Tacoma Power

Energy Imbalance Market (EIM) Business Case

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TACOMA POWER
TACOMA PUBLIC UTILITIES

Agenda

1. Introduction
2. Risks of Status Quo
3. Cost-Benefit Simulation
4. Cost Analysis
5. Benefit Analysis
6. Summary & Next Steps

Introduction

Section 1

Clay Norris

Introduction

Why Trade in a Market?

- Cost-Prohibitive to have enough resources to meet load obligations in any and all circumstances
- More reliable for utilities to help each other

Introduction

Markets Are Evolving

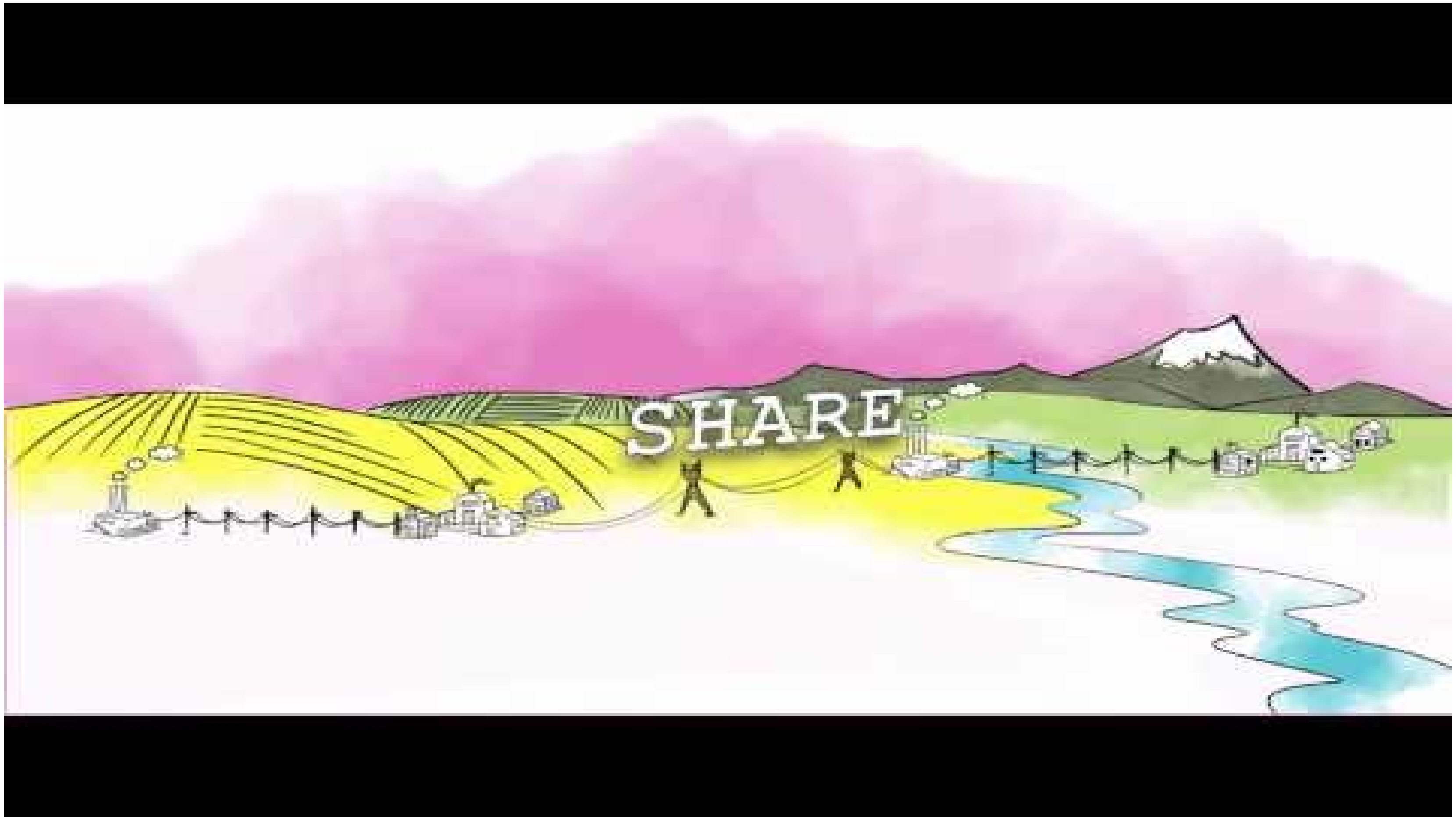
- 1980s somewhat limited trading between utility neighbors
- 1990s FERC opened up wholesale markets by making transmission available to third party marketers
- 2000s robust bilateral markets in the Northwest; centralized markets in most of the Eastern U.S.
- 2010s CAISO begins Energy Imbalance Market (EIM) and begins discussions about creating an Extended Day-Ahead Market (EDAM)
- 2020s EDAM? West-wide Regional Transmission Organization (RTO)?

Markets Overview

- Bilateral markets occur when a willing buyer meets a willing seller. Most of Tacoma Power's transactions happen this way.
- Centralized (or RTO/ISO) markets are run through a market operator to:
  - Collect bids from all generators
  - Collect load forecasts from all load-serving entities
  - Model the transmission system and solve for the lowest cost way to serve all load without overloading lines ("security constrained economic dispatch")
  - Dispatch generation to meet actual loads
- Centralized markets require extensive metering, communication, and powerful computers to function
- CAISO is the only market operator currently in the WECC

Introduction

What Is EIM?



EIM Overview

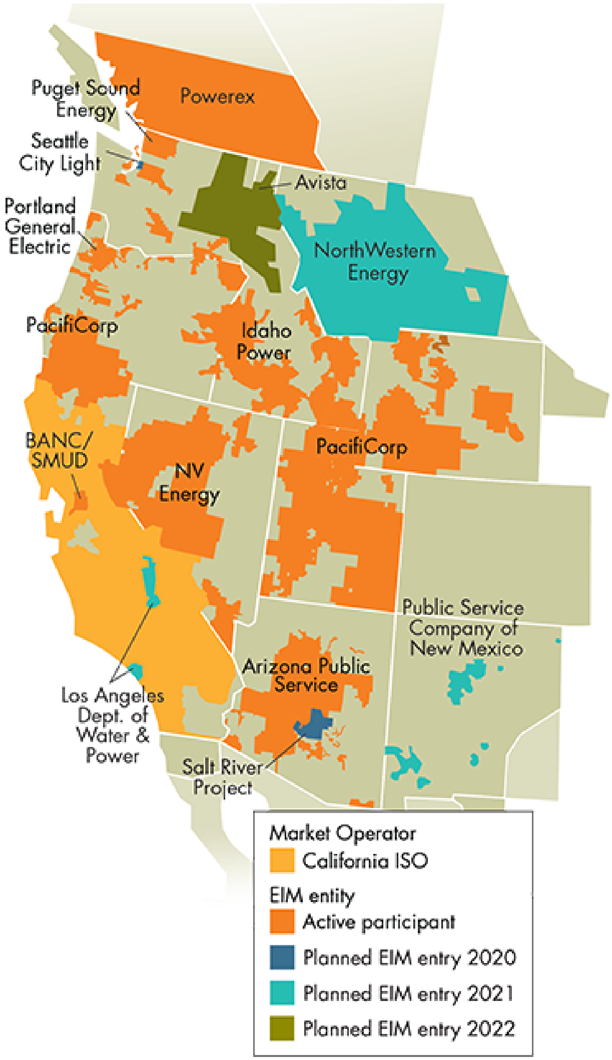
- CAISO operates a day ahead and a real time centralized market in their balancing area. Utilities in CAISO's balancing area turn over control of their transmission and generation to the CAISO.

- CAISO's Energy Imbalance Market (EIM) is an extension of just the real-time (5 and 15 minute) centralized market into other parts of WECC.

- EIM participants:
  - maintain operational control over their generating resources
  - retain all their obligations as NERC-certified Balancing Authorities (BAs), Transmission Operators (TOPs) and Transmission Service Providers (TSPs).

Introduction

Participants in the CAISO EIM



- Powerex and Idaho Power joined in April 2018
- BANC/SMUD joined in April 2019
- Seattle City Light and Salt River Project plan to join in April 2020
- NorthWestern Energy, Public Service Company of New Mexico, Los Angeles Department of Water & Power and Turlock Irrigation District plan to join in April 2021
- Avista plans to join in April 2022
- BPA has indicated a likelihood they will join in April 2022

NOTE: EIM entry is only allowed during the month of April each year

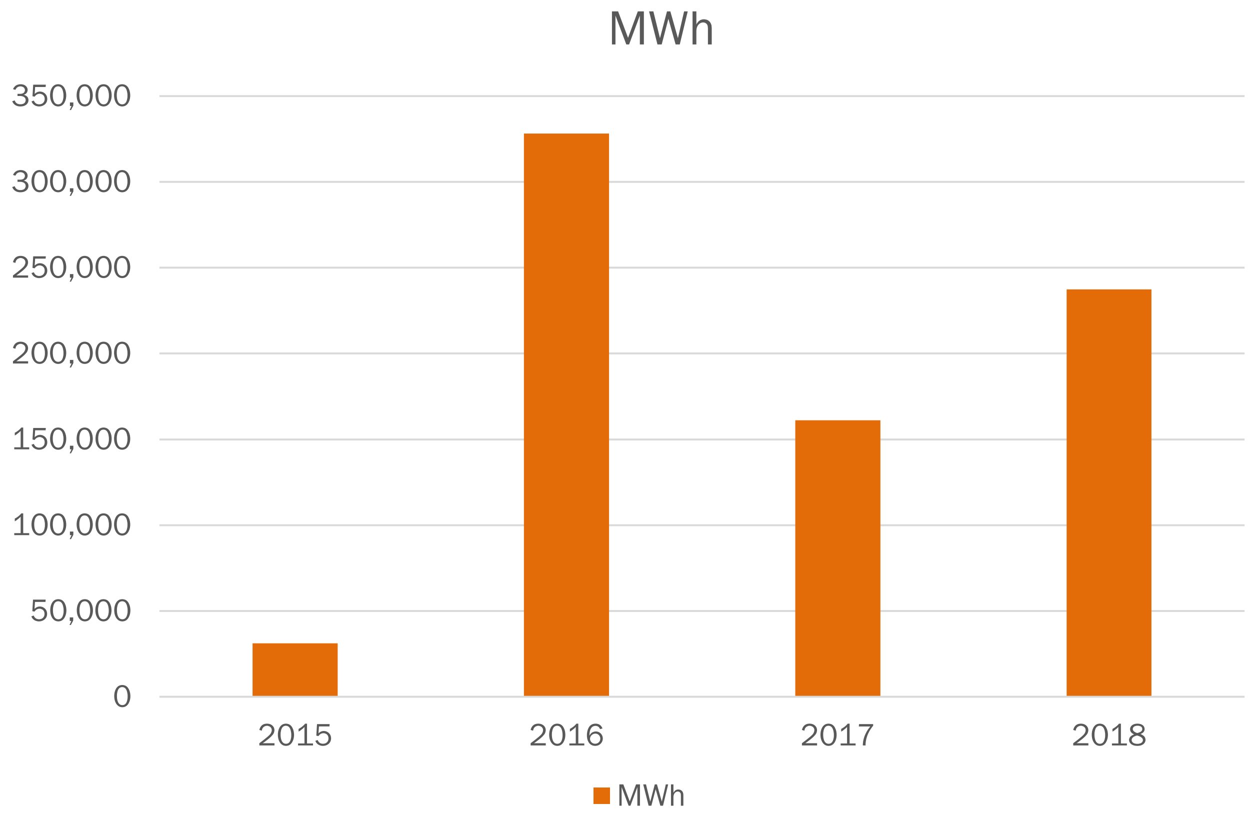
Hydro Value in EIM

The EIM provides a real-time market and a potential opportunity to use the flexibility of Tacoma Power's hydro system to better integrate solar and wind generation

