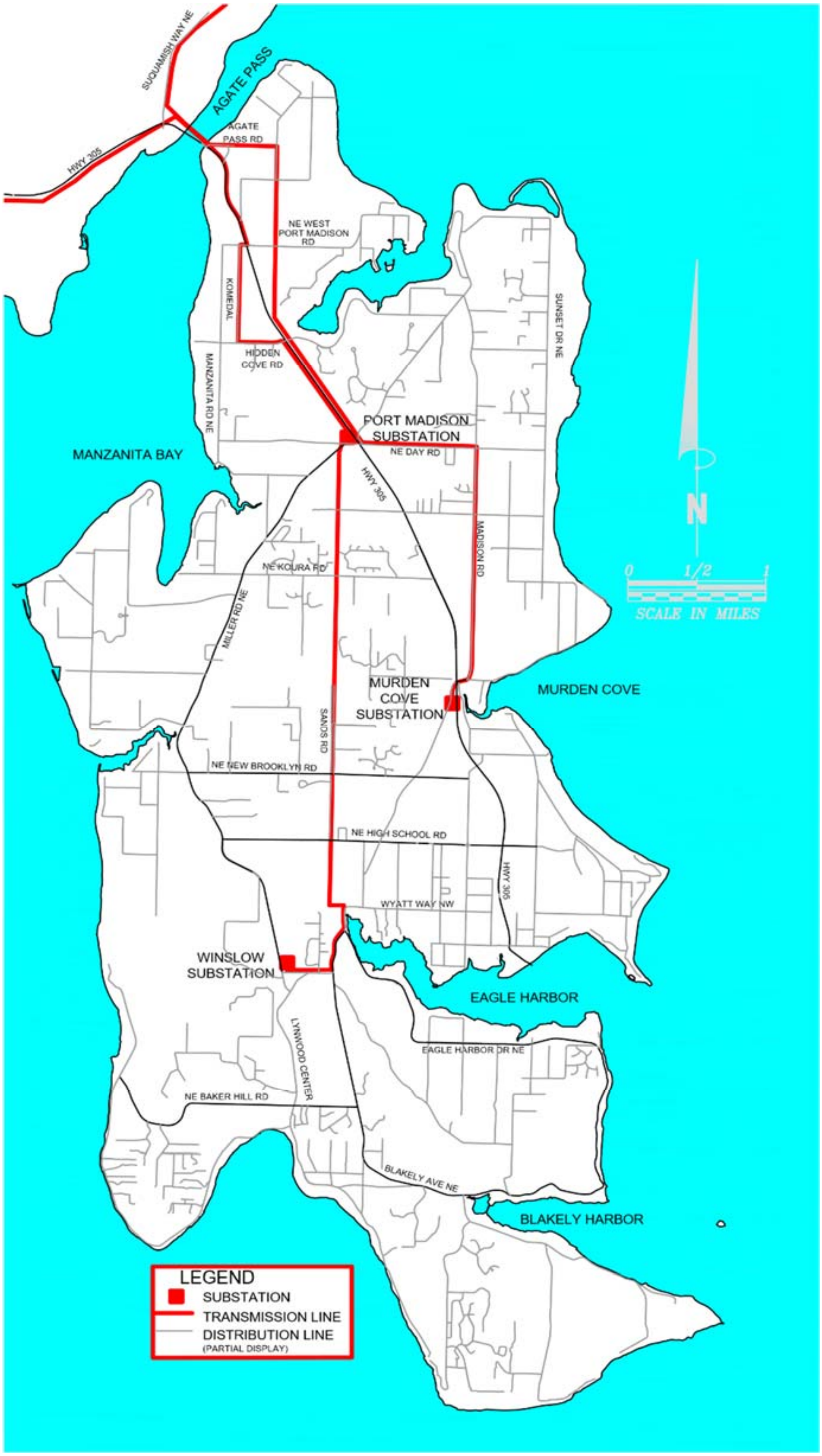


Figure 2 Bainbridge Island Transmission and Substation Facilities (*Partial representation of distribution lines*)

PSE indicates that there are 307 miles of distribution lines on Bainbridge Island of which 165 miles are underground. The overhead and underground lines are a mixture of three, two and single phase. In addition, 22 miles of overhead distribution lines use insulated tree wire. Overhead distribution and transmission lines are generally built with typical wood-pole construction and in some areas the distribution lines are underbuilt on transmission poles. The exception to the transmission is the steel pole/tower crossing of Agate Passage.

The distribution system appears to be a mixture of main feeders, some of which were rebuilt in the past few years, and many laterals and smaller feeder wire portions that are older. It was noted that some poles along Crystal Spring Drive NE are placed in the beach with anchoring extending into the tidal area. The distribution system appears to be designed and operated principally as a radial system.

Proposed Facilities to be Acquired

There are several options that the City could take in defining the electric facilities that would be acquired to establish a new electric utility system. It is expected that the substations, distribution lines, transformers, services and meters would be needed for the City to own the distribution system as required by BPA. All of the transmission lines, however, would not necessarily need to be acquired. Instead, PSE could continue to own some or all of the transmission lines on the island and BPA would make arrangements with PSE to deliver power over the lines to the City's substations. The City system would also need to acquire the streetlights owned by PSE.

BPA has historically even provided transmission service to and through PSE owned substations for some of its preference customers. Examples includes BPA service to the cities of Blaine and Sumas, both of which are served at primary voltages from PSE substations by BPA contract.

Alternatively, the new electric utility could acquire the transmission lines from the connection to PSE's Kitsap Peninsula transmission system at Suquamish Way NE and own the crossing at Agate Pass and all the 115-kV lines on Bainbridge Island. Another option could be to build a new transmission line from the Suquamish Way connection point to BPA's closest substation at the Bangor naval base. This line is estimated to be approximately eleven miles long and would potentially be difficult to permit and construct. It would also only provide a single radial line to the City's system from Bangor presenting a potential reliability risk.

Although BPA's customers typically take delivery of power directly from a BPA substation or over BPA transmission lines, BPA has indicated that it could deliver power to the City's electric system over PSE's transmission lines. This approach is used elsewhere in the Pacific Northwest where a direct connection to BPA's system is not currently available. BPA would negotiate with PSE for the use of PSE's transmission system to deliver power to the City system and would compensate PSE for this service. An advantage of this approach is that PSE's transmission system would continue to be used in the manner it is now and PSE would receive payments for the use of the system. PSE would, however, continue to be responsible for the maintenance and operation of its transmission system and provide outage restoration. A Line and Load Interconnection

Request[14] will need to be made to BPA to obtain more specific information about the capability of BPA's and PSE's transmission systems to serve the City system and define the specific interconnection equipment needed.

BPA indicates that it treats transfer customers (those served over other utilities' lines) the same as customers connected directly to BPA's system. If the City were to become a BPA transfer customer it would obtain a Network Transmission (NT) agreement with BPA. As an NT customer, the City system would pay the NT transmission charge similar to all other BPA customers with an NT agreement that are directly connected to BPA's system. Through the NT charge BPA pays for the cost to transmit power over BPA and non-BPA lines as needed to deliver power to its customers.

For the purpose of this analysis, we have developed a base case in which the new City electric utility would not acquire the transmission lines north of the Port Madison substation. Since BPA would be delivering power over PSE's transmission system in Kitsap County, transmission to the Port Madison substation would be a continuance of the use of PSE's system. BPA has indicated that it would most likely locate its metering system at a substation. A metering system would be installed at the Port Madison substation and this is where the new utility would take delivery of power from BPA. From this point the new electric utility would own the substations, the radial transmission lines between the substations, all overhead and underground distribution lines, distribution transformers, customer services, and meters.

An alternative ownership arrangement that could be evaluated would be for the City system to acquire only the distribution lines and customer services and for PSE to retain ownership of all transmission lines and substations. In this case, BPA would deliver power to the City system on the low voltage side of the substation transformers. This type of arrangement exists elsewhere in BPA's system. BPA assesses an additional charge to accommodate this arrangement and negotiates with the substation owner and pays for the use of the substation. If the City electric system were to undertake this kind of arrangement, PSE would continue to own, operate and maintain all of the transmission and substation systems in the City.

Based on our observations and information provided to the City by PSE, we have estimated the quantities and approximate sizes of electric facilities to be acquired by the new utility. Using this information and our experience with electric utility construction and costs, we have estimated a range of costs for the acquired facilities.

Estimated Cost of Electric Facilities

An appraisal of the value of electric facilities to be acquired by the City for its electric system has not been conducted. Such an appraisal would rely upon a detailed description of the facilities to be acquired and will potentially be needed if the City proceeds towards acquisition of the PSE

[14] https://www.bpa.gov/transmission/Doing%20Business/Interconnection/Pages/LLIP.aspx

system on Bainbridge Island. Such information could be provided by PSE or it could be developed independently by the City as part of a condemnation legal proceeding.

We have estimated that approximately 7.5 miles of 115-kV transmission lines currently owned by PSE, the transmission lines between the substations, would be acquired by the City. There are three substations and approximately 307 miles of distribution lines of which 165 miles are underground, as indicated by PSE. Since we do not have asset records from PSE or know what the original cost of these specific facilities was, we have estimated the original cost based on estimated current transmission and distribution costs deflated to the cost at the assumed average installation date separately for each type of facility.

For the purpose of this analysis, the cost the City would pay for the acquired facilities is estimated to be between the original cost less depreciation (OCLD) value and the reproduction cost new less depreciation (RCNLD) value of the electric facilities. OCLD is defined as the original cost of the property when it was first put into service as a public utility, less accrued depreciation. The OCLD value is an estimate of the net book value of property, which in general, is approximately the rate base value of the property for ratemaking purposes. In its order regarding the matter of PSE's petition for accounting of the proceeds from the sale of assets to Jefferson County PUD[15], the WUTC concluded that PSE was authorized to retain the net book value of the assets, plus certain transaction costs and 12.4% of the gain on the sale of the assets, for its shareholders. The remainder of the proceeds of $52.7 million was to be allocated to PSE's ratepayers as pro rata monthly bill credits over a four year period.

For state utility commission regulated properties such as the facilities to be acquired by the City, the rate base value generally is the portion of the original investment cost which the utility has not yet recovered through rate charges paid by its customers.

The following table summarizes the estimated RCN, RCNLD and OCLD costs for the facilities expected to be needed by the new City electric system. As previously indicated, the facilities to be acquired do not include the transmission lines north of the Port Madison substation. Further, the costs shown for the facilities are for those facilities in place at this time. No additional amounts are included for facilities that may potentially be installed in the future.

[15] Washington Utilities and Transportation Commission, Docket UE-132027, Order 04, Service Date September 11, 2014.

TABLE 2
Estimated Costs of Facilities to be Acquired by the City Electric System
($000)

	Estimated Weighted Average Year of Installation*	Average Service Life (Years)	Estimated Percent Depreciated	Estimated Reproduction Cost New ($000)	Estimated Reproduction Cost Less Depreciation (RCNLD) ($000)	Estimated Original Cost Less Depreciation (OCLD) ($000)
Substations and getaways	1995	50	44%	$ 9,780	$ 5,490	$ 2,560
Transmission Lines	1996	50	42%	2,160	1,250	750
Distribution Facilities						
Overhead Lines	1993	50	48%	19,900	10,420	4,980
Underground Lines	1996	50	42%	32,840	19,040	8,470
Services, Transformers, Meters	1996	50	42%	27,450	15,920	7,240
Subtotal - Distribution	1995	50	43%	80,190	45,380	20,690
Total				$ 92,130	$ 52,120	$ 24,000

* Average year of installation of facilities with adjustment for periodic renewals, replacements and additions.

As indicated in the table, the estimated cost of the facilities based on OCLD and RCNLD ranges between $24.0 million and $52.1 million. If in addition, the City electric system were to acquire the transmission lines north of the Port Madison substation, including the Agate Pass crossing, the estimated cost of the facilities would range between $28.7 million (OCLD) and $57.5 million (RCNLD). If the City system were to acquire only the distribution lines, services, transformers and meters, the estimated cost of the facilities would range between $20.7 million (OCLD) and $45.4 million (RCNLD).

For the purpose of comparison, the estimated total investment in electric distribution facilities on a per customer basis in PSE's total system has been evaluated. This distribution value includes PSE substation facilities, overhead and underground distribution lines, customer connections, meters and other facilities. PSE's total electric plant in service as of December 31, 2016 was $9.5 billion. The investment in distribution plant was $3.6 billion or $3,200 per customer based on the total number of electric customers in PSE's system of 1,126,200. These electric plant and distribution plant in service amounts are based on the original cost of the plant when it was installed. Overall, the value of PSE's distribution plant was 37.5% depreciated as of December 31, 2016.

Assuming that PSE's investment in Bainbridge Island on a per customer basis is proportional to investment in these facilities throughout PSE's entire system, the total estimated amount for distribution plant in Bainbridge Island would be $39.4 million. Applying 37.5% depreciation would result in the original cost less depreciation value of distribution plant being $24.6 million. This is comparable to, although slightly higher than the total amount shown for the original cost less depreciation in Table 2. Using PSE's reported system average depreciation on distribution plant to estimate the average installation date of distribution plant, the RCNLD of distribution plant on Bainbridge Island is estimated to be $54.9 million. The value of transmission plant to be acquired would need to be included in the total cost based on this methodology to provide a totally comparable estimated value.

As another point of information, the Washington State Department of Revenue (DOR) has estimated that the equalized taxing value of PSE real and personal property within Kitsap County, adjusted for market conditions in 2016 was $198,096,993[16]. It is important to note that DOR performs a complex review of various assets and information provided to it and then makes adjustments to price the real and personal property at approximately a market value. It is also important to understand that this DOR value includes buildings, transmission lines, substations, distribution facilities, land rights, computer software, etc. The Kitsap County Assessor's Office reports that the DOR assessed value of PSE's real and personal property for property tax purposes for 2017 in the Bainbridge Island tax code areas is $19,593,411.

Stranded Costs

Stranded costs represent a utility's investments in facilities that become unused or redundant as a result of regulatory or market changes. The proposed acquisition concept involves the continued use of portions of PSE's transmission system for which PSE will be compensated and as a result there should not be any stranded costs related to these facilities. The Federal Energy Regulatory Commission (FERC) established the concept of stranded costs after it established a transmission open access policy that requires utilities, such as PSE to provide transmission access. The application of stranded costs is based on a complex set of FERC definitions and formulae that can likely only be resolved by litigation or negotiation. Further evaluation may be needed but it is not expected that stranded costs would have a significant impact on the costs of acquisition for a new utility on Bainbridge Island.

Separation Costs

The physical separation of the electric systems of the new electric utility and PSE is expected to be relatively simple if the new utility takes delivery of BPA power over PSE's transmission system at the Port Madison substation. The new utility will need to install BPA bulk power metering equipment and assure that appropriate protection and switching systems are installed at the substation. The new utility will be responsible for any costs that are incurred to provide separation of the systems.

In the past it has been noted that third party owned customer metering equipment may be installed in PSE's system. If these meters are in the City's system it may mean that there would be some additional costs associated with meter acquisition. In addition, PSE's investment in residential and commercial energy efficiency systems in Bainbridge Island, identified by PSE as $2.8 million, may or may not need to be refunded at the time of acquisition or reflected in the acquisition cost. Likewise, there may be customer service or accounting costs associated with separating the

[16] http://www.dor.wa.gov/docs/reports/2016/utilvals2016/2016_Table_2.pdf

customers from PSE's system and costs of transferring legal assets that may or may not need to be reflected in the acquisition cost.

Section 4
Estimated Initial Financing Requirements

Financing Options and Conditions

The costs of acquiring the direct necessary electric facilities are combined with estimates of any necessary new construction costs, legal and consulting fees, engineering costs and startup costs to determine the initial financing requirement for the new utility. Funds are typically borrowed to pay these costs and the borrowed monies are repaid over a fairly long period such as 25 to 30 years. Because of the amount of investment needed to construct electric utility facilities as well as the long useful life of these facilities, electric utilities often have a fair amount of long-term debt to service. It is assumed that the City would finance the initial acquisition costs of the facilities with the issuance of revenue bonds that would not be tax-exempt. Costs of constructing new facilities or facilities for separation, purchases of equipment, inventories, supplies, reserves and other related costs are assumed to be financed with loans carrying tax-exempt interest rates. Certain costs associated with the issuance of revenue bonds, such as the funding of a bond reserve fund, would also be incurred and are included in the estimate of total financing requirements.

