1

Benton PUD Rate Information

August 21, 2019

Staff Preliminary Recommendation

BENTON P·U·D

Reliable Public Power Provider

Agenda

1. Overview	Chad Bartram
2. Net Power Costs & Reserves	Jon Meyer
3. Questions/Comments	
4. Financial Metrics	Jon Meyer
5. Cost of Service Analysis (COSA)	Tony Georgis
6. Questions/Comments (Short Break)	
7. Power Market Volatility	Rick Dunn
8. Questions/Comments	

Staff Proposal

- 2.9% average revenue increase effective October 1, 2019
  - Applied "across-the-board" to all rate classes (except unmetered)
- Applied evenly to all rate components
  - Base charge, kilowatt-hour charge, demand charge, etc.
- Remove seasonal rates from Medium/Large General Service
    - Effective January 1, 2020
- Last increase was two years ago: October 2017 (1.9%)

Key Driver – Power Costs

- Bonneville Power Administration (BPA) Contract
  - Costs heading up
    - BPA rate increase October 1, 2019
  - Generation heading down
    - Warmer weather impacting timing of run-off
    - Court-ordered spill
- Energy Independence Act
  - Must buy 15% of retail load from qualifying renewables
    - Wind, solar, and biomass (hydro not a qualifying renewable)
  - Up from 9%
- BPUD total power costs up $10.6 million in 2019
  - Water year significantly below average (less generation)
  - February/March weather event & price excursion

Staff preliminary recommendation. Commission decision expected September 10, 2019.

Average Retail Rates[1] per kWh

APPA[2] 2017 Report on Average Revenue (Cents per kWh)

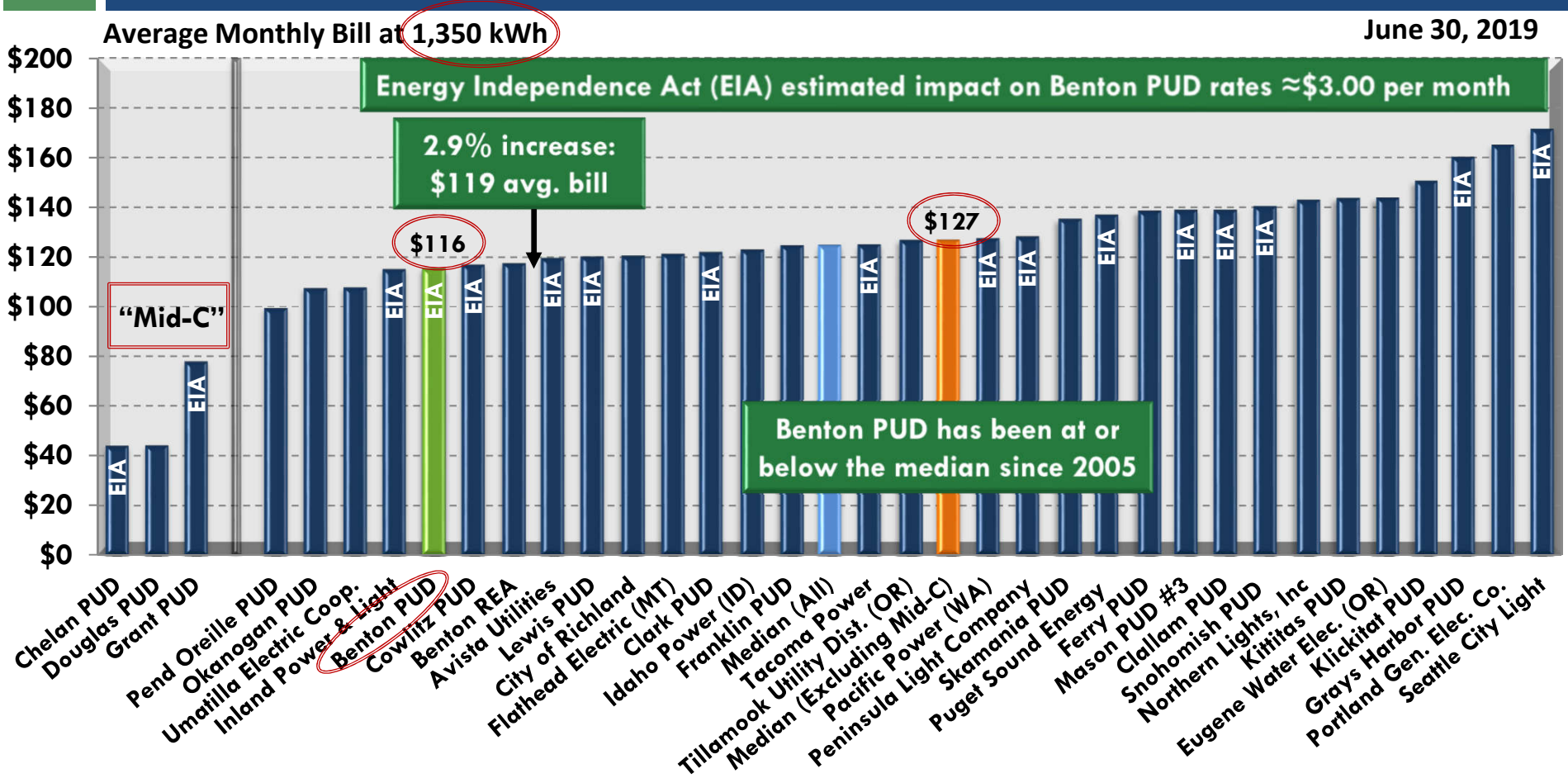
	Residential	Commercial	Industrial	Total
Benton PUD	8.3	6.7	5.3	7.0
WA Publicly Owned	8.9	7.8	5.0	7.4
WA Investor Owned	10.8	9.8	7.8	10.1
WA Cooperatives	8.9	7.8	6.3	8.1
National Average	12.9	10.7	6.9	10.5
California	18.3	15.8	12.7	16.1

[1] ***Revenues - includes all charges to customer***

[2] ***American Public Power Association***

Monthly Bill Comparison

Residential



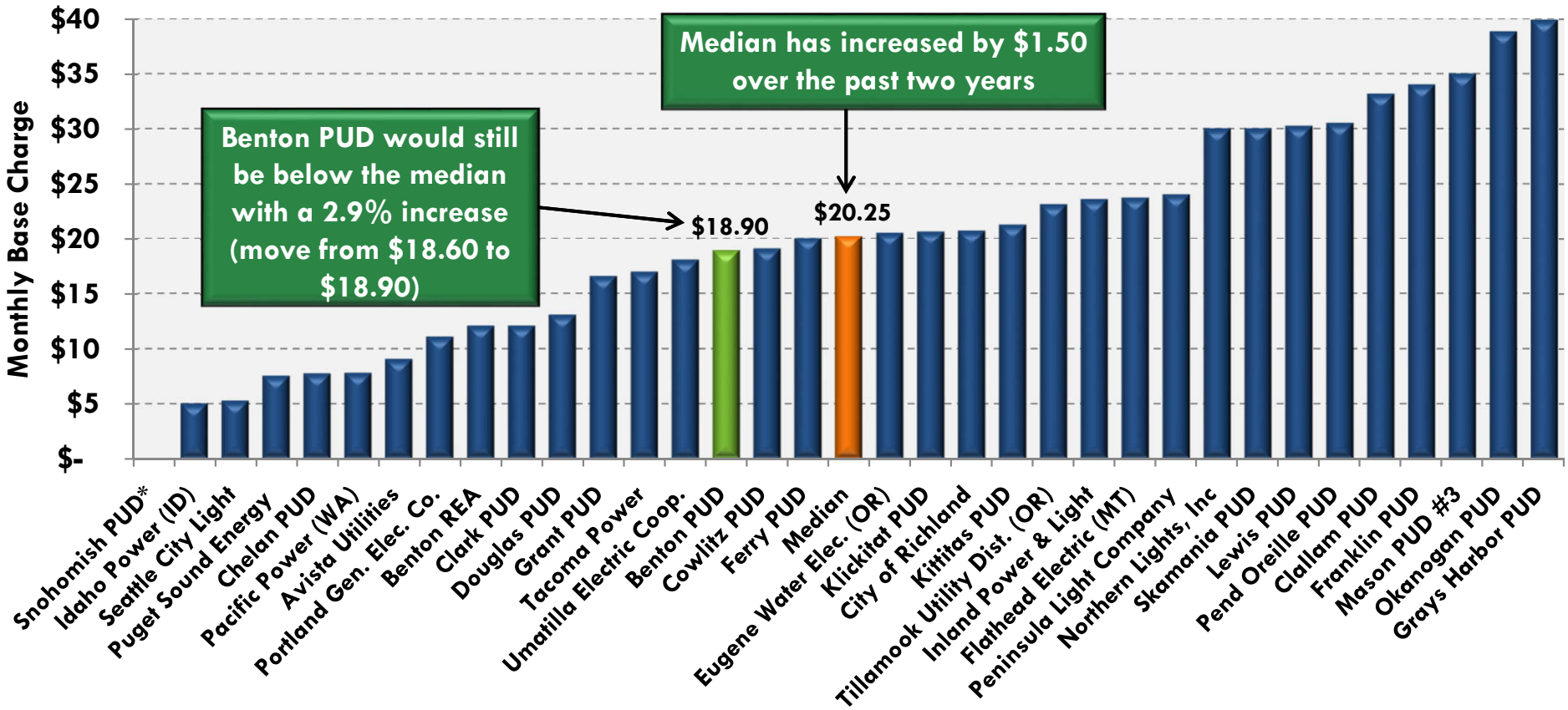
Average bill information has been calculated by Benton PUD staff from publicly available information from other utilities' websites. Calculation is Benton PUD's best effort to provide comparable information.

Staff preliminary recommendation. Commission decision expected September 10, 2019.

Residential Base Charge Comparison with Potential Increase

Details of all rate components are included at the end of your handout

As of June 30, 2019



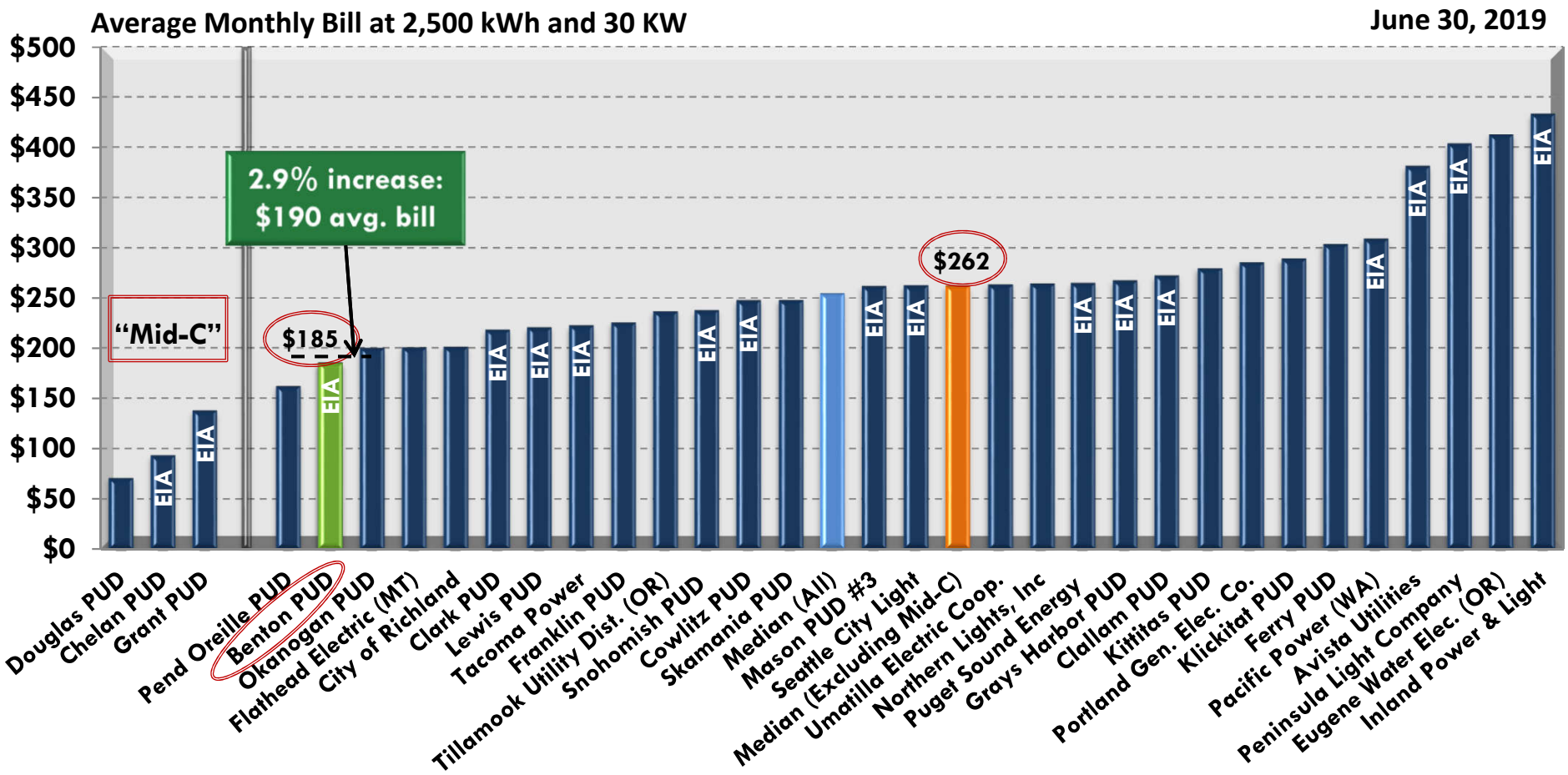
*Snohomish PUD has a monthly minimum bill in lieu of a monthly base charge. The monthly minimum bill is currently $0.53 per day or ~$15.90 per month.

Base Charge information has been calculated by Benton PUD staff from publicly available information from other utilities' websites. Calculation is Benton PUD's best effort to provide comparable information.

Staff preliminary recommendation. Commission decision expected September 10, 2019.

Monthly Bill Comparison

Small General Service



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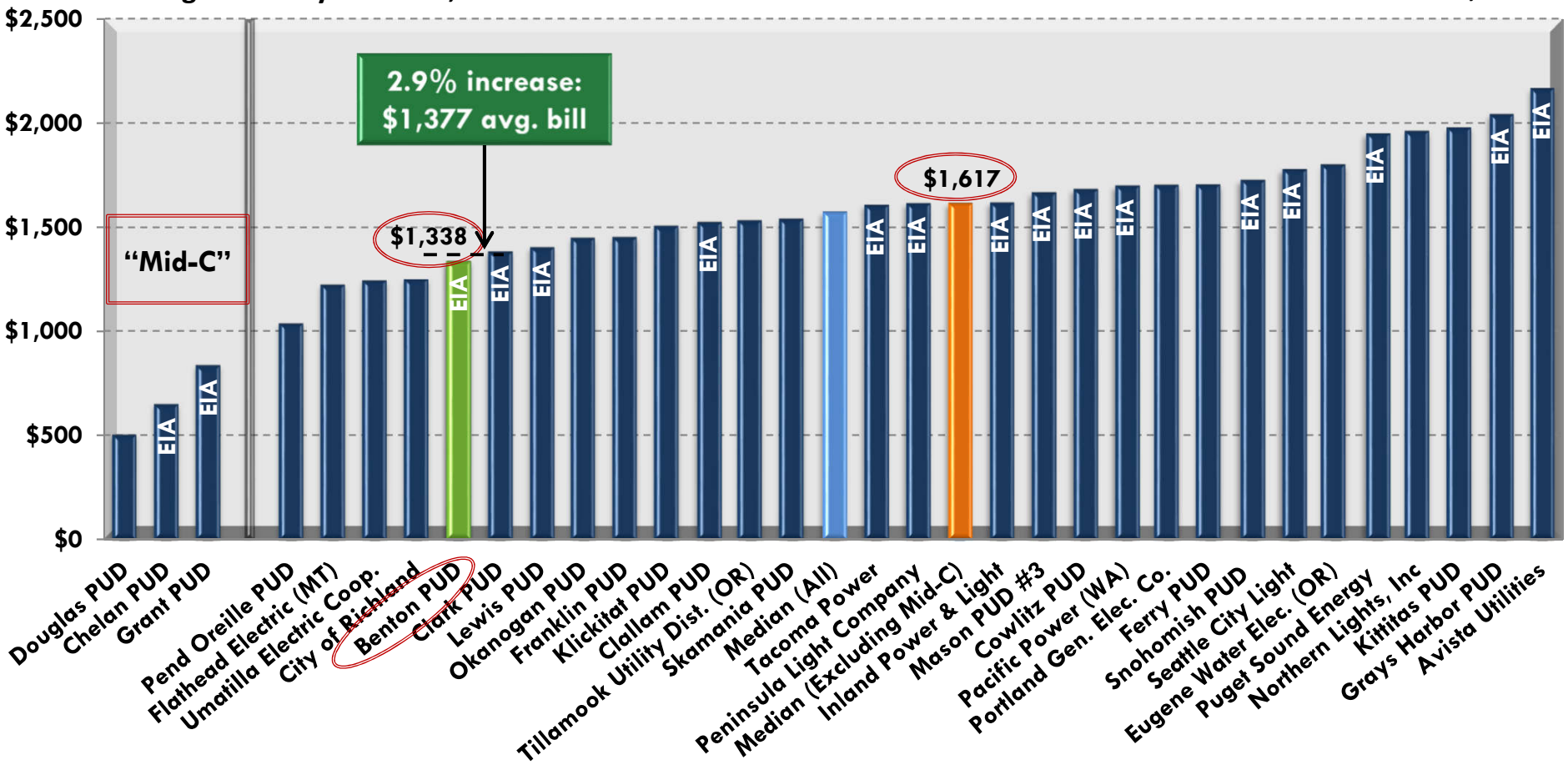
Staff preliminary recommendation. Commission decision expected September 10, 2019.