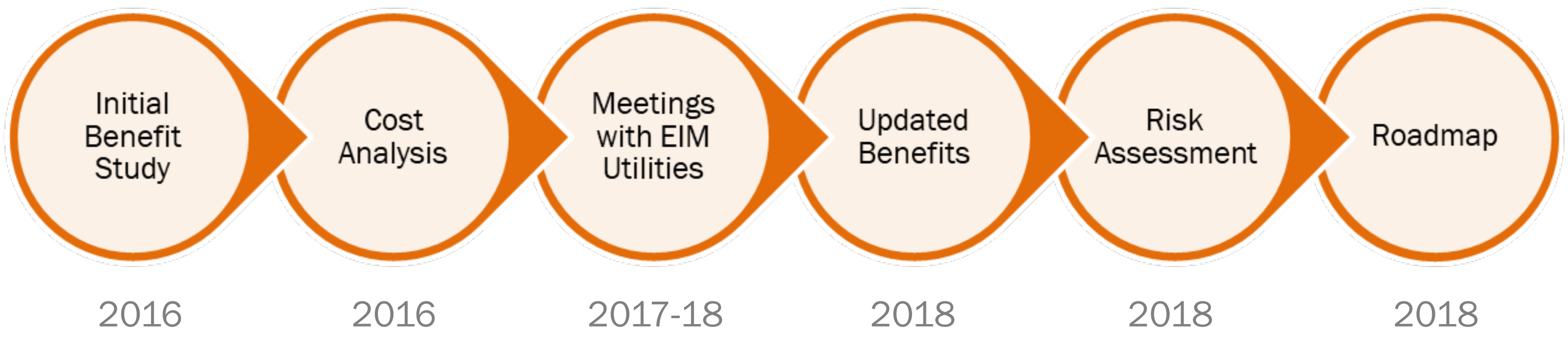
Mick Klass Photography

Introduction

Renewable Curtailments Avoided by EIM



Analysis Conducted to Date



Risks of Status Quo

Section 2

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The status quo carries significant risks for Tacoma Power

Ability to balance our system in real-time is diminishing

Bilateral real-time trading partners are getting harder to find

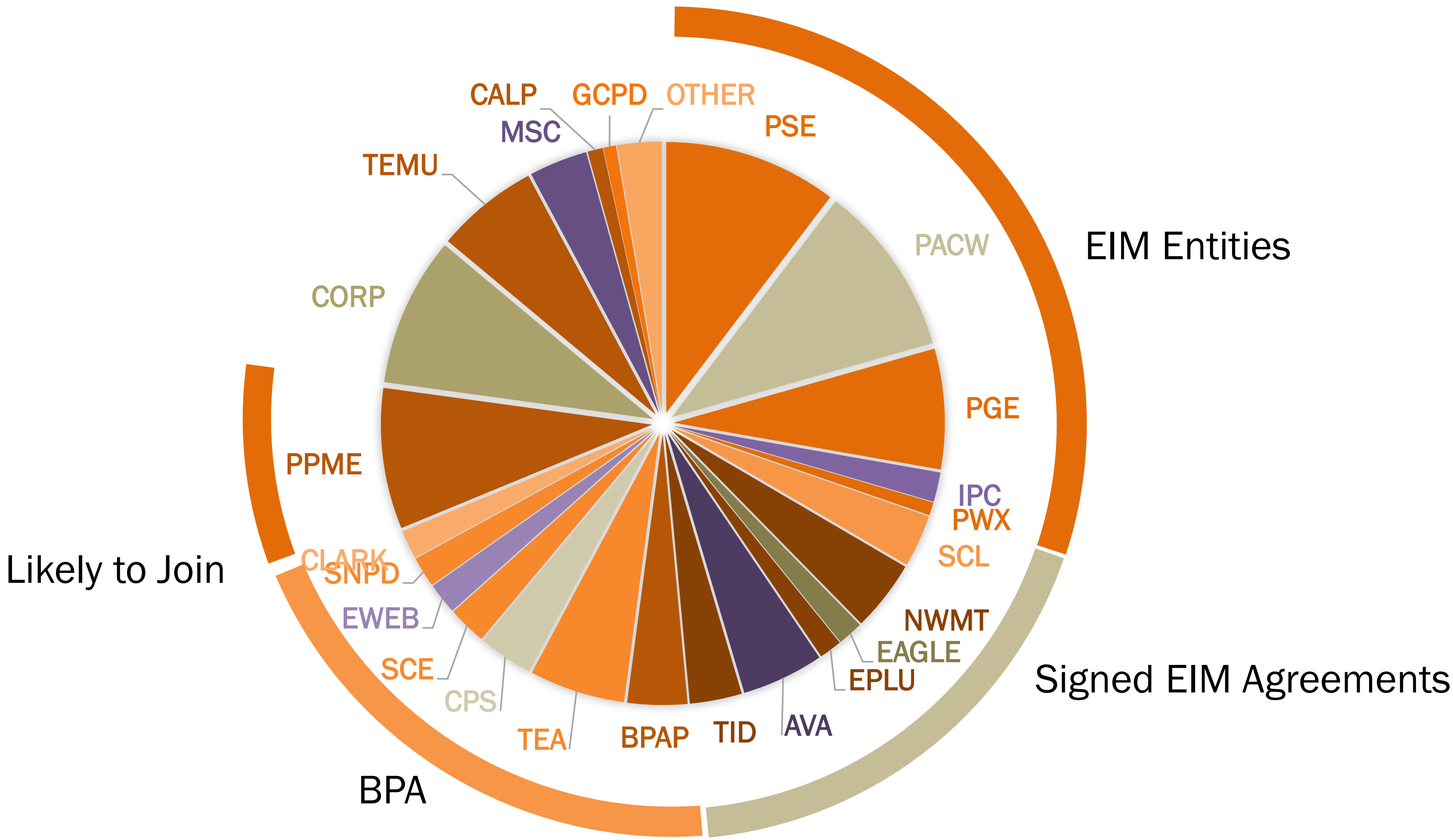
Risks

Loss of Liquidity in Real-Time Market

- Real-time trading volumes with PacifiCorp and PGE (our historically largest real-time counterparties) are dramatically lower
- More real-time transactions with wind counterparties. These counterparties may elect to join EIM
- Real-time transactions taking place earlier with EIM entities than non-EIM entities; once EIM bids are in, no need to make bilateral trades
- Liquidity of “later” transactions significantly reduced or even eliminated as wind generators enter the EIM

Risks of Status Quo

Most Traditional Real-Time Counterparties have Joined, or are Planning to Join, EIM



Risks of Status Quo

Risks

Loss of Liquidity in Day-Ahead Market & EDAM

The Extended Day-Ahead Market (EDAM) may extend loss of liquidity due to EIM into the Day-Ahead Market

What is EDAM?

- Since early in 2018, CAISO has been proposing to extend its Day-Ahead Market into the EIM footprint
- This would allow EIM participants to take advantage of CAISO’s Day-Ahead Market enhancements and more effectively integrate renewables
- EDAM Proposed Go-Live is April 2022
- Larger trading volume in the day-ahead market (EDAM) than real-time market (EIM)

EIM Cost-Benefit Simulation

Section 3

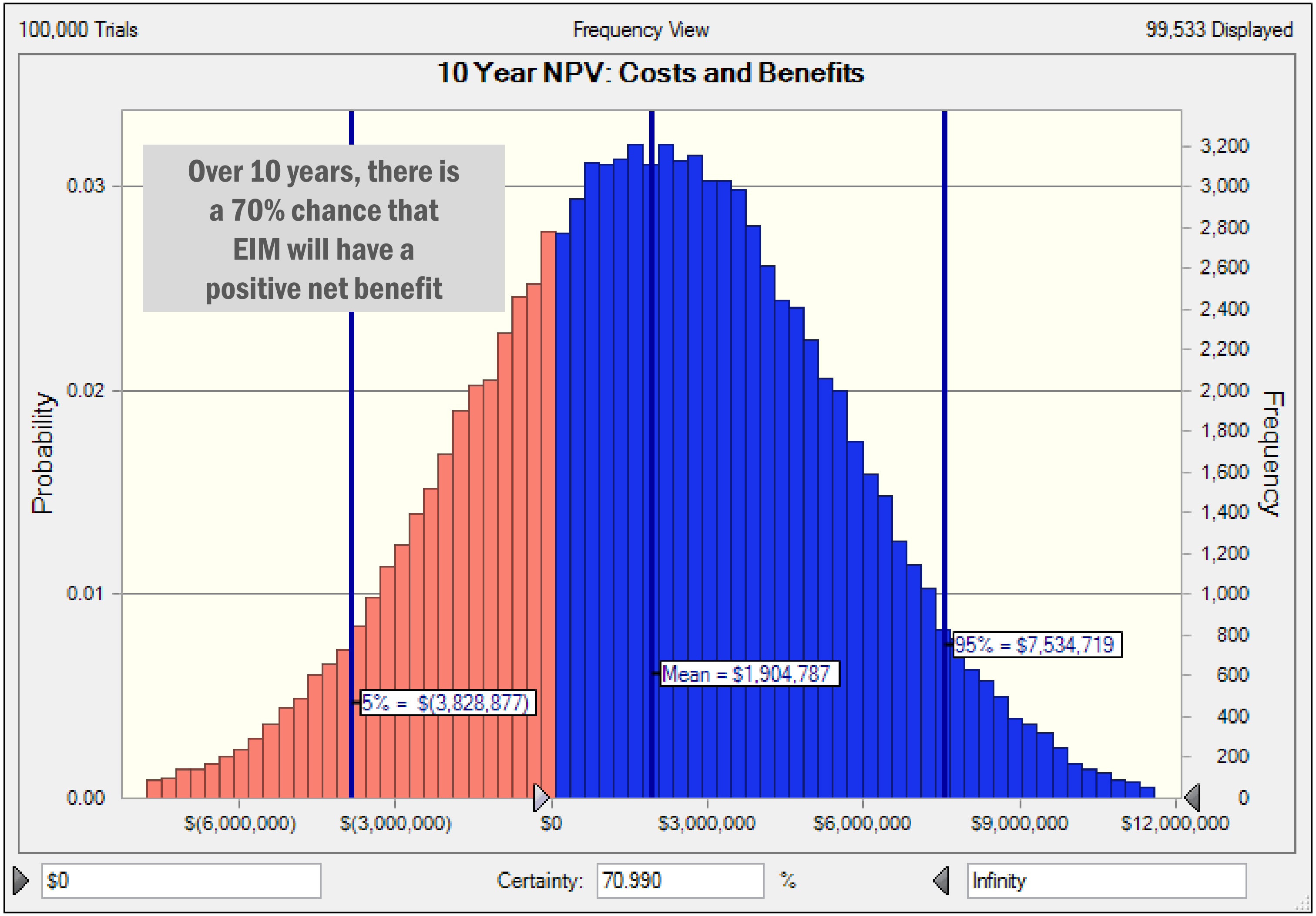
Clay Norris

Summary

- Staff recommends Tacoma Power join CAISO's EIM
- There is uncertainty on the costs and benefits for our participation in EIM (further explained in the cost and benefits sections)
- Status quo does not seem to be an option and will likely have reduced wholesale sales benefits; that reality is not included in the cost/benefit analysis
- Even though enhanced wholesale revenue is not the primary driver for our recommendation, there is a good likelihood that joining the EIM will result in positive net benefits; The expected 10 year NPV is $1.9 million