Municipally-owned electric utilities and PUD's generally use tax-exempt revenue bonds and loans to fund the capital costs associated with their systems. Federal tax laws generally prohibit the use of tax-exempt loans for the funding of municipal acquisition of electric systems owned by investor-owned or privately owned utilities. Taxable revenue bonds have a higher interest rate than tax-exempt interest rates. For our analysis we have assumed a 4.5% tax-exempt electric revenue bond interest rate and a 5.0% taxable electric revenue bond rate. These assumed rates are higher than would be experienced at the present time in that tax-exempt and taxable rates would be about 4.0% and 4.4%, respectively, for 30-year municipal revenue bonds at the present time. The 30-year flat repayment schedule for the initial bond issuance, as assumed for this analysis, could be shortened if desired or a non-levelized debt service payment schedule could be established. The 30-year levelized repayment of bond debt is reasonably typical for public power financing and is used to establish a regular payment schedule with lower payments than would be required for a shorter repayment period.

In determining the actual interest rates the new utility would incur for revenue bond financing a number of factors would be evaluated by lenders. Among these factors would be the potential risk of a reduction in energy sales in the future due to a loss of large loads, aggressive conservation efforts or lower economic activity. These factors are commonly evaluated by those involved in revenue bond lending and with regard to the new City electric system, are expected to be similar to the experience of other public power utilities in the Pacific Northwest.

A shorter repayment period would require higher annual debt service payments during the repayment period but would allow for earlier retirement of the bonds. It is important that legal and financial advisors be consulted with regard to the structuring of bond issues to fully evaluate financing alternatives. Full principal repayment could be partially deferred in the first year of electric system operation to lower the revenue requirements in the first year. Various exceptions and special conditions could exist that would allow more access to tax-exempt securities to fund the initial financing requirement.

It is important to note that the debt incurred by the new City electric system would be expected to be secured by the revenue of the electric system and not the City's general fund. As such, property taxes and other taxes within the City would not be used to support the electric system bonds.

Requirements for a New Utility to Issue Long-term Revenue Bonds

Issuing long-term debt is fairly common for municipalities, counties and other governmental agencies. A new, municipal electric utility would need to consider some of the following requirements in undertaking a revenue bond financing.

1. Agreement to purchase the system is complete so there is no question about ownership.
2. The governing body is in place (i.e. City Council)
3. A feasibility study has been completed showing projected revenues and expenses.
4. An initial rate schedule based on feasibility study has been adopted by the governing body.
5. Management and staff in place (contracted for or hired) so it is clear that the entity has the capability to run an electric utility.
6. A bond ordinance has been adopted with typical revenue bond covenants including a pledge to raise revenues as necessary to pay debt service, provide adequate debt service coverage, establish an adequate reserve account and address other covenants.
7. Indicate adequate cash on hand to fund startup and initial costs until revenues from rates and charges are received.
8. Have an agreement in place for power supply with BPA and/or other entities.

Additional items would potentially be added as the municipality's legal and financial advisors review the potential structure of the proposed borrowing. If necessary, the municipal entity could possibly issue debt and place proceeds into an escrow account until certain of the above requirements are met. Also, for initial startup costs, the municipal entity could provide funds through a general obligation bond or note or through interfund borrowing. The City has indicated that it could loan money from one fund to another through an interfund loan. These funds could be used until long term financing is in place and the system is in operation.

Typical Bond Covenants

Typical covenants included in the bond ordinance related to the issuance of municipal utility revenue bonds are shown in the following paragraphs. Bond council and the City's legal council will determine which of these covenants are needed and will adjust the wording as appropriate. An example could be with regard to insurance in that some utilities elect to self-insure certain elements of their systems. As such, the wording below would be adjusted to reflect this approach.

1. *Rate Covenant – General*. Rates will be established, maintained and revenues collected for electric energy sold through the ownership or operation of the electric distribution system, and all other commodities, services and facilities sold, furnished or supplied by the electric system in connection with the ownership or operation of the electric distribution system that shall be fair and nondiscriminatory and adequate to provide gross revenue sufficient for the payment of the principal of and interest on all outstanding Parity Bonds, for all payments which the electric system is obligated to set aside in the bond account, and for the proper operation and maintenance of the electric distribution system, and all necessary repairs, replacements and renewals thereof, the working capital necessary for the operation thereof, and for the payment of all amounts that the electric system may now or hereafter become obligated to pay from the gross revenue.

2. *Rate Covenant – Coverage Requirement*. Such rates or charges shall be sufficient to provide net revenue in any fiscal year in an amount equal to at least 1.25 times the annual debt service in such fiscal year on all outstanding bonds. A higher coverage requirement can possibly improve the rating of bonds and contribute towards a lower interest rate.

3. *Maintenance of the Electric Distribution System*. The electric distribution system will be maintained in good repair, working order and condition, and all necessary and proper repairs, renewals, replacements, extensions and betterments thereto will be properly and advantageously conducted, and the City will at all times operate such properties and the business in connection therewith in an efficient manner and at reasonable cost.

4. *Sale or Disposition of the Electric Distribution System*. The City will not sell, mortgage, lease or otherwise dispose of or encumber all or any portion of the electric distribution system properties, or permit the sale, mortgage, lease or other disposition thereof, except under certain conditions.

5. *Insurance*. The City will keep the works, plants, properties and facilities comprising the electric distribution system insured, and will carry such other insurance, with responsible insurers, with policies payable to the City, against risks, accidents or casualties, at least to the extent that insurance is usually carried by municipal corporations operating like properties.

6. *Books and Accounts*. The City shall keep proper books of account in accordance with the rules and regulations prescribed by the Washington State Auditor's Office, or other State department or agency succeeding to such duties of the Washington State Auditor's office. In the case of an RUS loan, the books and accounts along with periodic reports shall conform to RUS borrowing requirements (see below).

7. *No Free Service*. Except as permitted or required by law, the City will not furnish or supply or permit the furnishing or supplying of electric energy in connection with the operation of the electric distribution system, free of charge to any person, firm or corporation, public or private, so long as any bonds are outstanding and unpaid; provided, that, to the extent permitted by law, the City may lend money and may provide commodities, services or facilities free of charge

or at a reduced charge in connection with a plan of conservation of electric energy adopted by the City Council or to aid the poor, infirm or elderly.

Other Financing Options

The federal Rural Utilities Service (RUS) within the United States Department of Agriculture administers water and waste treatment, electric and telecommunications infrastructure to rural communities. The RUS Electric Program provides capital and leadership to maintain, expand, upgrade and modernize rural electric infrastructure. The loans and loan guarantees provided by RUS finance the construction or improvement of electric distribution, transmission and generation facilities in rural areas. The RUS Electric Program also provides funding to support demand-side management, energy efficiency and conservation programs, and on-and off-grid renewable energy systems.

RUS loans are made to cooperatives, corporations, states, territories, subdivisions, municipalities, utility districts and non-profit organizations. Jefferson County PUD obtained a loan from RUS to finance the acquisition of electric facilities to undertake electric service in Jefferson County beginning in 2013. RUS, in discussions with DHA, has indicated that the City could potentially qualify for an RUS loan to purchase electric facilities, however, an official determination would need to be obtained when more information is available and discussions are conducted with RUS.

RUS loans have an interest rate tied to the treasury rate plus 1/8 point and can typically have a repayment period up to 30-35 years. As of early May 2017, the RUS rate for long-term loans with a 30 year maturity to qualified electric utility borrowers is indicated to be approximately 2.895%.[17] RUS does not assess any fees to establish loans.

Estimated Initial Financing Requirements

It is expected that funds will be borrowed by the new electric utility very close to the beginning of initial utility operation so that revenues from the sale of electricity can be available to pay interest and principal obligations. This initial borrowing will provide sufficient funds to pay initial acquisition costs, construct any new electric facilities needed to begin electric service, pay legal and engineering costs incurred in the development of the new utility, and purchase equipment and materials to begin utility operation. In addition, the initial financing will need to fund the costs of the financing, as well as, establish a debt service reserve fund and any other reserve funds that may be needed to begin utility operation.

Prior to the initial financing, the City will most likely incur costs related to the establishment of the new utility. These costs can include legal, engineering and consulting fees that evaluate the

[17] FFB quarterly rates for 30-year maturity plus 0.125%. https://www.rd.usda.gov/programs-services/services/rural-utilities-loan-interest-rates

feasibility of the new utility and plan its development. These costs could potentially be paid initially by the City from general funds, for example, and then can be refunded to the City with the proceeds of the initial long-term borrowing. Short-term borrowings could also be used to fund some of the early costs. These borrowings would typically be refunded with the proceeds of a long-term borrowing.

For the purpose of the base case of this analysis, the estimated initial financing requirement is based on the assumption that the cost to acquire the electric facilities from PSE is two times the estimated original cost less depreciation (OCLD) value of the facilities as shown in Table 2. Note that the acquisition cost is expected to be either a negotiated or court mandated value. We have used two times OCLD as an initial estimate of the acquisition cost and included sensitivity analysis to indicate a range within which an acquisition price might be negotiated. As indicated previously, other public power utility acquisitions have been in the range of two times the OCLD value.

Other costs we have included in the initial financing requirement are the costs of installing equipment to meter wholesale power purchases at the substations, purchase necessary vehicles and equipment, purchase materials and supplies and pay the costs of additional warehouse and maintenance facilities that the City may need for the electric utility. The amount needed for these items will depend on how the facility and equipment needs of the City electric system could be accommodated somewhat through existing City operations. The estimated costs included in the analysis for these items are as follows:

Metering equipment at substations	$ 240,000
Vehicles, trucks, large equipment (14 total)	$1,340,000
Materials and stores	$1,500,000
Facilities, storage, other	$2,000,000
Subtotal	$5,080,000

Also included in the total amount to be financed is the initial costs of legal, engineering and consultant fees. Legal fees, in particular, are difficult to estimate. For the estimated financing requirement, $1,000,000 has been included for legal fees and $400,000 has been included for engineering and consulting fees[18]. If a condemnation proceeding is undertaken, legal fees are expected to be higher.

It is expected that the City would evaluate financing options and undertake loans that provide the most effective and lowest-cost approach. Interest and principal payments on loan balances are included among the costs to be recovered through electric rates so it is important to keep these costs at a reasonable level. Although there are potentially other options, the base case of our analysis assumes that the City would fund the initial financing requirement with a combination of taxable and tax-exempt interest rate revenue bonds. The taxable interest rate bonds would be used

[18] Jefferson County PUD indicates that its initial legal, engineering and consulting fees associated with evaluating and establishing electric service were approximately $1.3 million.

to pay PSE for the electric facilities to be purchased. All other costs could be funded with tax-exempt interest rate bonds.

In addition to the loan amounts needed to pay the initial costs of acquisition, startup and improvements, there will also be the need to fund initial working capital and reserve funds. The City may have other options available to provide these amounts. Revenue bonds usually require that a debt service reserve fund equal to one year's debt service be established and maintained as long as any of the bonds are outstanding. A portion of the proceeds of the bond issue are used to fund the debt service reserve fund. The costs to issue bonds are also funded with the proceeds of the bond issue.

Basic assumptions related to the debt to fund the initial financing requirement are as follows:

- Taxable debt interest rate 5.0%
- Tax-exempt debt interest rate 4.5%
- Repayment period 30 years
- Financing expense 1.5% of bond amount
- Debt service reserve One year's level debt service

The estimated initial financing requirements for the new utility are summarized in Table 3:

TABLE 3
City of Bainbridge Island Electric System
Estimated Initial Costs and Total Financing Requirements
(Based on Acquisition at Two Times OCLD Cost)

	Loan A (Taxable Rate)	Loan B (Tax-exempt Rate)	Total
Initial Acquistion Costs	$ 48,000,000	$ -	$ 48,000,000
Separation, Startup, Legal Costs [1]	-	$ 6,480,000	$ 6,480,000
Working Capital [2]	-	3,000,000	3,000,000
Contingency Reserve	-	-	-
Subtotal	$ 48,000,000	$ 9,480,000	$ 57,480,000
Financing Expense [3]	783,000	154,000	937,000
Debt Service Reserve [4]	3,394,000	630,000	4,024,000
Total Financing Requirement	$ 52,177,000	$ 10,264,000	$ 62,441,000

[1] Includes estimated costs of vehicles, equipment, materials, warehousing and facility modifications and legal, engineering and consulting fees.
[2] Assumed to be approximately two months of estimated electric utility operating expenses.
[3] Estimated at 1.5% of loan amount.
[4] Estimated at one year's debt service. Assumes level debt service, 5.0% taxable and 4.5% tax-exempt interest rates and a 30 year repayment period.

As shown in the preceding table, based on the foregoing assumptions the total estimated initial financing requirement is $62.4 million if revenue bonds are used to fund initial acquisition and startup costs. Of this amount, $52.2 million would be estimated to be financed with taxable debt and $10.3 million would be financed with tax-exempt debt. If financing with the RUS were pursued, the total loan amount would be estimated to be $57.5 million. An RUS loan would not require a financing fee or a debt service reserve fund.

It should be noted that the total initial financing requirement does not include costs for any improvements or modifications to the electric system facilities. The loan amount could be increased to obtain funds for system improvements such as undergrounding of overhead distribution lines. Additional funds could also be borrowed to establish a reserve and contingency fund.

For the alternative case in which it is assumed that PSE retains ownership of the substations and transmission lines and only the distribution lines are to be acquired, the total initial financing requirement is estimated to be $55.3 million with revenue bond financing and the same assumptions as used for the base case, above.

Section 5
Estimated Number of Customers and Load Forecast

Electric utilities generally classify their customers based on general characteristics of service. Typical customer classifications are residential (regular, low-income), commercial, industrial, irrigation, governmental, sale for resale and streetlights. The number of customers in the City's service territory has been estimated to serve as the basis for estimating energy sales and overall power requirements of the municipal electric system.

PSE has indicated that approximately 12,300 electric customers are presently served on Bainbridge Island. It is not known how many of these customers are residential and how many are commercial accounts, however, based on the estimated number of residential housing units in the City identified in the 2010 census, we have estimated the number of residential accounts served in 2010 to be approximately 10,700. PSE indicates that the total number of electric customers served on Bainbridge Island has increased about 0.7% on average per year between 2010 and 2016. Applying this average increase factor to the 2010 estimate, the total number of residential customers is estimated to be 11,210 in 2016. Based on this number of residential accounts, there would be an estimated 1,100 commercial and other electric customers in the City in 2016.

Electric energy sales to the residents and businesses in the City would be expected to be higher than the average for PSE's customers throughout its system primarily because of a higher use of electric space heat in the City. In other areas served by PSE, natural gas would generally be used to provide a significant amount of space heating. It is estimated that total electricity sales in the City in 2016 were about 219,000 MWh based on an evaluation of the amount of utility tax[19] received by the City in that year. Of this estimated total energy sales, 138,800 MWh or 63% is estimated to have been sold to residential customers and 80,200 MWh or 37% is estimated to have been sold to commercial customers. .

On average, PSE's residential customers used 10,404 kilowatt-hours (kWh) during 2016 and small commercial customers averaged 28,254 kWh of electric energy use. Average annual energy consumption per customer in the City is estimated to be 12,380 kWh for residential customers and 31,080 kWh for small commercial customers, representing approximately 19% and 10% more than PSE's system average for these two customer classes, respectively. As previously indicated, this is due to an expected higher use of electric space heat in the City. There is a large variation in the use of power by large commercial customers. For the purpose of this analysis it is assumed that large commercial customers in the City have similar average consumption to PSE's average for this class in 2016.

Over time the energy consumption of electric consumers in the City will be expected to change due to a number of factors including changes in weather conditions, energy use patterns, the cost of electricity, the cost of other energy sources, building codes, appliance standards, and implementation of conservation programs, among others. The number of electric customers served

[19] PSE collects a 6% tax on its electricity bills on behalf of the City.

is also expected to change most typically with changes in population and the number of housing units. For the purpose of this analysis, we have assumed that the number of customers served will increase in the future at the rate of 0.7% per year on average. This rate of growth is considered reasonable for this analysis although it is somewhat lower than the 0.85% average annual population growth rate for the City provided in the Kitsap County 2016-2036 Comprehensive Plan[20]. The average energy consumption per customer is assumed to remain constant in the future. An alternative case with lower load growth has been evaluated in the sensitivity analysis section.