Monthly Bill Comparison

Medium General Service

Average Monthly Bill at 19,000 kWh and 75 KW **June 30, 2019**



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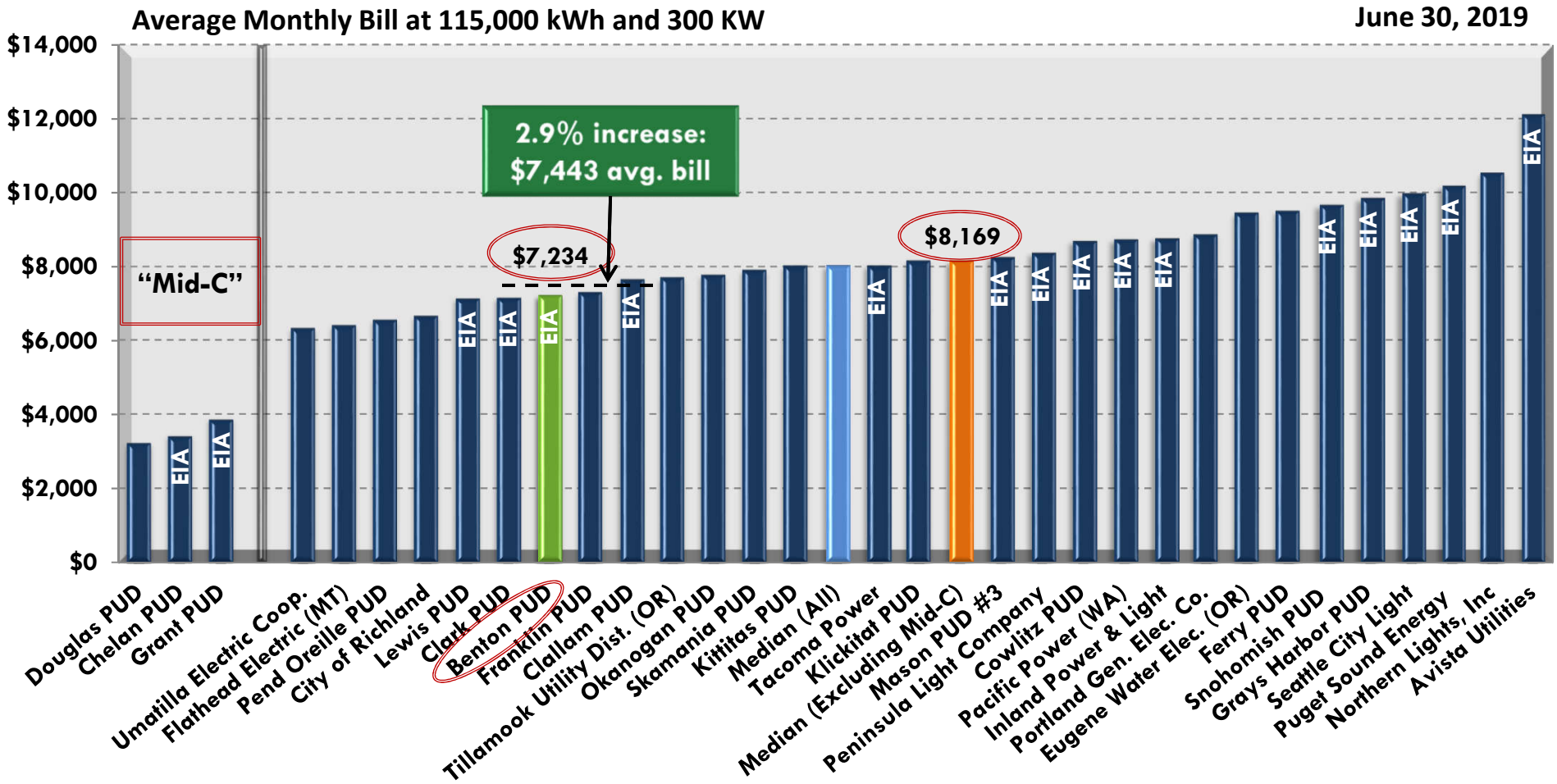
Staff preliminary recommendation. Commission decision expected September 10, 2019.

Monthly Bill Comparison

Large General Service



Average bill information has been calculated by Benton PUD staff from publicly available information from other utilities' websites. Calculation is Benton PUD's best effort to provide comparable information.

Staff preliminary recommendation. Commission decision expected September 10, 2019.

Low Income Programs

- Low Income Discount - $603 thousand
  - Assisted 1,900 customers per month (average) in 2018
  - Discounts range from 10% to 25% of monthly bill
  - Discount is greater of daily system charge or percentage of billed charges
  - Available to senior and disabled customers/members of household
  - Extended to Veterans/Active Military effective March 2019
- BPUD Low Income Energy Efficiency - $180 thousand
  - Assisted 44 households in 2018
  - Administered by BPUD and Community Action Committee
- Helping Hands (customer donations) - $48 thousand
  - Assisted 334 households in 2018

Staff preliminary recommendation. Commission decision expected September 10, 2019.

Net Power Costs & Reserves

Overview

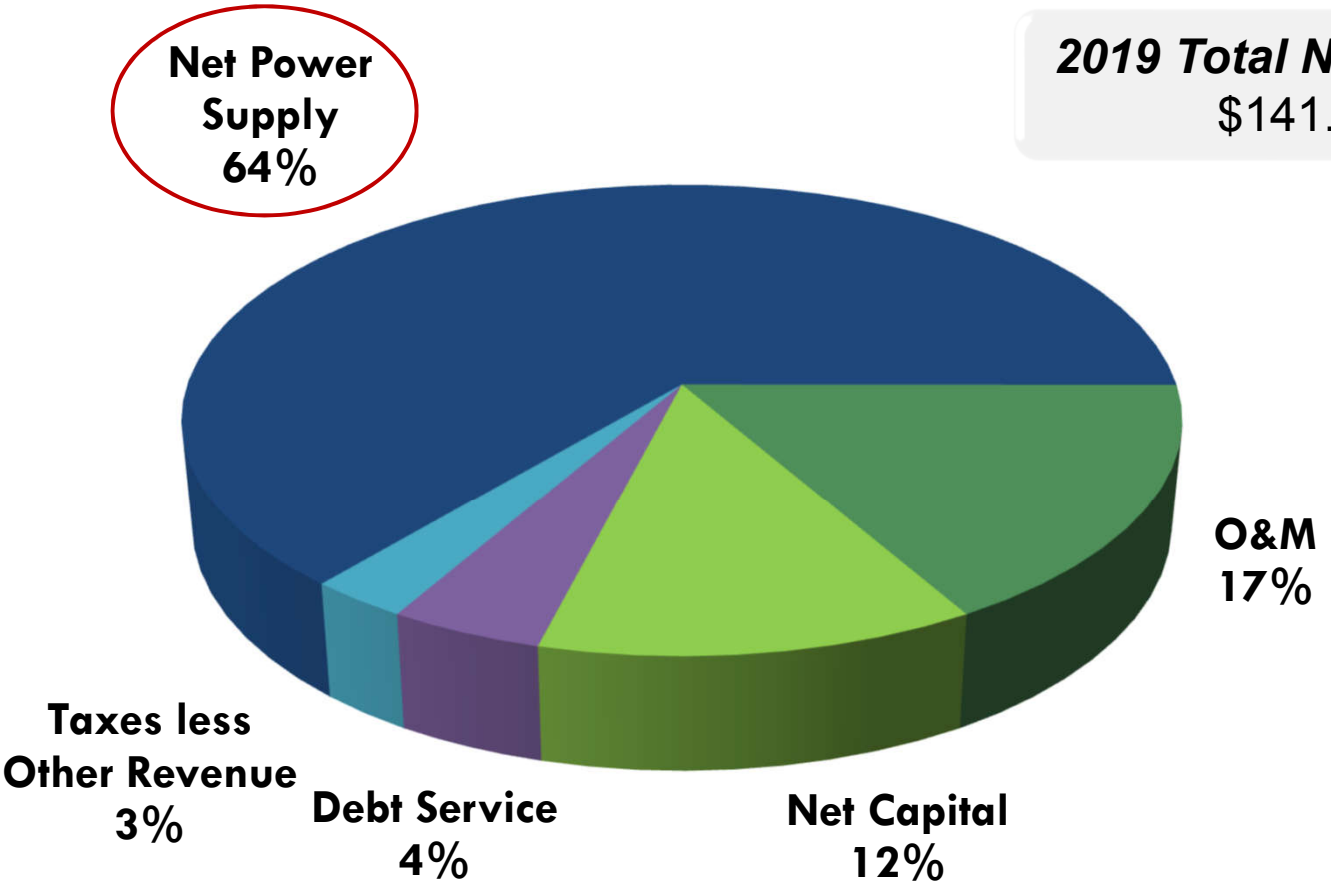
- The District plans conservatively
  - Power costs budgeted at 25th percentile using statistical modeling
  - Typically, actual results are better than planned three out of four years
  - Reserves (cash) generated in good years used to defer/mitigate rate actions in subsequent years
- Last several rate increases did not keep up with rising power costs
  - Reserves were used to fill the gap
- The District budgeted a draw down of reserves $8.5M in 2019
- 2019 has been a challenging year (more later)
  - Draw down of reserves now forecasted to be $12.6M[1]
- Rate increase necessary to keep up with net power costs

[1] Does not include potential changes in timing of completion of major capital projects sooner than originally planned.

2019 Costs

Expenditures by Major Category

2019 Total Net Expenditures
$141.9 million*



** Amount needed to collect through electric rates*

Staff preliminary recommendation. Commission decision expected September 10, 2019.

Net Power Costs vs. Retail Rate Increases

Line	Annual Change	2013	2014	2015	2016	2017	2018
1	Net Power Cost ($ increase in millions)	$6.4	$1.9	$3.4	$1.3	$2.4	$(0.8)
2	Net Power Cost (% increase)	9.8%	2.6%	4.6%	1.7%	3.1%	(1.0)%
3	Retail Revenue Increase (%)	0.0%	0.0%	3.9%	4.9%	1.9%	0.0%

Line	Cumulative Change since 2012	2013	2014	2015	2016	2017	2018
1	Net Power Cost ($ increase in millions)	$6.4	$8.3	$11.7	$13.0	$15.4	$14.6
2	Net Power Cost (% increase)	9.8%	12.7%	17.9%	19.8%	23.5%	22.3%
3	Retail Revenue Increase (%)	0.0%	0.0%	3.9%	9.0%	11.1%	11.1%

- For illustrative purposes only

  22.3% net power cost increase

  x 60% power cost percentage of total costs*

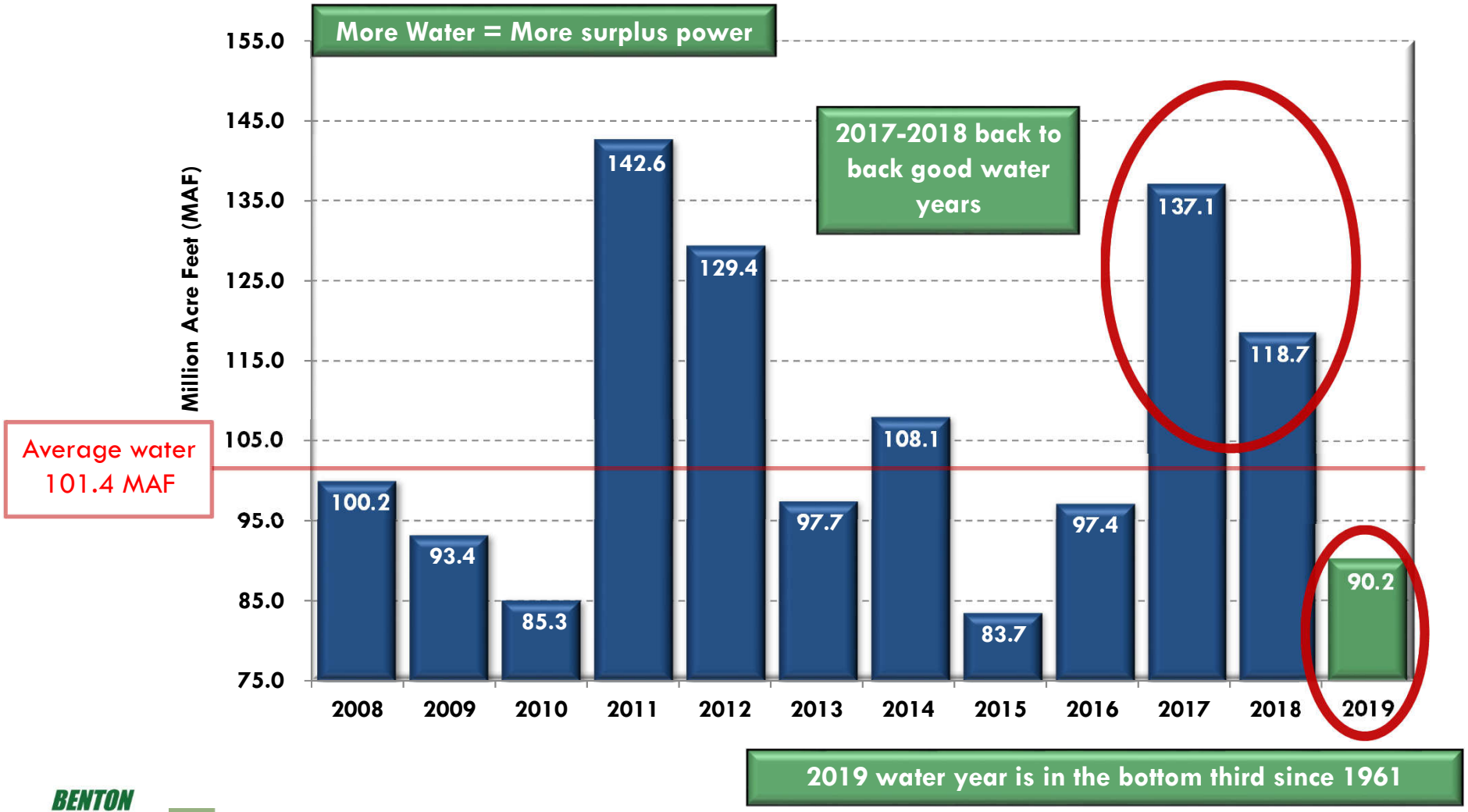
  13.4% equivalent retail rate impact (approximation only)

* *Costs or revenue requirement*

Staff preliminary recommendation. Commission decision expected September 10, 2019.

Water Volume by Year

January thru July Runoff at The Dalles Dam



Staff preliminary recommendation. Commission decision expected September 10, 2019.

Variables Impacting Net Power Costs

- BPA cost increases and generation decreases
- Energy Independence Act 2020
- Power market volatility

Staff preliminary recommendation. Commission decision expected September 10, 2019.

BPA Costs Increases

2020 Adopted Rates

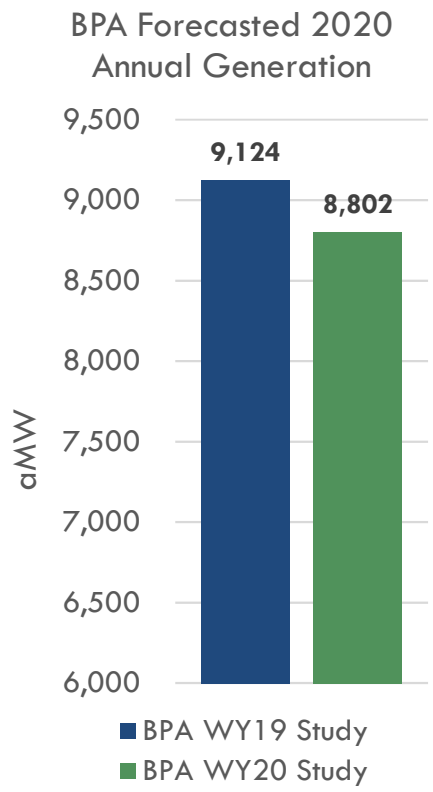
BPA Power & Transmission	
Description	BP-20
Power – Base	0.0%
Power – FRP* Surcharge	1.5%
Transmission	3.6%
As applied to Benton PUD	
Annual $ Increase	$0.8M
Annual % Increase	1.2%

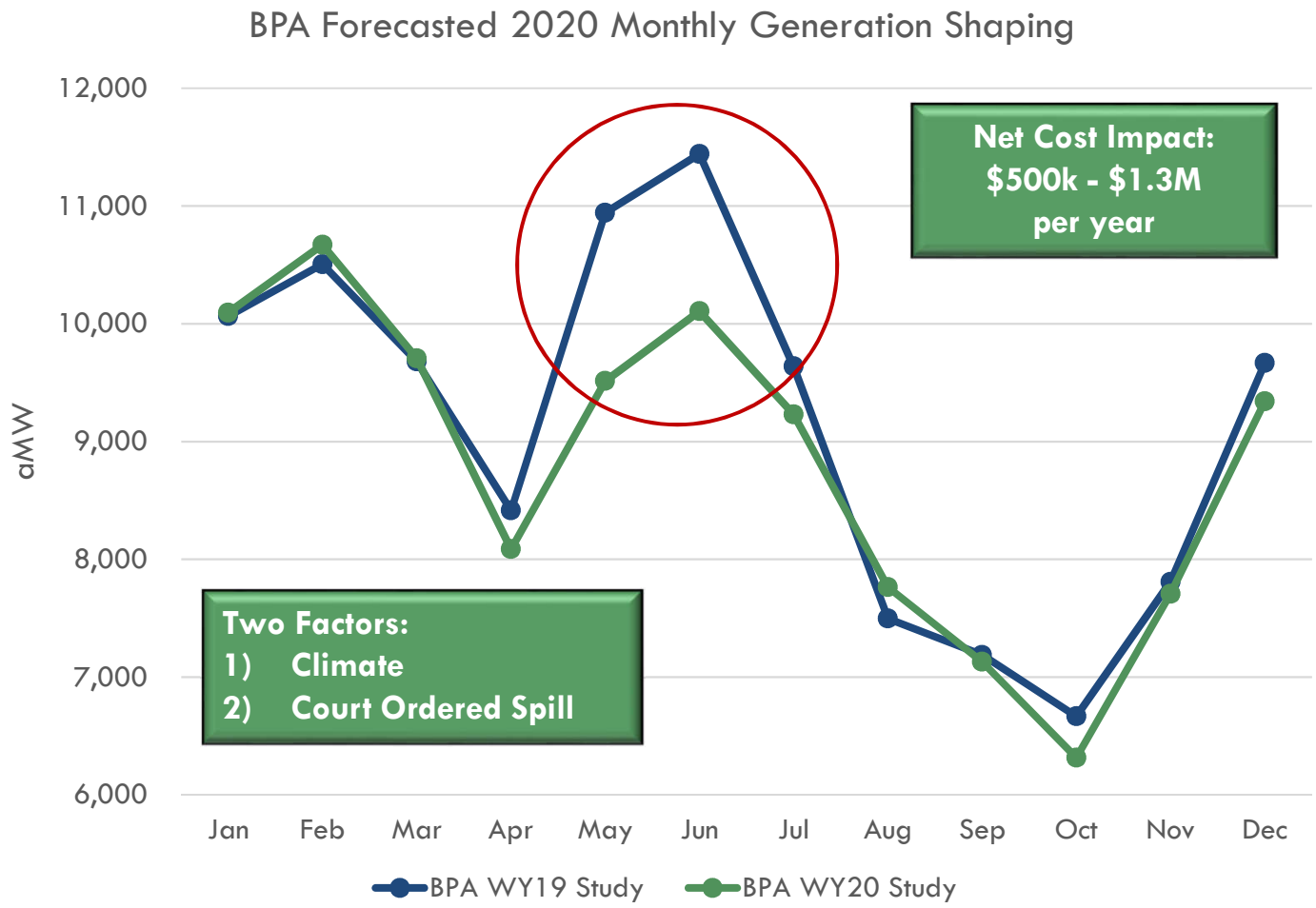
*Financial Reserve Policy

Staff preliminary recommendation. Commission decision expected September 10, 2019.