EIM Cost-Benefit Simulation

Costs & Benefits



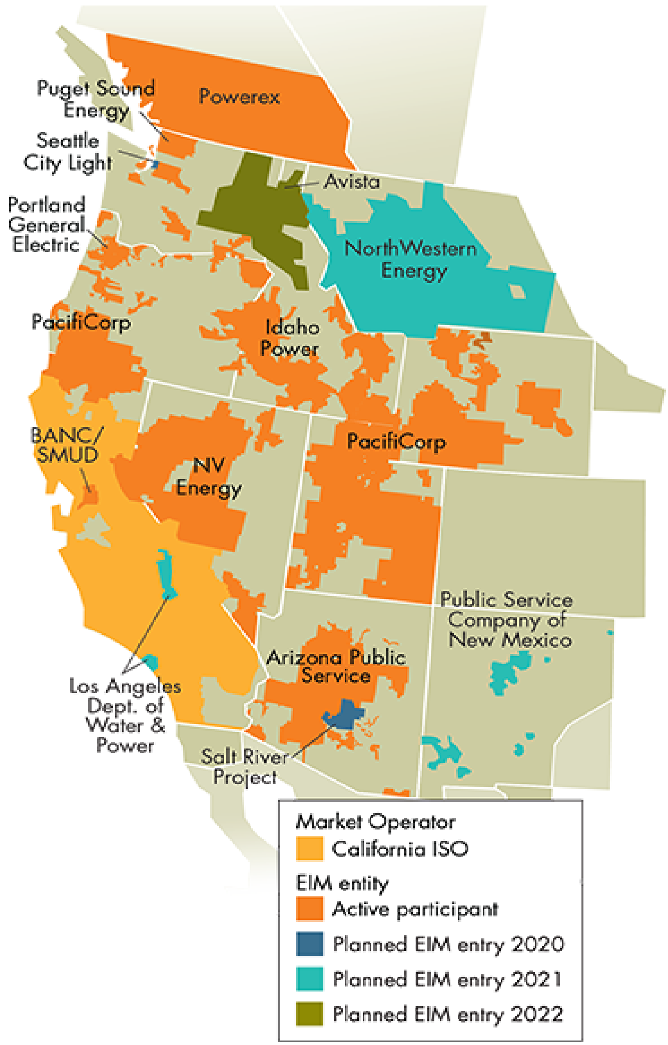
Cost Analysis

Section 4

Todd Lloyd

EIM Cost Estimates

EIM Participants



- Current EIM Participants
  - PacifiCorp
  - Portland General Electric
  - Puget Sound Energy
  - NV Energy
  - Powerex
  - Idaho Power
  - BANC/SMUD
- Upcoming EIM Participants
  - Seattle City Light (2020)
  - Salt River Project (2020)
  - Los Angeles Department of Water & Power (2021)
  - NorthWestern Energy (2021)
  - Public Service Company of New Mexico (2021)
  - Turlock Irrigation District (2021)
  - Avista (2022)

EIM Implementation Costs Summary

EIM Implementation will require a significant investment of $14 to $18 million over 3 years (from June 2019 until April 2022)

Implementation costs include new staff, consulting services, software and metering

Based on an evaluation of Tacoma Power's needs and a comparison with other EIM entities, the range of costs for 3-year implementation:

- New Staff for Implementation (10 to 11 FTE) $5.9M to $6.5M
- Consulting Services $3.5M
- Software Systems $2.3M to $4.3M
- Metering $400k to $1.2M
- Contingency 20%

EIM Implementation Costs Staffing and new FTEs

Total New FTEs for EIM Implementation		**10 to 11 FTE**
Program Manager		1 FTE
24x7 EIM Desk	5 FTE	
Settlements and Billing		1 to 2 FTE
EMS Support		1 FTE
Hydro Optimization and Bid Analyst		1 FTE
Software System Integration and Support		1 FTE

Additional support from existing staff in T&D, Power Management, UTS and Project Management Office will be required

It may be possible to repurpose existing staff to reduce FTE growth

Implementation Costs
Consultants and Contractors

Consulting Services are expected to cost approximately $3.5 million over the 3 year implementation period

Program Advisor and EIM Subject Matter Expert (SME)	1300 hours
Business Analyst	3600 hours
Project Manager	3700 hours
Balancing Authority Operations & Outage Management SME	1400 hours
CAISO Merchant & Trading SME	1500 hours
EIM Metering SME	300 hours
Settlements and Reconciliation SME	1000 hours
Training and Change Management SME	200 hours

These estimates are based on contractual resources used in similar sized EIM implementations

Implementation Costs
Software and Systems

Software and systems are expected to cost between $2.3 and $4.3 million

Generator Outage Management System	$300,000 to $450,000
Transmission Outage Management System	$400,000 to $550,000
Participating Resource Scheduling Coordinator Bidding Scheduling System	$150,000 to $600,000
EIM Entity Scheduling Coordinator Scheduling System	$400,000 to $750,000
Participating Resource Scheduling Coordinator Settlements System	$125,000 to $650,000
EIM Entity Scheduling Coordinator Settlements System	$300,000 to $575,000
Dispatch Integration to EMS	$100,000 to $200,000
EIM EMS module	$500,000

A description of these systems can be found at the end of this document

EIM On-going Costs Summary

EIM on-going costs are expected to range from $2.1 to $4 million per year

On-going costs include staff, CAISO administrative fees, and license fees of software systems

The expected range of annual on-going EIM costs include:

▪ Staff for on-going operations (7 to 10 FTE)	$1.7M to $2.4M
▪ CAISO Administrative Fees	$400k
▪ Software Licensing	$380k to $950k
▪ Contingency	10%

EIM On-Going Costs
Staffing and new FTEs

Total New FTEs for EIM Operations	**7 to 10 FTE**
24x7 EIM Desk	5 FTE
Settlements and Billing	1 to 2 FTE
EMS Support	0 to 1 FTE
Hydro Optimization and Bid Analyst	1 FTE
Software System Integration and Support	0 to 1 FTE

Benefit Analysis

Section 5

Kris Bobo

Model Design

Tacoma Power's Modeling

- We built a model that dispatches Tacoma's flexible hydro generation using historical EIM prices in order to see how much value would be gained or lost from joining the EIM historically.
- The model uses:
  - Historical data and system conditions
  - Considers the opportunity cost of water at each project
  - Doesn't start or stop dispatchable units or modify the discharge of regulated projects

- The model "bids in" the available flexibility of Tacoma's generation into the EIM
- The generation is then dispatched based on the historical EIM prices resulting in Tacoma either buying from or selling to the Market
- This process is repeated in the model for every 15-min and 5-min interval throughout the year (~140,000 intervals/yr)

Model Design

Tacoma Power's Modeling

- Using the historical actual system conditions, limitations and EIM prices (at the Starwood LMP point) over the two years since Puget Sound Energy joined EIM, Tacoma would have seen:

  $8.104 million in benefits in 2017

  $5.038 million in benefits in 2018

- Did similar analysis using an older EIM price point (at the Malin LMP point, 4 years of data but geographically far from Tacoma System). Using that price point Tacoma would have seen:

  $8.912 million in benefits in 2015

  $8.342 million in benefits in 2016

  $8.242 million in benefits in 2017

  $7.637 million in benefits in 2018

* Difference between price points is caused by Transmission Congestion

Model Design

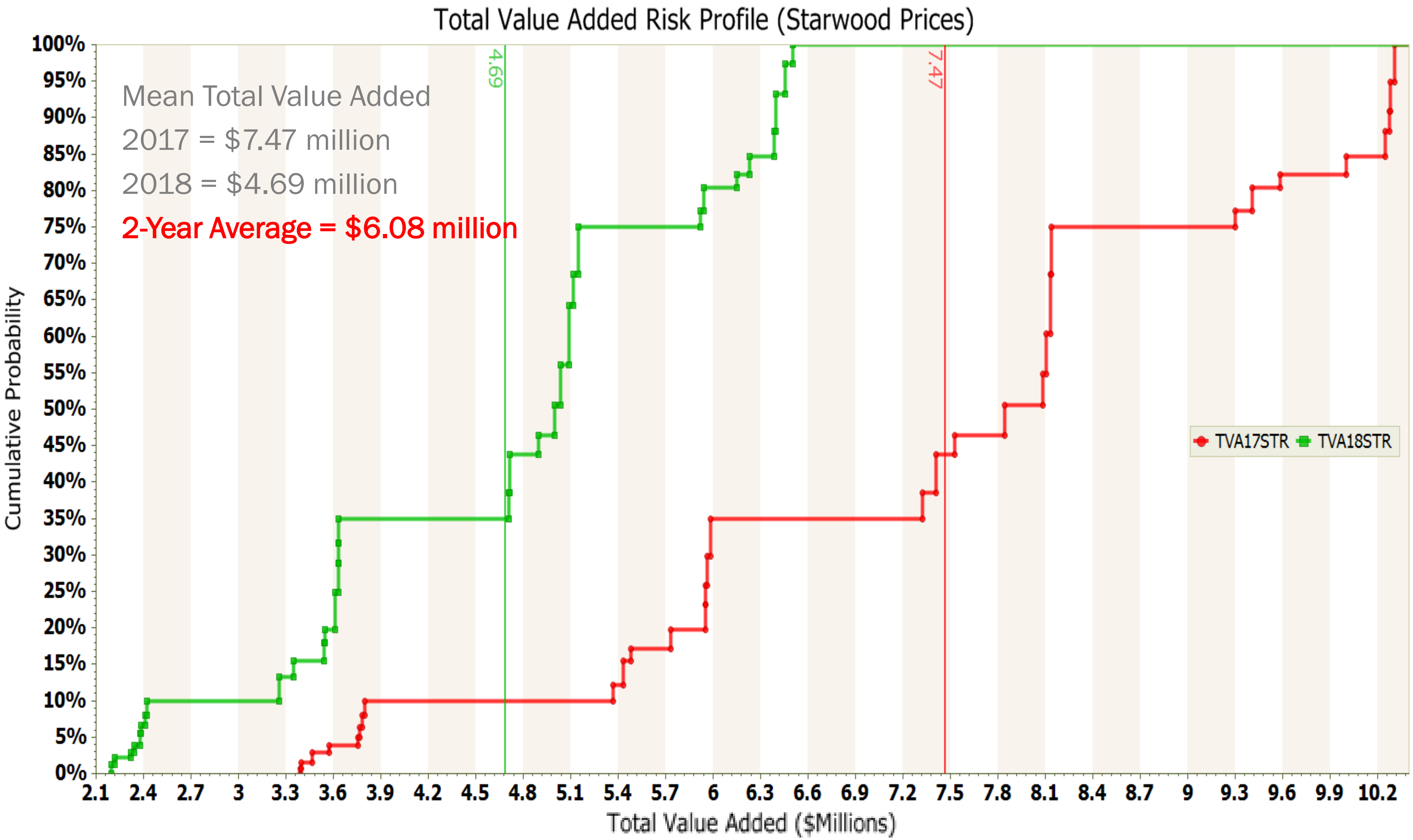
Tacoma Power's Modeling

- How will the future environment differ from historical conditions?
  - Balance of supply and demand
  - Amount of regional flexible generation vs variable generation
  - Regional transmission limitations
  - Mass adoption of efficient local energy storage technologies

- 3 main factors were found to drive model results
  1) EIM price volatility
  2) Quantity of Transmission available connecting Tacoma to the EIM footprint
  3) Tacoma's water conditions and generation limitations