The total electric energy needs of a utility include the amount of energy sold to customers, uses of energy by the utility itself, and energy losses. Examples of "own-use" energy include the power needed for utility buildings and facilities. Energy losses represent the amount of power "lost" between the point of wholesale power delivery to the utility and the customers' retail meters. A certain amount of power is lost in the conductors and transformers throughout the system. It is assumed that total losses for the new electric utility would be 6.5% of the total energy delivered. This is within the range of the typical level of losses for a smaller electric system.

In addition to the electric energy required by the customers in the City, measured in kWh or megawatt-hours (MWh), the maximum demand during the year is also important. Electric demand is metered in kilowatts (kW) or megawatts (MW) and is typically measured monthly for the utility as a whole. For most electric utilities in the Pacific Northwest, the maximum demand occurs during periods of cold temperatures in the winter and during high temperatures in the summer. Another measure of a utility's total load is average MW, the total energy use in megawatt-hours (MWh) divided by the number of hours in the period.

In estimating the peak demand, the ratio between average and peak demand, known as the annual loadfactor, has been assumed to be 40% for the City system which is reflective of a system with significant amounts of electric space heat. This annual load factor is low compared to most electric utilities and results in a high peak demand. While the peak demand on Bainbridge Island has been noted to be reflective of this low load factor in the past, it is subject to significant change from year to year based primarily on weather conditions and customer load characteristics.

The following table shows the estimated number of electric customers, annual energy sales, annual energy requirements and peak demand for the City system for each year, 2017 through 2021.

[20] Population Targets 2010-2036. Appendix D, Table A-1, Kitsap County Comprehensive Plan 2016-2036, June 2016.
http://compplan.kitsapgov.com/Documents/CompPlanUpdateDraft2016Final30June2016scribe.pdf

TABLE 4
City of Bainbridge Island Electric System
Estimated Number of Customers, Annual Energy Sales, Energy Requirements and Peak Demand

	2017	2018	2019	2020	2021
Number of Customers					
Assumed Growth Factor	0.70%	0.70%	0.70%	0.70%	0.70%
Residential	11,288	11,367	11,447	11,527	11,608
Commercial	1,098	1,106	1,114	1,122	1,130
Other	15	15	15	15	15
Total Customers	12,401	12,488	12,576	12,664	12,753
Energy Sales (MWh)					
Residential	139,700	140,700	141,700	142,700	143,700
Commercial	80,800	81,400	82,000	82,600	83,100
Other	100	100	100	100	100
Total Energy Sales	220,600	222,200	223,800	225,400	226,900
Losses and Own Use	15,300	15,400	15,600	15,700	15,800
Total Energy Reqs. (MWh)	235,900	237,600	239,400	241,100	242,700
Loss % of Total Reqs.	6.5%	6.5%	6.5%	6.5%	6.5%
Total Energy Req. (AveMW)	26.9	27.1	27.3	27.5	27.7
Annual Loadfactor	40%	40%	40%	40%	40%
Peak Demand (MW)	67.3	67.8	68.3	68.8	69.3

As shown in the table, the total annual energy requirement of the City electric system is estimated to be 235,900 MWh, or 26.9 average MW, at present levels. The peak demand is estimated to be 67 MW. In colder years the total energy requirements and peak demand would be expected to be higher whereas warmer years would yield lower energy requirements and peak demand.

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Section 6
Projected Costs of Operation and Revenue Requirements

Annual Revenue Requirement

Publicly-owned electric utilities generally establish rates to recover revenues through the sale of power sufficient to pay all operating expenses, taxes, and debt service as well as provide a margin from which to fund renewals, replacements and additions to the system. The total of all these cost obligations on an annual basis are referred to as the annual revenue requirement. Operating expenses of the electric system will include purchased power, purchased transmission services, transmission and distribution system operations and maintenance (O&M), customer accounting, and administrative and general expenses.

It is expected that the City will initially either contract for O&M services and/or hire its own staff to perform some or all of these functions. The management and administration of the City's electric system would be expected to be coordinated in some manner with other City operations. The electric utility, however, would need to retain certain specialized management, supervisory and administrative personnel familiar with electric utility operation. If the City were to proceed towards establishing an electric utility a more detailed evaluation of staffing requirements would need to be conducted

At the time of initial operation it would most likely be necessary to contract at least some of the O&M services to other utilities or regional electrical contractors used by other public power utilities and by investor owned utilities. In the past, when new publicly-owned utilities have acquired electric facilities from an existing utility, some of the employees of the acquired utility have been hired by the new utility. This provides both continued local employment for the workers and provides the new utility with necessary skilled workers familiar with the local electric system. Jefferson County PUD contracted with PSE to provide certain O&M services for a period of time when the PUD first became operational. This is another option.

The largest component of cost that the City's electric system would incur each year is the cost of purchased power. This is typical of most electric utilities. Another significant annual expense to be incurred is the interest and principal payments on revenue bonds and other debt obligations. For a new electric utility, annual debt service payments can be relatively large early on but would be expected to become a smaller component of the overall revenue requirements as time goes on. Upon repayment of the initial bonds and loans, the rates of the electric utility could potentially be reduced.

Over time, the electric facilities in the system will need to be repaired, refurbished, and potentially replaced. There may also be the need to expand and improve the system such as adding new underground lines. The costs associated with these efforts will need to be included in the revenue requirement when they are incurred. Electric facilities are typically long-lived and can be funded with additional debt and amortized over the life of the facilities at tax-exempt interest rates for a municipal utility. Most electric utilities fund the costs of renewals, replacements and additions through a combination of annual revenues, draws upon reserve funds and new debt. Major capital expenses for new or replacement facilities may be best funded with new debt to spread the cost of the new facilities, through debt repayment, over the usable life of the facilities. This is commonly done by public power utilities.

Many publicly-owned electric systems also collect additional revenues through their electric rates to make tax payments, franchise fee payments and payments in lieu of taxes to local governmental agencies.

Costs that would comprise the annual revenue requirement for the City's electric system are described more fully in this section. For the purpose of the analysis, various assumptions have been made to provide a basis for estimating the annual revenue requirement. The assumptions are based on the factors as described as well as our experience with electric utility operation. The City will have some flexibility in how it operates the electric system and as such, there could be a fair amount of variation in the costs of the operation.

Power Supply Costs

As previously indicated, the most significant annual operating expense that the City's electric system will incur is the cost of wholesale power. Upon fulfillment of certain criteria primarily related to establishing ownership of its distribution system, the new utility will be entitled to purchase power from BPA as a preference customer. The City electric system can reasonably expect to purchase a significant portion, if not all, of its power supply from BPA at the priority firm power rate, also referred to as the Tier 1 power rate.

In addition to BPA, a number of other opportunities for near-term power supply could be available to the City including power purchases from other utilities, independent generating facilities or power marketers. In the future, it is expected that the City will most likely continue to purchase power from BPA but will also be able to participate jointly with other utilities in new generation facilities, contract to purchase power from other suppliers and/or construct new generating facilities of its own locally including solar, wind, wastewater treatment bio-mass, and other renewable resources. The new City utility could consider aggressively expanding the existing energy efficiency measure and/or measures to reduce the City's carbon footprint.

For our initial analysis, we have assumed that the full power requirement of the new utility is supplied with BPA wholesale power.

Estimated Cost of BPA Power and Transmission

BPA has provided an estimate of the cost of power and transmission for an electric system with power requirements similar in size to those estimated for the City electric system. The estimated cost of power is based on BPA's rates currently in effect and assumes that the City system would obtain Tier 1 power to meet its total power needs in the first year of system operation. Tier 2 rates are presently about the same as Tier 1 rates so if initially the City system needed to phase in its purchase of Tier 1 power, the cost impact would be minimal.

BPA's priority firm power rate that the City system would be expected to pay is primarily composed of three components: the customer charge, the demand charge and the load shaping charge. Based on the experience of other similar sized public utility customers served by BPA, the customer, demand and load shaping charges would be expected to represent about 94%, 1% and 5%, respectively, of the City system's total BPA power cost. The customer charge is billed monthly and is established for each BPA rate period on the basis of a utility's Tier 1 Cost Allocator (TOCA)[21]. The demand charge is reflective of a utility's kW demand whereas the load shaping charge is billed on the basis of kWh. The billing determinants for the demand and load shaping charges are calculated each month based on several adjustment factors[22].

As a BPA customer, the new utility would pay BPA's Network Integration Transmission Service charge[23]. This charge provides for the delivery of power from BPA's generating resources to the City's delivery point. BPA has indicated that if the City electric system takes delivery of power at transmission voltage and owns the equipment to step the power down to distribution voltage, there would be no GTA delivery charges assessed. The GTA delivery charge only applies if power is delivered to a utility at less than 34.5-kV. If the City system owns the substations on Bainbridge Island, as described previously, the delivery of BPA power would be at a 115 kV transmission voltage, thus avoiding any GTA delivery charges.

BPA has established a policy of reviewing and adjusting its wholesale power rates every two years. The rates are established for a two year period based on BPA's fiscal year which begins October 1. The present rates (BP-16) went into effect on October 1, 2015 and will remain effective through September 30, 2017. The total Tier 1 charge for each BPA customer varies based on each utility's load characteristics, however, the average Tier 1 power rate currently charged to BPA's public power customers is $33.75 per MWh[24].

BPA has estimated that the Tier 1 power rate to the City's system at the current BP-16 rates would be $36.50 per MWh. Of this amount, $34.50 per MWh is estimated to be the total for the customer charge and the load shaping charge and $2.00 per MWh is estimated to be for the demand charge. The BPA transmission charge at the present NT-16 rate would be $1.735 per kW per month. An

[21] The Tier 1 Cost Allocator (TOCA) is based on a customer's Rate Period High Water Mark (RHWM) divided by the sum of all customers' RHWM.
[22] For more information on BPA power rates see BPA's Power Rate Schedules and General Rate Schedule Provisions (FY 2016 – 2017). https://www.bpa.gov/Finance/RateInformation/RatesInfoPower/BP-16%20Final%20Rate%20Schedules%20-%20Power_Rev%2001-09-2017.pdf
[23] For more information on BPA transmission rates see BPA's Transmission, Ancillary and Control Area Service Rate Schedules and General Rate Schedule Provisions (FY 2016 – 2017). https://www.bpa.gov/Finance/RateInformation/RatesInfoTransmission/BP-16%20Final%20Rate%20Schedules%20-%20Transmission%20-%20WEB.pdf
[24] https://www.bpa.gov/Finance/RateInformation/Pages/Current-Power-Rates.aspx

additional $0.35 per kW per month is estimated to be charged for scheduling, system control and dispatching services.

BPA's power and transmission rates are to be adjusted on October 1, 2017. The BP-18 rate proceeding began in the fall of 2016 and will continue until final rates are approved in the late summer of 2017. The initial proposal provided by BPA for the BP-18 rates indicates an approximately 2.3% increase in overall power charges with the new rates, as estimated by BPA. The initial BP-18 proposal for transmission rates shows little change in the network transmission rate. The BP-18 rates will be effective from October 1, 2018 to September 30, 2019.

It is expected that BPA will continue to adjust its rates every two years in the future. For the purpose of this analysis, it is assumed that Tier 1 rates will increase 6% every two years. Although short-term Tier 2 rates are lower at the present time, they have historically been higher than Tier 1 rates and as such, it is assumed for the analysis that Tier 2 rates are 15% above the Tier 1 rates. BPA Network Transmission rates are assumed to increase at 6% every two years as well.

Annual Operating Costs other than Power and Transmission

In addition to power supply costs which represent the largest cost component for most electric utilities, the City electric system will incur costs for on-going operation and maintenance of the system, planning, engineering, administration, management, customer service, billing, accounting, and other costs. To provide these electric utility service functions it is expected that the City will hire necessary employees and/or contract out for others. Some of the functions, primarily related to billing, administration and management can be coordinated with current City functions, which may result in some reduced or shared costs by various functions. Certain operation and management functions can be contracted out similar in manner as to how PSE contracts for a significant portion of its maintenance and engineering work.

Among other Northwest public power electric utilities, the number of employees varies significantly. A good example of a municipal electric utility serving a similar number of customers to that of the City electric system is Centralia City Light. Centralia has 30 full time electric employees and approximately 11,500 customers. The City of Port Angeles has 35 electric employees with approximately 9,000 customers, and the City of Ellensburg indicates that it has 14 electric employees with approximately 9,600 customers, although this number does not include billing and accounting personnel who operate within the municipality's administrative services. Jefferson County PUD reports that it presently has about 40 electric employees for its system serving 19,200 customers.

As another point of reference, in 2015 the PUDs in Washington indicated that the average number of customers per electric employee was 272. Based on the PUD average number, with 12,300 customers, the City system would require about 45 employees. The City service area is far more compact than the service area of the PUDs in Washington, which would indicate a need for fewer employees.

Based on a review of similarly sized municipal electric utilities in the Northwest, we would estimate that the City electric system would need approximately 30-40 employees, but this could vary based on what services the City would contract out and how the electric utility might be integrated with other City operations. Considering all factors, DHA feels that the number of full-time employees (FTE) by function are conceptually identified as follows:

TABLE 5
City Electric System

Example Electric System Staffing (FTE)

Management and Administrative	4
Operations, Maintenance and Engineering	18
Customer Accounting, Customer Service,Conservation	10
	32

The estimated costs of operation for the City electric system will include personnel costs as well as contracted services, materials, supplies, equipment and other expenses. Electric utilities purchase insurance to cover the costs of certain equipment failure and other potential losses due to business operations. Some elements of an electric utility, such as overhead power lines, may be self-insured. Tree trimming activities will most likely be conducted by a combination of contractors and employees with contractors doing the majority of the work. This will be an important activity for the City system. We have estimated that tree trimming activities near overhead lines in the City electric system will be conducted every year and on average will affect all portions of the lines approximately every four years.

Meter reading and billing could also be contracted out if the City decided to do so, but should in the long run be incorporated with other City meter reading and billing functions. It could also be possible to contract out the majority of operations and maintenance to another utility or to an independent contractor[25]. A subset of certain engineering and system planning efforts are expected to be contracted out in the early years of operation and used as a method of providing staff training.

A significant advantage for the City with its own electric utility staff would be some regular permanent presence of utility workers, equipment and materials in the City. Line and service crew workers can be available to conduct maintenance and storm restoration functions relatively quickly. It may still be necessary to use contract workers for certain major activities. The regular presence of utility workers can have a noticeable impact on monitoring of vegetation management

[25] A municipal electric system in Oregon about half the size of the City electric system contracts with another utility for all aspects of operation, maintenance, and administration. For another municipality in Oregon evaluating electric service, a bid was requested and received from a private contractor to provide operation and maintenance of its proposed electric system.

issues and in working within the community to assure proper care of trees and manage vegetation growth around power lines. As an example, some utilities provide landscape gift certificates to home owners to help pay for the cost of low growing plants to replace larger plants that pose significant risk to power lines.

For the purpose of developing an estimate for the operating costs of the new electric system, we have reviewed the costs of electric operations for a number of PUDs in Washington. Acknowledging the size and characteristics of these utilities, we have estimated unit costs based on the number of customers served or the amount of electric energy sold and applied the unit costs to the City electric system. These costs are inclusive of labor, benefits, contracted services, materials and other expenses.

Based on this indicated approach, total annual operating expenses for the City electric system exclusive of power costs, taxes, depreciation and interest expense are estimated to be approximately $510 per customer at present cost levels. This is comparable to the operating costs for several of the small to medium sized PUDs in the state. Jefferson County PUD reported that total operating expenses exclusive of power costs, taxes, depreciation and interest were $342 per customer in 2016. The estimated operating costs for the City system shown above would provide for an estimated average annual labor cost, including benefits, of about $125,000 per employee at present cost levels, for the number of employees shown in Table 5.

Projected Revenue Requirements

The annual revenue requirements have been projected for the first twenty years of City electric system operation. Electric system operation is assumed to begin in 2021. Unit operating costs, other than power and transmission costs, are assumed to escalate at 2% per year primarily due to the assumed general rate of inflation.

The cost of BPA power to the City system at current BP-16 rates, as estimated by BPA, is $36.50 per MWh. BPA power costs are assumed to increase 2.3% in 2018 [26] and are assumed to increase 6% every two years thereafter. BPA transmission rates are assumed to increase 2.0% in 2018 and are assumed to increase 6% every two years thereafter. The cost of BPA network transmission to the City system, as estimated by BPA, is approximately $4.75 per MWh at current rates.

