The following presentation was presented at the Rate Information meeting held at 6pm in the Benton PUD auditorium on Tuesday, May 5, 2015. The presentation is a modified version of the draft presentation presented to the Commission at the regularly scheduled Commission meeting on Tuesday, April 14, 2015.
Benton PUD
Rate Information

May 5, 2015
Agenda

1. Key Takeaways
2. Bill Comparisons
3. Key Driver: Power Costs
4. Pause for Questions/Comments
5. Debt and Reserves
6. Pause for Questions/Comments
7. Retail Rate Design
8. Cost of Service Analysis and Rate Recommendation
9. Questions / Comments
Key Takeaways

1. **Staff proposing a 3.9% *average* revenue increase on 9/1/2015**
   - Rate increases by customer class range between 1%-7%
   - Final staff recommendation to Commission on June 23, 2015

2. **Last Benton PUD rate increase was in January 2012**
   - Cash reserves used to avoid increases

3. **Rising power costs are primary reason for increase**
   - $10M increase since 2012
   - BPA wholesale rate increases + Energy Independence Act

4. **Cost of Service Analysis (COSA) shows need for 5.9% increase**
   - Use reserves to “buy-down” to 3.9%
Bill Comparisons
Cumulative Impact of Rate Actions
Since 2003 on a $100 Residential Bill

From 2002 to 2015, increase equates to an annual 1.27% increase

*September 2015 based on proposed 4.6% rate increase for residential customer class
Bill Comparison

Residential

Disclaimer: Average bill information has been calculated by Benton PUD staff from other utilities’ websites. Calculation is Benton PUD’s best effort to provide comparable information. See Slide 11 for factors impacting rates.
Bill Comparison
Small General Service

Average Monthly Bill at 9,000 kWh and 30 KW

Small General Service Average Monthly Bill Comparison

Proposed Rates
$572

“Mid-C”

Disclaimer: Average bill information has been calculated by Benton PUD staff from other utilities’ websites. Calculation is Benton PUD’s best effort to provide comparable information. See Slide 10 for factors impacting rates.
Bill Comparison
Medium General Service

Average Monthly Bill at 15,001 kWh and 75 KW

Medium General Service Average Monthly Bill Comparison

Proposed Rates
$1,039

“Mid-C”

$1,026

$1,219

$1,239

Disclaimer: Average bill information has been calculated by Benton PUD staff from other utilities’ websites. Calculation is Benton PUD’s best effort to provide comparable information. See Slide 10 for factors impacting rates.
Bill Comparison
Large General Service

Average Monthly Bill at 150,000 kWh and 400 KW

Large General Service Average Monthly Bill Comparison

Proposed Rates $8,982

“Mid-C”

Disclaimer: Average bill information has been calculated by Benton PUD staff from other utilities’ websites. Calculation is Benton PUD’s best effort to provide comparable information. See Slide 10 for factors impacting rates.
## Proposed Rate Action by Customer Class

<table>
<thead>
<tr>
<th>Customer Class</th>
<th>Proposed Rate Action (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>4.6%</td>
</tr>
<tr>
<td>General Service</td>
<td>1.0%</td>
</tr>
<tr>
<td>Large Industrial</td>
<td>7.0%</td>
</tr>
<tr>
<td>Small Ag. Irrigation</td>
<td>3.4%</td>
</tr>
<tr>
<td>Large Ag. Irrigation w/o AFC</td>
<td>3.4%</td>
</tr>
<tr>
<td>Large Ag. w/AFC</td>
<td>7.0%</td>
</tr>
<tr>
<td>Other Customer Classes</td>
<td>7.0%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>3.9%</strong></td>
</tr>
</tbody>
</table>
Individual Utility Bill Comparisons

Key Factors Impacting Bill Size (Rates)

• Over time, utilities can change positions on the comparison charts
  o Benton PUD was high relative to other utilities in early 2000s
  o Benton PUD has been below the median the last nine years

• Key factors that can influence utility rates:
  o EIA - utilities subject to EIA pay more for power
  o Customer growth – higher growth can lead to higher rates
  o Customer density – greater density is generally less expensive
  o State/local taxes – different taxes paid by different entity types
    o Amount of debt – can delay a rate action in the short term, but too much debt will catch up with a utility down the road
    o Cash reserves – can be used to defer/mitigate rate actions
Power Costs
2015 Budget

Expenses and Expenditures by Major Budget Category

- Net Power Supply 60.2%
- Net Capital 9.8%
- O&M 16.1%
- Taxes/Other 9.9%
- Debt Service 4.0%

*Net of sales for resale of $12.8 million, capital contributions of $2.1 million, and Build America Bonds subsidy of $376,000

2015 Budget
Total Net Expenditures
$127,903,000*

* Net of sales for resale of $12.8 million, capital contributions of $2.1 million, and Build America Bonds subsidy of $376,000
Water Years
January thru July Runoff at The Dalles Dam

More Water = More surplus power to sell and lower retail rates

54 year average 102.4

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Average Wholesale Power Price

Wholesale power prices are expected to remain low throughout the forecast period.
Net Power Costs*

* Net power costs (NPC) = gross power costs (including power and transmission) less sales for resale.
Net Power Costs Drive Rates

Retail Revenue Adjustments / Net Power Cost

Net Power Costs are the largest portion of rates

* Yellow bars represent the temporary rate credit associated with BPA residential exchange. $8.3 million was returned to retail customers during the period June 2008 – May 2009. The effective annualized rate credits were 5.6% in 2008 and 3.8% in 2009.
What is Primary Driver of Rate Increase?