BPA Generation Decreases

Benton PUD receives a "slice" or 1.37% of this generation





Net Cost Impact: $500k - $1.3M per year

Two Factors:
1) **Climate**
2) **Court Ordered Spill**

Staff preliminary recommendation. Commission decision expected September 10, 2019.

Energy Independence Act (EIA)

2020 Renewable Energy Requirement

- **EIA applicable to utilities with more than 25,000 customers**
  - Currently, 17 utilities in the state subject to the EIA
  - Benton PUD is the only local utility fully 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 $2.6M annually to meet the 9% EIA requirement
  - Rising to $3.2M in 2020 to meet the 15% EIA requirement

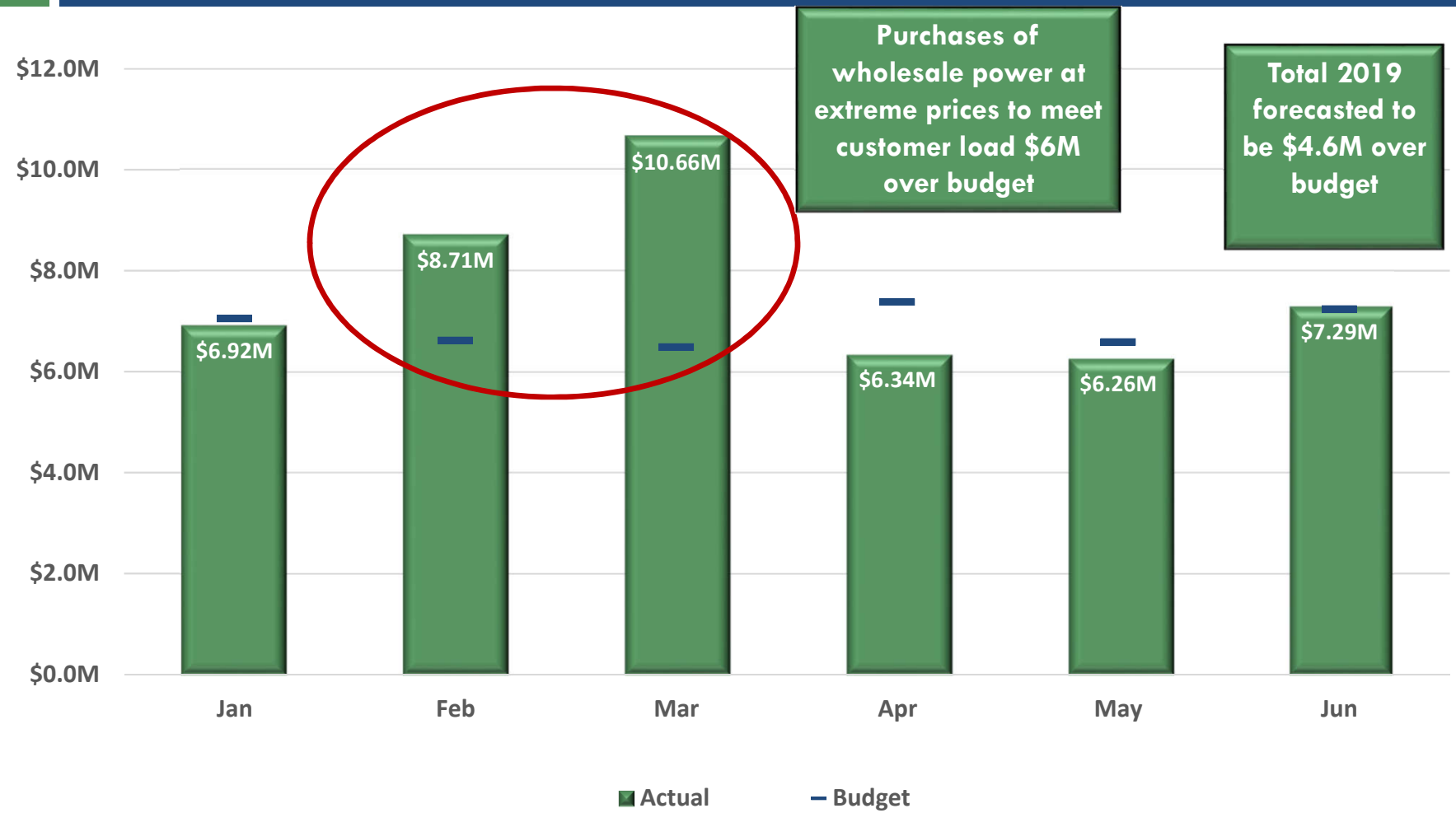
Staff preliminary recommendation. Commission decision expected September 10, 2019.

Power Market Volatility

- The District buys and sells power in the power market
  - Typically a net seller
- Low prices reduce surplus sales revenues
- High prices increase purchased power cost
- Major Event - Feb/Mar 2019
  - Customer loads significantly higher than projected
  - Market prices significantly higher than expected
  - Effects of event felt throughout the Northwest (including BPA)

Power Market Volatility

2019 Net Power Cost Monthly Actual vs Budget



Staff preliminary recommendation. Commission decision expected September 10, 2019.

Power Market Volatility

Net Power Cost History and Projection

Primary cost drivers since 2007
- BPA increases every two years
- Lower surplus power sales
- Energy Independence Act (EIA)

Forecast: August 2019

Significant Uncertainty

2019 Budget: $86.1M

Primary cost drivers - future
- BPA increases every two years
- Less stable wholesale market

Better

$ Millions

$100.0, $95.0, $90.0, $85.0, $80.0, $75.0, $70.0, $65.0, $60.0, $55.0, $50.0, $45.0, $40.0

2007: $49.7
2008: $48.8
2009: $46.7
2010: $59.5
2011: $60.4
2012: $65.5
2013: $71.9
2014: $73.8
2015: $77.2
2016: $78.5
2017: $80.9
2018: $80.1
2019: $90.7
2020: $81.5
2021: $80.9
2022: $81.6
2023: $84.0

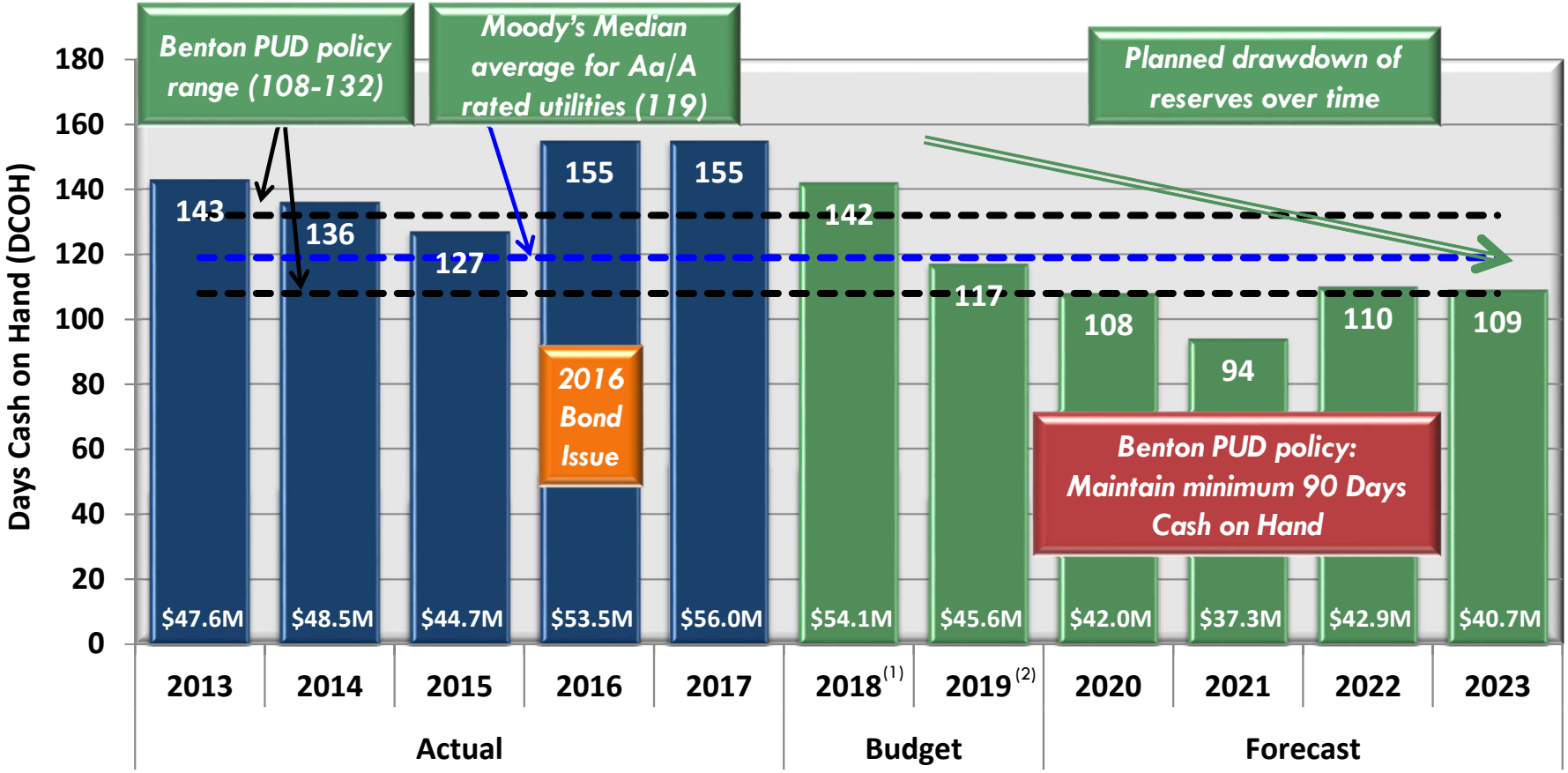
Actual · Forecast

(1) Net power costs (NPC) = gross power costs (including power and transmission) less secondary market sales.

Staff preliminary recommendation. Commission decision expected September 10, 2019.

Reserves - Days Cash on Hand

Historical and 2019 Original Forecast



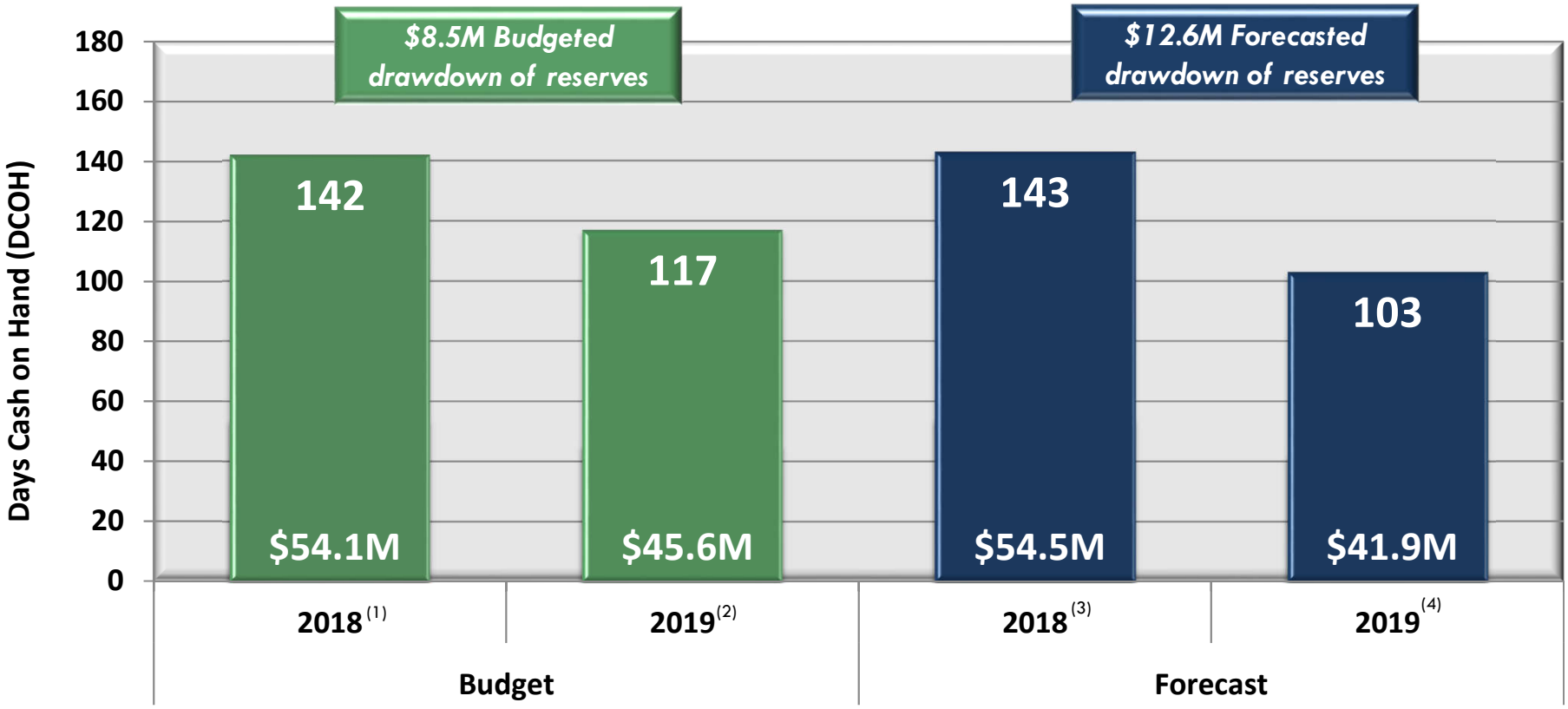
1. Estimated ending balance
2. Budget included a proposed 2.4% increase effective May 1, 2019

Source - *Moody's Investors Service Public Power Electric Utility Medians and Methodology, September 2016*

Staff preliminary recommendation. Commission decision expected September 10, 2019.