Annual debt service payments are based on level debt repayment of bonds issued to finance initial acquisition and startup costs (see Table 3) at assumed annual interest rates of 5.0% for taxable debt and 4.5% for tax-exempt debt over a 30 year repayment period. These interest rates are higher than interest rates that the City would potentially incur at the present time. Future economic

[26] BPA's rates are adjusted at the beginning of BPA's fiscal year, October 1. The next rate adjustment will be October 1, 2017. For this analysis, the full impact of the BPA rate adjustments occur in the calendar year following the rate adjustment.

conditions will impact what the interest rates will be at the time of actual issuance of tax exempt and taxable bonds.

The City electric system will be expected to incur annual expenses for renewals, replacements and additions to the system, assumed to be approximately 3.5% of the system replacement value per year. This percentage is based on a typical average expected operating life of electric utility facilities of about 30 years. Annual expenditures for capital replacements and additions are projected to be funded out of annual revenues. If the amounts estimated for capital replacement are not used in any given year, they can be retained in a reserve fund for use in the future. In developing the estimated annual revenue requirement, the state utility tax of 3.873% has been included. It is presumed that the City would continue to require a municipal tax, currently 6.0%, on electric bills and this tax could be included in the overall revenue requirement or it could be included as a separate line item on customer bills similar to the approach used by PSE. The municipal tax is not included in the revenue requirement in this analysis. The projected annual revenue requirements for the City electric system, assuming startup in 2021 are shown in the following table:

TABLE 6
City of Bainbridge Island Electric System
Projected Annual Revenue Requirements
(Base Case)
($000)

	2021	2022	2023	2024	2025	2030	2040
Operating Expenses							
Purchased Power [1]	9,610	10,270	10,350	11,050	11,140	13,770	19,900
Network Transmission [2]	1,390	1,480	1,490	1,590	1,600	1,980	2,840
Trans. Oper. & Maint. [3]	160	160	160	170	170	200	260
Dist. Oper. & Maint. [3]	4,280	4,400	4,520	4,640	4,760	5,440	7,120
Customer Accounts [3]	1,090	1,120	1,150	1,180	1,220	1,390	1,820
Admin. & General [3]	1,690	1,730	1,780	1,830	1,880	2,140	2,800
Taxes [4]	1,040	1,080	1,090	1,130	1,150	1,330	1,770
Total Operating Exp.	$ 19,260	$ 20,240	$ 20,540	$ 21,590	$ 21,920	$ 26,250	$ 36,510
Debt Service							
Initial Loans [5]	$ 4,020	$ 4,020	$ 4,020	$ 4,020	$ 4,020	$ 4,020	$ 4,020
Subsequent Loans [6]	-	-	-	-	-	-	-
Total Debt Service	$ 4,020	$ 4,020	$ 4,020	$ 4,020	$ 4,020	$ 4,020	$ 4,020
Renewals, Replacements & Additions							
Funded from Revenues [7]	$ 3,530	$ 3,600	$ 3,670	$ 3,740	$ 3,810	$ 4,210	$ 5,130
Funded from Debt	-	-	-	-	-	-	-
Total Ren., Repl, Adds.	$ 3,530	$ 3,600	$ 3,670	$ 3,740	$ 3,810	$ 4,210	$ 5,130
Less: Interest Earnings [8]	$ (60)	$ (60)	$ (60)	$ (60)	$ (60)	$ (60)	$ (60)
Total Sales Rev. Required [9]	$ 26,750	$ 27,800	$ 28,170	$ 29,290	$ 29,690	$ 34,420	$ 45,600
Total Energy Sales (MWh) [10]	226,900	228,500	230,100	231,700	233,400	241,500	259,100
Unit Revenue Req. (¢/kWh) [11]	11.8	12.2	12.2	12.6	12.7	14.3	17.6
Peak Demand (MW) [12]	69.3	69.7	70.2	70.7	71.2	73.7	79.1
Debt Service Coverage [13]	1.86	1.88	1.90	1.92	1.93	2.03	2.26

[1] Estimated cost of BPA power purchases.

[2] Estimated cost of BPA network transmission services.
[3] Assumed to increase annually relative to changes in sales and customers and includes inflation at the assumed rate of 2.0%.
[4] Includes state utility tax of 3.873%.
[5] Interest and principal on initial acquisition bond issues shown in Table 3. Assumes level debt service, 5.0% taxable and 4.5% tax-exempt interest rates and a 30 year repayment period.
[6] No additional debt is assumed to be incurred during the analysis period.
[7] Estimated annual cost of renewals, replacements and additions to the electric system facilities. Cost is assumed to be funded from revenues each year.
[8] Estimated interest earnings on invested reserve fund balances at a 1.5% interest earnings rate.
[9] Sum of Total Operating Expenses, Debt Service, and Total Renewals, Replacements and Additions, less interest earnings.
[10] Estimated energy sales assuming 0.7% annual load growth.
[11] Total Revenue Required divided by Total Energy Sales.
[12] Estimated annual peak demand. See Table 4
[13] Calculated as Total Sales Revenue Required less Total Operating Expenses divided by Total Debt Service.

Debt service coverage is required by bond underwriters and is typically set at a minimum of 1.25 times annual debt service for publicly-owned distribution electric utilities. Publicly-owned utilities usually establish a policy concerning the percentage of capital. improvements to be funded from bonds and the amount to be funded from current revenues. The policy may be driven to some extent by limits on the amount of bonds that financial institutions will reasonably allow particular utilities to incur.

The City's main source of revenue for the electric utility will be through the sale of power to its customers. Table 6 shows the estimated revenue requirements for the period, 2021 through 2040. As can be seen in Table 6, the total unit revenue requirement in the first year (2021) of the projections is estimated to be 11.8 cents per kWh. Note that if the 6.0% municipal tax were included in the revenue requirement, the unit revenue requirement in 2021 is estimated to be 12.5 cents per kWh. The unit revenue requirement, which is the average unit revenue that the City would need to collect through energy sales to its customers, is projected to increase through the projection period shown in Table 6 due to general inflation in operating costs and expected increases in the cost of wholesale power and transmission services purchased from BPA.

Average revenue requirements are not specific rates. Rates will need to be adopted by the governing board of the City electric system. Rates would need to be established that would reflect the actual cost to serve certain customer classifications (i.e. residential, small commercial, large commercial). The rates could also include multiple components such as monthly basic charges (e.g. $15.00 per month), demand charges and energy charges and or blocks or energy tiers or monthly/seasonal components. The total amount received through these various rate components, however, would need to approximate the estimated Total Sales Revenue Required shown in Table 6 on an annual basis.

Rates can be set to somewhat reflect fixed and variable components of the overall revenue requirement but normally rates are expected to remain relatively stable or change gradually from year to year. A significant amount of the cost shown in Table 6 is fixed in that the costs would need to be incurred regardless of the level of retail sales the utility would experience each year. BPA power costs would go up or down depending on the energy sales each year however, debt service costs and much of the other operating expenses of the utility would remain. In years when energy sales are lower the net margins of the electric system would be expected to be lower whereas in years when energy sales are higher, the net margins would be expected to be higher. If a lasting trend is detected either way, rates would need to be adjusted to reflect this change.

Section 7
Estimated Net Benefits and Comparison of Rates

The estimated annual revenue requirements for the City electric system derived in Table 6 are representative of the average weighted rates for electric service that the City system would charge its various customers. Comparing these average charges to PSE's electric system average revenue requirements allows for an evaluation of the net benefits that electric consumers on Bainbridge Island would realize with the City electric system. With a public power utility the benefits are very long-term in that they are realized far into the future. For a new utility with a fairly high initial investment, the full level of benefits may not be realized until the initial loans are repaid. The long-term benefits are potentially many years in the future and as a result, are valued less today. Although an estimation of net benefits in the first ten years of new utility operation are presented in this analysis it is important to acknowledge that benefits would typically be greater in the future.

The estimation of revenue requirements for the new City electric system have been developed based on the assumptions and variables defined in the previous section of this report. PSE's future revenue needs and resulting rates are dependent on many complex factors. Although PSE's current electric rates are published in detail, we are unaware of any detailed projections of future PSE electric rates. As such, to compare the estimated future rates of the City electric system to the future rates for PSE electric service, it is necessary to develop an estimate of PSE's future charges.

A compilation of rate adjustments[27] from the Washington UTC indicates that PSE's charges for electric service were adjusted a number of times between April 2002 and January 2017. Many of the adjustments were minor and were for specific changes in direct costs such as conservation. Over the fifteen year period shown in the UTC rate compilation, the adjustments to electric rates averaged 2.34% per year[28].

As another comparison, PSE's monthly charge for electric service to residential customers with average power consumption increased at an average rate of about 1.7% per year between January 2009 and May 2017, exclusive of the residential energy exchange credit.

In recent years, PSE's electric rates have remained relatively stable. PSE filed a general rate case on January 13, 2017[29]. In the rate filing PSE indicates that the net impact to customers' rates is anticipated to be an increase in electric rates of 4.1%. PSE adjusted its rates on May 1, 2017. As indicated by PSE, residential rates (Schedule 7) increased 3.7 percent and small and medium general service rates (Schedules 24 and 25) increased 2.1 percent on May 1, 2017.

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[27] Source: Electric and Natural Gas Rate Adjustments since 2000. Washington Utilities and Transportation Commission.
https://www.utc.wa.gov/regulatedIndustries/utilities/Documents/2016%20Electric%20and%20Gas%20Rate%20Increases%20Since%202000.xls

[28] Without adjustments noted to be associated with the residential exchange credit, which primarily impacts residential rates, the average annual increase is approximately 3.0% over the fifteen year period.

[29] http://www.pse.com/aboutpse/Rates/Documents/prop_2017_01_and_02_2017_GRC_elec_gas.pdf

PSE's FERC Form No.1 for 2016 indicates that the average unit revenue from its customer classes in 2016 were as follows:

TABLE 7
PSE Average Unit Revenue in 2016 for Representative Customer Classes
(Compiled from PSE 2016 FERC Form No. 1)

	2016 Revenue (¢/kWh)
Residential [1]	11.12
Commercial [2]	9.81
Industrial [3]	9.54
Street and Highway Lights	23.49
Total for all Sales	10.50

[1] Includes combined Residential Service customer classes, primarily Schedule 7.
[2] Includes Farm General Service and Commercial Schedules 24, 25, 26, 49 and other commercial tariffs.
[3] Combined industrial revenues

The WUTC requires the utilities it regulates to develop an integrated resource plan (IRP). In a recent presentation[30] related to its current IRP development process, PSE indicates that its input assumption for average annual electric residential rate growth is 2.1%. Using this value along with the historical adjustments for the purpose of comparing future rates we have assumed that PSE rates will increase 2.2% per year beginning in 2019. The impact of the May 1, 2017 rate adjustment has been applied to the PSE rates shown in the table above, however, for the purpose of our analysis, no further adjustments to PSE rates are assumed to occur for the remainder of 2017 and in 2018.

Based on the unit revenues shown in Table 6 with adjustments for current charges and the estimated energy sales in the City electric service area as shown in Table 3, the total cost of electric service to residents and businesses in the City with continued service from PSE has been estimated for a ten year projection period.

The cost of continued electric service with PSE is compared to the cost of electric service from the City electric system assuming the City electric system were to establish rates to recover the estimated revenue requirements as shown in Table 6. The comparison of charges is shown in Table 8 for the twenty year period, 2021 through 2040. It is important to note that the average

[30] 2017 IRP Advisory Group presentation, Page 35. November 14, 2016.
http://pse.com/aboutpse/EnergySupply/Documents/Post_IRPAG_Nov14_IRPAG_Distribution.pdf

unit revenues shown in Table 8 for PSE are reflective of the estimated sales by customer class in Bainbridge Island.

TABLE 8
Comparative Charges for Electric Service and Estimated Savings
With City Electric Service

	2021	2022	2023	2024	2025	2030	2040
Energy Sales (MWh)							
Residential	143,700	144,700	145,700	146,700	147,800	153,000	164,100
Commercial	83,100	83,700	84,300	84,900	85,500	88,400	94,900
Industrial	-	-	-	-	-	-	-
Other	100	100	100	100	100	100	100
Total Energy Sales (MWh)	226,900	228,500	230,100	231,700	233,400	241,500	259,100
Peak Demand (MW)	69.3	69.7	70.2	70.7	71.2	73.7	79.1
Estimated PSE Revenues from Energy Sales in City							
Assumed Increase in Rates	2.20%	2.20%	2.20%	2.20%	2.20%	2.20%	2.20%
Revenues ($000) [1]	$ 26,900	$ 27,700	$ 28,500	$ 29,400	$ 30,200	$ 34,900	$ 46,500
Unit Revenues (¢/kWh) [2]	11.86	12.12	12.39	12.69	12.94	14.45	17.95
Estimated City Electric System Revenues from Energy Sales							
Revenues ($000) [3]	$ 26,750	$ 27,800	$ 28,170	$ 29,290	$ 29,690	$ 34,420	$ 45,600
Unit Revenues (c/kWh) [2]	11.79	12.17	12.24	12.64	12.72	14.25	17.60
Savings with City System ($000)	$ 150	$ (100)	$ 330	$ 110	$ 510	$ 480	$ 900
Savings with City System (¢/kWh)	0.07	(0.04)	0.14	0.05	0.22	0.20	0.35
Savings with City System (%) [4]	0.6%	-0.4%	1.2%	0.4%	1.7%	1.4%	1.9%
Average Annual Savings with City Electric Service - First 10 Years ($000)					$ 358		
Average Annual Savings with City Electric Service - Years 11-20 ($000)					$ 1,021		

[1] Calculated using average customer class revenue and estimated customer class loads with assumed increase in rates applied uniformly to each customer class.
[2] Revenues divided by Total Energy Sales.
[3] Estimated Total Revenue Required for the City electric system as shown in Table 6.
[4] Relative to estimated PSE revenues.

As shown in Table 8, the estimated cost of electric service with the City electric system is estimated to be comparable but generally slightly lower than the cost of service from PSE. By 2030, the annual savings are estimated to be about 1.4%. Over the first ten years of operation, electric consumers in the City are estimated to pay approximately $358,000 less per year in total with City electric service than they would with continued service from PSE. Over the first twenty years of operation, the City system would save an estimated $690,000 per year in total electricity charges for the residents and businesses in the City.

Rather than establish rates that would achieve the estimated savings shown in Table 8, the City could establish higher rates and use the savings amount to invest in renewable generation resources, additional energy efficiency programs or improvements to the electric system, such as additional undergrounded power lines.

Alternative assumptions to the analysis would result in different results. Key variables include the estimated cost of acquisition, the estimated cost of financing, and assumed increases in the number of electric customers served and load growth on Bainbridge Island. As previously indicated, the acquisition price will be either negotiated or established in a court proceeding. The base case analysis assumes the acquisition price is 2 times the estimated OCLD of the system facilities. Alternative cases have been developed to evaluate the net costs and benefits with acquisition at 1.35 times OCLD (Case 2) and at the estimated RCNLD value (Case 3).

The cost of financing related to the initial system acquisition will be a significant cost. If the City could obtain a lower interest rate loan through the federal RUS it could realize a lower revenue requirement. An alternative case assuming a 3.25% interest rate loan from the RUS with a 30 year repayment has been developed (Case 4). With an RUS loan there would be no loan origin fees and it is not expected that there would be a debt service reserve fund. This lowers the overall financing requirement. To determine the impact of lower customer and load growth in the City a case with customer growth at 0.35% per year, half the assumed base case growth, has been developed (Case 5).

Table 9 provides a comparison of the estimated net benefits with City electric service using alternative assumptions for certain variables. It should be noted that for each alternative case, only the specifically identified variable is changed. All other assumptions are kept at the base case values. Scenario analysis or sensitivity analysis can help the City identify the most important variables or where the most risk/reward to forming an electric utility resides.