1. **BPA wholesale rate increases** *(power & transmission)*
   - 5.2% rate increase in October 2013 *(already happened)*
     - Benton PUD “absorbed” increase through use of cash reserves
   - 6.5% rate increase in October 2015 *(projected)*

2. **Renewable energy requirements** *(Energy Independence Act)*
   - 2012-2015, must purchase 3% of load from qualifying renewables
   - 2016-2019, must purchase 9% of load from qualifying renewables
BPA Wholesale Power Rates

- Incurred BPA 2013 increase of 5.2% without a retail rate increase
- BPA increases effective October 1, 2015
  - **Power** – 6.7%
    - Aging infrastructure (dams)
    - Reduced revenue from surplus power sales
    - Variable resource integration and other items
  - **Transmission** - 5.2%
    - Construction of new transmission lines and replacements
    - Increased mandatory compliance requirements (i.e., cyber and physical security)
Renewable Energy Requirements

_Energy Independence Act (EIA)_

- **EIA applicable to utilities with more than 25,000 customers**
  - Currently, 17 utilities in the state subject to the EIA
  - Benton PUD is only local utility subject to the EIA
- **Must purchase percentage of retail load from qualifying resources**
  - Wind, solar, biomass (hydro not a qualifying resource)
  - 2012 (3%) .......... 2016 (9%) .......... 2020 (15%)
  - Can be energy or renewable energy credits
- **Impact of EIA on Benton PUD**
  - Currently spending $3.1M annually to comply with EIA (added to retail rates)
  - Rising to $3.4M in 2016
  - EIA has a “cost cap” that limits the impact on utilities
    - Cost impact limited to 4.0% of retail revenues, currently 2.6%
# Power & Transmission Costs

## Summary

Net power costs up from 2012 *(since last rate increase)*

- **BPA** $8.0M
- **Reduced Surplus Power Sales** $1.3M
- **Renewable energy (EIA)** $0.3M
- **Other** $0.5M
- **Total** $10.1M

**Rate Information Meeting - May 5, 2015**

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**Benton PUD**

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Pause for Questions/Comments
Debt and Reserves
Debt Per Customer

WPUDA Survey – December 2013 (Transmission & Distribution Systems Only)

Source: WPUDA Source Book for Dec 2013

District below median and average of Washington PUDs

Median for survey respondents ($1,851)
Mountain Snowfall Impacts Rates
2011/2012 Were Strong Years

More Water = More surplus power to sell and lower retail rates

Water Flow at The Dalles Dam
(in million acre feet or MAF; January-July)

- Estimated Water Year
- Actual Water Year

54 year average 102.4

Two of the best back-to-back years on record

Latest Forecast: Concerning

Early 2014 Forecasts

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Cash Reserves: Days Cash on Hand\(^1\)

**Benton PUD vs. National Public Utilities** *(with A+ Bond Ratings)*

\(^1\)Source - Moody’s Investors Service Public Power Electric Utility Medians and Methodology, June 2014

Unrestricted Reserves: $55.3M $47.6M $48.5M $43.5M

Days Cash on Hand - allows for an “apples to apples” comparison between utilities. It’s a measure used by bond rating agencies; measures the number of days a utility can cover its operating expenses using unrestricted reserves assuming no additional revenue.
Cash Reserves: Days Cash on Hand

Benton PUD vs. Washington PUDs (Transmission & Distribution Systems Only)

Source: WPUDA Source Book for Dec 2013

1 Days Cash on Hand - a measure used by bond rating agencies; measures the number of days a utility can cover its operating expenses using unrestricted reserves assuming no additional revenue
How are Financial Reserves Created?

• District uses conservatism in setting rates
  o As do most Northwest utilities: considered industry best practice

• Power budgets established at the 25\textsuperscript{th} percentile
  o 75% of time, actual costs will come in at or below budget
  o Monte Carlo analysis – 1,000 outcomes

• Will generate reserves higher than planned in some years
  o Commission determines the application of reserves annually

• Options for year-end excess reserves
  1. Immediately reduce rates
     o Between 2000-2010, option used five times, but power costs were dropping
  2. Use to delay or mitigate future rate increases
  3. Use to fund future capital or other special needs
Financial Reserves:
*Year-end 2014 Example*