Reserves - Days Cash on Hand

Budget vs Latest Forecast



1. *Estimated ending balance*
2. *Budget included a proposed 2.4% increase effective May 1, 2019*
3. *Actual ending balance $56.3M less $1.8M timing (revenue received in 2018 for a 2019 capital project and 2018 expenses paid in 2019)*
4. *Forecast includes a proposed 2.9% increase effective October 1, 2019. Does not include potential changes in timing of capital projects*

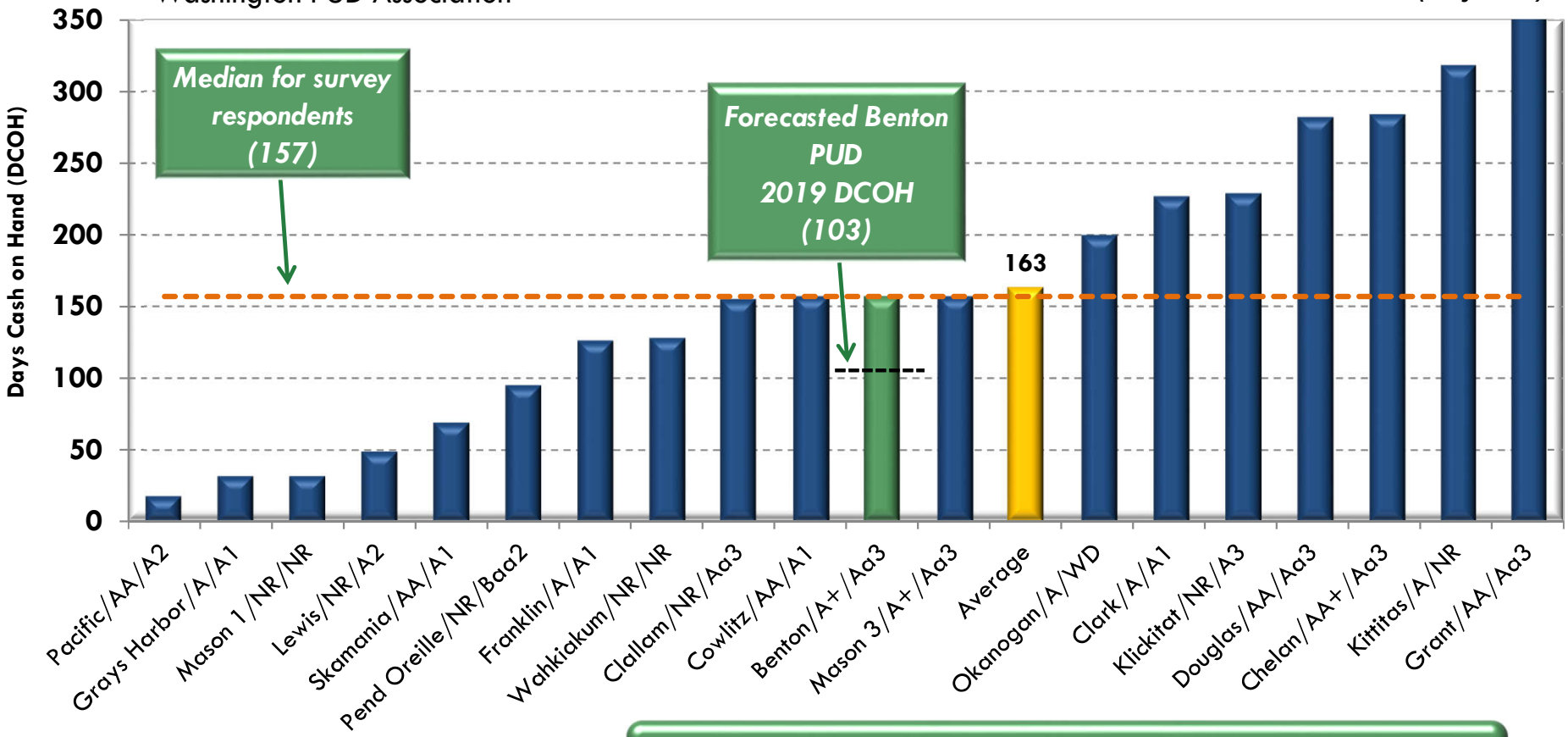
Staff preliminary recommendation. Commission decision expected September 10, 2019.

Days Cash on Hand (Reserves)

WPUDA[1] Survey – December 2017 (Distribution Systems Only)

[1]Washington PUD Association

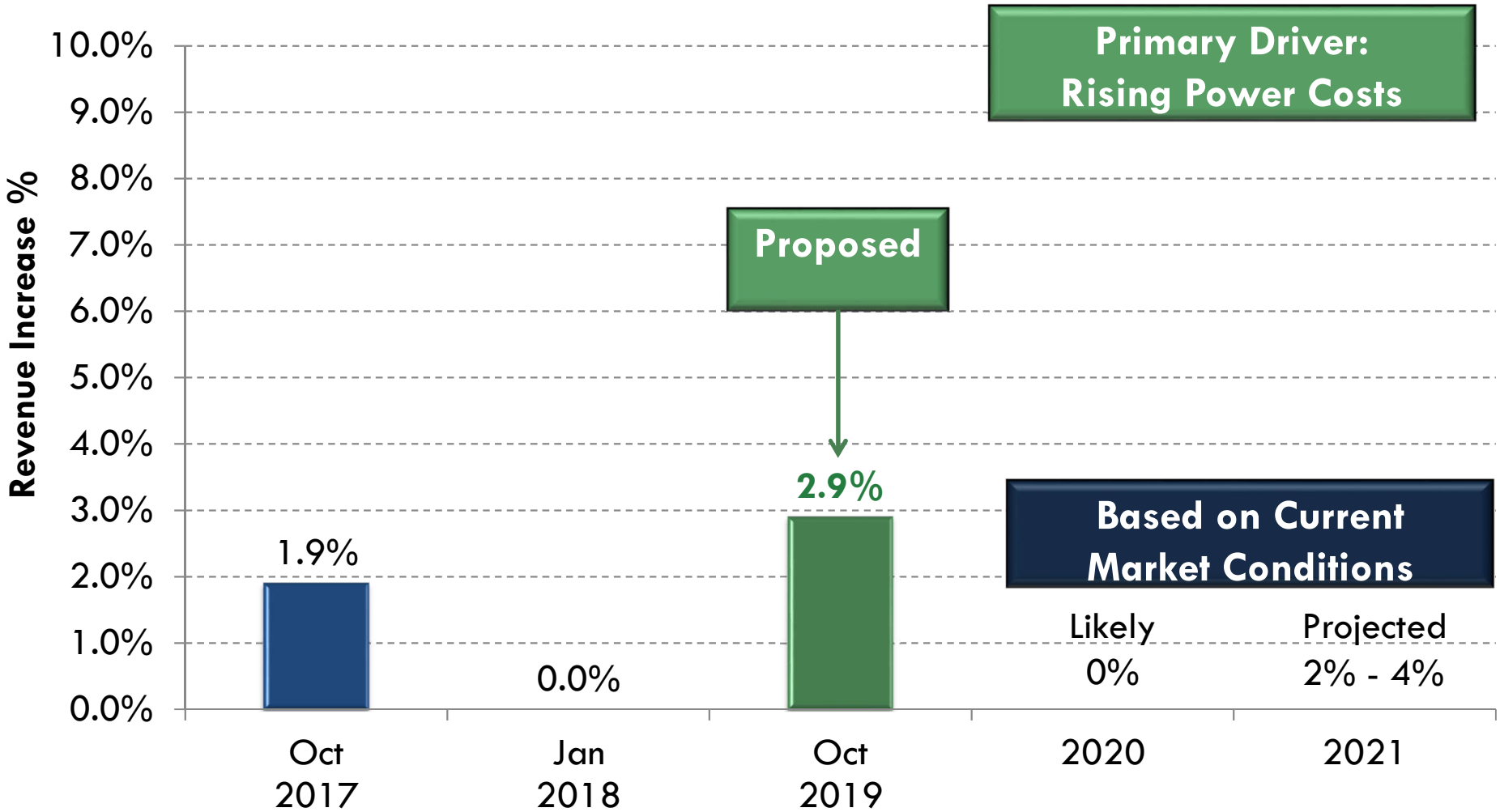
Source: WPUDA Source Book (July 2018)



Measures the number of days utility can cover its operating expenses using unrestricted reserves and assuming no additional revenue

Staff preliminary recommendation. Commission decision expected September 10, 2019.

Projected Revenue Increases



Staff preliminary recommendation. Commission decision expected September 10, 2019.

Pause for Questions / Comments

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RP3 Reliable Public Power Provider

Financial Metrics

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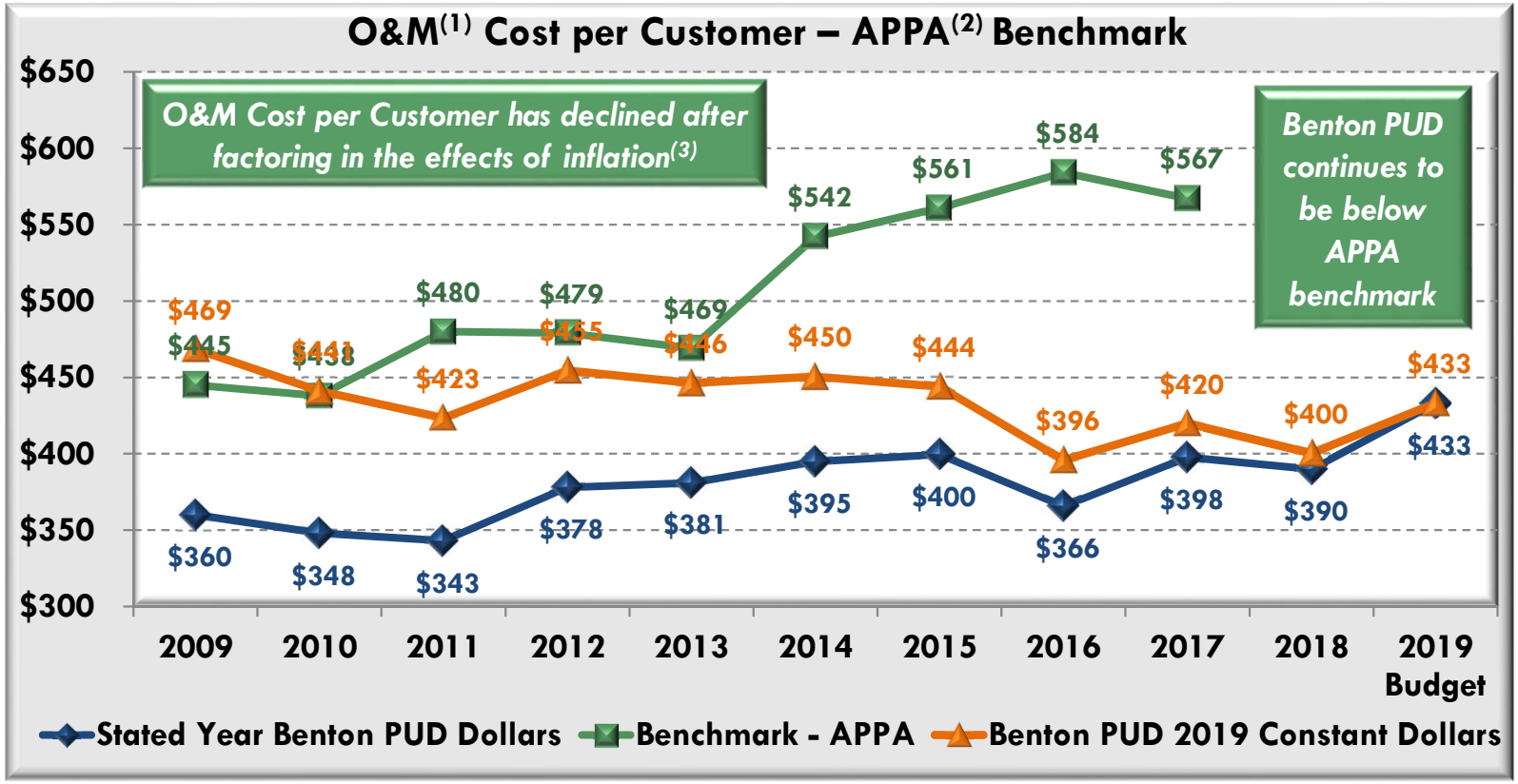
RP3 Reliable Public Power Provider

Operations and Maintenance (O&M)

APPA[2] Survey – 2017 Median for West utilities



(1) O&M = non-power operations & maintenance cost (distribution, transmission, customer accounts, and administrative and general). Excludes Broadband.

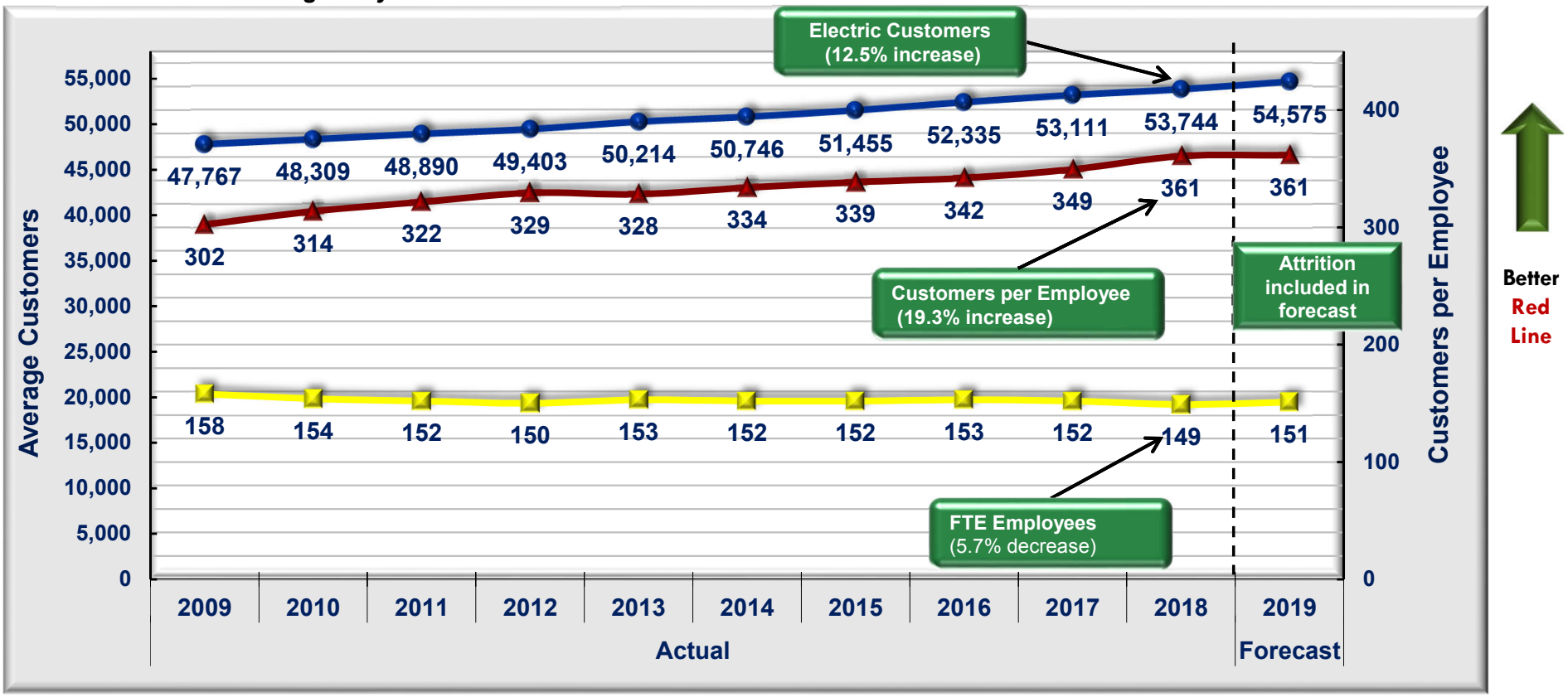
(2) American Public Power Association - 2017 median for West utilities.

(3) Inflation rate utilized comes from a producer price index for electric utilities, which on average has been slightly under 3%

Staff preliminary recommendation. Commission decision expected September 10, 2019.

Customers per District Employee

Actual annual average for years 2009-2018



Definition of Customer per American Public Power Association

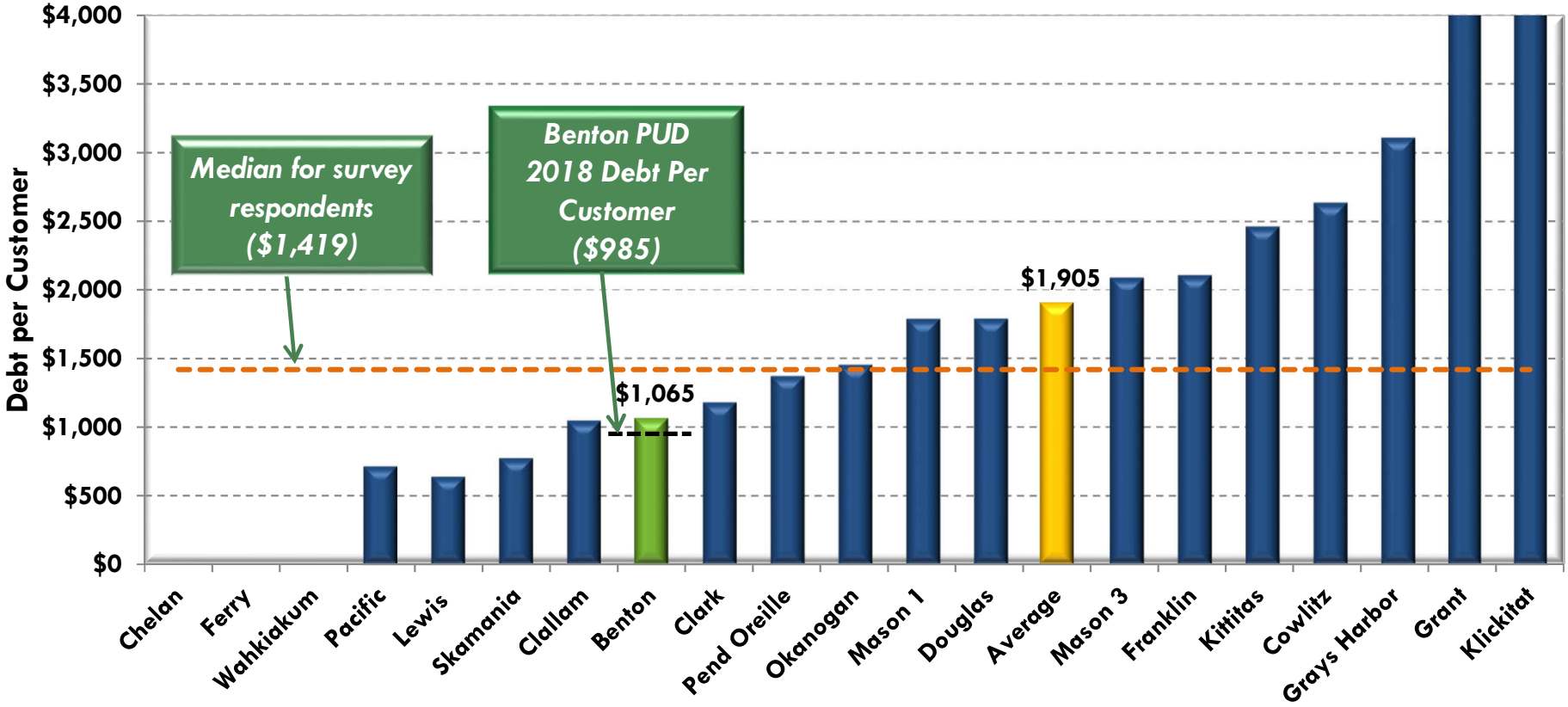
Staff preliminary recommendation. Commission decision expected September 10, 2019.