TABLE 9
Comparative Net Benefits with Alternative Assumptions

Case	Basis of Initital Acquisition Cost	On-line Year	Initial Financing Requirement	Interest Rates	First Year Unit Revenue (¢/kWh)	Average Annual Savings with City System Over First 10 Years	Average Annual Savings with City System Years 11-20	Average Annual Savings with City System Over First 20 Years (%)
1 (Base)	Initial Acquisition at 2 times OCLD	2021	$62,441,000	5.0% taxable, 4.5% tax-exempt	11.8	$358,000	$1,021,000	1.8%
2	Initial Acquisition at OCLD + 35%	2021	$46,566,000	5.0% taxable, 4.5% tax-exempt	11.3	$1,419,000	$2,082,000	4.8%
3	Initial Acquisition at RCNLD	2021	$66,920,000	5.0% taxable, 4.5% tax-exempt	11.9	$44,000	$711,000	0.9%
4	Initial Acquisition at 2 times OCLD, Initial loans financed through RUS	2021	$57,480,000	3.25% on all debt	11.4	$1,324,000	$1,991,000	4.6%
5	Initial Acquisition at OCLD + 35%, Initial loans financed through RUS	2021	$42,880,000	3.25% on all debt	11.0	$2,126,000	$2,791,000	6.9%
6	Initial Acquisition at 2 times OCLD, Customer growth at 0.35% per year	2021	$62,441,000	5.0% taxable, 4.5% tax-exempt	11.8	$107,000	$455,000	0.8%

As can be seen in Table 9 the total estimated savings with the City electric system are significantly higher in the lower acquisition cost case (Case 2) and in the lower financing cost case (Case 4) than for the base case. If the acquisition cost is higher (Case 3) the savings are less. Lower load growth (Case 5) also reduces the estimated savings of the City electric system since there are fewer units of sales from which to recover revenues needed to pay the fixed costs of the system.

For the alternative case in which the City electric system would only acquire the distribution lines, meters, services, etc. and PSE would continue to own and operate all the transmission lines and substations, the first year unit revenue is estimated to be 11.6 cents per kWh and the average annual savings with the City electric system over the first ten years of operation is estimated to be $835,000 and the average annual percentage savings over the first 20 years of operation is estimated to be 3.0%. For this case, the total financing requirement is estimated to be $55,266,000 based on the assumption that the distribution facilities are acquired at two times the OCLD value of these facilities.

BPA's GTA charge, presently at $0.94 per kW-month, would be incurred by the City system if it did not own the substations. Transmission O&M expenses would not be incurred by the City and distribution O&M expenses are estimated to be about 4% lower if substation maintenance is not incurred. Further, the City system would have a lower cost associated with annual renewals and replacements without the need to replace the substation and transmission facilities over time. It should be noted that BPA has indicated that for an operating scenario involving low-voltage delivery such as this, there may some additional charges related to PSE's costs of operating the transmission and substation facilities. These potential additional charges cannot be estimated at this time.

It should also be noted that if PSE's rates do not change as assumed in this analysis, the estimated savings with the City electric system will be different.

Comparative Electric Rates

A comparison of charges for electric service for several electric utilities primarily in Western Washington has been made. Rates effective on May 1, 2017 were used to determine the cost of monthly service for a residential customer consuming 1,000 kilowatt-hours and a small commercial customer receiving 6,000 kilowatt-hours per month. The monthly charges are shown in the following table:

TABLE 10
Comparative Monthly Charges for Electric Service
(Based on Rates Effective on May 1, 2017)

	Residential (1,000 kWh)	Commercial (15 kW, 6,000 kWh) [1]
Puget Sound Energy	$108.63	$581.54
Public Utility Districts		
Jefferson County PUD	$106.94	$568.84
Mason County PUD No. 3	$105.70	$517.20
Clallam County PUD	$98.03	$447.53
Snohomish County PUD	$102.50	$545.70
Municipalities		
City of Port Angeles	$101.00	$484.24
City of Ellensburg	$85.58	$418.64
Seattle City Light	$117.79	$554.19
Tacoma Power	$90.37	$489.57
Cooperatives		
Peninsula Light Company	$97.84	$485.60
Lakeview Light & Power	$94.00	$529.50

[1] Assumes single phase service. Summer rates used where applicable.

As can be seen in Table 10, there is significant variation in the charges for electric service among the various utilities. It should also be noted that additional local taxes may apply to electric charges.

A comparison of residential electric rates effective on May 1, 2017 for the same group of electric utilities is shown in the following table:

TABLE 11
Residential Rates for Electric Service
(Based on Rates Effective on May 1, 2017)

	Basic Charge ($/month)	Energy Charge (¢/kWh)
Puget Sound Energy[1]	$ 7.87	8.93 first 600 kWh, 10.81 all other kWh
Public Utility Districts		
Jefferson County PUD	$ 14.50	8.50 first 600 kWh, 10.36 all other kWh
Mason County PUD No. 3	$ 33.00	7.27
Clallam County PUD	$ 28.33	6.97
Snohomish County PUD	$ -	10.25
Municipalities		
City of Port Angeles	$ 20.10	8.09
City of Ellensburg	$ 20.82	6.26 first 600 kWh, 6.80 all other kWh
Seattle City Light	$ 4.86	7.01 first 300 kWh, 12.88 all other kWh
Tacoma Power	$ 13.50	7.69
Cooperatives		
Peninsula Light Company	$ 23.00	7.17 first 399 kWh 7.69 next 1,100 kWh 7.91 all other kWh
Lakeview Light & Power	$ 19.00	7.50

[1] Energy rates include net effect of applicable credits and charges including the energy exchange credit.

It is noted that there is significant variance in the monthly basic charge. For some utilities, a higher basic charge can be used to recover necessary revenues when many customers are part-time or seasonal residents.

As previously indicated, actual rates would need to be developed for the City system that would recover the estimated revenue requirement. Rates usually include a monthly customer charge and an energy charge. Larger commercial customers typically have a demand component in their rates related to the largest level of power use during the month. Demand charges require a demand meter.

Although the rates to be charged by the City system have not been derived for this analysis, if the estimated unit revenue requirement of 11.79 cents/kWh shown in Table 8 for 2021 were charged uniformly to all customers served by the City in that year, the monthly cost of electricity for a residential customer using 1,000 kWh would be $117.90. Deflating this cost in 2021 to 2017 at 2.0% per year would result in a monthly charge of $108.92 in 2017. This is comparable to the monthly charge for 1,000 kWh charged by PSE at the present time as shown in Table 10. As a further example, if the City system were to establish a $15.00 per month basic charge for all customers, the energy rate would need to be 10.78 cents per kWh to achieve an overall unit revenue of 11.79 cents per kWh.

Section 8
Other Factors

High-Speed Broadband

The City could develop and finance its own high-speed broadband network to serve its residents and businesses. See In Re City of Edmonds, 162 Wn. App. 513 (2011) (upholding code city's authority to complete and finance its fiber optic network as part of a city-owned broadband network). The potential benefits include cost efficiencies, community service, economic stimulation, enhancing public safety, and others. As with the City of Edmonds, it is not a requirement that the City have an electric utility to engage in telecommunications.

There can, however, be advantages to having an electric utility system and engaging in telecommunications activities. Thus, for example, where some of the telecommunications activities are related to services needed by the City for its internal purposes, such as automated meter reading, connecting different City facilities with one another, security, etc., some of the telecommunications expenses might appropriately be attributed to the electric or other system. The same generally would be true, perhaps in varying degree, of a separate water or other system, even in the absence of an electric utility system.

Some public entities conduct their telecommunications activities as a separate utility system; others do so as a department or division of other of their utility systems. Further detail on the financial, practical, and political advantages and disadvantages of creating a separate telecommunications utility, versus structuring it as a component of another system, is beyond the scope of this report, but would merit further review if the City so desires.

Kitsap PUD began installing a high capacity fiber optic network throughout Kitsap County beginning in 2000. The network, called KPUD Fiber, provides wholesale telecommunications services to citizens in the county. Kitsap PUD and its partners presently have over 150 miles of fiber optic cable deployed throughout the county, including in the City.

Kitsap PUD's initial role as a wholesale telecommunications provider is to sell its services to retail providers. The retail providers provide the services that homes and businesses require. PUDs are restricted from selling full retail telecommunications services to county citizens, agencies and businesses. Washington PUDs are only allowed to provide non-retail services, including wholesale networks, community networks, and certain other telecommunications services.

Kitsap PUD indicates that its fiber optic lines in the City are attached to PSE poles. PSE does not assess the PUD any pole attachment fees because the PUD allows PSE use of the fiber network for PSE's internal communication system.

Energy Efficiency Opportunities and Renewable Energy

BPA has historically provided a very robust energy efficiency program that touches all the various sectors (residential, commercial, industrial) in an electric utility's service area. If the City were to become a customer of BPA, they would be assigned a BPA Energy Efficiency Representative (EER). The EER would work with the utility to help identify energy efficiency or conservation opportunities on Bainbridge Island. The EER would inform the utility of BPA programs and assist the utility with reporting savings to BPA. BPA's programs are reviewed for cost effectiveness and funded in large part by BPA revenues.

The way the BPA energy efficiency programs work are that each utility is assigned an energy efficiency budget amount for a BPA rate period, which is typically two years. Throughout the term, as a utility completes energy efficiency or conservation projects, they report the energy savings to BPA and get reimbursed for the savings achieved. The payment is from their energy efficiency budget and the reimbursement is sent directly to the utility. There is an opportunity for utilities that are aggressive in implementing conservation to make applications to use portions of other utilities unused energy efficiency budgets. There is also a provision where utilities can join together to pool their energy efficiency budgets. There are also opportunities to make presentations to BPA for funding of energy efficiency measures that are not part of the BPA measures, but meet the cost effectiveness criteria.

The current BPA energy efficiency measures can be found in the Implementation Manual on the BPA website: https://www.bpa.gov/EE/Policy/IManual/Pages/default.aspx. The number and complexity of the programs and measures are significant. To a degree, a utility customer of BPA can work with BPA to pick and choose energy efficiency measures that better reflect the needs of its customers. Some Pacific Northwest consumer owned utilities focus their conservation programs on low income elderly, residential, small commercial and governmental sectors as a way of keeping maximizing societal benefits, and jobs in their service territory.

Based on conversations with Snohomish County PUD and Seattle City Light conservation employees, the conservation programs sponsored by PSE, Snohomish County PUD, and Seattle City Light are roughly comparable. As such, it can be concluded that the energy efficiency programs sponsored and promoted by BPA that public utilities adopt are reasonably comparable to those of PSE. PSE as both a natural gas and electricity provider can be more comprehensive with its conservation programs in areas where it also serves natural gas. An example of energy efficiency programs offered by a public power utility, Snohomish County PUD, can be found on the PUD website at http://www.snopud.com/conservation.ashx?p=1100.

Historically, BPA programs have focused on weatherization (HVAC, windows, insulation) in the residential sector, lighting in the commercial and municipal sector and variable speed motor programs in the commercial and industrial sectors. BPA residential programs are shifting to LED lighting and energy efficient appliance rebates, as the other efficiency measures have saturated the market. In the commercial section the shift is toward HVAC and web-enabled devices. Future

BPA programs are likely to focus even more on web-enabled devices as a way of providing ancillary services and helping with demand management.

PSE also has a large number of energy efficiency programs. These programs can be found on a series of web pages starting with: http://pse.com/savingsandenergycenter/Pages/default.aspx. PSE has historically provided a large number of energy efficiency programs on Bainbridge Island and has attempted to implement demand side management programs to defer the need for an additional substation on the island. In areas where PSE has natural gas service there are some fuel switching programs. PSE energy efficient appliance rebates are similar to those of neighboring public power utilities. PSE also has many LED lighting and HVAC programs as well.

In many respects the City of Bainbridge Island is a leader in many energy efficiency or “green” areas. There are a large number of roof mounted solar panels, a large number of electric vehicles, and a number of Tesla battery power walls being permitted. As such, through local control of the building permit process a City electric utility could provide more focused energy efficiency measures to meet the needs of the City residents and businesses.

For example, even though the Washington State Energy Code is very aggressive, some cities, such as Seattle, have adopted even more aggressive energy codes. The City, could adopt a more stringent energy code than the State. The City could also, if it chose to, aggressively require remodeling permits to bring large parts of a structure or facility up to current energy codes. Likewise, the City could require remodeling permits to include an energy efficiency analysis that identifies cost effective energy efficiency measures that might be warranted. Alternately, the City could encourage through reduced permitting fees with City Council approval, permitting requirements that would encourage more energy efficient buildings

It is difficult to make a 20 year projection of energy efficiency impacts as codes and the market place are making rapid changes. For example, the amount of electricity used by LED lights and the improvement in this technology is dramatically changing the State of Washington Energy Code. What would have been considered an impossibly low energy use per square foot a few years ago is now part of the current building code that the City Planning Department reviews for compliance with building plans and inspects to. Similarly, Energy Star washing, drying and dishwashing appliances of today are far more energy and water efficient than those of just 5 years ago and are projected to be even more efficient in the future. What we can say is that new buildings will use far less energy than historically designed buildings and that retrofitted or remodeled buildings will also use less energy than they use today.

It is noted that one of the reasons indicated to be contributing to lower market power prices being experienced in recent years is lower demand due to energy efficiency programs, new energy efficient lighting, appliances and electrical equipment being used today.

Although lower demand for power can be beneficial in lowering prices for market power, for a utility the impact of energy efficiency programs can cause a different situation. Included among the factors to consider with regard to the promotion of energy efficiency programs by a utility are the potential reductions in energy sales that will result. Since a portion of the revenue requirements of a public power utility are fixed, the reduction in energy sales associated with energy efficiency programs can put pressure on a utility to reallocate costs to make up the incremental loss in revenue. As such, it would be important to acknowledge that the promotion of energy efficiency programs is a policy of the utility for which the costs are to be shared by all customers.

Renewable Energy

In 2006, Washington state voters approved the Energy Independence Act, also known as Initiative 937. Initiative 937 requires electric utilities with 25,000 or more customers to use "eligible renewable resources' to meet the following annual targets:

- At least 3 percent of its load by January 1, 2012, and each year thereafter through December 31, 2015;
- At least 9 percent of its load by January 1, 2016, and each year thereafter through December 31, 2019; and
- At least 15 percent of its load by January 1, 2020, and each year thereafter.

Under Initiative 937, "eligible renewable resources" include wind, solar, geothermal, landfill and sewage gas, wave and tidal power and certain biomass and biodiesel fuels. Electricity produced from an eligible renewable resource must be generated in a facility that started operating after March 31, 1999 and the generating facility must be located in the Pacific Northwest. Initiative 937 allows utilities to use "renewable energy credits" (RECs) to meet the acquisition targets. RECs can be bought and sold in the marketplace.

As a smaller electric utility, the City electric system would not be subject to the requirements of Initiative 937 but could certainly pursue similar goals. Opportunities to jointly participate in wind and solar generating projects exist. Some utilities such as Emerald Peoples' Utility District in Springfield, Oregon have on their own developed renewable energy projects. In the case of Emerald, the Short Mountain Methane Power Plant uses gas from a local landfill to generate electricity. The plant has been operating since 1992 and produces about 15 million kWh per year.

PSE offers a green power product that is composed of a mix of 71% wind energy, 12% livestock methane, 5% landfill gas, 6% low impact hydro, 5% solar and 1% geothermal. The product is sold to PSE customers who pay a monthly premium on their power bills. For the average home, PSE indicates that $10 per month is enough to fully supply the electricity requirements of the home with green power. The actual generating facilities may be located some distance from the home, however, the payment for green power is used to support the costs of developing and operating the renewable resources. PSE indicates that 10.2% of electric customers in Bainbridge Island participate in the green power program.

Prior to implementation of the tiered rate methodology, BPA used to provide a product to its utility customers called Environmentally Preferred Power (EPP). At the present time, BPA indicates that a customer can request BPA to purchase RECs on the open market on behalf of the customer.

These RECs can be used to establish a renewable or green energy project that the utility could offer to its retail customers.

Solar generation installed by customers at their homes and businesses is also gaining popularity in many communities. Snohomish County PUD, for example, through a program called Solar Express[31], offers cash incentives of $300 per kW for qualifying photovoltaic (PV) solar power generating installations. Through "net-metering", the customer can offset their own electricity needs with their own generation and to the extent additional power is available at certain times, receive a credit for this surplus generation that is delivered back to the PUD. Federal and state credits and subsidies related to solar installations are subject to change as is the net metering credits the PUD offers.

A problem that some utilities have with net metering is that the cost of providing electric service to a house or business may not be fully recovered from a customer with a net metering installation. If the customer's generation unit provides a significant portion of the electricity needs of the customer but the customer still relies on the utility for power at certain times, the revenue collected from the customer on an annual basis may not cover the full cost of service to the customer. Electric utility rates to residential customers are not typically designed to recover the cost of service when electricity consumption is minimal much of the time and high only a little of the time. In order to limit the cost impacts on other customers of the utility, this issue would need to be addressed in the design of retail rates.