**Days Cash on Hand**

- **Total DCOH: 136 Days**
- **90 Day Minimum DCOH**
- **Funds set aside to smooth out or lower rate actions ($4.3M)**
- **12 Days**
- **Power Market Volatility**
- **Funds set aside for bond insurance when policies expire in 2015 & 2021 ($4.0M)**
- **11 Days**
- **Bond Insurance Replacement**
- **Funds set aside for customer deposits ($1.4M)**
- **4 Days**
- **Customer Deposits**
- **Funds set aside for future capital ($6.7M)**
- **19 Days**
- **Special Capital Fund**
Factors Affecting Reserve Levels

- Day to day operations (working capital)
- Risk management
  - Weather related events and energy market volatility
- Rate management
- Planned future expenditures (major capital)
- Credit ratings
Western U.S. Electricity Markets

- Highly interconnected grid
- Potentially volatile pricing
- Increased penetration of intermittent generation (wind & solar)
- Reliable grid operations becoming more challenging and expensive
- California events can significantly impact Northwest Markets
### Impact of Energy Crisis and Record Low Water Year

#### Table: End of Year Figures

<table>
<thead>
<tr>
<th>Metric</th>
<th>2000</th>
<th>2001</th>
<th>2002</th>
<th>2014</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power costs</td>
<td>$36.5M</td>
<td>$41.1M</td>
<td>$69.7M</td>
<td>$73.8M</td>
</tr>
<tr>
<td>Average Residential Bill</td>
<td>$68</td>
<td>$95</td>
<td>$95</td>
<td>$107</td>
</tr>
<tr>
<td>Debt Per Customer</td>
<td>$958</td>
<td>$1,574</td>
<td>$1,886</td>
<td>$1,071</td>
</tr>
</tbody>
</table>

**Bond Ratings**

<table>
<thead>
<tr>
<th></th>
<th>A-/A3</th>
<th>A-/A3</th>
<th>BBB/A3</th>
<th>A+/Aa3</th>
</tr>
</thead>
</table>

1. Power costs rose 91% - inadequate reserves to mitigate rate increase

2. Average residential bill increased 38% (followed by additional rate actions in following years leading to an increase of 64% by the end of 2003)

3. Debt doubled

4. BBB *with negative outlook* (BBB- is lowest investment grade rating)
### Benton PUD Ratings

**Then vs. Now**

<table>
<thead>
<tr>
<th>Moody's</th>
<th>S &amp; P</th>
<th>Fitch</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aaa</td>
<td>AAA</td>
<td>AAA</td>
</tr>
<tr>
<td>Aa1</td>
<td>AA+</td>
<td>AA+</td>
</tr>
<tr>
<td>Aa2</td>
<td>AA</td>
<td>AA</td>
</tr>
<tr>
<td>Aa3</td>
<td>AA-</td>
<td>AA-</td>
</tr>
<tr>
<td>A1</td>
<td>A+</td>
<td>A+</td>
</tr>
<tr>
<td>A2</td>
<td>A</td>
<td>A</td>
</tr>
<tr>
<td>A3</td>
<td>A-</td>
<td>A-</td>
</tr>
<tr>
<td>Baa1</td>
<td>BBB+</td>
<td>BBB+</td>
</tr>
<tr>
<td>Baa2</td>
<td>BBB</td>
<td>BBB</td>
</tr>
<tr>
<td>Baa3</td>
<td>BBB-</td>
<td>BBB-</td>
</tr>
<tr>
<td>Ba1</td>
<td>BB+</td>
<td>BB+</td>
</tr>
<tr>
<td>Ba2</td>
<td>BB</td>
<td>BB</td>
</tr>
<tr>
<td>Ba3</td>
<td>BB-</td>
<td>BB-</td>
</tr>
<tr>
<td>B1</td>
<td>B+</td>
<td>B+</td>
</tr>
<tr>
<td>B2</td>
<td>B</td>
<td>B</td>
</tr>
<tr>
<td>B3</td>
<td>B-</td>
<td>B-</td>
</tr>
</tbody>
</table>

- **Moody's**
- **S & P**
- **Fitch**

- **Prime**
- **High grade**
- **Upper medium grade**
- **Lower medium grade**
- **Non-investment grade speculative**
- **Highly speculative**

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**Benton PUD’s Current ratings**

**Benton PUD’s 2002/2003 ratings**

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**Benton PUD’s Current ratings**

**Benton PUD’s 2002/2003 ratings**

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**A+ is the median rating for public power utilities**

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Rating Comparisons: Utility Industry

Comparative Credit Ratings Distribution

Majority of Public Power Utilities are A+ or higher.