Debt Per Customer

WPUDA[1] Survey – December 2017 (Distribution Systems Only)

[1]Washington PUD Association

Source: WPUDA Source Book (July 2018)



District below the median and average of Washington PUDs

Staff preliminary recommendation. Commission decision expected September 10, 2019.

Credit Ratings History

Independent Credit Rating Agencies

Date	Moody's	S & P	Fitch
July 2019(1)	Aa3	A+ (affirmed)	AA-
May 2019(2)	Aa3	A+	AA- upgrade
Sept 2016(3)	Aa3	A+	A+
July 2010	Aa3	A+	A+
Feb 2010	A2	A+	A
Oct 2009	A2	A	A
Sept 2006	A3	A-	A-
March 2005	A3	A-	A-
Sept 2004	A3	BBB+ Positive	A- Stable
Oct 2003	A3	BBB+ Stable	BBB+ Positive
Nov 2002	A3	BBB Neg.	-
Nov 2001	A3	A- Stable	-
Number of rating levels we have improved since Nov. 2002:			
	3	4	4

2019 S&P/Fitch Reports:

- Low Rates
- Low Debt
- Solid Reserves
- Strong Economy

(1) S&P affirmed District's A+ rating
(2) Fitch upgraded the District's rating to AA- from A+
(3) Moody's, S&P, and Fitch ratings affirmed with the 2016 series bond issue

Cost of Service

Overview of Rate Making Process

Financial Forecast
Multi-year financial forecast to project total utility costs and initial revenue requirement for average rate impacts.

Test Year Revenue Requirement
Total costs and allocations to customers to be recovered through the COSA process and rate making.

Cost of Service Analysis
Unbundling, classification and allocation of Revenue Requirement to be recovered from customer classes

Rate Design
Use the cost of service results and Rate Strategy to guide rate design. Rates should fully recover all costs not funded by reserves and/or debt.

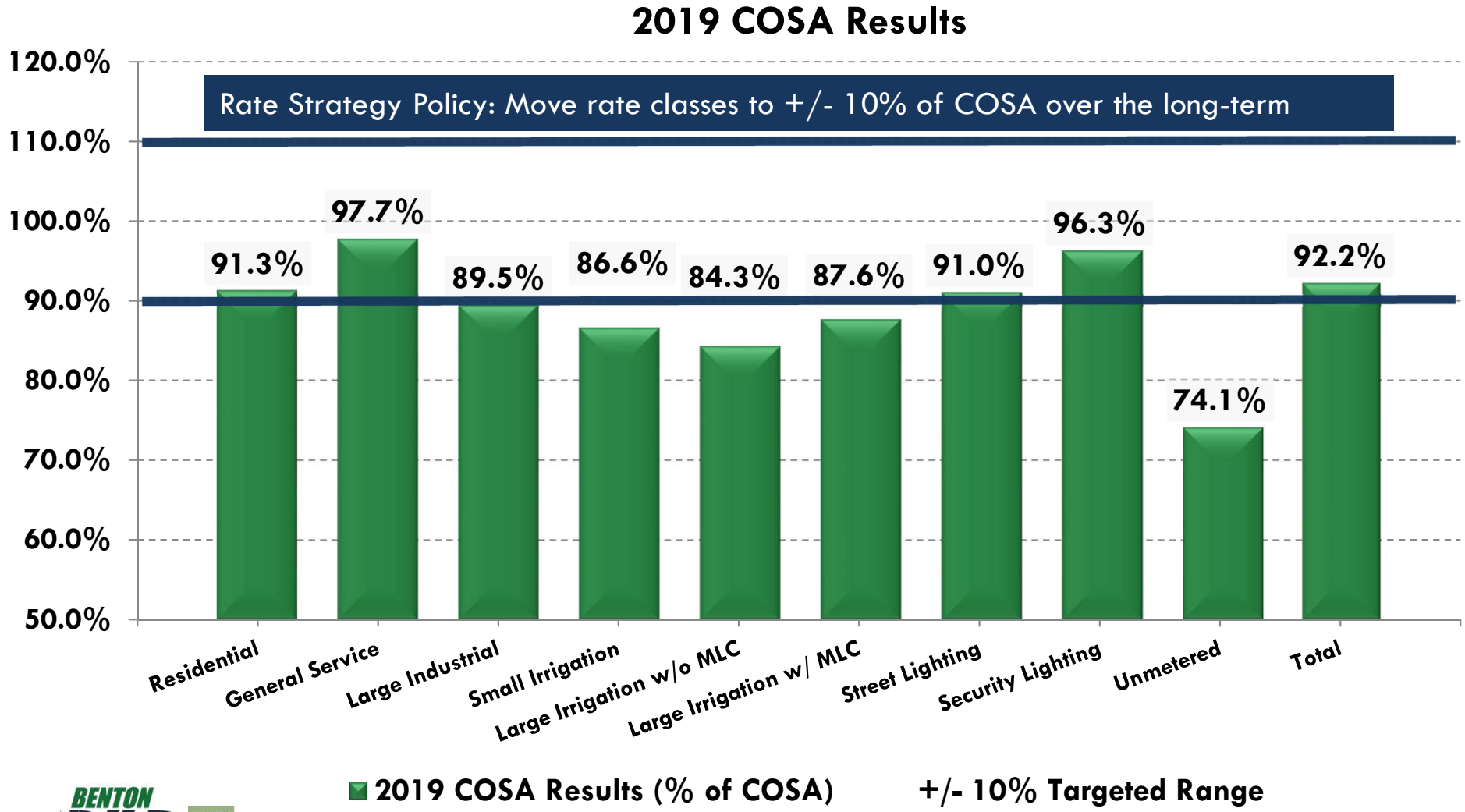
Staff preliminary recommendation. Commission decision expected September 10, 2019.

COSA Model Components

COSA vs. Rate Making

- COSA is a quantitative tool to guide setting rates for each class
- COSA results for each class can vary from year-to-year
- Policy goals/decisions can influence how rates are set
- Benchmarking rates is another tool to guide rate setting

2019 COSA Results Comparison to Target



Staff preliminary recommendation. Commission decision expected September 10, 2019.

Summary and Next Steps

- Staff proposal: 2.9% average revenue increase
  - Key Driver: Power Costs
  - Applied across the board to all rate classes (except unmetered)
  - Applied evenly to all rate components
- Draft rates presented to Commission at August 27 meeting
- Consider adoption of new rates at September 10 meeting
  - New rates would be effective October 1, 2019

Pause for Questions / Comments

Then 5 Minute Break

BENTON P·U·D

RP3 Reliable Public Power Provider

Power Market Volatility

Maintaining Grid Reliability and Affordability in a Clean Energy Era

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Reliable Public Power Provider

Agenda

- Benton PUD Power Supply Portfolio
- Northwest Power Market Capacity Concerns
- Washington State's100% Clean Legislation

Benton PUD

Power Supply Portfolio

Staff preliminary recommendation. Commission decision expected September 10, 2019.

Generation Resources

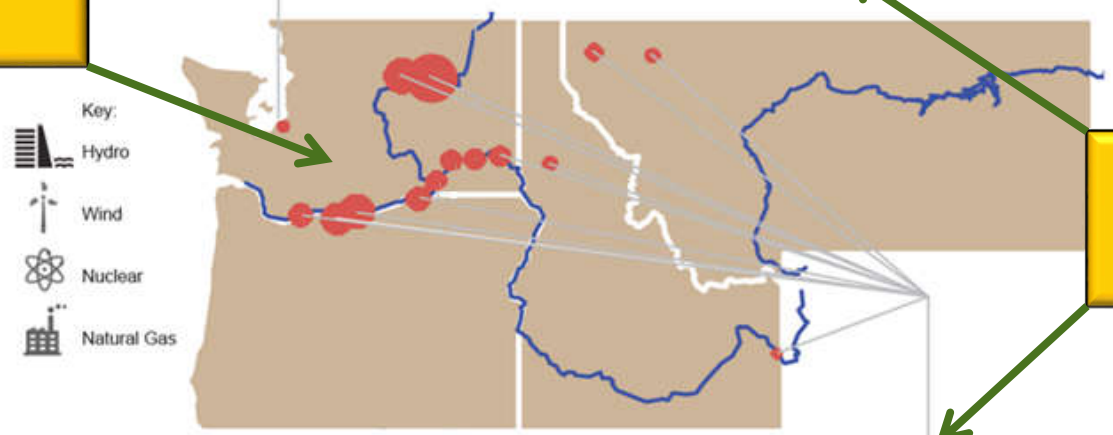
Natural Gas CCCT
50 MW
Dispatched as Needed

FREDERICKSON
Capacity 250MW
In Service 2002
Decommissioning 2022

COLUMBIA GENERATING STATION
Capacity 1100MW
In Service 1984
Decommissioning 2050

BPUD Load
430 MW Peak
210 aMW

Small Hydroelectric
3.7 MW
0.92 aMW



BPA Slice/Block Contract
2.85% of FCRPS
198 aMW

WHITE CREEK
Capacity 205MW
In Service 2007

NINE CANYON
Capacity 96MW
In Service 2007

FEDERAL COLUMBIA RIVER POWER SYSTEM DAMS
Capacity 22,000+ MW
In Service: Various, beginning 1936

Wind Power
18 MW
5.4 aMW

NET POWER COST ANNUAL BUDGET
$80 TO $90 MILLION

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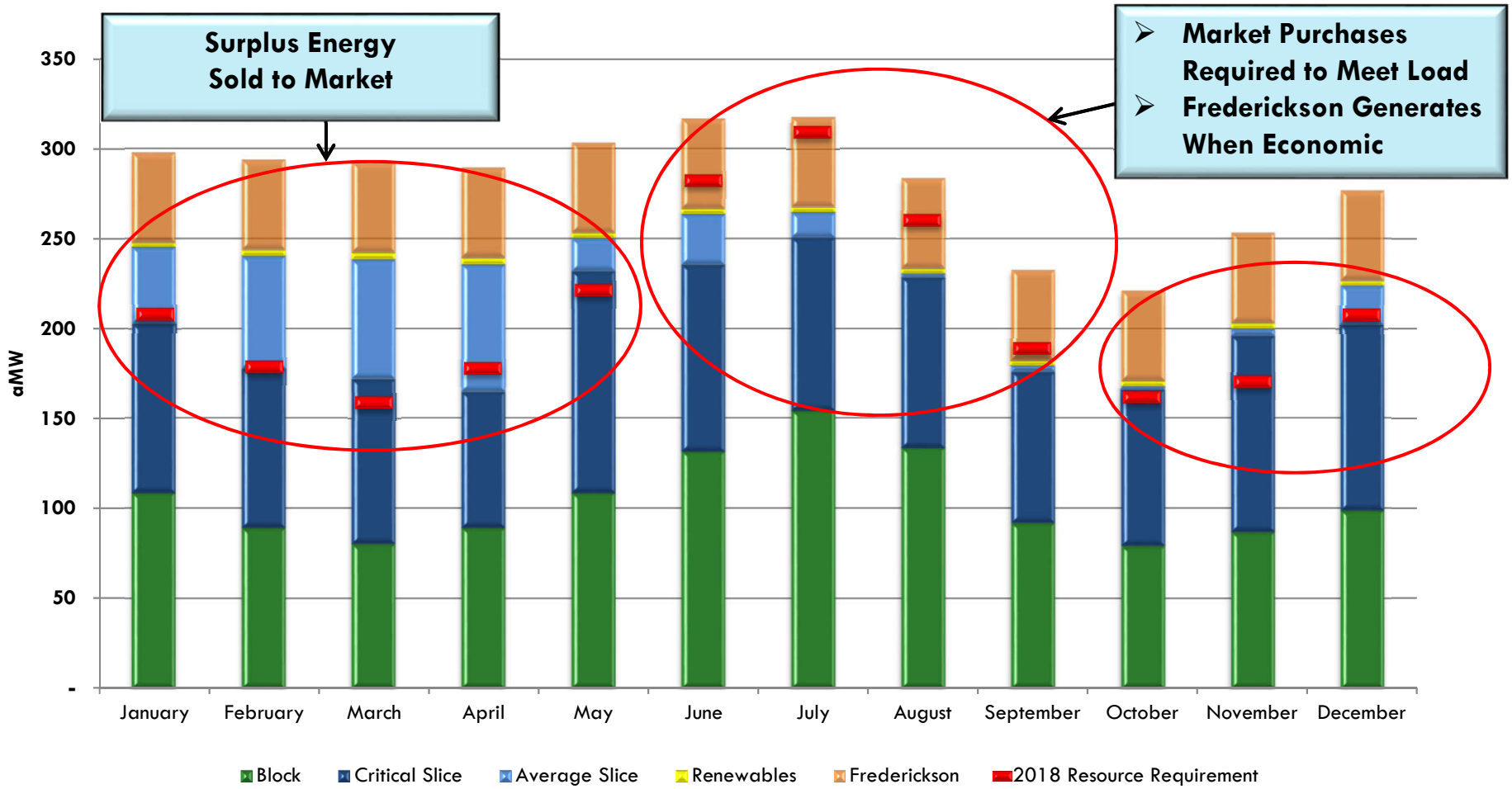
Reliable Public Power Provider

Load/Resource Balance

2018 Block and Critical/Average Slice

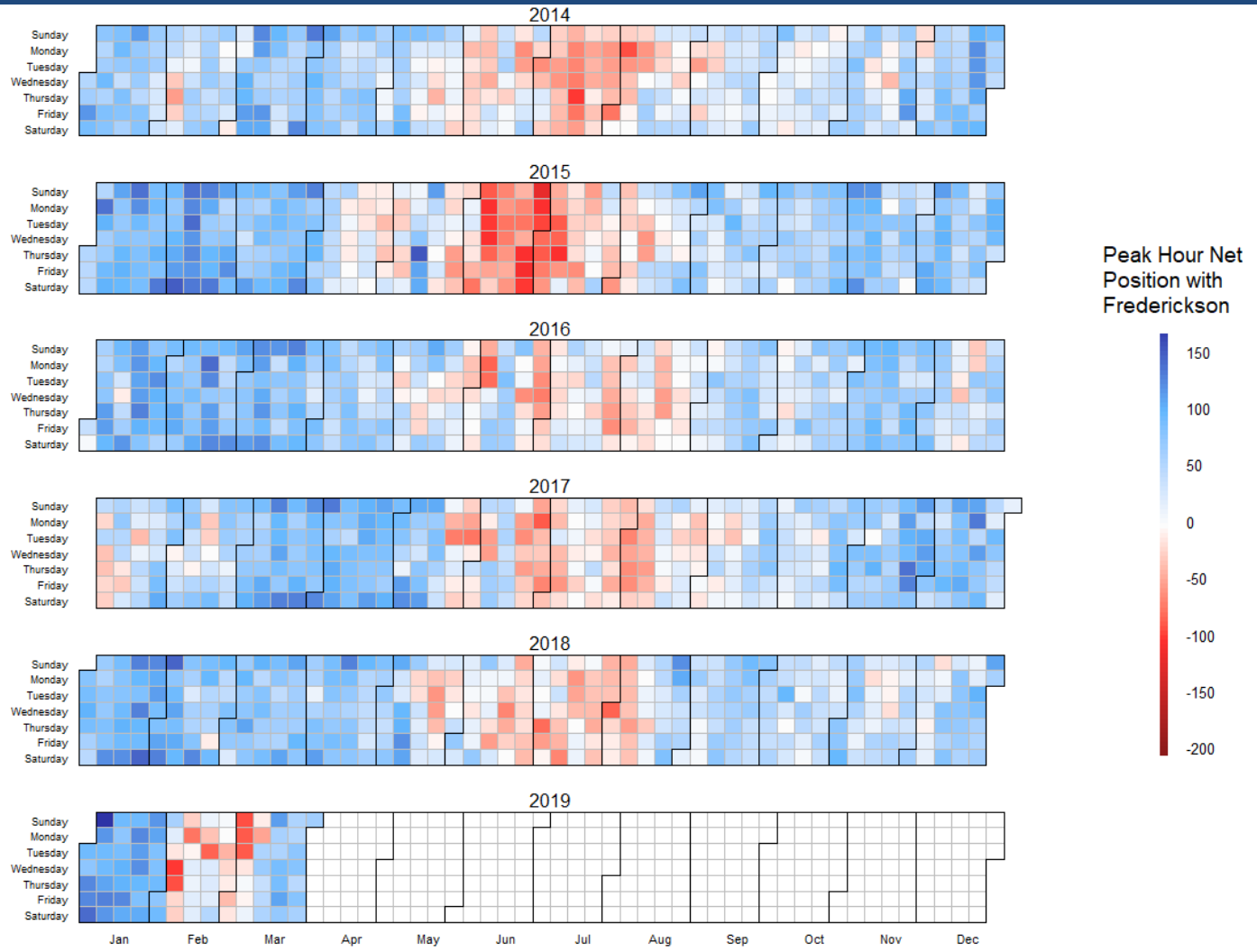


Block/Slice Generation observed over the last 3 years
Frederickson available as energy call option through August 2022

Staff preliminary recommendation. Commission decision expected September 10, 2019.