Comparative Greenhouse Gas Emissions

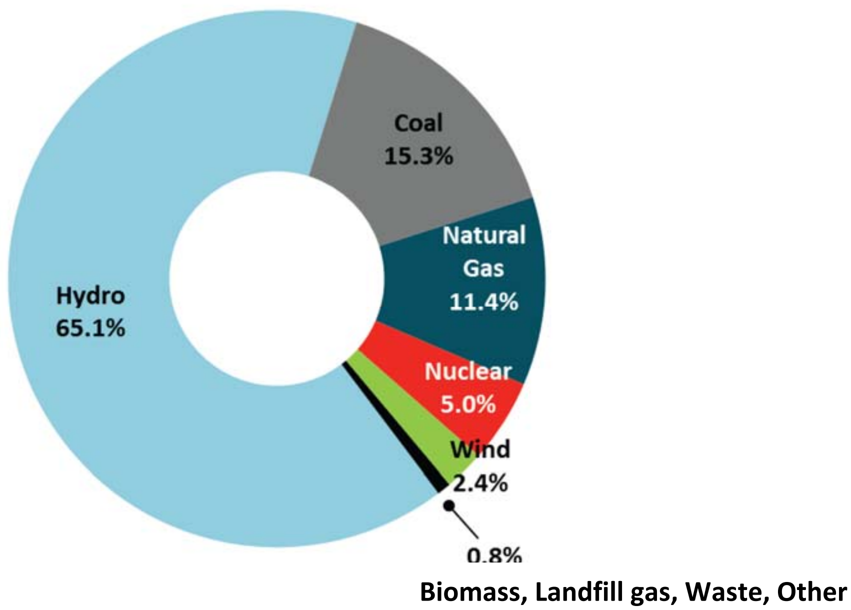
The electricity used in the State of Washington is generated by a variety of power plants located primarily in the Pacific Northwest. Power plants using fossil fuels as the source of input energy emit greenhouse gases (GHG). Four major GHG are regularly inventoried by electric utilities: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O) and sulfur hexafluoride (SF_6). CO_2 represents the largest component of GHG by volume. Federal regulations require the reporting of GHG emissions from large sources and suppliers in the United States to collect accurate and timely emissions data to inform future policy decisions.

The State of Washington through RCW 19.29A.060 requires that each retail supplier disclose the fuel mix of each electricity product it offers to retail electric customers each calendar year. The reported fuel mix can be used to estimate the amount of GHG emissions attributed to the use of electricity for any utility. The Washington State Department of Commerce Energy Office (the "Energy Office") obtains fuel mix information from each utility in the state each year. The Washington "fuel mix" is the aggregate of fuel sources associated with the electricity delivered by all electric utilities to end users in the state of Washington, including BPA's direct electricity sales. It includes all electric power that is used to serve retail customers that is owned, purchased under

[31] Snohomish County PUD indicates that the Solar Express program will be ending June 30, 2017.

contract, or purchased on the spot market. The following chart shows the aggregate fuel mix for Washington State electric utilities in 2014[32].

FIGURE 3
Aggregate Fuel Mix in 2014 for Washington Electric Utilities



Public power utilities in the Pacific Northwest generally purchase the majority of their power supply from BPA. BPA's fuel mix is significantly different from that of PSE. As such, the amount of GHG emitted to specifically supply power to the City would be different if the power were supplied by BPA or by PSE. The following table provides a comparison of the fuel mix of PSE and the City of Ellensburg, a representative full requirements public power customer of BPA with a total load similar to the City, in 2014 as reported by the Energy Office:

[32] http://www.commerce.wa.gov/wp-content/uploads/2016/09/Energy-FMD-2014-final.pdf

TABLE 12
2014 Fuel Mix for PSE and the City of Ellensburg Electric Utility

	PSE	City of Ellensburg
Biomass	0%	0%
Coal	35%	2%
Cogeneration	4%	0%
Geothermal	0%	0%
Hydroelectric	36%	86%
Landfill Gas	0%	0%
Natural Gas	20%	1%
Nuclear	1%	11%
Other	0%	0%
Petroleum	0%	0%
Solar	0%	0%
Waste	0%	0%
Wind	3%	0%

PSE reports its GHG emissions annually based on federal and state regulatory standards. In PSE's 2015 Greenhouse Gas Inventory[33], it is reported that for all of PSE's electric generation and electric purchases, CO_2 emissions were approximately 12 million metric tons. The GHG emission intensity was 1.03 pounds per kWh, slightly up from 0.99 pounds per kWh in 2014. The report indicates that PSE's overall CO_2 emission intensity, which includes both electricity generated by PSE and purchased by PSE, is lower than the national average due to the large proportion of hydroelectric generation utilized by PSE.

For its preference power customers, BPA does not identify specific resources for specific sales. Rather, the "mix" of BPA's power resources is used to establish the overall power product. For its fiscal year 2014, BPA indicates that the mix of its resources by generation type[34] was as follows:

- Large Hydroelectric 83.3%
- Nuclear 10.4%
- Non-specified purchases 4.4%
- Small hydro, biomass, wind 1.9%

[33] Puget Sound Energy, 2015 Greenhouse Gas Inventory, September 2016. Prepared by Environmental Resources Management, Seattle, WA. https://www.pse.com/aboutpse/Environment/Documents/GHG_Inventory_2015.pdf
[34] https://www.bpa.gov/power/BPA_Fuel_Mix/

The nuclear energy shown in BPA's resource mix is from the Columbia Generating Station (CGS), a 1,190 MW nuclear energy facility located about ten miles north of Richland, Washington. The CGS began operation in 1984 and it is the only commercially operating nuclear facility in the Pacific Northwest. Its output is provided to BPA and BPA pays the costs of operating and maintain the facility. CGS emits virtually no GHG or carbon emissions commonly associated with natural gas, coal and other fossil fuel power plants. Refueling and maintenance outages occur every other year and CGS's current operating license expires in December 2043.

The Energy Office provides an estimate of the non-specified purchases identified by BPA to include some energy from coal and natural gas generating plants. The use of these resources is reflected in the fuel mix shown for the City of Ellensburg, above. Based on the fuel mix shown for Ellensburg in 2014 and the average emissions for fuel type in the Energy Office report for 2014, we have estimated the CO_2 emissions intensity attributed to Ellensburg's electricity use to be 0.05 pounds per kWh. No CO_2 emissions are attributed to hydroelectric or nuclear generation.

Assuming a total annual energy requirement of 234,300 MWh for the City, the total CO_2 emissions attributed to the City's electricity use would be approximately 116,000 tons per year based on PSE's average emission intensity in 2014[35]. Based on the estimated 2014 average emissions intensity for the City of Ellensburg, the total CO_2 emissions attributed to the City of Bainbridge Island's electricity use would be approximately 6,500 tons per year. As such, if the City were served with power from BPA rather than PSE, CO_2 emissions attributed to the City's electricity use would be reduced by about 94%.

The estimated impact on regional carbon emissions as a result of the City load being served by BPA rather than PSE would be difficult to estimate. If it were not serving the City, it is not known what generating resources or purchases PSE would or could reduce. The vast majority of BPA's power is from hydroelectric resources, for which power generation varies each year based on regional precipitation and other factors. It is expected that the majority of power used to serve the City load by BPA would be from hydroelectric resources, however, in some years the amount of power needed to serve the City load would potentially be supplied by other sources of generation. BPA has noted that in 2014, 12% of its total revenues came from sales of power to public and investor-owned utilities in the Southwest and California. If the City were to become a new customer of BPA it could be that BPA's sales outside the Pacific Northwest region might be slightly reduced in some years when hydroelectric generation is lower.

According to PSE's 2015 Greenhouse Gas Inventory, approximately 6.8% of total electricity generated and purchased by PSE in 2015 and 17.1% of PSE's total CO_2 emissions from electric operations were attributed to PSE's share of Colstrip Units 1 and 2. PSE has indicated that it will be closing Colstrip Units 1 and 2 by July 2022. It is not known at this time what energy resources

[35] Note that the total emissions attributed to the City load would be less as a result of customer participation in PSE's green power program. PSE indicates that 10.2% of the Bainbridge Island customers participate in this program and assuming that all participants offset their entire power requirement with green power, the estimated GHGs attributed to the City load would be 10.2% lower than shown, i.e. 104,000 tons as compared to 116,000 tons.

will be used by PSE to supplant its 50% ownership share (307 MW) of the closing Colstrip units. It could be expected, however, that a combination of resources, including natural gas generation would be obtained. Natural gas generation produces GHG but to a lesser extent than coal generation. If the City were to establish its electric system, the reduction of PSE's total energy requirement by the City's load would reduce the need for PSE to obtain that increment of power from any GHG emitting resources after Colstrip is closed.

Miscellaneous Issues

Many consumer-owned utilities provide discounts to low income residents and seniors, as does PSE. However, a new municipal utility can start with a "clean slate" and explore options that PSE has for historic reasons not chosen. The disadvantage of this is that there may be some Bainbridge Island customer expectations and reliance of existing rate forms. The advantage is that a different rate form may be better able to meet community needs.

There are many categories of electric utility rate programs for low-income customers. Some of them include the following:

- Flat rate discount or an across the board percentage discount. Similar to the 50% low income senior and low income disabled rate discount provided to the City water and sewer customers
- Payment programs that cover only the variable costs of serving the customer and/or a discount on the fixed costs.
- Percentage if income plans, where the maximum energy bill is set to a percentage of income based on the Federal Poverty Level of household data.
- Waiver of all or a portion of fixed or monthly fees.
- Blocked rate or lowest tier approach. This is where the customer purchases all power at the lowest tier rate even if they exceed the low tier quantity.
- Lifeline rate, based on a minimum quantity of electric power.
- Seasonal discounts, either tied the winter heating season or in other parts of the country the air conditioning season.
- Special discounts, specifically associated with the electrical consumption of certain life sustaining medical equipment or equipment associated with preventing deterioration of a medical condition.
- Direct vendor payment approach. Customers receive a rate discount when they agree to allow utility bill payment to be taken directly out of a public benefit that customer may receive, such as Aid to Families with Dependent Children or other programs. Similarly, if there were arrangements with a Quest logo organizations, a bank or credit union funds

could be transferred from a Washington DSHS EBT Quest Card. The City already has ACH and bank initiated Bill Payer methods of paying utility bills, so such methods or extensions of them could be incorporated into an electric utility.

There are also federal programs to benefit this class of customers, such as the Low Income Home Energy Assistance Program (LIHEAP), which is focused on helping low income households manage and meet their home heating and/or cooling needs. Such programs are available to both PSE customers and locally controlled municipal utilities._PSE's programs of this type need to accommodate the needs of its service area and are subject to review by the WUTC.

LIHEAP and other similar programs can include one-time crisis oriented financial assistance, weatherization grants to reduce heating or cooling needs, free energy efficiency upgrades to lower utility bills while improving the health and safety of the household's occupants, energy budget counseling, education on energy efficiency practices, etc. Such kinds of programs can include implementation of solar or other renewables in some jurisdictions. There are also State and local programs that can be targeted at this customer class. They range from Department of Commerce grants and Weatherization Assistance Program to local programs offered by Kitsap Community Resources or specific charities.

Most consumer owned electric utilities target federal, BPA, state conservation programs and conservation assistance at their low income elderly customers so as to create socially responsible community programs. BPA has a long history of identifying conservation programs that its utility customers can target to improve the lives of low income elderly customers. Also, the State of Washington, through the Department of Commerce has conservation programs that target low income residents of the state. The City as an electric utility could partner with both to deliver such programs locally.

According to the PSE website, PSE has two programs (beyond LIHEAP and local agency programs) to keep bills low and income-eligible customers warm in the winter:

- HELP or Home Energy Lifeline Program provides qualified customers with bill paying assistance beyond that offered by the federal LIHEAP program.
- The PSE Weatherization Assistance Program (aligned with the Washington State Department of Commerce Weatherization Assistance Program) provides for upgrades to home insulation, sealing air leaks, and lighting and refrigeration replacements.

As a private corporation, PSE can do some things that public agencies cannot do. For example, PSE has provided a grant to help fund a standby diesel generator for a warming station in the event of long term outages at a local church on Bainbridge Island. PSE also, as a larger utility, has the ability to get customer contributions from across its broader service territory and distribute them fairly to those in need. This may or may not change the amount of such aid for those on Bainbridge Island. What can be said about a local municipal utility is that whatever aid can be obtained by federal, state and local programs would be distributed to Bainbridge Island community members. It is not expected that municipalization will dramatically change the ability of low income or elderly residents to receive energy assistance. Some of the focus and emphasis within such programs may change, though.

Again an important advantage of a City electric utility is local control and this means a focus on local issues and concerns. This is especially true when it comes to Socially Responsible Initiatives. That is, the City will be in better touch with the needs of its residents than almost any other organization and can adjust programs for the unique mix and needs of Island residents. For example, if life sustaining medical equipment is an especially important need within the City, rates and methods of qualifying for such a rate can be implemented similar to those used by the Los Angeles Department of Water & Power (LADWP). While a city utility like LADWP could narrowly focus such a rate to their own particular city, PSE would need to have its rates approved by the WUTC and be fair across a much more geographically diverse area with differing levels of need. Also, what may be appropriate in Bainbridge Island might not fit the customers of Skagit County or western Kittitas County.

Alternately, there can be multi-utility benefits identified by the City and factored into a socially responsible rates or appliance rebates/grants programs. For example, for qualifying customers who purchase electricity, water and wastewater services treated by the City, there could be a recognition that a new energy efficient dishwasher or clothes washing machine will jointly save electric energy and help avoid Tier 2 BPA power, reduce the quantity of potable water that needs to be produced, treated and distributed by the City and further reduce the amount of waste water that needs to be treated and sludge that needs to be disposed of by the City. PSE can acknowledge and compensate for combined benefits where it has combined natural gas and electric utility service. PSE does not provide natural gas service on Bainbridge Island.

Similarly, City governments can more easily in a combined utility way accomplish other kinds of programs not usually implemented if different utilities provide services. An example of this is the City of Anchorage, Alaska. The George M. Sullivan combined cycle power plant owned by Anchorage Municipal Light and Power uses potable City water through an additional heat exchanger to providing cooling for the steam condensers. This was done for a variety of reasons, including enhanced electric utility power generation economics and winter fire protection, and fire hydrant freeze protection. A conservation benefit of this integrated municipal decision was that the potable water to the city residents is slightly warmer than it would be otherwise. This reduces the need for home and commercial water heating by an incremental amount.

While such kinds of integrated multi-utility planning and cooperation can still occur with a privately held company like PSE, it would likely take more negotiations, as the different customer groups might have dramatically different perspectives. That is, a customer in Bainbridge Island and their elected representatives would have a different perspective than say a WUTC commissioner representing Skagit County, King County or Thurston County customers or even a PSE employee representing the owners of PSE. Again, such multi-utility cooperation is not impossible, it is just more difficult when a different set of stakeholders are involved in the negotiations.

Synergies and Other Benefits

Synergies

One of the concepts almost always debated during municipalization feasibility evaluations is the concept of economies of scale versus the efficiency of small nimble organizations. There is business research on economies of scale of large bureaucracies and if at a certain point they start losing economic efficiency. There is also research on small organizations in a rapidly changing environment. While the electric utility industry has been stable in some sense for a long time, it is also in an era of rapid change and enhanced pressure to provide a broader array of customer initiated programs.

Many city electric utilities are very efficient. For example small municipal utilities like Sumas and Blaine compete on the basis of electric rates very favorably with PSE which serves the areas surrounding these cities. Various synergies are a significant part of the reason for the comparability of rates with a much larger utility.

Local control can reduce the complexity of regulation and the bureaucracy associated with a large organization that is regulated by multiple layers of governing bodies (Security Exchange Commission, Washington Utilities and Transportation Commission, Federal Energy Regulatory Commission, corporate owners, and utility management). By having a City Council or utility board as the primary regulatory body, various reports, studies, and costly legal proceedings are potentially reduced. Considering that WUTC and FERC hearings are often before administrative law judges with specially hired expert witnesses and specialized law firms presenting the case, costs per proceeding can easily reach six figures. Such costs have to be mostly borne by the utility customers, however, the costs are admittedly spread over a broader base. Alternatively, presentations by City staff to a City Council or utility board are traditionally much less costly.