Source: Standard & Poor’s presentation at March 6, 2014 APPA Public Power Webinar
Reasons Our Ratings Improved

- Conservative planning – set rates to 25\textsuperscript{th} percentile
- Demonstrated willingness to raise rates when needed
- Days Cash on Hand improved
- Demonstrated robust power risk management program
- Adopted more strict financial policies
- Improved financial forecasts for all key metrics
- Outperformed financial plans
Why Utilities Value Credit Ratings

• Banks
  o Accessibility and cost of lines of credit
• Power Counterparties
  o Credit terms/collateral impacted by bond ratings
• Capital financing (tax free municipal bonds)
  o Cost of borrowing (particularly for small, occasional issuers)
  o Bond insurance no longer a viable tool to prop up the credit rating
• Volatile or challenging industry conditions
  o 2010 financial crisis
• Public perception
  o Reflects stewardship of public resources
  o How well is my public agency run for the long-term?
**Days Cash on Hand**

**Public Power Medians**

*For Distribution Utilities in “A” rating categories*

<table>
<thead>
<tr>
<th>Item</th>
<th>Fitch</th>
<th>Moody’s</th>
<th>Standard &amp; Poor’s</th>
</tr>
</thead>
<tbody>
<tr>
<td>Median Days Cash on Hand</td>
<td>151</td>
<td>122 (Retail Distribution Utilities, A/Aa)</td>
<td>N/A (Unable to obtain metrics)</td>
</tr>
<tr>
<td></td>
<td>(Retail Distribution Utilities, A+)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Quotes</td>
<td>“More than 120 days cash on hand indicates solid financial flexibility to meet unforeseen spending needs”</td>
<td>“Cash is the paramount resource utilities have to meet expenses, cope with emergencies, and navigate business interruptions”</td>
<td>“Liquidity is solid at 144 days of operating expenses, but in our opinion, it is necessitated by hydrological risks”</td>
</tr>
<tr>
<td>Liquidity Comments</td>
<td>Cash is cash – bank liquidity is not the same as cash</td>
<td>Adjusted Days Liquidity considers irrevocable line of credit</td>
<td>Considers line of credit, but liquidity is not the same as cash</td>
</tr>
</tbody>
</table>

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*“Liquidity is solid at 144 days of operating expenses, but in our opinion, it is necessitated by hydrological risks” from 2014 S&P Report on Benton PUD.*
Maintaining Credit Rating: Other Metrics

<table>
<thead>
<tr>
<th>Metric</th>
<th>2015 Forecast*</th>
<th>Fitch Median A+</th>
<th>Moody’s A/Aa Median Range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Debt Service Coverage with capital contributions</td>
<td>2.62x</td>
<td>N/A</td>
<td>2.65x – 3.51x</td>
</tr>
<tr>
<td>Debt Service Coverage without capital contributions</td>
<td>2.27x</td>
<td>2.33x</td>
<td>N/A</td>
</tr>
<tr>
<td>Fixed Charge Coverage</td>
<td>1.26x</td>
<td>1.37x</td>
<td>N/A</td>
</tr>
</tbody>
</table>

*2015 Forecast includes the proposed 2015 revenue increase effective September 1, 2015

- **Debt Service Coverage**
  - Measures the ability of a utility to pay its debt

- **Fixed Charge Coverage**
  - Measures the ability of a utility to pay its debt and “debt-like” obligations related to purchased power (e.g. a portion of BPA costs are treated as “debt-like” obligations)
Debt and Reserves

Summary

1. Debt per customer lower than median
   - We continue to use debt at conservative levels

2. Cash reserves below PUD median
   - Reserves will continue to decline to mitigate future rate increases
   - Reserves expected to fall within 108-120 DCOH
Pause for Questions/Comments
Retail Rate Design
Radical Change in the Utility Industry  
“Electricity 2.0”

**Utility Realities**
- Power costs
- Load growth
- Aging infrastructure
- Aging workforce

**Customer Expectations**
- Safe
- Reliable
- Low Cost
- Responsive

**Last 3 years**
- Regulations
- Technology
- Renewables
- Conservation
- Flattening loads now
- Declining loads future

**Last 3 years**
- More information
- Better technology
- Customer generation
- Sustainable
- Social responsibility
Retail Rate Design Project

Primary objectives

1. Need to address changes occurring within the industry
   - Impacts on rate design

2. Need for a comprehensive, top-to-bottom review of assumptions
   - Rate analysis conducted annually
   - Last top-to-bottom review was 14 years ago
   - Change in BPA contract and other regulatory impacts
Project Overview and Recap

Phase 1: Rate Strategy
- Draft Rate Strategy
- Stakeholder Meetings and Commission Discussions
- Finalize / Adopt Rate Strategy

Phase 2: Implementation
- Cost of Service Analysis (COSA) Model
- Revenue Adequacy, Rate Making
Rate Strategy Implementation

Key Outcomes

1. **Financial Stability**
   - Use conservative financial planning criteria in setting rates
   - Use excess reserves to buy down rate actions

2. **Gradualism**
   - Work to mitigate significant changes to rates
   - Gradually change rates to align with costs

3. **Low Income Assistance**
   - Expand the low income discount program
   - Spread the cost of the program across all rate classes

4. **Equity and Fairness**
   - Better align fixed revenues with fixed costs
Equity and Fairness