Peak Hour Net Position

with Frederickson



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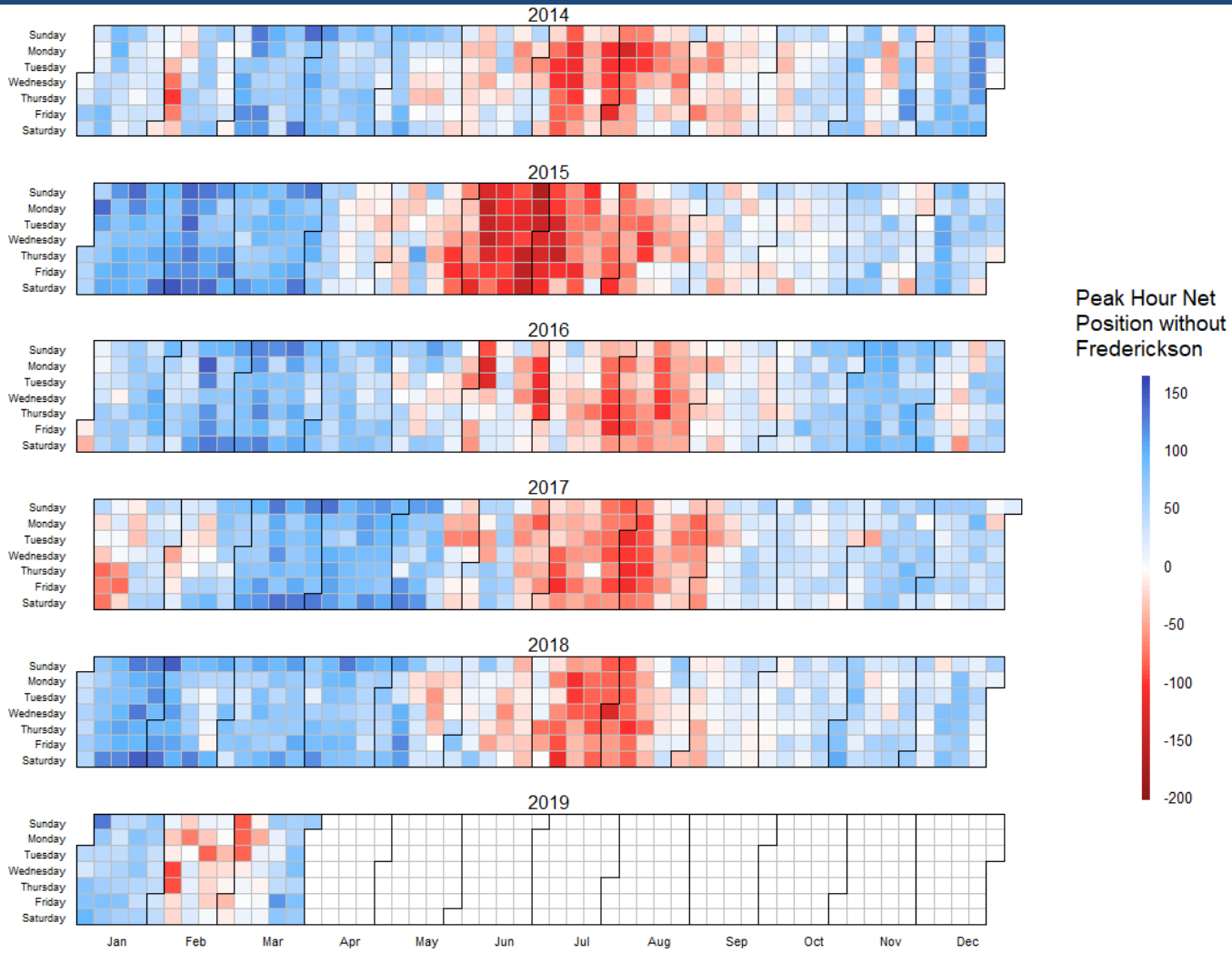
Peak Hour Net Position

without Frederickson



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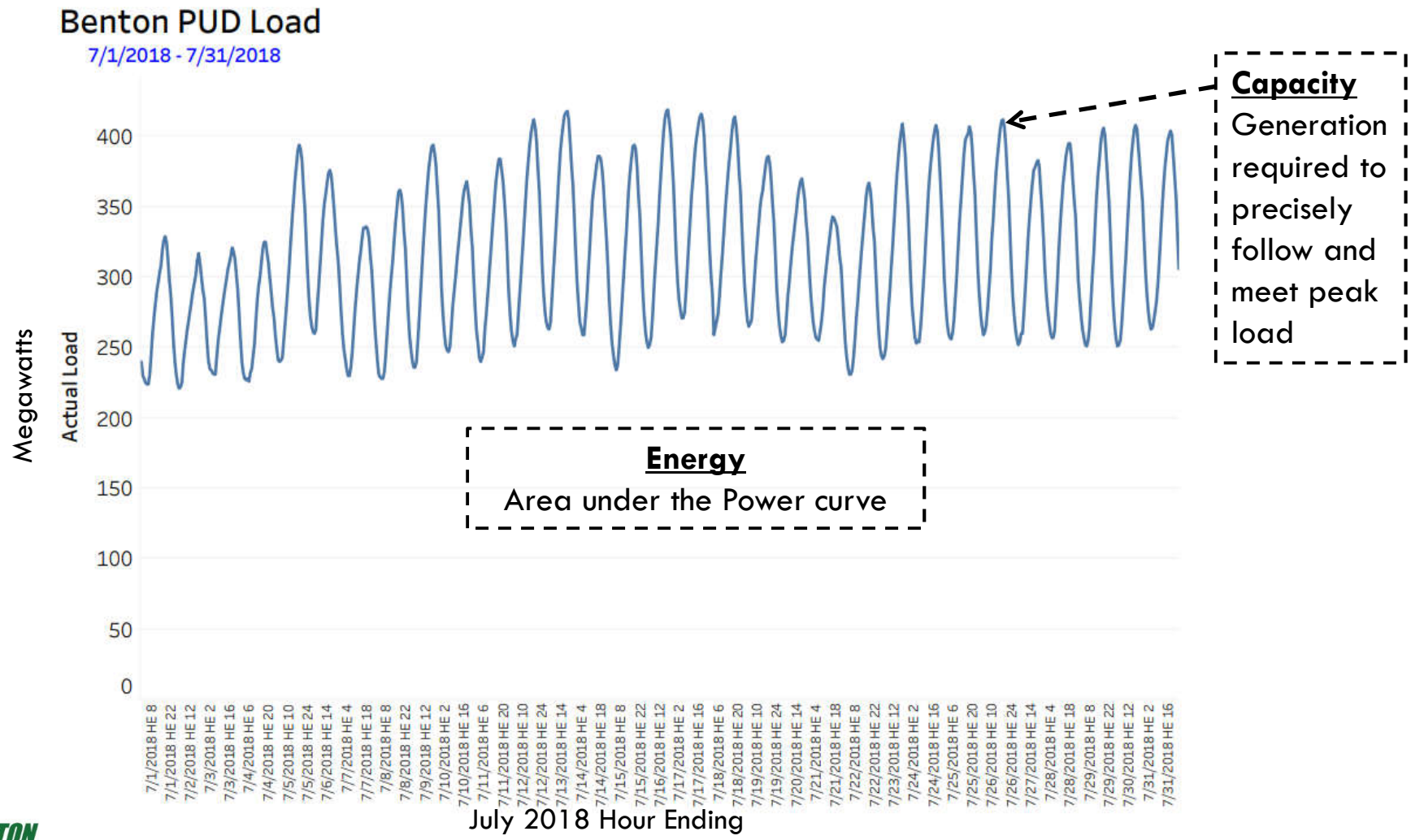
Electrical Energy & Generation Capacity

- Electrical Energy
  - Amount of electricity generated or consumed over a period of time
- Generation Capacity
  - Ability to generate electricity during peak demand periods
    - Coldest hours on the coldest days in Winter
    - Hottest hours on the hottest days in Summer
  - Capacity resources are required for stable and reliable power grid operations

Benton PUD – Summer Load Profile

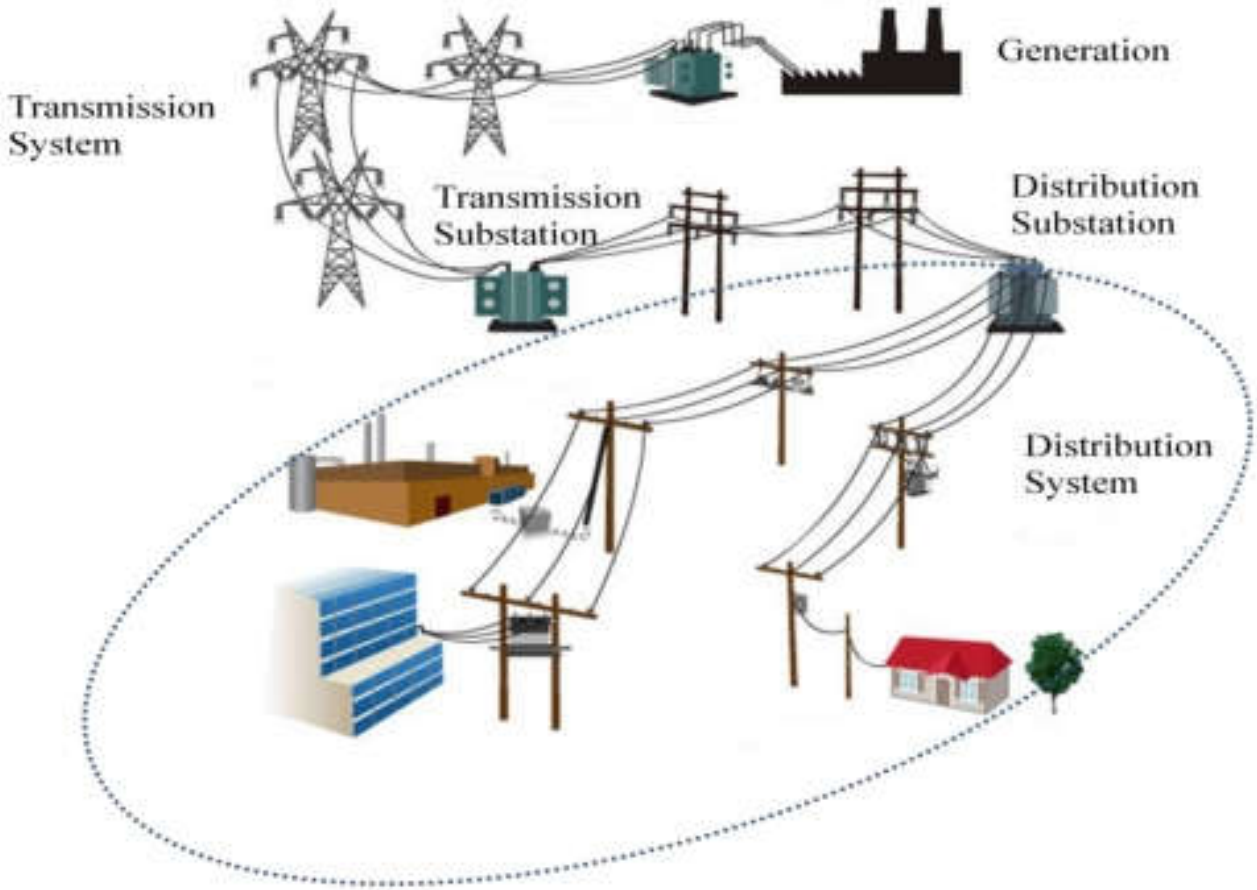


Staff preliminary recommendation. Commission decision expected September 10, 2019.

Northwest Power Market Capacity Concerns

Staff preliminary recommendation. Commission decision expected September 10, 2019.

Electricity is Simultaneously…



Produced

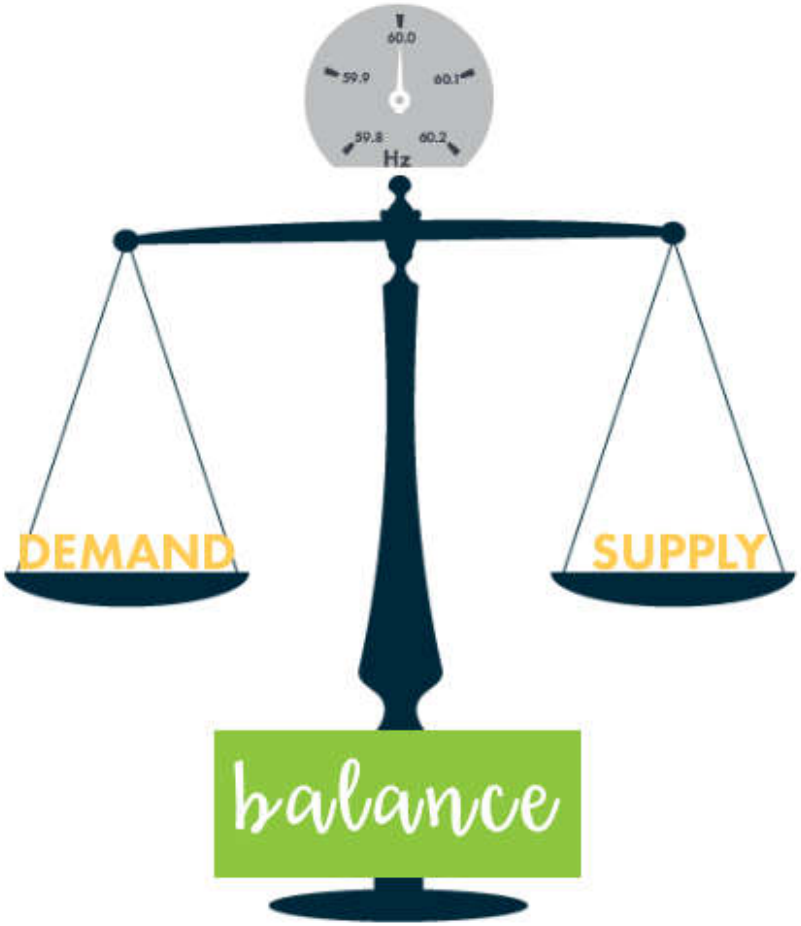
Delivered

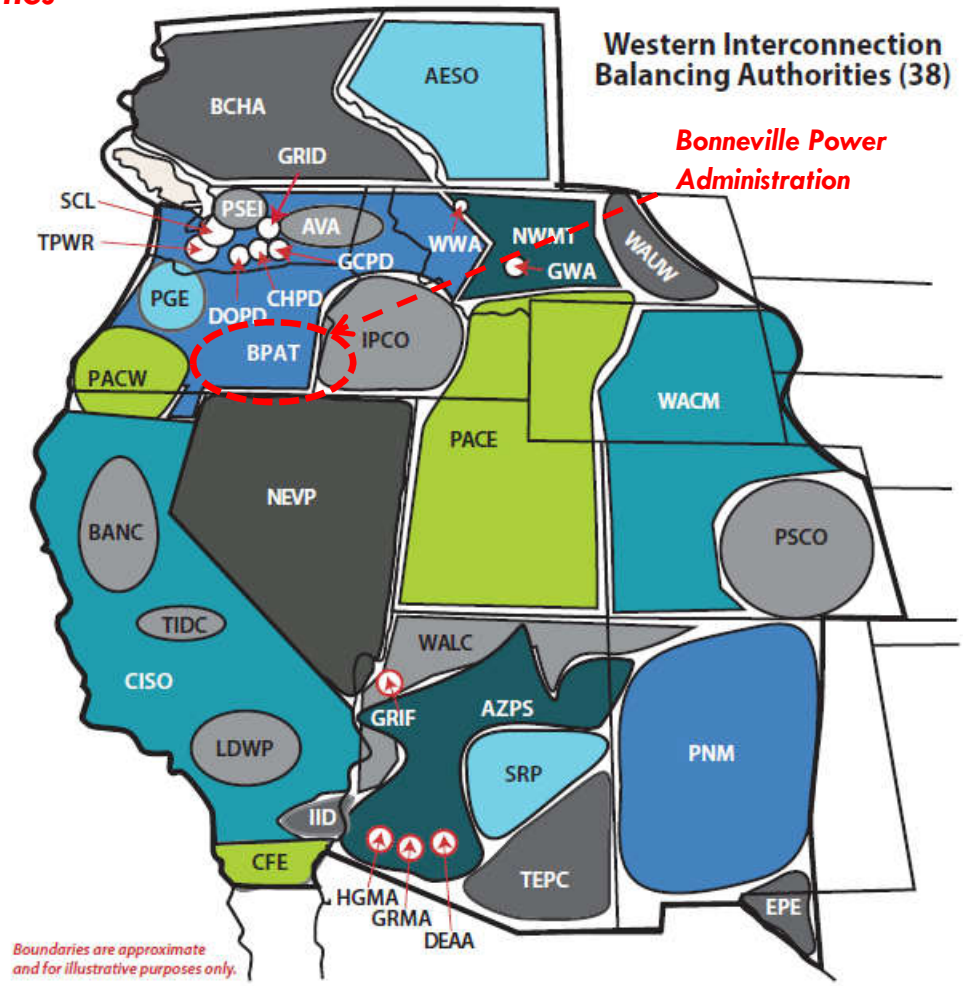
Consumed

Staff preliminary recommendation. Commission decision expected September 10, 2019.

Electric Load & Resource Balance

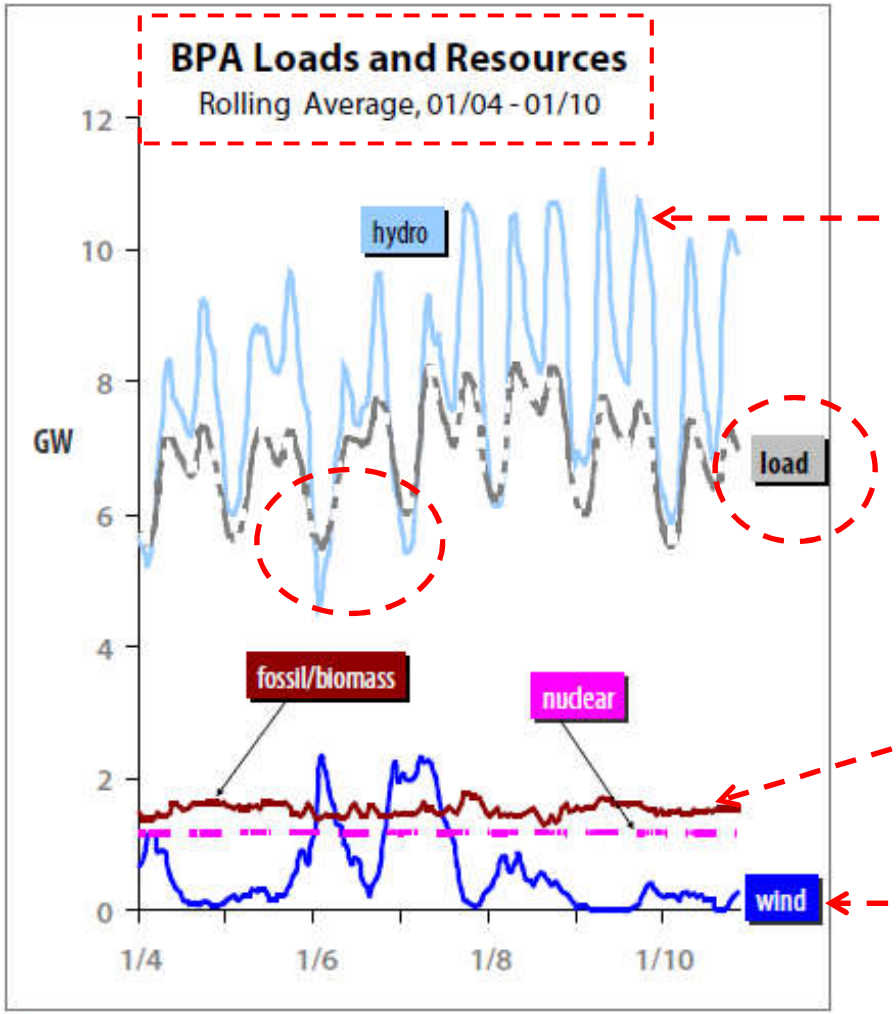
Electrical Load and Generation Must Be Equal at All Times





Staff preliminary recommendation. Commission decision expected September 10, 2019.