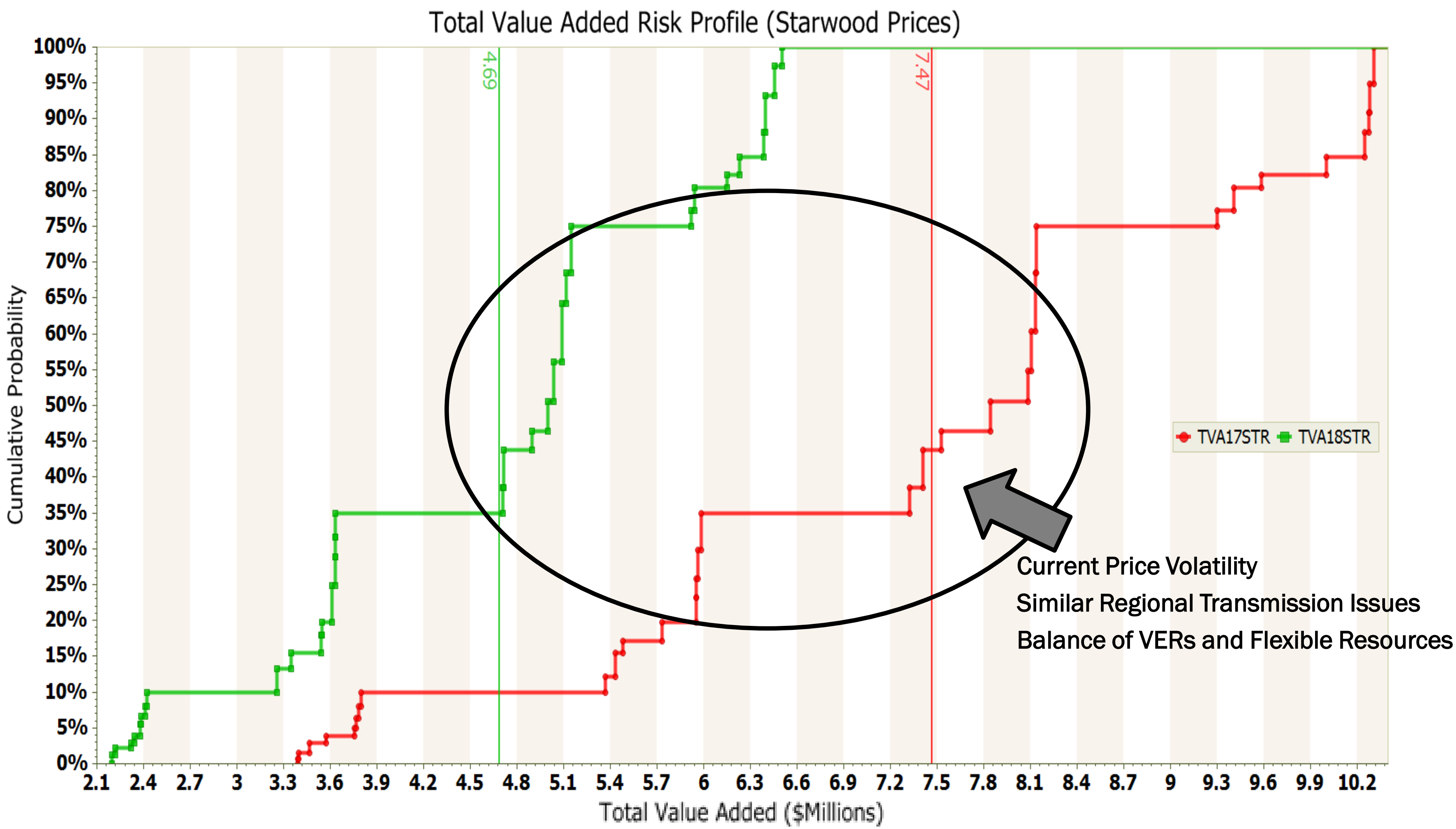
- Created 32 different scenarios to perform a sensitivity analysis on the range of possible outcomes for the historical years

Benefit Estimates



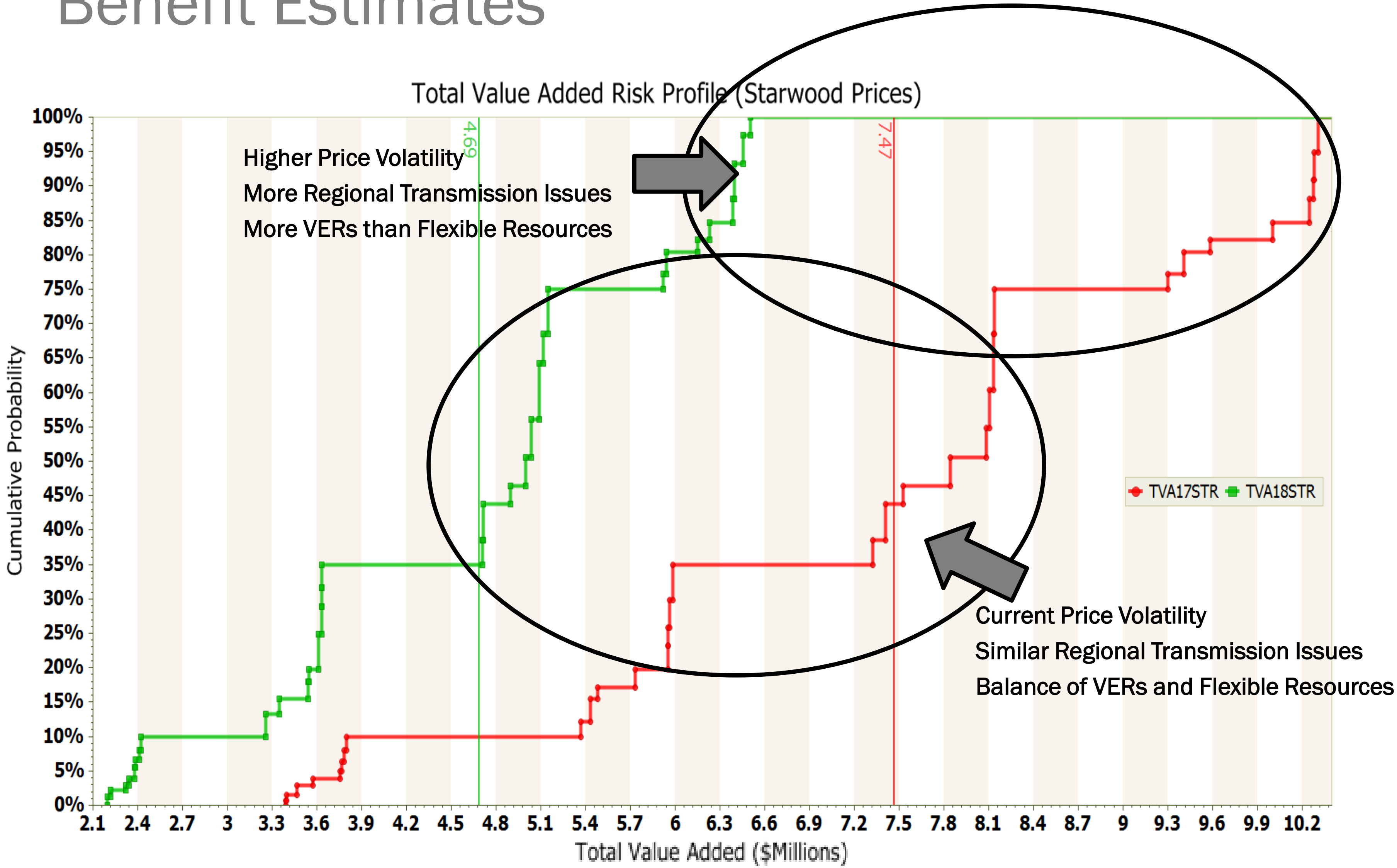
Energy Imbalance Market --- 2018 Cost/Benefit Refresh

Benefit Estimates



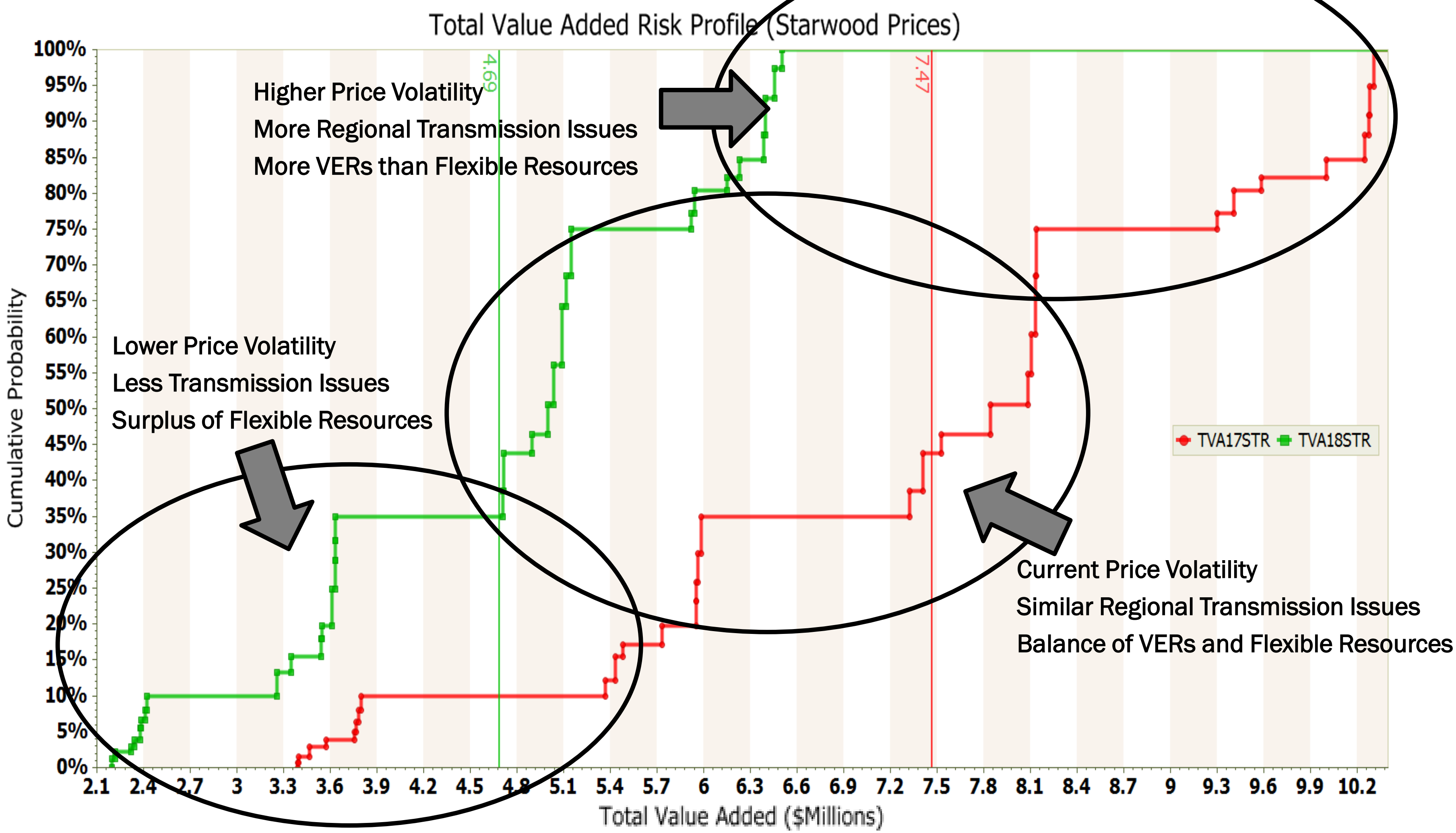
Energy Imbalance Market --- 2018 Cost/Benefit Refresh