*Fixed Costs vs. Variable Costs*

- **Fixed Costs**:
  - Converts High Voltage Electricity to Lower Voltage Electricity
  - Transfers Lower Voltage Electricity from Substation Built to meet Peak Load (Maximum KW at Any Time) and Deliver Power to Customers
  - Also, Transfers Lower Voltage Electricity from Customer Owned Generation
  - Much of the System Costs do not vary by power consumed

- **Variable Costs**:
  - Transfers High Voltage Electricity from Power Plant Built to meet Peak Load (Maximum KW at Any Time)
  - Produces Electricity Based on Customer Load (kWh Consumed)

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*Rate Information Meeting - May 5, 2015*
**Industry-Wide Challenge**

*Fixed Costs vs. Fixed Revenues*

- **Benton PUD Costs vs. Current Revenues**

  - Costs - COSA
    - Fixed: Demand & Customer
    - Variable: Energy
  - Revenues
    - $59.9 M
    - $93.7 M

**Fixed costs vs. revenue percentages typical for most utilities**

**Industry-wide effort to increase fixed revenue percentage**

- While lowering variable revenue percentage

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Equity and Fairness:

**Fixed Cost Recovery**

- **Industry-wide, fixed revenues have been less than fixed costs**
  - Fixed costs collected through the energy rate (century old model)
  - This is not a new issue - common for virtually all utilities
  - Previously, no motivation for utilities or regulators to change rate structure

- **Customer-owned solar now highlighting this *existing* rate issue:**
  - Significant solar growth in California and Arizona
  - Solar customers use less energy from utility
  - Solar customers able to avoid fixed costs (because fixed costs are in energy rate)
  - Non-solar customers can be disadvantaged
  - Utilities (and low income advocacy groups) are calling for change

- **Customer solar will undoubtedly become an increasingly important component of Northwest’s energy mix**
  - Northwest utilities feel the need to address the rate structure issue now
Customer-Owned Solar

• **Solar customers use less energy, but still need “poles & wires”:**
  - Nighttime: when sun does not shine
  - Daytime: when solar output < household use
  - Daytime: when solar output > household use (to sell back to utility)

• **Under current rate structure, fixed costs are avoided**
  - Because fixed charge recovery is in “energy” charge
  - Will ultimately raise rates on non-solar customers if not addressed

• **Utilities are starting to modernize pricing models**
  - Properly allocate fixed cost via a higher customer base charge
  - Other solutions
Utilities are Increasing their Base Charges

*Monthly Base Charge – Residential*

**Residential Monthly Base Charge**

As of April 1, 2015

Utility base charges are rising in the Northwest & Nationally

Information calculated by Benton PUD staff from other utilities’ websites.

*Snohomish PUD has a monthly minimum bill in lieu of a monthly base charge. The monthly minimum bill is currently about $14.*

Rate Information Meeting - May 5, 2015
## Base Charges

**Staff Recommendation**

*Increase in base charge is included within the proposed 3.9% average revenue increase*

<table>
<thead>
<tr>
<th>Class</th>
<th>Existing</th>
<th>COSA(^1) Results</th>
<th>Recommendation</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Avg Monthly(^2)</td>
</tr>
<tr>
<td><strong>Residential</strong></td>
<td>$11.05</td>
<td>$19.40</td>
<td>$23.74</td>
</tr>
<tr>
<td><strong>Small General Service</strong></td>
<td>$11.95</td>
<td>$17.65</td>
<td>$24.70</td>
</tr>
<tr>
<td><strong>Medium General Service</strong></td>
<td>$17.55</td>
<td>$26.35</td>
<td>$106.96</td>
</tr>
<tr>
<td><strong>Large General Service</strong></td>
<td>$26.10</td>
<td></td>
<td>$111.70</td>
</tr>
<tr>
<td><strong>Large Industrial</strong></td>
<td>$0.00</td>
<td>$215.61</td>
<td></td>
</tr>
<tr>
<td><strong>Small Ag. Irrigation</strong></td>
<td>$6.74 per HP per Season</td>
<td>$32.58</td>
<td></td>
</tr>
<tr>
<td><strong>Large Ag. Irrigation w/o AFC</strong></td>
<td>N/A</td>
<td>$135.17</td>
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<tr>
<td><strong>Large Ag. w/AFC</strong></td>
<td>N/A - AFC</td>
<td>N/A - AFC</td>
<td>N/A - AFC</td>
</tr>
<tr>
<td><strong>Other Customer Classes</strong></td>
<td>N/A</td>
<td>Range: $19-$33</td>
<td></td>
</tr>
</tbody>
</table>

\(^1\) COSA - Cost of Service Analysis  
\(^2\) Calculated using a 30 day month
# Energy Charges (per kWh)