The other side of the coin is that expensive consultants and extra layers of regulatory review can sometimes prevent bad decisions. As such, the expense may be sometimes worth the cost. This is something to consider when municipalizing. However, the history within Washington State, where the majority of electric utility customers are served by consumer or cooperatively owned electric utilities, has shown that the added levels of regulation are not generally required except in the field of bulk power supply (large generation projects, such as hydroelectric facilities) or regional high voltage transmission that affects grid stability and reliability of large numbers of customers.

Another form of synergy often found by municipal utilities is in customer billing and invoicing, where water and/or sewer bills and/or meter reading costs can be combined or shared. While the

City only serves a portion of Bainbridge Island with water and sewer service there is still some potential for savings, although not as great as other cities. These benefits need to be balanced against the larger base of customers that can be used to amortize PSE billing software and programs.

Alternately, national consumer owned electric utility organizations like the American Public Power Association (APPA) have brought together many small electric utilities and created standardized software packages that can also spread the costs over a broader base. A new City electric utility can take advantage of billing and accounting systems used by other established municipal utilities like Centralia, Blaine, Steilacoom, Ellensburg, or Eatonville. We would strongly recommend investigation of such options.

Many small electric utilities the size of the City electric system would also not require full time human resources staff, attorney, public relations, off hour call answering, or certain other administrative functions. With a City electric utility a portion of an FTE (full time equivalent) could be assigned to the electric utility for such positions and save the remainder of the FTE cost for other City functions. The City of Blaine and Sumas municipal utilities shared a conservation person between them for many years. Also, historically a human resources firm was involved in union negotiations for several Washington State PUD's. These kinds of approaches can be used to address areas where economies of scale may be significant.

Alternately, synergies can arise from coordination on public works projects. Some municipal electric utilities of which we are familiar coordinate road paving projects with sewer line, water main, and electric utility projects, especially undergrounding projects. The main cost in electric utility undergrounding projects are the costs associated with trenching and site restoration, especially paving, at the end of the project. This kind of sharing has the benefit of reducing certain shared expenses among all the utilities.

In theory such coordination can occur with a private utility like PSE if it is flexible enough to perform such coordinated efforts. The best way for the City to see if this might be an advantage or disadvantage would be to examine its own interactions with PSE on road widening, pavement restoration and joint planning. Some cities are able to coordinate with PSE and others have had problems, so this represents both a potential advantage and disadvantage of municipalization depending on the level of cooperation and commitment by PSE.

Whenever economies of scale are discussed one area is often focused upon: purchasing of equipment and supplies. While everyone is familiar with bulk purchases and the Costco model of getting large quantities at a discount, most people are also familiar with the of certain military items like hammers and aircraft toilet seats that are manufactured to "milspec" requirements. The point being that while there can be advantages of scale in the purchase of some items in a free market, some large organizations or bureaucracies can induce diseconomies of scale.

When PSE orders power poles, conductor and transformers it can arrange for volume pricing discounts. Some utilities band together to get group pricing and in a competitive environment discounts for volume pricing may be offset by some of the purchasing related costs and requirements. So there can be a disadvantage to purchasing. However, many cities have addressed this problem through participation in various state contract programs where negotiated bulk prices are achieved.

For example, the City is familiar with the Municipal Research and Services Center (MRSC) which is a nonprofit organization that helps local governments across Washington State better serve their citizens by providing legal and policy guidance on any topic. There are similar electric utility organizations like the American Public Power Association (APPA) and the Northwest Public Power Association (NWPPA) that also provide for the ability to act in concert with other municipal electric utilities to capture economies of scale in regards to training, and certain products such as financial software or engineering software. Hometown Connections, which is a subsidiary of APPA designed to provide competitive advantage to public power systems has discount agreements with many vendors of products used by electric utilities. A final example of group buying power is the Washington State Department of Enterprise Services state negotiated blanket contracts under which cities can purchase.

The concept of economies of scale for purchases is not new. Many individuals have historically come together to form cooperatives to buy in bulk and distribute to their members. These kinds of programs are readily available to a new municipal utility and so the advantages and disadvantages of economies of scale, efficiency or synergies are not one sided, but a mix of advantages and disadvantages.

Other Benefits

Sometimes locally controlled utilities better understand their customers and the needs of their community. An example of this is the City of Sumas. At one point the mayor and city council wanted to encourage more jobs locally. During an electric rate proceeding, they directed their consultant to establish industrial rates that did not change the cost allocations between customer classes, but did change the rate form in a way that would reduce the cost impact of adding a second or third shift of operation at a local industry. While the above is an example of an advantage of locally controlled rates, PSE has become more flexible in its rates in recent history.

For example, the PSE custom program to monitor and work with the City on keeping loads on the island under 58 MW is an example of a PSE program to meet local needs. Similarly, the recent PSE rate agreement with Microsoft to allow that company and other similar companies to seek their own wholesale power supplies is an example of PSE being customer focused. This means that PSE may be able to provide some of the advantages normally associated with local control.

In communities such as the City of Blaine and the Town of Steilacoom, the governing board has established resolutions favoring the undergrounding of new electric utility distribution lines. These long term policies have gradually changed both utilities to mostly underground service, which allows them both to have low storm outage rates and better electric reliability than a similar overhead electric utility. While an advantage of local control, there is no reason that PSE could not adopt such a policy on its own or in negotiations with some of its franchise granting government agencies if approved by the WUTC.

Another example of recognizing a local problem and implementing different local reliability solutions can be learned from Grays Harbor County PUD, Peninsular Light Company, and Ferry County PUD. At Grays Harbor County PUD, there was a localized, but significant high voltage reliability problem where a subtransmission line with distribution underbuild on the same pole was subject to impacts from trees blowing over during wind storms. This resulted in trees contacting both transmission and distribution lines at the same time and having significant high voltage spikes occur within home wiring that destroyed televisions, computers and various electronics. Part of Grays Harbor County PUD's solution was to offer meter socket, whole house, surge protectors to customers in the affected area at cost. This does not mean that PSE could not offer such a program, but that program would need to be approved by the WUTC and apply to a potentially broader geographic area.

Another similar reliability example was where Peninsula Light Company offered a program of supply auxiliary gas/diesel generators and isolation equipment as a package for customer in remote areas who desired back up power sources. Similarly, Ferry County PUD provided some remote homeowners with non-grid connected solar photovoltaic systems. Again, the idea is that a locally controlled electric utility can identify a community need or the needs of a small set of customers and develop a program to meet those needs. PSE has also done a very good job in identifying broad customer needs. In fact the focused demand side management program that PSE implemented in keeping Bainbridge Island loads to under 58 MW is a good example of PSE being innovative and getting approval to focus on an area the size of Bainbridge Island.

Another synergy is associated with employees living within the City electric system service area and being an important part and source of skills for the community. For example, electrical line workers or engineers often have advanced skills that enrich a community. Each year the NWPPA gives out awards for various forms of community service. Annually there are awards for line crew members or engineers with training in advanced first aid that have saved lives of community members while either on the job or while they were not at work. This does not mean that PSE employees or its contract employees, such as Potelco employees, could not provide similar benefits. The City, however, through its hiring practices can encourage or require employees to live within the City providing the knowledge of its employees to benefit others more regularly in the community.

Another aspect of local control is local accountability. For example, many utility manages and City Council members have had neighbors or friends ask about the causes of extended outages or high electrical rates. This creates "peer pressure" on these leaders to focus their attention on meeting local needs. It also provides for a local education and public relations. For example, a person at a little league game or standing in line at the grocery checkout counter with someone who works at the local electric utility who is known to the person, concerns and issues can be discussed and the reasons why certain things are done the way they are can be learned.

A different perspective on this type of peer pressure is that city council or utility board meetings are regularly scheduled and most have public comment periods. This allows meetings at which customers can attend without spending a lot of travel time to personally express concerns about utility policy or programs, gain an understanding of the issues and ask for change. The ability of the decision makers and the regulators of a privately held electric utility are much more remote and less accessible. That does not mean that there could not be changes in the future of how and where WUTC proceedings are held, but this would require pressure by the public and the regulated utilities to make such changes which currently does not appear to be happening.

Another non-economic aspect of a City electric utility is community support. Many small electric utilities provide parks, trails and other benefits to their community. Seattle City Light has provided a number of small parks associated with abandoned substations and regularly includes public spaces and picnic areas adjacent to new substations. Chelan County PUD, Lewis County PUD, and the City of Blaine all have park facilities that were provided by the electric utility.

The APPA has a list of benefits that are also associated with public power electric utilities. The APPA list is provided as Appendix C. APPA also has a very good primer on forming a new municipal electric utility and the reasons and challenges that are likely to be faced[36].

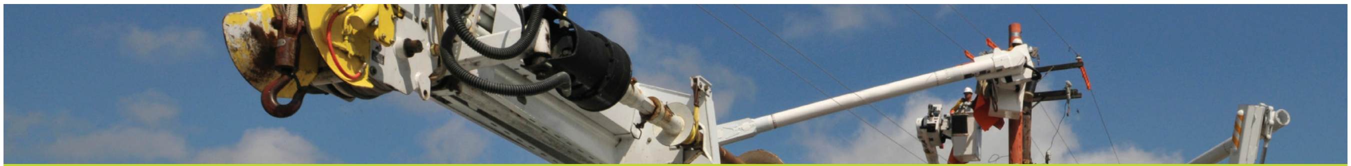
New Public Power Utilities

Many cities and municipal entities nationwide have established new public power utilities in the past. Appendix B attached to this report is a list provided by the American Public Power Association of new consumer-owned electric utilities that have been formed since 1973. The list includes 88 publicly-owned electric utilities that began operations between 1973 and 2015. Many of these new public power utilities were formed from the service areas of investor-owned utilities.

In addition to the new public power utilities that have formed and are operating many other communities have evaluated the potential costs and benefits of providing electric service in their communities. The primary purpose in pursuing a public power utility has been to establish reliable, cost effective electric service and allow for local community-focused input as to how electric service is provided in their communities.

[36]http://www.publicpower.org/files/PDFs/Summary_of_Public_Power_for_Your_Community.pdf

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



Fact Sheet

June 2014

BPA and new public utilities

While public utilities are common in the Northwest, the formation of a new publicly owned utility is rare. In fact, by 1949, there were more than 120 such utilities being served by the Bonneville Power Administration and there have been only eight more since. However, increases in electric utility costs have recently prompted grass-roots organizations to begin investigating the possibility of creating new publicly owned utilities.

In theory, these new utilities would acquire inexpensive power from BPA, a nonprofit federal power marketing administration that sells wholesale electricity, and be able to provide their customers with power that is less expensive than is currently available.

As a result, interest in BPA's policy on the creation of new utilities has increased. It is important to understand that BPA is absolutely neutral on whether new public utilities form or where they form.

In 2008, BPA completed a multiyear process to define how and under what conditions BPA will supply power to regional utilities under new long-term contracts that went into effect Oct. 1, 2011. Considering how long it takes to form a new utility, interested parties are well advised to consider BPA's Long-Term Regional Dialogue Policy and what it says about new utilities.

BPA's newest publicly owned utility customer, Jefferson County PUD, began receiving BPA power April 1, 2013.

BPA's Regional Dialogue Policy for serving newly formed public utilities is designed to strike a balance between providing new publics significant access to BPA's lowest-cost power and setting a limit on the costs that would dilute benefits to existing purchasers at BPA's lowest-cost rates.

Since the new policy was adopted, one new publicly-owned utility has formed. Jefferson County PUD, located in the northwest corner of Washington state, began receiving power April 1, 2013. The PUD purchases 46 average megawatts to serve about 18,000 customers.

What constitutes a "new public" utility?

To be eligible to purchase power from BPA on a preference and priority basis, an applicant must meet three fundamental requirements. First, the prospective applicant must meet the statutory definition of the terms "public body" or "cooperative." The Bonneville

Project Act defines "public body" or "public bodies" to mean "States, public power districts, counties, and municipalities, including agencies or subdivisions of any thereof." It also defines "cooperative" or "cooperatives" to mean "any form of nonprofit-making organization or organization of citizens supplying, or which may be created to supply, members with any kind of goods, commodities, or services, as nearly as possible at cost."

The second requirement is that a public body or cooperative applicant be in the public business of selling and distributing the federal power to be purchased from BPA. If not currently in business, the Act directs BPA to afford the prospective customer a reasonable time, as determined by the administrator, to allow it to get into the public business of selling and distributing power.

The third requirement is that the prospective new utility be within the BPA service territory — Oregon, Washington, Idaho and western Montana.

Can BPA deny a request for service from a public entity that meets the legal definitions above?

The Northwest Power Act requires that BPA offer a contract for service to a public body or cooperative utility whenever requested for its net requirements load, even if it means BPA must acquire power to serve a new request.

BPA may only deny such a request if the applicant has failed after a "reasonable time" has passed to obtain necessary financing to get itself into the business of selling and distributing electric energy.

Determining a reasonable time period is at the BPA administrator's discretion.

Why are applicants allowed a "reasonable" period to set up their business?

The parties are to be given reasonable opportunity and time to hold any elections or to take any other necessary action to create a public body or cooperative. Once created, the public body or cooperative is to be afforded reasonable time and opportunity to authorize and issue bonds, or to arrange other financing necessary to construct or acquire necessary and desirable electric distribution facilities and to become in all other respects a qualified purchaser and distributor of federal power.

How does a customer become eligible to purchase federal power from BPA?

In addition to the standards outlined above, the applicant must meet BPA's "Standards for Service" as revised in January 2000.

What are BPA's standards for service?

BPA requires that the applicant:

- be legally formed in accordance with local, state, tribal or federal laws;
- own a distribution system and be ready, willing and able to take power from BPA within a reasonable period of time;
- have a general utility responsibility within the service area;
- have the financial ability to pay BPA for the federal power it purchases;
- have adequate utility operations and structure; and
- be able to purchase power in wholesale amounts.

In addition, the standards for service address matters related to the configuration and operation of electrical facilities, including the need to have an electrical plan of service and the ability to operate electrical facilities in a safe and reliable manner.

How does a new public apply for service under a Regional Dialogue contract?

A new public utility that qualifies for BPA service must request service from BPA through a three-year binding notice before it may buy federal power at BPA's Tier 1 rate (expected to be its lowest rate). The notice may be made at any point after the new public meets the standards for service. The contract high water mark — the contract right used to determine eligibility to buy

Tier 1 power — for a new public will be set at the customer's net requirement level in the year deliveries begin. There is the potential for a slight reduction or increase so that the new public's load has similar access to lowest-cost rates as that of existing publics.

What led to BPA's approach to new publics in the Regional Dialogue?

BPA has earmarked 250 average megawatts of high water marks for service to the net requirement loads of new public customers in order to make federal power at the Tier 1 rate more widely available while providing planning certainty for the amount of power that BPA may need to acquire to serve load in the future.

One of BPA's rate-setting requirements is to encourage the widest possible diversified use of electric power. BPA believes that excluding new publics from an opportunity to obtain power at the Tier 1 rate would place them in an unfavorable position and would not promote the widest possible use of federal power. However, BPA also wishes to ensure that utilities receive price signals that more directly represent the true incremental costs of load growth. The 250 aMW is intended to strike a reasonable balance in achieving these objectives.

What is a contract high water mark?

BPA is limiting its sale of wholesale power at a Tier 1 rate to the output of the federal system, plus a limited amount of augmentation. Each utility's "contract high water mark," or CHWM, sets the contract right used to determine eligibility for Tier 1 power.

Tier 1 power will be sold consistent with the amount of power available from the federal system with limited augmentation. What "augmentation" is included in Tier 1 rates?

Some features in the Regional Dialogue Policy leave Tier 1 rates and costs somewhat higher than they otherwise would be. These include the proposals for resource removal, up to 250 aMW of power for new publics and up to 300 aMW of augmentation for existing publics. BPA believes that these limited cost and rate impacts are reasonable in light of the other key interests they would serve.

BPA will most likely have to augment to meet any new public's request, but it isn't a given. There is a chance, albeit small, that there would be enough power in the existing Federal Base System to serve some of the 250 aMW of new public requests.

What happens if total eligible high water mark requests exceed the limit for the rate period?

When the total eligible high water mark requests exceed the 50 aMW limit in a two year rate period, individual HWM amounts of new publics will be prorated down to meet the limit. Amounts not provided to any new public due to the 50 aMW limit will automatically be added to eligible amounts in the next rate period.