Benefit Estimates



Energy Imbalance Market --- 2018 Cost/Benefit Refresh

Benefit Estimates



Recommendation & Next Steps

Section 6

Clay Norris

Recommendations/Next Steps

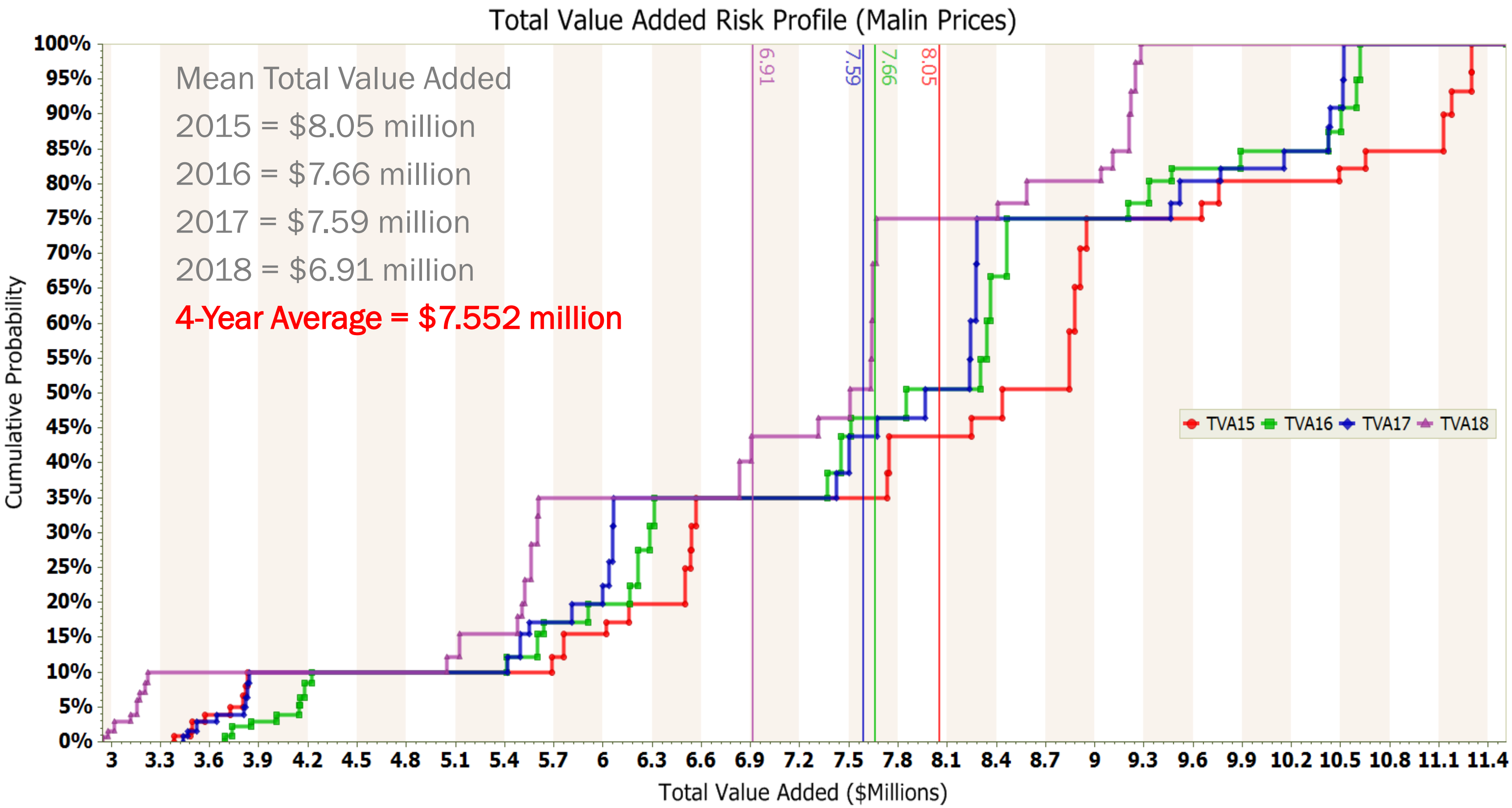
- Staff recommends that Tacoma Power join the EIM because:
  - ✓ Modernizes wholesale trading practices
  - ✓ Prepares Tacoma Power for likely evolution of markets
  - ✓ Reduces risk of reduced trading partners
  - ✓ Improves reliability on pathway to 100% clean grid
  - ✓ Expected benefits exceed expected costs
- This will require the following next steps:
  - Authorization to execute an Implementation Agreement with CAISO
  - Authorization to begin hiring the implementation team, starting with a Program Manager, and procuring the necessary consulting services and software
  - Resolution for project of limited duration

Questions?

2019 EIM Benefit/Cost/Risk Analysis Discussion

Benefit Estimates

Note: In addition to the analysis presented on Slides 35-38, further benefit analysis was conducted using Malin Prices. Malin has a longer period of record but may not be as indicative of prices in the Tacoma area.



Description of Software and Systems

Generator Outage Management System
- Interface for entering generator outage information, operating limits, rough zones, ramp rates, and start/stop limits
- Essential for communicating real-time changes in generation capability to the market and ensuring realistic redispatch instructions
- Can be used to limit generator response to bids within the hour, since bids are submitted hourly

Transmission Outage Management System
- Interface for entering transmission outage information and transmission limits
- Essential for communicating real-time changes in transmission capability to the market and ensuring reliable redispatch instructions

Participating Resource Scheduling Coordinator Bidding Scheduling System
- Interface for submitting real-time bids and generator schedules to the Market Operator (CAISO)
- Structured as a matrix of megawatts and dollars and submitted each hour
- Essential for market redispatch of resources at a price that is reflective of the cost of power production and/or opportunity cost
- Interface for submitting interchange schedules as transaction IDs, used by the market for determining energy demands and supply contractual commitments

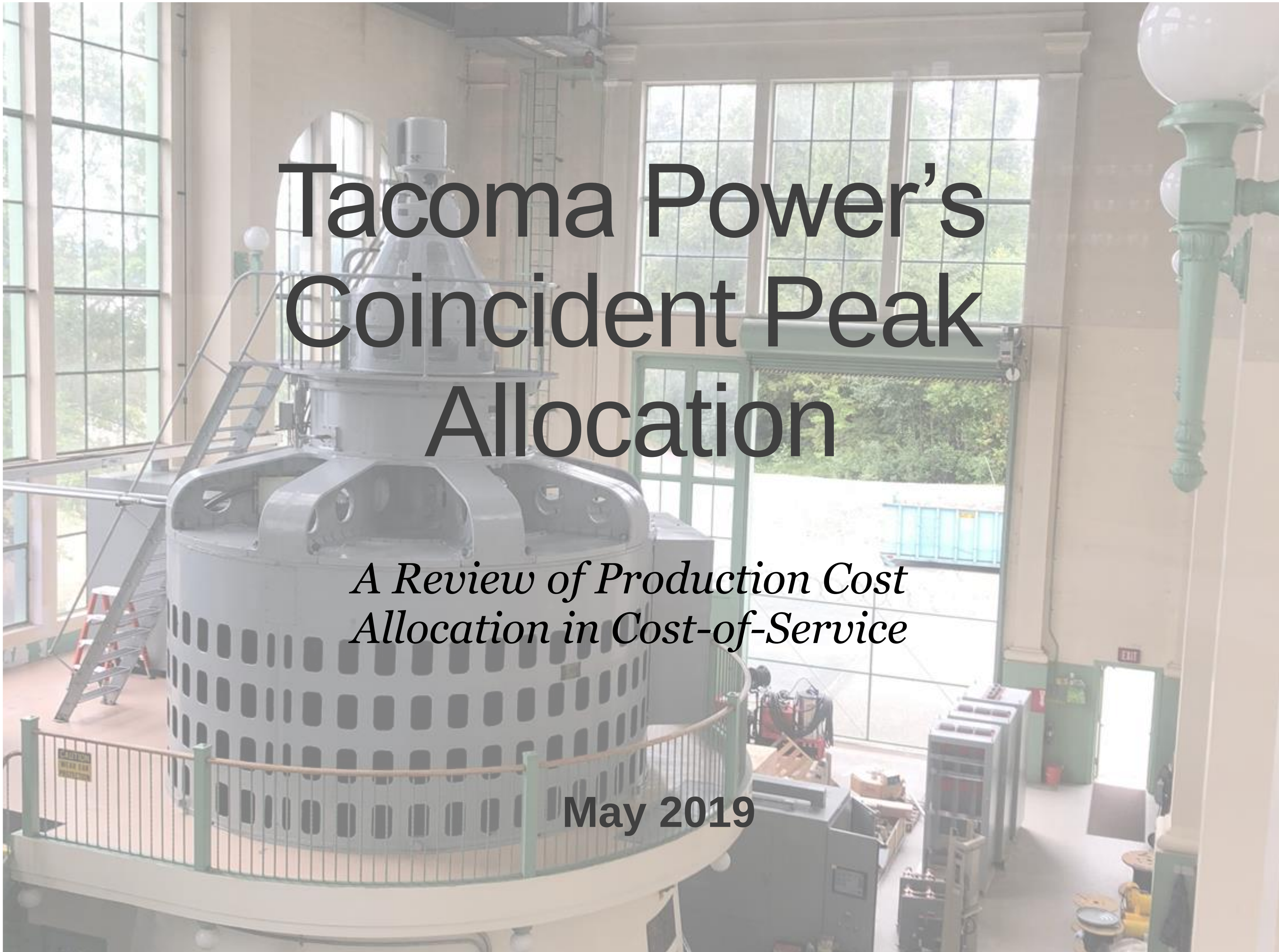
EIM Entity Scheduling Coordinator Scheduling System
- Interface for submitting information on loads and generation of third-party resources to EIM Entity BAA
- Essential for oversight of entire BAA schedules and bid range information

Participating Resource Scheduling Coordination Settlements System
- System for tracking settlement charges, per generator, every 5 minutes
- Essential for ensuring accurate settlements and bid submission

EIM Entity Scheduling Coordinator Settlements System
- System for settling charges and payments of non-participating loads and third-party resources
- Essential for ensuring balanced settlements for entire BAA

Dispatch Integration to EMS
- Interface for remote dispatch instructions into AGC
- Essential for automation of dispatch instructions, compliance, and management of the grid

EIM EMS module
- Essential for OSI EMS system capability that incorporates external setpoints into EMS AGC calculation for dispatch to be sent to Plant Control Systems at the resources



Tacoma Power's Coincident Peak Allocation

A Review of Production Cost Allocation in Cost-of-Service

May 2019

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During the 2018 rate process, McChord Air Force Base representatives brought forward a number of questions regarding Tacoma Power's use of a 12-CP allocator for Production-functionalized, Demand-classified costs. Tacoma Power committed to a review of its practice. This document is one work product responsive to that commitment.

EXECUTIVE SUMMARY

Tacoma Power maintains that the existing 12-CP allocator best reflects the current cost structure of the utility.

Arguments for seasonal CP allocators are more applicable to thermal utilities.