*Staff Recommendation*

<table>
<thead>
<tr>
<th>Class</th>
<th>Existing Apr 1 – Aug 31</th>
<th>Existing Sep 1 – Mar 31</th>
<th>Recommendation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>$0.0684</td>
<td>$0.0684</td>
<td>$0.0684</td>
</tr>
<tr>
<td>Small General Service</td>
<td>$0.0614</td>
<td>$0.0614</td>
<td>$0.0614</td>
</tr>
<tr>
<td>Medium General Service*</td>
<td>$0.0485</td>
<td>$0.0569</td>
<td>$0.0485/$0.0569</td>
</tr>
<tr>
<td>Large General Service*</td>
<td>$0.0389</td>
<td>$0.0465</td>
<td>$0.0392/$0.0469</td>
</tr>
<tr>
<td>Large Industrial*</td>
<td>$0.0331</td>
<td>$0.0392</td>
<td>$0.0366</td>
</tr>
<tr>
<td>Small Ag. Irrigation*</td>
<td>$0.0416</td>
<td>$0.0675</td>
<td>$0.0435/$0.0706</td>
</tr>
<tr>
<td>Large Ag. Irrigation w/o AFC**</td>
<td>$0.0414/$0.0362</td>
<td>$0.0517/$0.0439</td>
<td>$0.0420</td>
</tr>
<tr>
<td>Large Ag. w/AFC**</td>
<td>$0.0376/$0.0325</td>
<td>$0.0477/$0.0400</td>
<td>$0.0395</td>
</tr>
</tbody>
</table>

*Existing rate structure has seasonal components
**Existing rate structure has seasonal and time-of-use components
Cost of Service Analysis and Rate Recommendation
## Revenue Requirements

### By Customer Class

<table>
<thead>
<tr>
<th>Customer Class</th>
<th>Revenue Requirement(1)</th>
<th>Estimated 2015 Revenues with Current Rates(2)</th>
<th>Difference ($)</th>
<th>COSA Results Increase Needed (%) (3)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>$ 58,979,481</td>
<td>$ 54,234,989</td>
<td>$ 4,744,492</td>
<td>8.7%</td>
</tr>
<tr>
<td>General Service</td>
<td>32,419,939</td>
<td>34,003,341</td>
<td>(1,583,402)</td>
<td>-4.7%</td>
</tr>
<tr>
<td>Large Industrial</td>
<td>3,615,066</td>
<td>3,157,597</td>
<td>457,469</td>
<td>14.4%</td>
</tr>
<tr>
<td>Small Ag. Irrigation</td>
<td>1,024,531</td>
<td>952,378</td>
<td>72,153</td>
<td>7.6%</td>
</tr>
<tr>
<td>Large Ag. Irrigation w/o AFC</td>
<td>821,250</td>
<td>763,412</td>
<td>57,838</td>
<td>7.6%</td>
</tr>
<tr>
<td>Large Ag. w/AFC(3)</td>
<td>18,306,097</td>
<td>16,195,513</td>
<td>2,110,584</td>
<td>13.0%</td>
</tr>
<tr>
<td>Other Customer Classes</td>
<td>1,350,036</td>
<td>754,804</td>
<td>595,232</td>
<td>78.9%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$116,516,400</strong></td>
<td><strong>$110,062,034</strong></td>
<td><strong>$6,454,366</strong></td>
<td><strong>5.9%</strong></td>
</tr>
</tbody>
</table>

Note:

1. **Revenue requirement does not reflect application of reserves**
2. **Reflects low income allocation**
3. **Revenue requirement has been reduced for AFC revenue of $1,450,000**

---

Revenue shortfall
Bridging the Gap in 2015

- Revenue requirements  $116.5M
- Current rates  $110.0M
- Shortfall  $6.5M

- Revenue increase (3.9%)  $1.0M (partial year increase*)
- Use of reserves  $5.5M

*The transition from seasonal to flat rates in September 2015 for some customer classes will result in those customers receiving a new rate that is lower than the current rate for the last four months of 2015
## COSA Results and Proposed Rate Action

Proposed rate action utilizes a 7% cap and a 1% minimum for each rate class

<table>
<thead>
<tr>
<th>Customer Class</th>
<th>COSA Results Increase Needed(^{(1)}) (%)</th>
<th>Proposed Rate Action (%)</th>
<th>Equivalent of Annual Increase Jan 2012 to Sep 2015</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>8.7%</td>
<td>4.6%</td>
<td>1.2%</td>
</tr>
<tr>
<td>General Service</td>
<td>-4.7%</td>
<td>1.0%</td>
<td>0.3%</td>
</tr>
<tr>
<td>Large Industrial</td>
<td>14.4%</td>
<td>7.0%</td>
<td>1.9%</td>
</tr>
<tr>
<td>Small Ag. Irrigation</td>
<td>7.6%</td>
<td>3.4%</td>
<td>0.9%</td>
</tr>
<tr>
<td>Large Ag. Irrigation w/o AFC</td>
<td>7.6%</td>
<td>3.4%</td>
<td>0.9%</td>
</tr>
<tr>
<td>Large Ag. w/AFC(^{(2)})</td>
<td>13.0%</td>
<td>7.0%</td>
<td>1.9%</td>
</tr>
<tr>
<td>Other Customer Classes</td>
<td>78.9%</td>
<td>7.0%</td>
<td>1.9%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>5.9%</strong></td>
<td><strong>3.9%</strong></td>
<td><strong>1.1%</strong></td>
</tr>
</tbody>
</table>