How will BPA prevent larger new publics from using up the available Tier 1 allotment?

During the first year of eligibility for a high water mark, all utilities would be eligible for the lesser of their load or 10 average megawatts. To ensure that access to the 250 aMW is spread broadly and not used solely by one large new public utility, utilities larger than 10 aMW would have their HWM amounts over 10 aMW phased in two-year increments if there is more than one new public formed and their requests exceed the 50 aMW yearly cap. The phasing-in would be 33.3 percent for the next 24 aMW of HWM and 20 percent for any remaining HWM amount after that. It is worth noting that Jefferson County PUD has a 46-megawatt high water mark, leaving a little over 200 aMW for service to the net requirement loads of new public customers at Tier 1 rates.

What are the exceptions to the 50 aMW rate-period limit?

Small Utility Exception. Because this type of pro rata reduction could inordinately impact a small customer, BPA proposes that the first five new publics smaller than 10 aMW that would otherwise be affected by the

50 aMW limit will receive their full HWM without reduction. Since this will only happen when rate-period limits are exceeded and is limited to five customers, BPA believes this accommodation for small publics still meets the region's interests while taking care of the special needs of these customers.

Tribal Utility Exception. BPA has earmarked 40 aMW for additions of contract high water marks for the load growth and annexed loads of tribal utilities. These additions will potentially add to the 50 aMW limit for the rate period.

What happens if a new public is formed from an existing public?

New public customers that form out of an existing public utility will receive a percentage of the existing public utility's CHWM equal to their proportion of the existing utility's total retail load. If the utilities involved agree on the CHWM split, we will use their numbers. If not, BPA will take into account information received from the involved utilities about the characteristics of the load when we determine the high water mark.

What happens if a new public is formed from an investor-owned utility?

New publics that form out of an existing IOU will be eligible for CHWMs within the new publics limits discussed above.

Are tribes eligible to form new public utilities?

A federally recognized tribe that forms a cooperative utility pursuant to its tribal constitution and laws would be eligible for preference status. However, a tribe could not create a cooperative inconsistent with state law for service to nontribal members or outside the tribe's jurisdiction.

What happens if a new large single load is embedded in a request for service by a newly formed public utility?

BPA's New Large Single Load (NLSL) Policy applies to consumer load within a new public's proposed service territory or expansion. Such load will be treated like any new large single load if it is 10 aMW or more at the time the new public is formed, regardless of when the load started taking service from the existing supplier.

How are new publics treated with regard to the Residential Exchange Program?

A new public customer that chooses to sign a contract with a CHWM would have the same access to the Residential Exchange Program as an existing public customer that signs a CHWM contract.

What does BPA expect in terms of new publics forming?

BPA believes new public customers, in addition to Jefferson County PUD, are likely to form and request service during the term of the Regional Dialogue contracts, which extend into 2028. However, such formations are not likely to involve large amounts of load. Over the past 25 years, a little over 300 average megawatts of new publics have formed and taken PF service. For the 20-year term of the Regional Dialogue contracts, BPA will earmark 250 aMW that, adjusted for the five-year time difference and the potential for additional amounts for small utilities, provides an amount of power for new publics that is approximately equivalent to this recent history.

Appendix B
Publicly Owned Electric Utilities
Established 1973-2011

85 new public power utilities began operating, 41 of the new systems were formed in service areas of investor-owned utilities; the others were formerly served by non-utility businesses, federal agencies or local publicly owned utilities. This list does not include communities that were previously served by investor-owned utilities or rural electric cooperatives and instead joined existing public power systems.

New Utility Formed	State	Year Est.	Previous Supplier
City of Atka (42 customers)	ALASKA	2008	Andreanof Electric Corporation*
Island Power, Pittsburg, Calif. (400 customers)	CALIFORNIA	2006	Former military base
Winter Park (13,750 customers)	FLORIDA	2005	Progress Energy*
Berea (4,700 customers)	KENTUCKY	2005	Berea College Electric Utility
Moreno Valley Utilities (4,300 customers)	CALIFORNIA	2004	SCE*
Huron (2 customers)	OHIO	2004	Ohio Edison*
Elk City (8 customers)	OKLAHOMA	2004	AEP*
Electric City Power, Great Falls, Montana (large governmental and industrial customers)	MONTANA	2004	NorthWestern Energy
City of Williams (1,721 customers)	ARIZONA	2003	Arizona Public Service*
McAllister Ranch Irrigation District[1]	CALIFORNIA	2003	PG&E*
Rancho Cucamonga Municipal Utility[1] (400 customers/commercial and industrial)	CALIFORNIA	2004	SCE*
Industry, California[1] (23 customers)	CALIFORNIA	2003	SCE*
Port of Stockton Electric[1] (3,208 customers)	CALIFORNIA	2003	PG&E*
City of Victorville[1]	CALIFORNIA	2003	SCE*
Hercules Municipal Utility[1] (825 customers)	CALIFORNIA	2002	PG&E*
Corona Municipal Electric Utility[1] (1,700 customers)	CALIFORNIA	2001	SCE*

[1] A "greenfield growth area" project, serving new industrial and/or residential development.

New Utility Formed	State	Year Est.	Previous Supplier
Hermiston (5,123 customers)	OREGON	2001	PacifiCorp*
Long Island Power Authority (1,090,538 customers)	NEW YORK	1998	Long Island Lighting Company*
Town of Eagle Mountain (382 customers)	UTAH	1998	New Community
Ak-Chin Electric Utility Authority (378 customers)	ARIZONA	1997	Arizona Public Service*
Hohokam Irrigation & Drainage District (498 customers)	ARIZONA	1997	Arizona Public Service*
Village of Obetz (14 customers)	OHIO	1997	American Electric Power Co.*
Merced Irrigation District[2] (3,157 customers)	CALIFORNIA	1996	Pacific Gas & Electric*
Mohegan Tribal Utility Authority (54 customers)	CONNECTICUT	1996	New Entity
MassDevelopment Devens Utility (100 commercial customers)	MASSACHUSETTS	1996	Former Military Base
Tarentum Borough (2,651 customers)	PENNSYLVANIA	1996	West Penn Power*
Bozrah Light & Power (2,587 customers)	CONNECTICUT	1995	Bozrah Light & Power (private company)*
City of Broken Bow (5 customers)	OKLAHOMA	1995	Public Service Company of Oklahoma*
Asotin County Public Utility District No. 1 (3 customers)	WASHINGTON	1994	Clearwater Power Company*
Byng (53 customers)	OKLAHOMA	1990	Oklahoma Gas & Electric*
Clyde Light & Power (2,872 customers)	OHIO	1989	Toledo Edison*
City of Santa Clara (1,707 customers)	UTAH	1989	Utah Power & Light*
Hayfork Valley Public Utility District (724 customers) (Merged with Trinity County PUD in 1993)	CALIFORNIA	1988	Pacific Gas & Electric*
Lassen Municipal Utility District (12,059 customers)	CALIFORNIA	1988	CP National*
City of Scribner (589) customers	NEBRASKA	1988	Nebraska Public Power District

[2] Merced Irrigation District, Calif., began distribution utility in 1996.

New Utility Formed	State	Year Est.	Previous Supplier
City of Riverdale (206 customers)	NORTH DAKOTA	1988	Corps of Engineers
City of San Saba Electric Utility (2,196 customers)	TEXAS	1988	Lower Colorado River Authority
City of Washington (5,750 customers)	UTAH	1988	Utah Power & Light*
Electrical District #8 of Maricopa County (456 customers)	ARIZONA	1987	Arizona Public Service*
Town of Fredonia (731customers)	ARIZONA	1987	CP National*
Reedy Creek Improvement District (1,213 customers)	FLORIDA	1987	New Entity
Troy Power & Light (923 customers)	MONTANA	1987	Montana Light & Power*
Kerrville Public Utility Board (20,157 customers)	TEXAS	1987	Lower Colorado River Authority
Kanab City Corporation (1,378 customers) (Sold to Garkane Energy Cooperative in 2004)	UTAH	1987	Utah Power & Light*
Town of Pickstown (63 customers)	SOUTH DAKOTA	1986	Corps of Engineers
City of San Marcos Electric Utility District (20,320 customers)	TEXAS	1986	Lower Colorado River Authority
Strawberry Electric Service District (2,972 customers)	UTAH	1986	Strawberry Waters Users
City of Galena (335 customers)	ALASKA	1985	M & D Enterprises
Page Electric Utility (3,780 customers)	ARIZONA	1985	Arizona Public Service*
Ipnatchiaq Electric Co. (67 customers)	ALASKA	1984	Supplier Unknown
Larsen Bay Utility Co. (86 customers)	ALASKA	1984	Individual Generators
Aguila Irrigation District (39 customers)	ARIZONA	1984	Supplier Unknown
Columbia River People's Utility District (St. Helens, Oregon) (17,347 customers)	OREGON	1984	Pacific Power & Light*
Kwig Power Co. (111 customers)	ALASKA	1983	Supplier Unknown

New Utility Formed	State	Year Est.	Previous Supplier
St. Paul Municipal Electric Utility (231 customers)	ALASKA	1983	Federal Government
City of Thorne Bay Utilities (261 customers) (Sold to Alaska Power & Telephone* in 2001)	ALASKA	1983	Federal Government
Needles Department of Public Utilities (2,092 customers)	CALIFORNIA	1983	CP National*
Tuolumne County Public Power Agency (30 customers)	CALIFORNIA	1983	Pacific Gas & Electric*
Emerald People's Utility District (Eugene, Oregon) (18,104 customers)	OREGON	1983	Pacific Power & Light*
Akutan Electric Utility (65 customers)	ALASKA	1982	Supplier Unknown
City of Kotlik Utility (176 customers)	ALASKA	1982	Supplier Unknown
City of White Mountain (101 customers)	ALASKA	1982	Supplier Unknown
Trinity County Public Utility District (6,797 customers)	CALIFORNIA	1982	CP National*
City of Chignik (87 customers)	ALASKA	1981	Sea Alaska
Massena Electric Department (9,406 customers)	NEW YORK	1981	Niagara Mohawk*
Markham Hydro Distribution, Inc. (62,126 customers)	ONTARIO	1979	Supplier Unknown
Tatitlek Electric Authority (55 customers)	ALASKA	1978	Supplier Unknown
White, City of (254 customers)	SOUTH DAKOTA	1978	Supplier Unknown
Tlingit Haida Regional Electric Authority (1,268 customers)	ALASKA	1977	Supplier Unknown
Tonopah Irrigation District (31 customers)	ARIZONA	1977	Supplier Unknown
Sherrill, City of (1,884 customers)	NEW YORK	1977	Supplier Unknown
Manokotak, City of (136 customers)	ALASKA	1976	Supplier Unknown
Ellaville, City of (958 customers)	GEORGIA	1976	Supplier Unknown
Anthon, City of (374 customers)	IOWA	1976	Supplier Unknown
Kiowa, City of (753 customers)	KANSAS	1976	Supplier Unknown

Matinicus Plantation Electric Co. (120 customers)	MAINE	1976	Supplier Unknown
North Slope Borough Dept. of Municipal Services (1,180 customers)	ALASKA	1975	Supplier Unknown
De Witt, Village of (313 customers)	NEBRASKA	1975	Supplier Unknown
Hurricane Power Committee (5,229 customers)	UTAH	1975	Supplier Unknown
Tohono O'odam Utility Authority (3,746 customers)	ARIZONA	1974	Supplier Unknown
Lyons, Town of (1,095 customers)	COLORADO	1974	Supplier Unknown
Aurelia, City of (555 customers)	IOWA	1974	Supplier Unknown
Stanton, City of (228 customers)	NORTH DAKOTA	1974	Supplier Unknown
Kirbyville Light & Power Co. (1,318 customers)	TEXAS	1974	Supplier Unknown
Hobgood, Town of (324 customers)	NORTH CAROLINA	1973	Supplier Unknown

* Represents an investor-owned utility

Source: ***American Public Power Association (2012)***

"Customers" refers to the number of customer-meters served. The population served would be some multiple of this number.

Publicly Owned Electric Utilities Established 2005-2015

During this period 8 new public power utilities began operating (6 were formed from the service areas of investor-owned utilities). This list does not include communities that were previously served by investor-owned utilities or rural electric cooperatives and instead joined existing public power systems.

New Utility Formed	State	Year Est.	Previous Supplier
Jefferson County, Wash. (18,000 customers)	WASHINGTON	2013	Puget Sound Energy*
Toledo Public Power (1 customer)	OHIO	2012	First Energy*
City of Egegik (77 customers)	ALASKA	2011	Egegik Light & Power Company*
City of Atka (42 customers)	ALASKA	2008	Andreanof Electric Corporation*
Island, Power, Pittsburg, Calif. (400 customers)	CALIFORNIA	2006	Former Military Base
Winter Park (13,750 customers)	FLORIDA	2005	Progress Energy*
Berea (4,700 customers)	KENTUCKY	2005	Berea College Electric Utility
Cerritos (60 customers)	CALIFORNIA	2005	SCE*

"Customers" refers to the number of customer-meters served. The population served would be some multiple of this number.
Source: American Public Power Association (2016)

*Represents an investor-owned utility

American Public Power Association

Public Power: Shining a Light on Public Service

Public Power is Hometown Power

More than 2,000 cities and towns in the United States light up their homes, businesses and streets with "public power"—electricity that comes from a community-owned and -operated utility. Each public power utility is different, reflecting its hometown characteristics and values, but all have a common purpose: providing reliable and safe not-for-profit electricity at a reasonable price while protecting the environment. While the vast majority are owned by cities and towns, a number of counties, public utility districts, and even a handful of states have public power utilities. Most—especially the smaller ones—are governed by a city council, while others are overseen by an independently elected or appointed board.

47 million

Number of people served by public power

Lower Costs Boost Local Economies

Unlike private power companies, public power utilities are public service institutions and do not serve stockholders. Instead, their mission is to serve their customers. They measure success by how much money stays within the community through low rates and contributions to the city budget, not how much goes out to stockholders across the country and around the world.

On a national basis, private power residential customers pay average electricity rates that are about 14 percent more than those paid by public power customers. On average, public power utilities return to state and local governments in-lieu-of-tax payments and other contributions that are 33 percent greater than state and local taxes paid by private power companies. Public power utilities lower costs through their partnerships with other local government departments and other organizations. There are more than 70 joint action agencies that operate within states or regions to offer local utilities power supply or other services.

APPA's national subsidiary, Hometown Connections, provides a portfolio of lower-cost products and services.

Public Power is Customer-Focused

For more than 130 years, public power has been a tradition that works across the nation on behalf of its communities and customers. Today, it is a thriving segment of the electric utility industry, enhancing overall economic development, often with additional infrastructure responsibilities for broadband services. Public power has a strong environmental-protection track record, solid credentials with bond ratings agencies, and a reputation for reliable, customer-focused service. Public power also continues to be an appealing institution for many cities and towns currently served by private power companies and interested in the opportunity to obtain lower rates and local control over an essential service. Growing failures of wholesale electricity markets—especially those run by regional transmission organizations—and the impacts of these failures on wholesale and retail customers are priority issues for public power. Climate change, environmental protection, and energy efficiency; maintaining and enhancing reliability; developing new generation and other power supply options; and financing infrastructure are all high on public power's agenda.

Electric Industry Ownership and Consumers

Number and type of provider	% of customers served
2,006 public power systems	15%
193 investor-owned electric utilities	68%
873 rural electric cooperatives	13%
181 power marketers	4%

Public Power Has a Voice in Washington

Public power utilities work collectively through the American Public Power Association to ensure policies that put customers first and ensure a stable supply of electricity while protecting the environment. Since two-thirds of public power utilities do not generate their own electricity, and instead buy it on the wholesale market for distribution to their customers, securing competitively priced and reliable wholesale power is a priority.

3 million

Number of business customers served by public power nationwide

The American Public Power Association is the service organization for the nation's more than 2,000 community- and state-owned electric utilities. It represents public power's interests in Washington, D.C., and provides an array of services to help its members with managerial and operational issues.

More Facts About Public Power:

49

Number of states with public power systems (all but Hawaii)

2,006

Number of public power systems in the U.S.

1880

Year first public power systems were created

2021

Year by which half of all public power systems will celebrate a centennial

1,400

Number of public power systems serving communities with populations of 10,000 or fewer

1.4 million

Number of customers served by the largest municipally owned public power utility, the Los Angeles Department of Water & Power

May 2013