Hydroelectric systems are **unique** because:

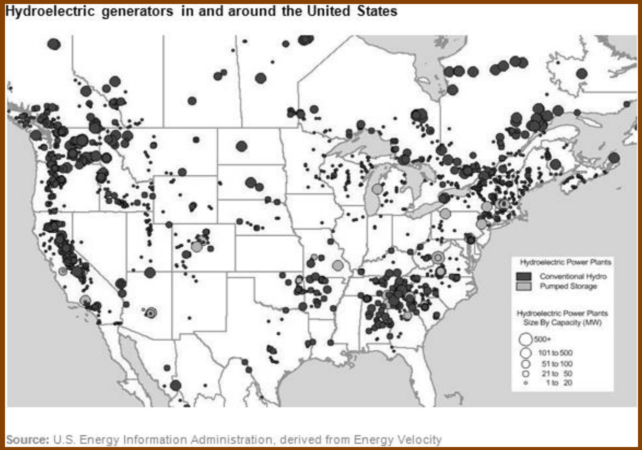
- Plants are **built for energy** instead of capacity
- Time of **greatest resource constraint** is **not** necessarily time of **highest load**
- **Zero fuel cost and fish passage costs** greatly reduce direct link between generator cost and output

Should policymakers decide to change allocation methodologies, changes should be made in accordance with principles of:

- Gradualism
- Public process
- Stakeholder input

The conclusions of this study are based on current utility operating conditions and constraints. Should significant systemic changes occur, a reevaluation may be warranted.

Hydro is Different



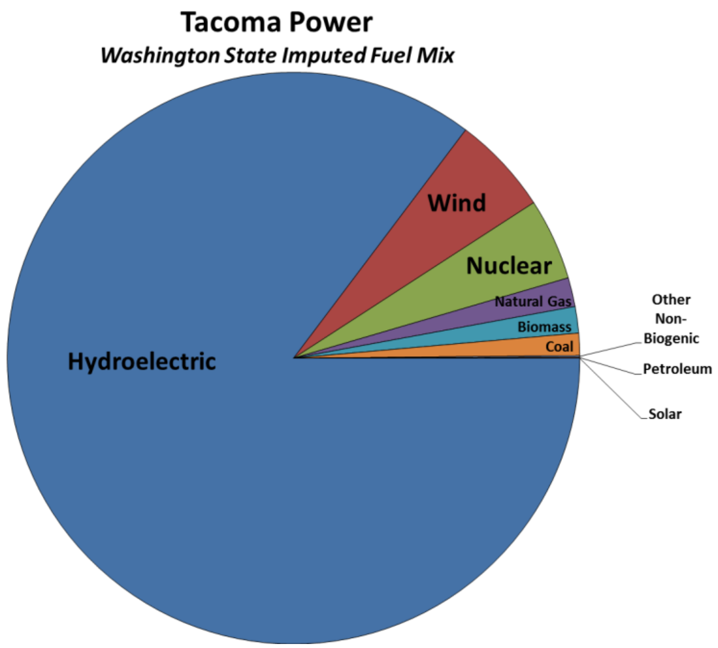
...only 7% of total American electric generation comes from conventional hydroelectric dams.

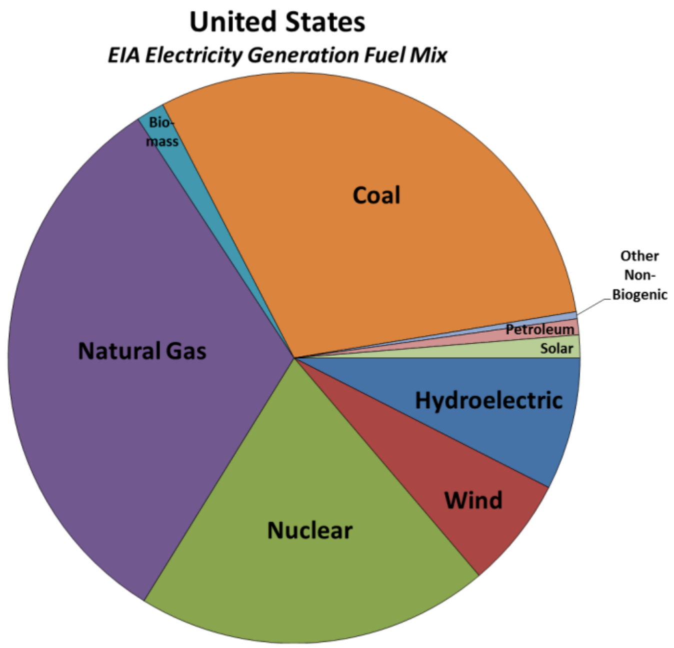
What is Different About Hydroelectric?

01

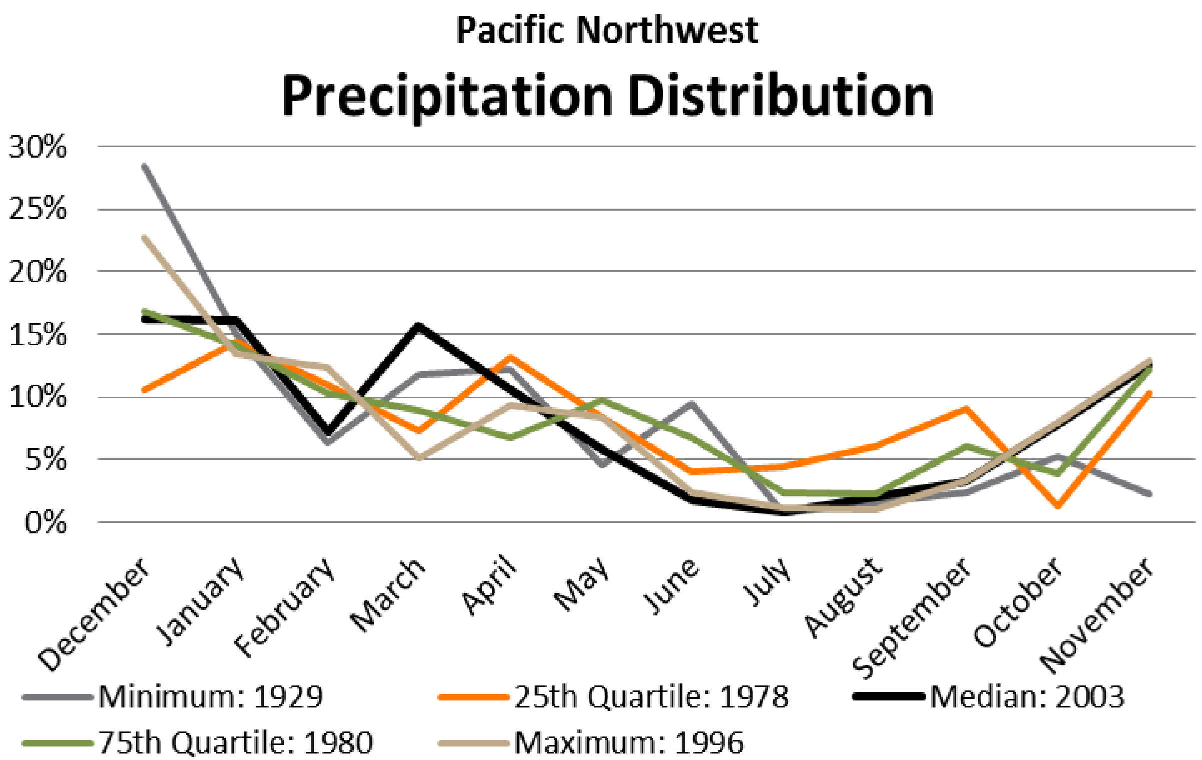
- *Plants built to optimize energy rather than capacity*
- *Constrained load-resource balance not necessarily linked to times of highest retail load*
- *Weather-driven fuel availability*
- *Cost drivers generally not linked to output*

The fundamentals of generation in the Pacific Northwest are different than national norms.





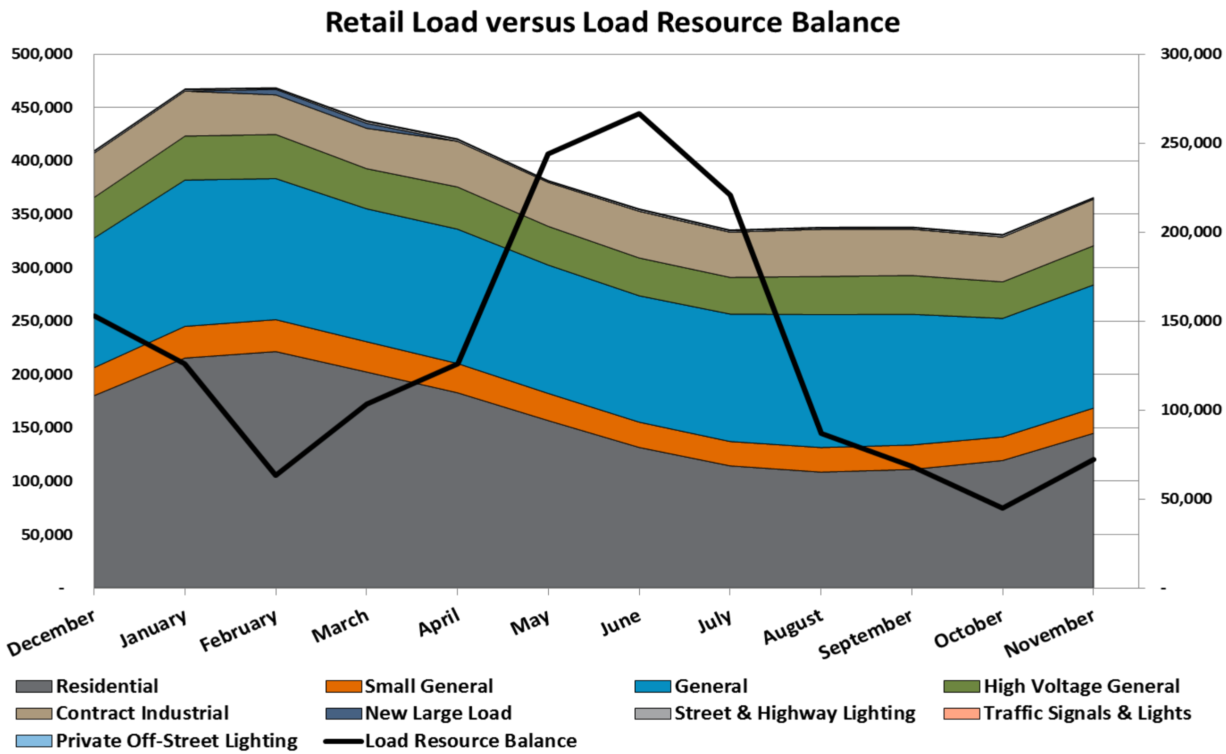
Hydro plants are built to optimize energy and storage rather than time-based capacity.



Hydroelectric generation systems must be managed to deal with extremes of flood and drought… historically, hydro utilities have not even calculated expected peak, but rather "average MW" (aMW).

Since 1912, in the Pacific Northwest basin, an average of 39% of annual calendar-year rainfall has fallen during Winter, while only 11% has fallen on average in the Summer. Of course, these averages mask considerable year-to-year variation.

Constrained load-resource balance does not occur at times of highest retail load.



Fuel availability cannot be aligned with load, as it is in most other utilities.

Instead of being inversely related, lowest load/resource balance and lowest load both occur in the same month.

In traditional thermal-based systems, the time of most constrained power supply (lowest load/resource balance) occurs at time of system peak. In contrast, Tacoma Power experiences lowest load/resource balance in October, while experiencing retail peak in February.

Peak capacity is not coincident with peak load.