Note:
1. Revenue requirement does not reflect application of reserves
2. Revenue requirement has been reduced for AFC revenue of $1,450,000
Other Proposed Changes: **Base Charge**

**Staff Recommendation**

1. **Increase the base charge for all customer classes** *(discussed previously)*

2. **Change to a Daily System Charge vs. Monthly Base Charge**
   - Simplifies billing of base charge when customers open or close accounts
   - Daily charge is conducive to a residential prepay program that Benton PUD plans to offer to customers in the future
   - Several other Northwest utilities utilize a daily rate

3. **Transition to one base charge rate per customer class**
   - Residential, Irrigation, Industrial
   - Some rate classes have single-phase and multi-phase rates
   - Having a single base charge simplifies our rate structure
Other Proposed Changes: **Seasonal and Time-of-Use Rates**

*Staff Recommendation*

1. **Transition to flat rates with no seasonality**
   - Irrigation and Industrial
   - District has some rate classes with seasonal rates
     - Only 16% of benchmarked utilities have General Service seasonal rates
   - Currently, no price signal from BPA
     - Existing BPA contract terms not conducive to seasonal rates
     - Existing seasonal rates incentivize consumption during the District’s highest demand period - contrary to the purpose of seasonal rates

2. **Eliminate time-of-use (TOU) rates**
   - Irrigation
   - Existing TOU rate differential is small (≈$0.006 per kWh)
   - Small number of customers currently have TOU rates
   - Currently, no price signal from BPA
Other Changes: **Low Income Discount Program**

*Drivers for Change*

- Benton PUD has a history of updating the discount program to reflect customer needs
- **Stakeholder Panel input regarding discount program:**
  - Program viewed as a community-wide obligation; thus allocate costs to all customer classes
  - Current program costs allocated to residential rate class only
- **Benchmarked with other utilities**
  - Reviewed program costs and structures
  - Utilities program costs ranged from 0.2% to 2.4% of Residential revenue
Low Income Discount Program

Revised Program

• Program changes implemented January 2015
  o Increased discount for lowest income qualified customers to 25%
  o Added new layer of discount (10%) for qualified customers up to 225% of federal poverty level
  o Allocate costs of program to all rate classes

• Targeted annual amount - $500K
  o Program costs in 2014 - $361K (0.7% of residential revenue)
    • About 1,500 customers received discounts
Summary of Staff Recommendations

1. **Average increase of 3.9% effective September 1, 2015**
   - Use reserves to “buy down” rate increase from 5.9%
   - Impacts customer classes differently
   - Customer class increases capped at 7% with a 1% minimum

2. **Increase to customer base charge (included in 3.9% average)**
   - Included in the overall rate increase for each customer class
     - For residential, small and medium general service, base charge increase is the entire increase
   - Gradually begin to better align fixed rate components with fixed costs

3. **Transition to flat rates with no seasonality or time-of-use**
   - Certain rate classes

4. **Expand and increase the low income discount program**
   - Implemented January 1, 2015
Key Dates

• May 5, 2015
  o Customer meetings – 8am and 6pm

• Upcoming Commission meetings – public comment available
  o May 12, 2015
  o May 26, 2015
  o June 9, 2015

• June 9, 2015
  o Customer feedback requested

• June 23, 2015
  o Commission meeting – final staff rate recommendation and Commission action requested

• September 1, 2015
  o Effective date of retail rate changes
Financial Reserves:  
*Year-end 2014 Example*

**Days Cash on Hand**

- **90 Day Minimum DCOH**: 90 days
- **Power Market Volatility**: 12 days
- **Bond Insurance Replacement**: 11 days
- **Customer Deposits**: 4 days
- **Special Capital Fund**: 19 days

**Total DCOH: 136 Days**

- **Funds set aside for day-to-day operations & emergencies ($32.1M)**
- **Funds set aside to smooth out or lower rate actions ($4.3M)**
- **Funds set aside for bond insurance when policies expire in 2015 & 2021 ($4.0M)**
- **Funds set aside for customer deposits ($1.4M)**
- **Funds set aside for future capital ($6.7M)**

---

Rate Information Meeting - May 5, 2015
Transmission & Substation Capital Requirements Plan

115,000 volt Transmission Line Additions

115-12.47 kV Substation Upgrades/Additions
Transmission & Substation Capital Requirements Plan

Rate Information Meeting - May 5, 2015
Transmission & Substation
Capital Requirements Plan