Load & Resource Balance - BPA



Hydro-Generation Follows Load Maintains Load & Resource Balance (with surplus to sell)

Thermal Plants Produce Constant Generation

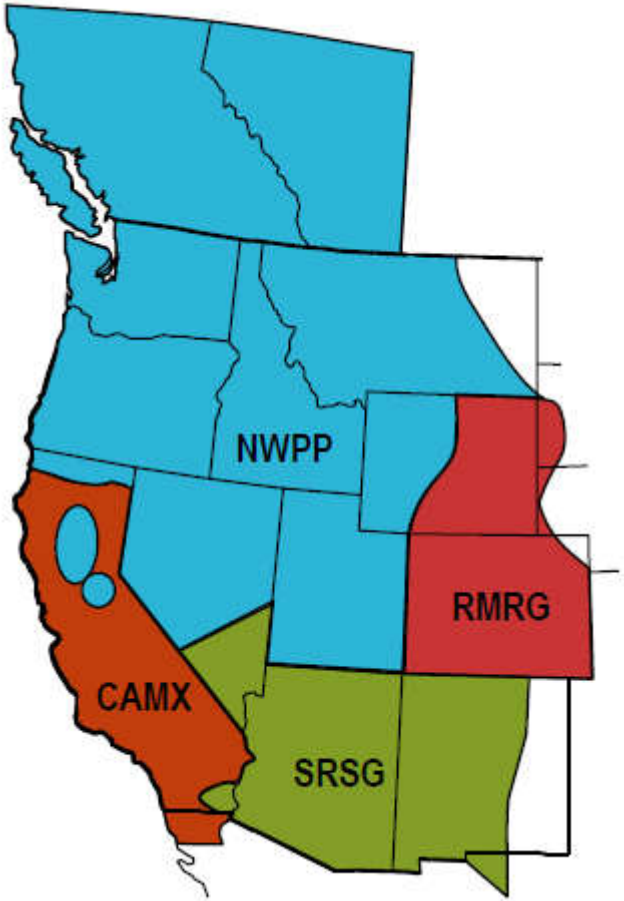
Wind Displaces Hydro (Effectively Negative Load)

Staff preliminary recommendation. Commission decision expected September 10, 2019.

Northwest Power Plant Retirements

- Retirement of NWPP baseload generation

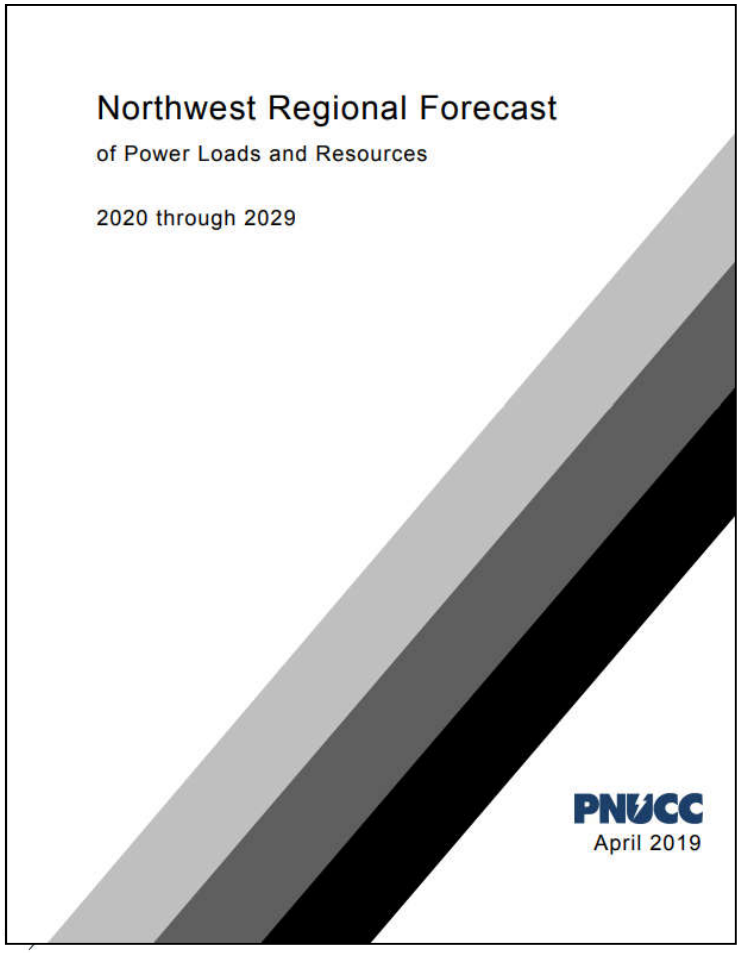
Plant Name	Capacity (MW)	Retirement Year
Centralia Generation (1)	670	2020
Boardman	585	2021
Colstrip (1)	307	End of 2019
Colstrip (2)	307	End of 2019
Centralia Generation (2)	670	2025
Various Coal, NG, Hydro	1,769	2018-2025
TOTAL	**4,308**	



Staff preliminary recommendation. Commission decision expected September 10, 2019.

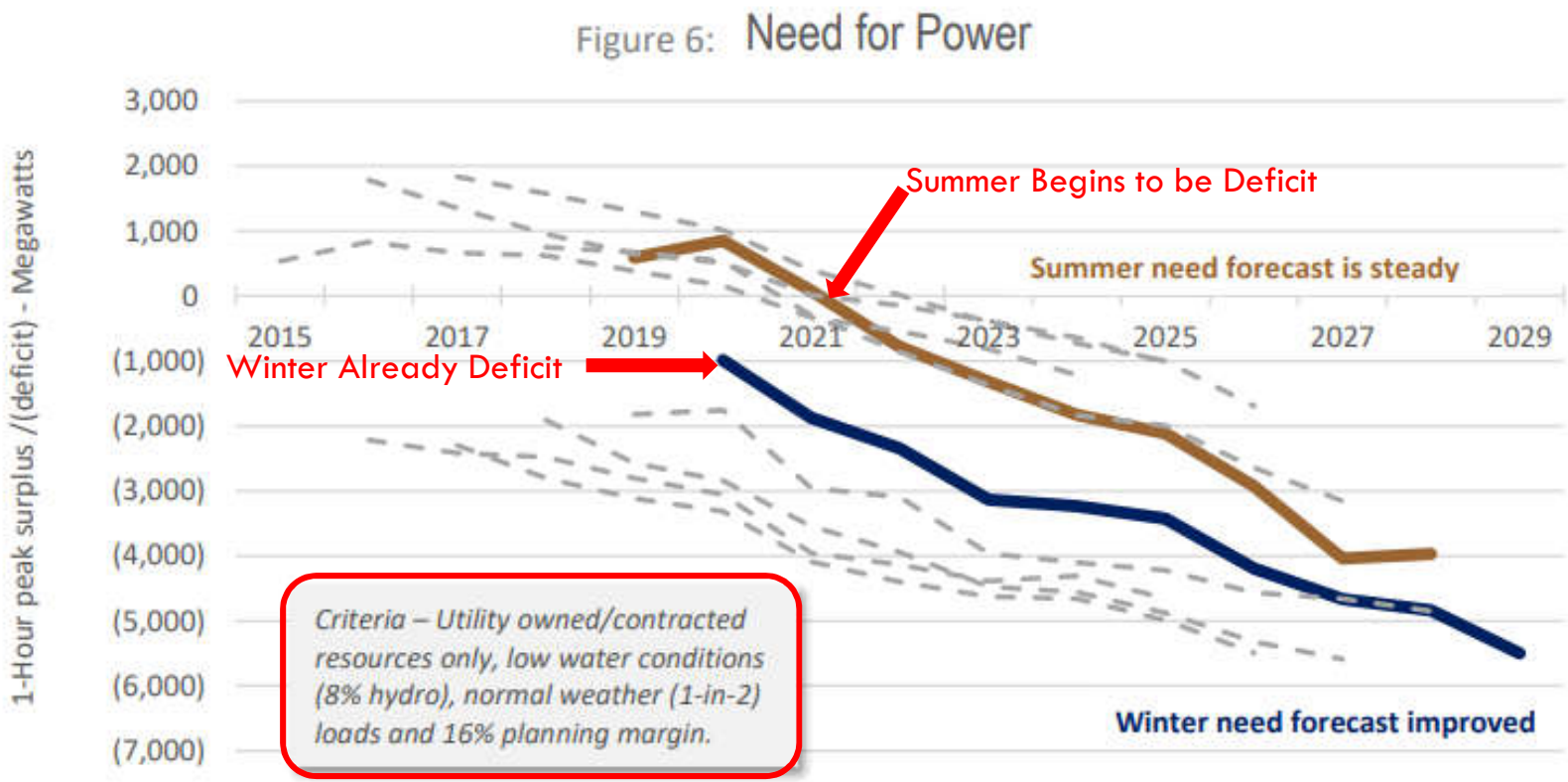
Regional Capacity Assessment

PNUCC Pacific Northwest Utilities Conference Committee



- **Coal Retirements Underscore Reliability Challenges**
- "Plans to retire eight coal-fired power units that serve the region will reduce the almost 6,800 megawatts of coal-fired generation available today to below 3,200 megawatts by 2028."
- "This loss of more than 3,600 megawatts of dispatchable generation will be most notable during peak-demand periods in the winter and summer."

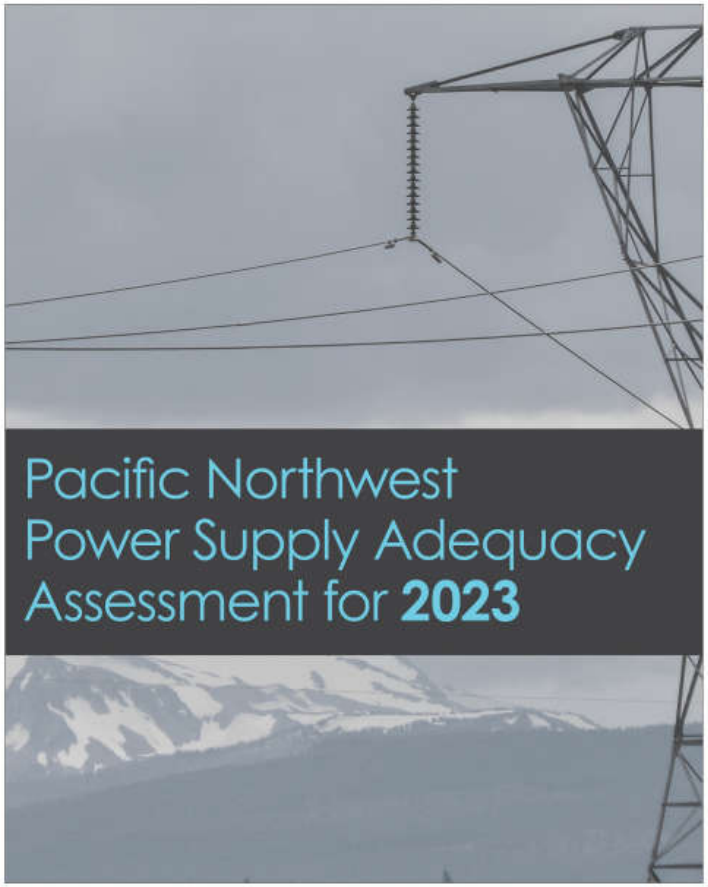
Regional Capacity Assessment



2019 PNUCC Northwest Regional Forecast

Staff preliminary recommendation. Commission decision expected September 10, 2019.

Regional Capacity Assessment



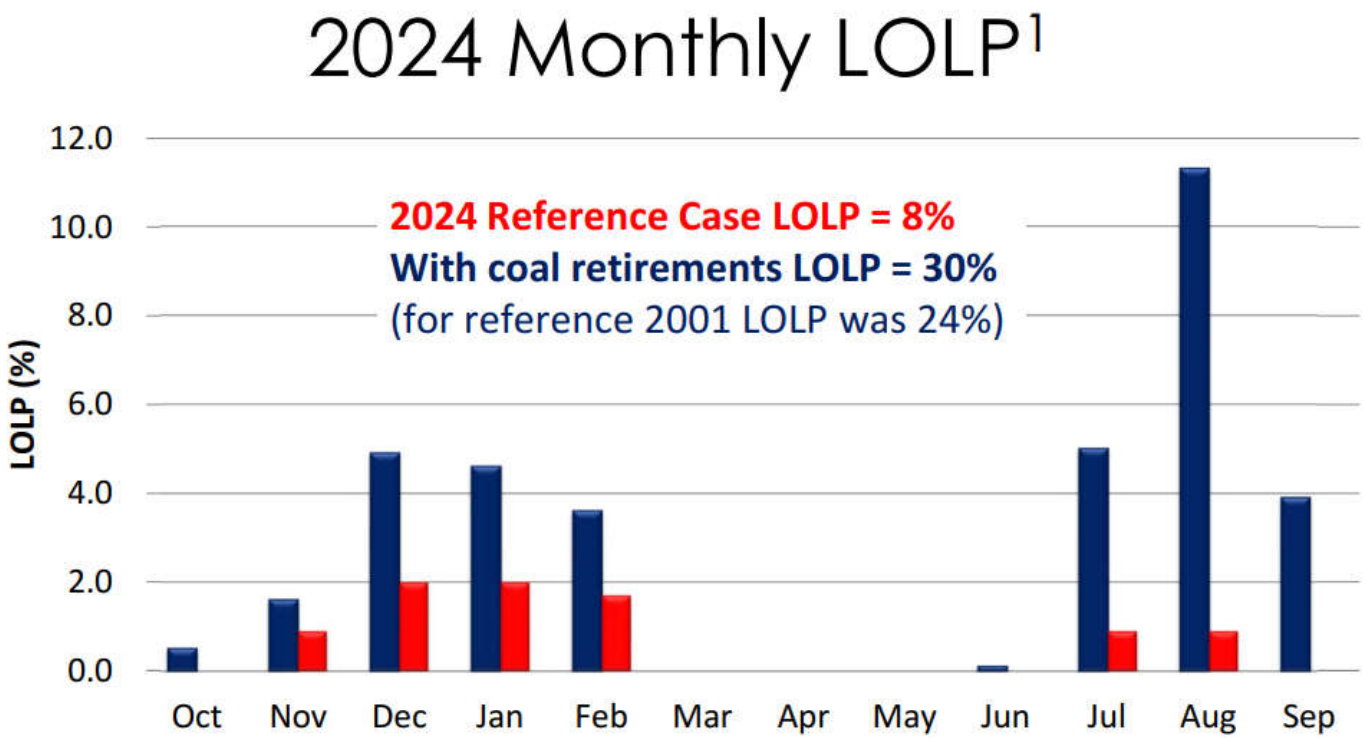
June 14, 2018
Document 2018-7

Northwest Power and Conservation Council

- "…Northwest power supply is likely to become inadequate by 2021, primarily due to the retirement of the Centralia 1 and Boardman coal plants…The loss-of-load probability (LOLP) for that year is estimated to be over 6 percent, which exceeds the Council's standard of 5 percent. "
- "By 2022 the LOLP is projected to rise to about 7 percent, due to the additional retirements of the North Valmy 1 coal plant, the Colstrip 1 and 2 coal plants…"

Staff preliminary recommendation. Commission decision expected September 10, 2019.

Capacity Assessment Update



[1]Sum of monthly LOLP values is equal to or greater than the annual LOLP value because curtailments across multiple months can occur in the same year.