		Load Resource Balance (MWh)	rank	Retail Load (MWh)	rank
Winter	December	153,050	9	409,648	5
	January	125,906	8	467,474	2
	February	63,338	2	**468,615**	**1**
Spring	March	103,444	6	437,776	3
	April	125,844	7	420,777	4
	May	243,906	11	381,667	6
Summer	June	*266,766*	*12*	355,200	8
	July	220,605	10	335,446	11
	August	86,911	5	337,882	10
Autumn	September	68,271	3	338,129	9
	October	**45,077**	**1**	*331,174*	*12*
	November	72,216	4	365,739	7
Winter		342,294	2	*1,345,737*	*4*
Spring		473,195	3	1,240,219	3
Summer		*574,283*	*4*	**1,028,528**	**1**
Autumn		**185,564**	**1**	1,035,042	2

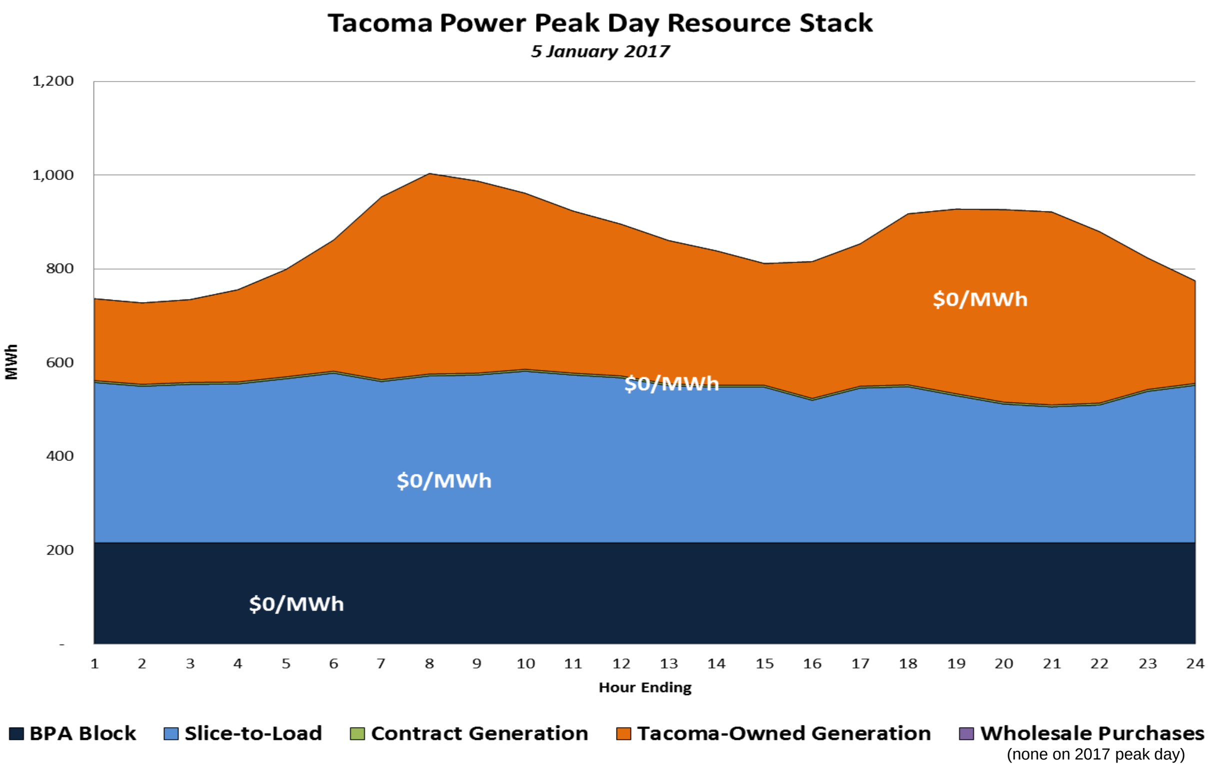
Therefore,

time of
peak load

≠

time of greatest
resource constraint
or expense.

There is no fuel cost.



Graph shows marginal resource cost.

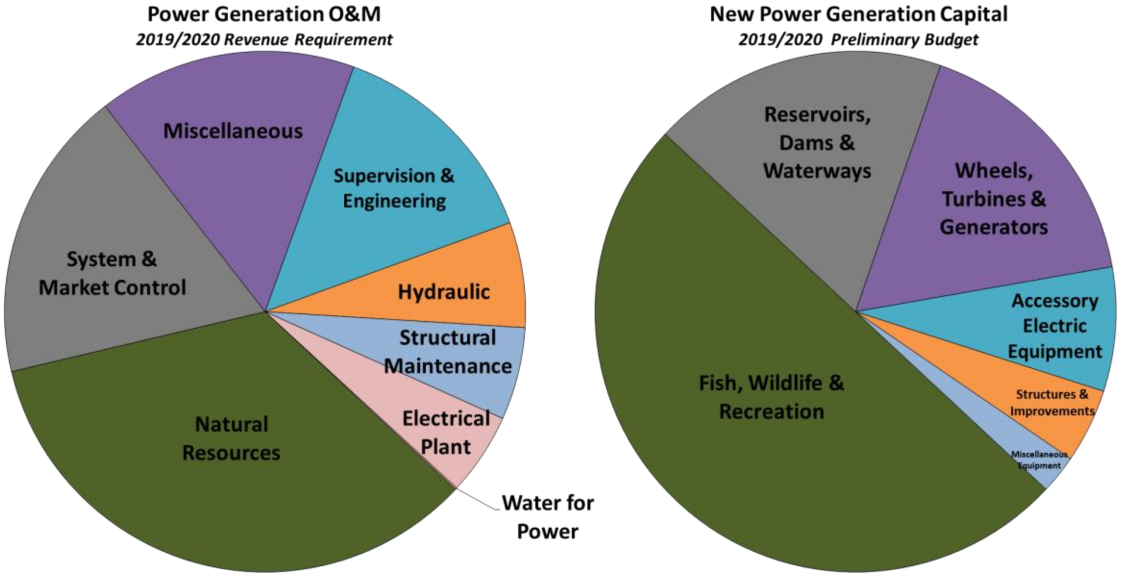
Therefore,

most production costs are effectively fixed.

Costs that occur in peak seasons have no special significance.

If sufficient water is behind the dam, additional power may be generated by merely opening a valve. This has a de minimis *impact on operating and maintenance costs, which are overwhelmingly driven by safety and environment needs.*

Cost drivers are generally not linked to output.



Therefore,

peaks have
no special relevance
in determining cost-causation.

Many of the costs associated with Tacoma Power generation are not associated with the Winter load peak. Some, such as fish and recreation costs, may actually be anti-seasonal (i.e. Summer-peaking).

The Case for 12-CP

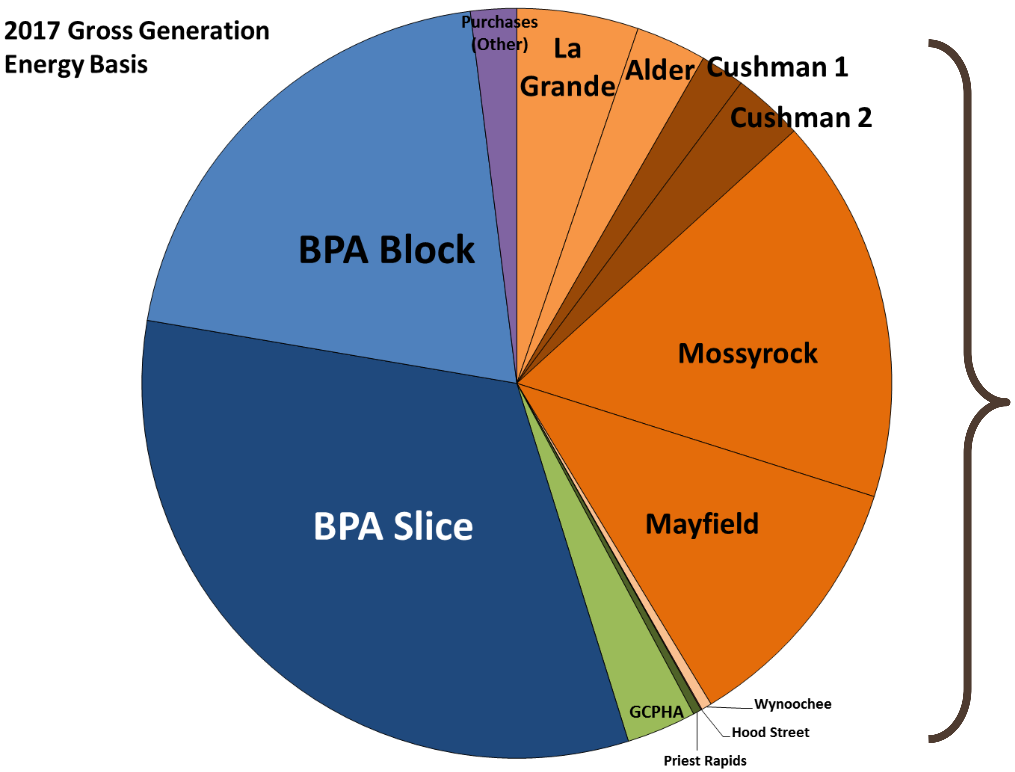
Tacoma Power enjoys the benefits of regional hydropower.

Does 12-CP reflect costs?

+ *System design driven by energy, not peak*
+ *BPA Billing*
+ *Peer Utilities*
+ *Other Considerations: FERC Test, Market Activity*

02

Tacoma-owned hydro and BPA purchases dominate Tacoma Power's resource mix.



Tacoma-owned in orange

The allocation methodology chosen should reflect Tacoma Power's unique resource mix.

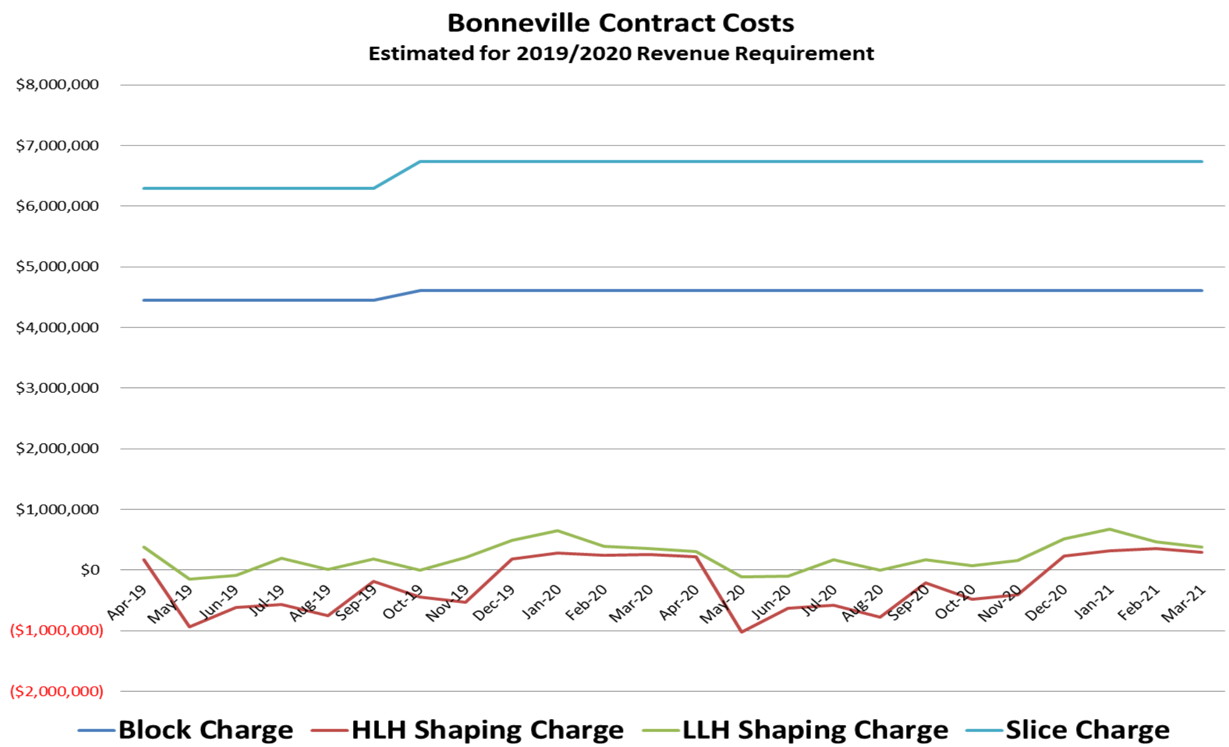
The Tacoma-owned hydro portion of the system was not designed for peaks.