<table>
<thead>
<tr>
<th>Project Description</th>
<th>Project</th>
<th>Comments</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>2019 or later</th>
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</thead>
<tbody>
<tr>
<td>Urban Area</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Upgrades and Improvements</td>
<td>U1</td>
<td>Substation Circuit Switchers, switchgear, relays/controls</td>
<td>1,075,000</td>
<td>1,040,000</td>
<td>985,000</td>
<td>250,000</td>
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<tr>
<td>Power Xfmr - LTC spare - Vista #2</td>
<td>U2</td>
<td>Substation Replace existing unit to create a backup</td>
<td></td>
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<tr>
<td>Power Xfmr - Non LTC spare (Lead/Lag) - Phillips #4</td>
<td>U3</td>
<td>Substation Phillips Unit will become backup</td>
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<tr>
<td>Southridge Substation</td>
<td>U4</td>
<td>Substation Including BPA Transmission Interconnection</td>
<td>3,000,000</td>
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<td></td>
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<tr>
<td>Badger Road Substation Transmission Line</td>
<td>U5</td>
<td>115-kV Transmission Line - 6 miles</td>
<td>1,200,000</td>
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<tr>
<td>Badger Road Substation</td>
<td>U6</td>
<td>Substation addition for Badger Canyon/Dallas Road</td>
<td>2,200,000</td>
<td></td>
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<tr>
<td>Benton City Substation Upgrade</td>
<td>U7</td>
<td>Substation Circuit Switcher, Power Xfmr w/ Reg, Relays</td>
<td>1,300,000</td>
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<tr>
<td>Clodfelter Substation</td>
<td>U8</td>
<td>Substation Including BPA Transmission Interconnection</td>
<td>3,000,000</td>
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<td></td>
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<tr>
<td>Hedges Substation Upgrade</td>
<td>U9</td>
<td>Substation Ckt Swr, Pwr Xfmr, Relays</td>
<td>1,100,000</td>
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<tr>
<td>Benton REA Matbon-Prosser Intertie</td>
<td>U10</td>
<td>115-kV Transmission Line - 10.2 miles ($2.4M split 50/50)</td>
<td>1,200,000</td>
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<tr>
<td>Transmission &amp; Substation - Urban</td>
<td>TOTAL</td>
<td></td>
<td>$1,075,000</td>
<td>$4,040,000</td>
<td>$2,185,000</td>
<td>$3,750,000</td>
<td>$5,300,000</td>
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<tr>
<td>South County Farms</td>
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<tr>
<td>Power Xfmr - River spare - Location TBD</td>
<td>F1</td>
<td>Substation Replace existing unit to create a backup</td>
<td>59,000</td>
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<tr>
<td>115-kV Switches Additions and Structure Upgrades</td>
<td>F2</td>
<td>115-kV Switches, Replace Poles/Davit Arms</td>
<td>136,674</td>
<td>210,000</td>
<td>160,000</td>
<td>160,000</td>
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<tr>
<td>Upgrades and improvements</td>
<td>F3</td>
<td>Substation Capacitor banks, ground fault detection</td>
<td>440,000</td>
<td>385,000</td>
<td>205,000</td>
<td>25,000</td>
<td>-</td>
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<tr>
<td>Prior #4-Sunheaven #2 397.5 ACSR</td>
<td>F4</td>
<td>115-kV Transmission Line - 8.5 Miles</td>
<td>148,750</td>
<td>1,633,250</td>
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<tr>
<td>Phillips-Spaw 397.5 ACSR</td>
<td>F5</td>
<td>115-kV Transmission Line - 15.8 Miles</td>
<td>2,456,900</td>
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<td>Kickitat PUD Intertie</td>
<td>F6</td>
<td>115-kV Transmission Line - 17 miles ($3.5M split 50/50)</td>
<td>1,750,000</td>
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<tr>
<td>Prior #4-H2F#4 397.5 ACSR</td>
<td>F7</td>
<td>115-kV Transmission Line - Phase 1: 5 Miles</td>
<td>1,000,000</td>
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<td></td>
<td></td>
<td></td>
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<tr>
<td>Sunheaven/Prior Substation</td>
<td>F8</td>
<td>Substation for reliability (TRIP)</td>
<td>2,000,000</td>
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<tr>
<td>Prior #4-H2F#4 397.5 ACSR</td>
<td>F9</td>
<td>115-kV Transmission Line - Phase 2: 10 Miles</td>
<td>1,332,500</td>
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<tr>
<td>Finley Road Substation</td>
<td>F10</td>
<td>Substation for reliability (TRIP)</td>
<td>2,000,000</td>
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<td>Beck Road Switchyard Interties</td>
<td>F11</td>
<td>115-kV Transmission Line - 18.3 Miles</td>
<td>2,850,000</td>
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<tr>
<td>Transmission &amp; Substation - Farms</td>
<td>TOTAL</td>
<td></td>
<td>$784,424</td>
<td>$2,228,250</td>
<td>$4,571,900</td>
<td>$3,185,000</td>
<td>$6,182,500</td>
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<tr>
<td>Total Transmission and Substations</td>
<td></td>
<td></td>
<td>$1,859,424</td>
<td>$6,268,250</td>
<td>$6,756,900</td>
<td>$6,935,000</td>
<td>$11,482,500</td>
</tr>
</tbody>
</table>

Note: Capital plan is not a factor in the proposed 2015 revenue increase
Questions / Comments