Northwest Power and Conservation Council

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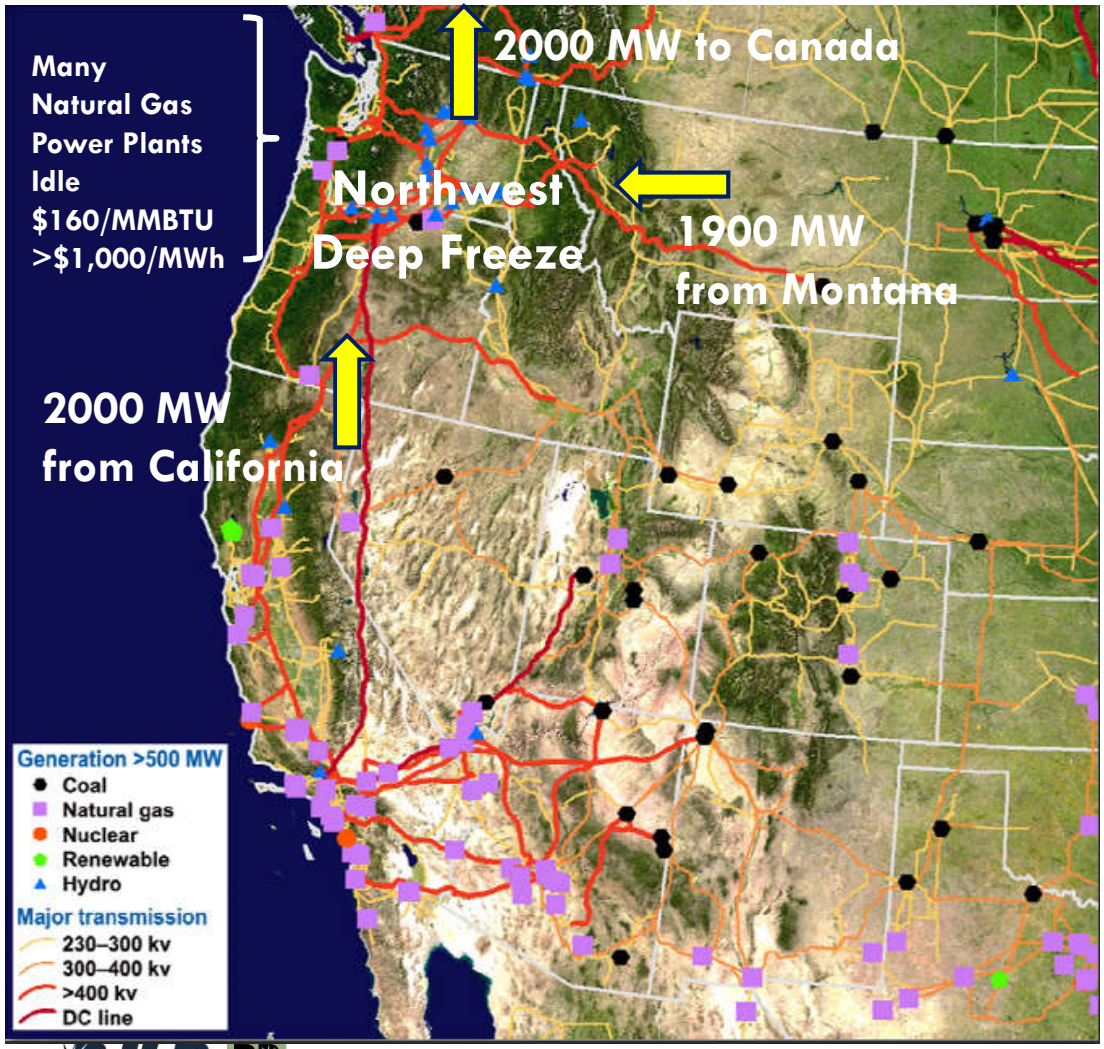
BENTON P·U·D

Reliable Public Power Provider

Staff preliminary recommendation. Commission decision expected September 10, 2019.

March 2019 Power Market Spike

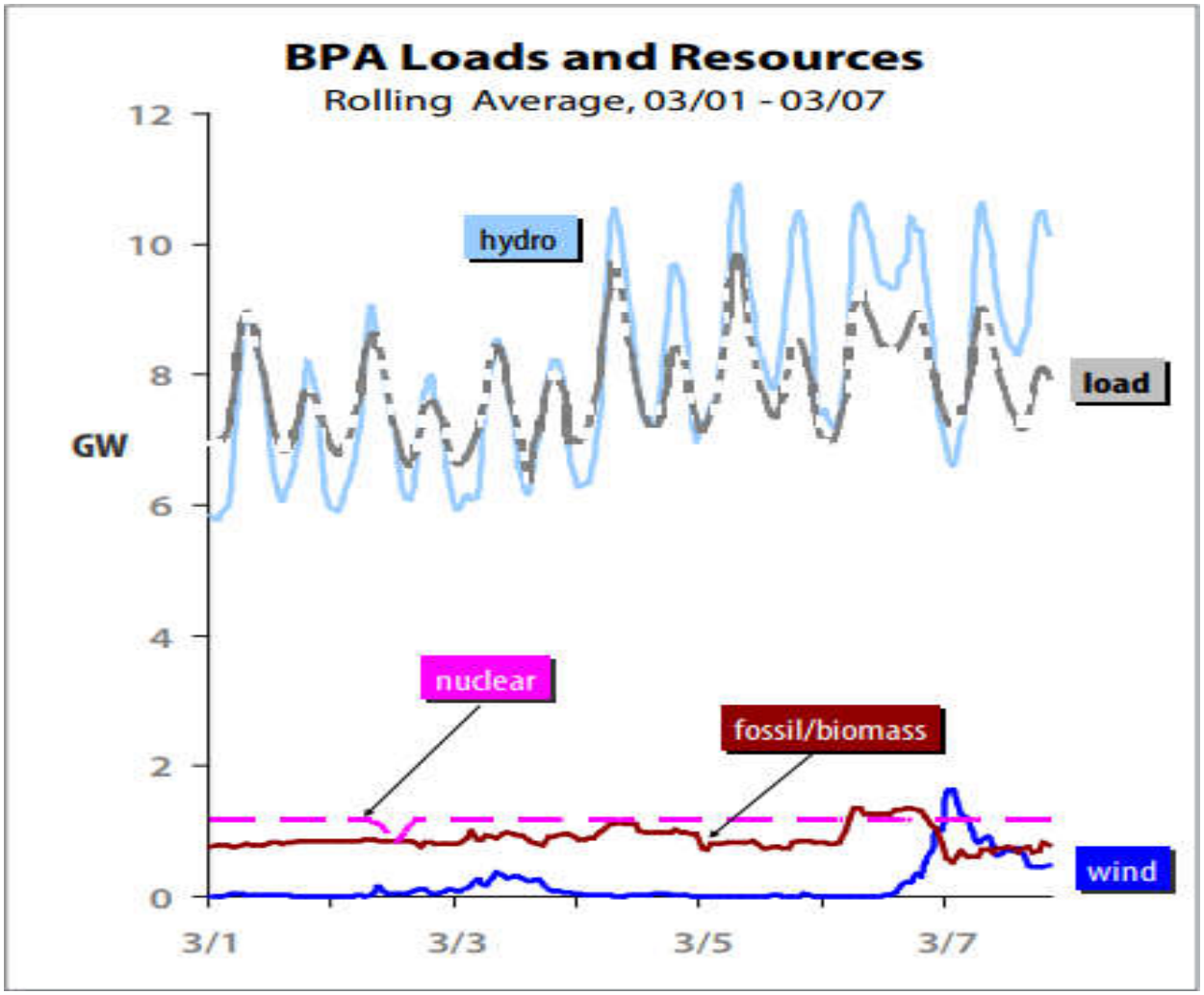


COAL-FIRED POWER PLANT STATUS

Plant Name Capacity MW	March 1 to 6 Power Production	Retirement Year
Centralia (1/2) 1,340	500 – 1,250	2020/2025
Boardman 585	475	2021
Colstrip 2,094	2,000	2019 (614 MW)

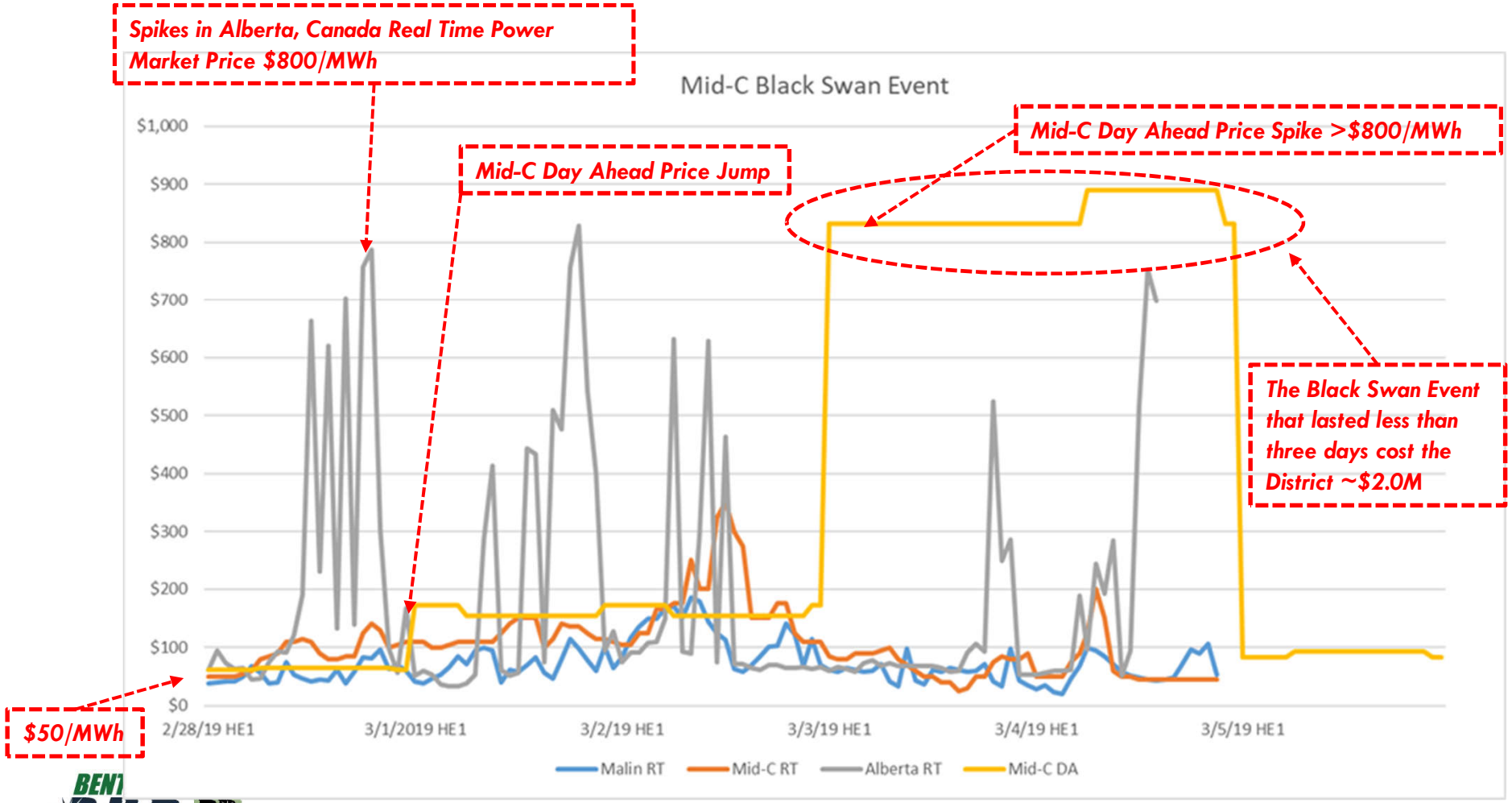
Staff preliminary recommendation. Commission decision expected September 10, 2019.

March 2019 Power Market Spike



Staff preliminary recommendation. Commission decision expected September 10, 2019.

March 2019 Power Market Spike



Staff preliminary recommendation. Commission decision expected September 10, 2019.

Washington State's 100% Clean Legislation

Staff preliminary recommendation. Commission decision expected September 10, 2019.

WA 100% Clean - Summary

- 100% carbon free energy by 2045
- Coal-fired electricity eliminated by 2025
- 100% greenhouse gas neutral by 2030
  - Up to 20% through alternative compliance
    - compliance payment
    - unbundled RECs
    - energy transformation projects
- Existing hydro & nuclear energy count
- Energy Independence Act (EIA) investments count

Staff preliminary recommendation. Commission decision expected September 10, 2019.

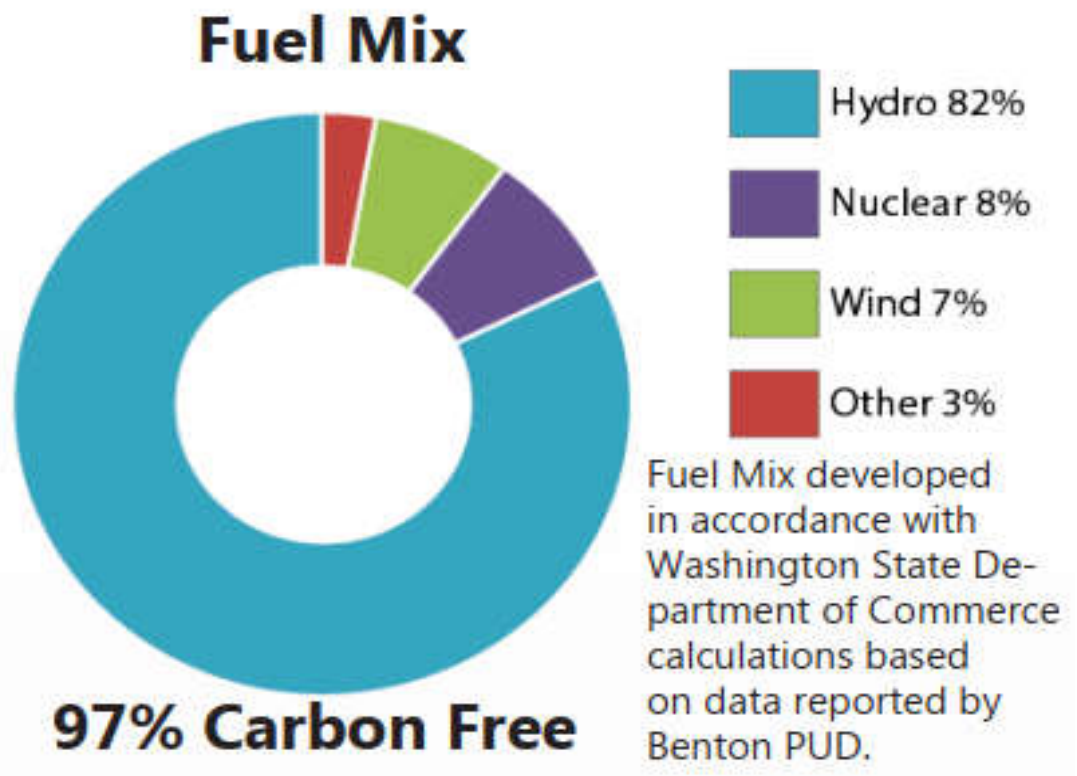
WA 100% Clean - Summary

- Compliance payment/penalty
  - Coal-fired: $150/MWh
  - Gas-fired peaking: $84/MWh
  - Gas-fired combined cycle: $60/MWh
  - Inflation factor after 2027
- Considered compliant if investments meet or exceed 2% of prior year's revenue requirement (limits rate increases)
- Attempts to address grid reliability risks
  - Technically and financially complex problems
  - Existing studies already indicate retirement of coal-fired generation will cause unacceptable increase in regional loss-of-load probability
- Significant increase in the amount and complexity of Utility reporting and planning

Staff preliminary recommendation. Commission decision expected September 10, 2019.

WA 100% Clean - Summary

Benton PUD 2018 Portfolio



Staff preliminary recommendation. Commission decision expected September 10, 2019.

Benton PUD Challenges/Concerns

- **BPUD is long energy and short capacity**
  - Capacity resources being retired with no firm plans for replacement
    - WA 100% Clean chills potential investments in operationally proven and cost-effective capacity such as natural-gas power plants
  - Big $ risk increase in relying on market purchases
    - Too many utilities relying on market purchases to cover capacity deficits
    - Mid-C market volatility increasing during peak load periods
- **Grid reliability concerns**
  - Wind and solar power does not provide replacement capacity needed during poor water years and extreme temperatures
    - Energy gluts erode business case for capacity resources in current power markets (energy based payments)

Staff preliminary recommendation. Commission decision expected September 10, 2019.

Questions / Comments?

BENTON P·U·D

RP3 Reliable Public Power Provider

Proposed Increase: Rate Components

Customer Class	Current Rates			Proposed Rates		
	Energy	DSC [1]	Demand	Energy	DSC [1]	Demand
Residential	$0.0718	$18.60	N/A	$0.0739	$18.90	N/A
Small General Service	$0.0644	$16.20	N/A	$0.0663	$16.50	N/A
Medium General Service						
Jan – Mar & Sept – Dec	$0.0597	$48.30	$9.55	$0.0614	$49.50	$9.82
April – August	$0.0509	$48.30	$9.55	$0.0524	$49.50	$9.82
Large General Service						
Jan – Mar & Sept – Dec	$0.0492	$58.80	$7.93	$0.0506	$60.30	$8.15
April – August	$0.0411	$58.80	$7.93	$0.0423	$60.30	$8.15
Large Industrial	$0.0384	$226.20	$8.53	$0.0395	$232.50	$8.77
Small Irrigation	$0.0520	$5.40	$3.34	$0.0535	$5.70	$3.43
Large Irrigation w/o MLC	$0.0441	$36.00	$3.57	$0.0454	$36.90	$3.67
Large Irrigation w/MLC	$0.0414	MLC [2]	$4.21	$0.0426	MLC [2]	$4.33

1) Daily system charge: $ per month based on a 30-day month
   Small General Service rates based on Single-Phase service
   Medium General Service rates based on Multi-Phase service

2) Large irrigation w/MLC class has a Miles of Line Charge in lieu of a daily system charge

Staff preliminary recommendation. Commission decision expected September 10, 2019.

Medium/Large General Service
Proposed Increase: Energy Component Only

Customer Class	Current Rates Energy	Proposed Rates Energy[1]	Proposed Rates Energy[2]
Medium General Service			
Jan – Mar & Sept – Dec	$0.0597	$0.0614	$0.0577
April – August	$0.0509	$0.0524	$0.0577
Large General Service			
Jan – Mar & Sept – Dec	$0.0492	$0.0506	$0.0471
April – August	$0.0411	$0.0423	$0.0471

1) Rate effective October 1, 2019 through December 31, 2019
2) Rate effective January 1, 2020 through December 31, 2020 (Seasonality removed January 1, 2020)

Staff preliminary recommendation. Commission decision expected September 10, 2019.