> …A critical year could have normal stream flows in the months of November-January, followed by very dry months from March-June. Resource adequacy metrics using historical critical year would indicate that December and January are not a resource concern and favor a resource strategy that targeted energy supply in April-June. Using a probabilistic resource adequacy standard based on the 5th percentile of each month would more accurately describe the possible future risk; i.e. each month has a possibility of low stream flows…

Existing evidence is suggestive that historical planning for Tacoma Power was focused on energy, not peak. The most recent IRP also noted that resource inadequacy cannot be limited to one month or season.

A peak-season allocator for Demand-allocated Production costs is most theoretically appropriate when the system is built to meet the seasonal load peak. Tacoma Power's current Integrated Resource Plan (IRP) standard specifically notes that hydroelectric resource inadequacy might occur in any month, due to low stream flows, not just in Winter, due to high loads.

BPA costs are based on energy and primarily fixed ("take-or-pay").



Block and Slice charges, which represent 99.94% of billing dollars for the rate period, change once annually, in October.

BPA charges are based on each utility's % of total BPA system energy generation. The billing determinant is essentially at fixed customer charge. Coincident peak capacity does not factor into the BPA cost allocation methodology.

Peer utilities use various methodologies.

Seattle City Light

No classification of Production costs as either Energy- or Demand- related.

Use a marginal cost methodology.

Snohomish County Public Utility District

No Production costs classified as Demand-related until 2017.

Now a very small share of Demand-classified costs are allocated on 1-CP basis.

Only has one dispatchable hydroelectric dam.

The rest is largely BPA.

Puget Sound Energy

Just changed to interim 4-CP allocator under recent settlement negotiation.

- *Allocation is still under review.*
- *Allocation only applies to 25% of generation portfolio. The rest is allocated based on energy.*

Mostly fossil generation. Only 7% of generation nameplate capacity is hydroelectric.

Idaho Power

For areas under the Idaho Public Utilities Commission:

- *Hydroelectric resources are "base and intermediate" resources allocated on 12-CP basis.*
- *Natural-gas resources allocated on 3-CP basis.*

Areas under the Oregon Public Utility Commission use a marginal cost methodology.

FERC Test is One Measure for IOUs.

FERC Federal Energy Regulatory Commission

FERC 12-CP Allocation Tests

FERC traditionally uses three load tests to determine whether it will approve of use of a 12-CP allocator for demand-related production costs for a utility under its jurisdiction.

- On and Off Peak Test
- Low to Annual Peak Test
- Average to Annual Peak Test

Results

In eight out of the last ten years, Tacoma Power has not met any of the three tests used by FERC to determine eligibility for use of a 12-CP allocator.

If Tacoma Power were a FERC-regulated utility, it might be directed to use a Winter peak (3-CP) allocator.

Considerations

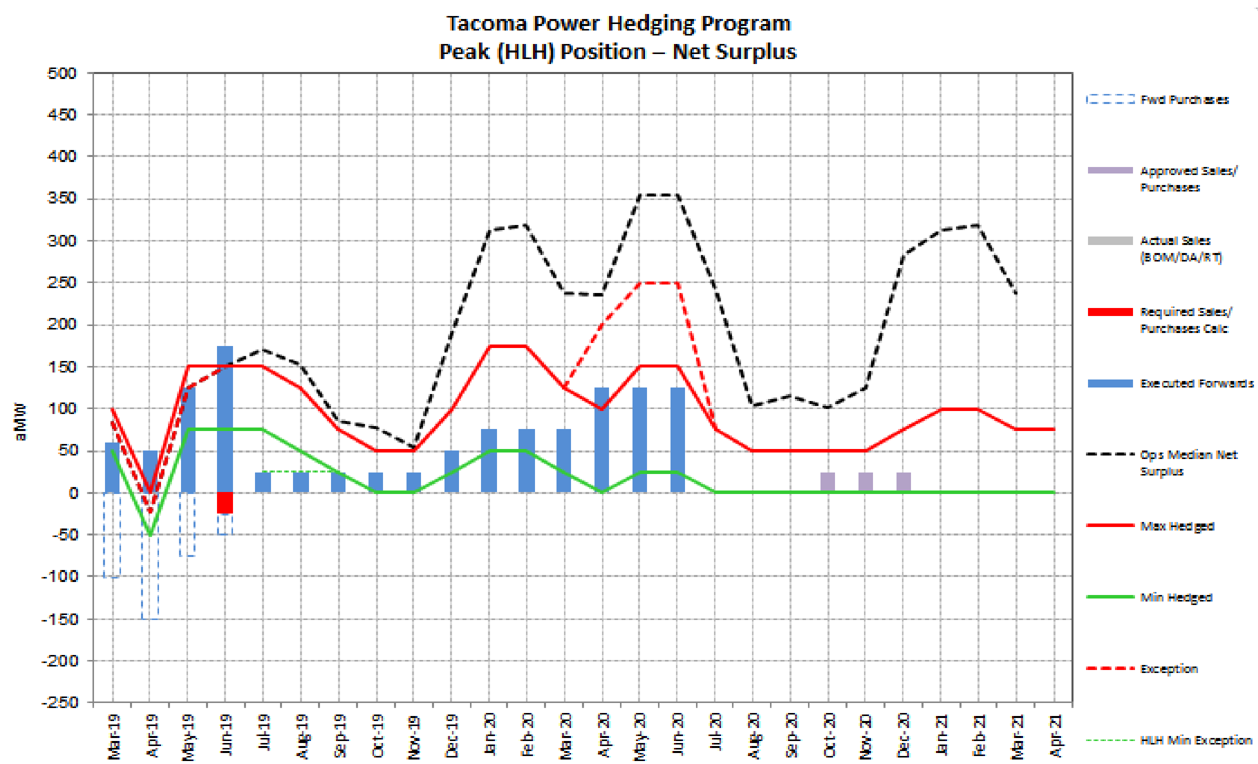
Tacoma Power is not a FERC-jurisdictional utility,

Differs from utilities under FERC jurisdiction by its extensive use of hydroelectric resources.

Utilities governed by FERC are almost always thermal-dominated.

The Pacific Northwest power market is unique in resource supply mix and large presence of public power.

Market focus is selling excess supply, not buying capacity for seasonal peaks.



Tacoma Power's market activity seeks to maximize wholesale revenues while reducing risk through hedging.

This activity occurs year-round, not just during peak load periods.

Tacoma Power's hedging program often requires the utility to sell projected excess energy generation in the future ("forward sales"). The very concept of "excess generation" would not make sense in the world of thermal generation, where fuel supply (and related generation ability) is controlled entirely by the utility.

Future Possibilities

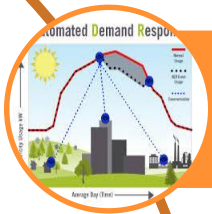
The industry is changing as are the marginal supply sources in the U.S. Tacoma is just starting to see a potential need for, and value in, peaking capacity. The utility has made no financial commitments or determinations to date, but will be assessing in future resource planning cycles.

What could change this result?

+ *Demand response*
+ *Wholesale market changes*
+ *Contract changes*
+ *Climate change*

03

Appropriate allocations may change over time.



Demand Response

Pilot DR rate under consideration; seeking opportunities to partner with customers to share benefits of load flexibility

Wholesale Market Changes

introduction of Energy Imbalance Market into the Northwest may fundamentally change cost drivers

Contract Changes

Current long-term contract with BPA expires in 2028; new contract terms may change cost drivers

Climate Change

Systematic operational changes due to systematic weather shifts may change cost drivers

Ratemaking values should guide any decision and change process.

- Gradualism
- Public Process
- Diverse Stakeholder Input
- Balance of Objectives

Appendix

+ What is a CP allocator?

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WHAT IS A COINCIDENT PEAK (CP) ALLOCATOR?

Demand-driven costs are often allocated based on "coincident peak". At the moment of a system peak, the demand of each class of customers is estimated. The contribution of each customer class to the peak is used to allocate the costs to each class.

In a 3-CP allocation, monthly peak for each of the three highest months is used to create the allocator. In a 12-CP allocation, monthly peak for each of the months of the year is used to create the allocator.

During the peak season (winter), the residential class tends to contribute the most to the peak, because residential customers tend to be the most weather-sensitive (have the most heating load). Therefore, a peak-season (3-CP) allocator allocates more to the residential class.

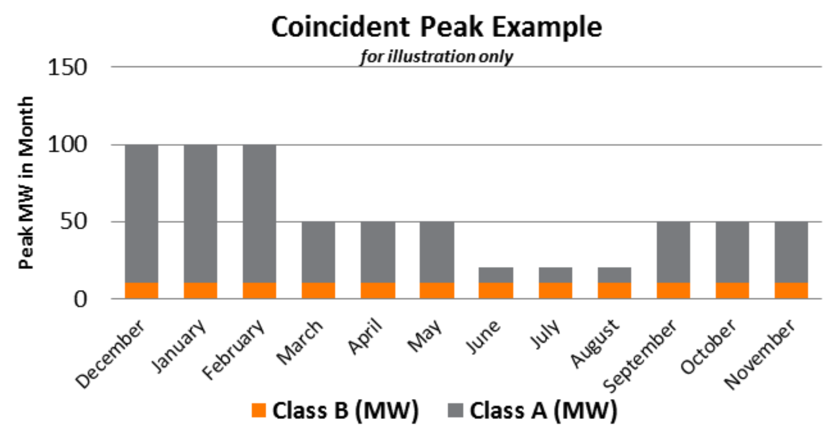
In the 2019/2020 Cost-of-Service Analysis, use of a 12-CP allocator results in $4.9 million dollars of the biennial rate increase being allocated to the residential class. Use of a 3-CP allocator results in $12.3 million dollars of the rate increase being allocated to the residential class.

In percentage terms, use of a 12-CP allocator results in a +1.3% residential rate increase levelized over the biennium. Use of a 3-CP allocator results in a +3.4% residential rate increase levelized over the biennium.

WHAT IS A COINCIDENT PEAK (CP) ALLOCATOR?

Consider the example of a winter-peaking utility with two classes, a weather-sensitive Class A and a flat-load Class B.

The percent contribution to monthly peak of Class A varies from 90% in winter to 50% in summer. Therefore, an average that includes the summer months is lower than an average which only includes winter months.



Estimated Class Load at Time of Monthly Peak	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov
Class A (MW)	90	90	90	40	40	40	10	10	10	40	40	40
Class B (MW)	10	10	10	10	10	10	10	10	10	10	10	10
Total System (MW)	**100**	**100**	**100**	**50**	**50**	**50**	**20**	**20**	**20**	**50**	**50**	**50**

Class Contribution to Peak as percent	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov
Class A	90%	90%	90%	80%	80%	80%	50%	50%	50%	80%	80%	80%
Class B	10%	10%	10%	20%	20%	20%	50%	50%	50%	20%	20%	20%
Average for 3 Months (Winter)	**90% Class A, 10% Class B**											
Average for 12 Months	**75% Class A, 25% Class B**											