2023 Electric Integrated Resource Plan

Technical Advisory Committee Meeting No. 5 Agenda

Wednesday, September 7, 2022

Microsoft Teams Virtual Meeting

Topic	Time	Staff
Introductions	12:30	John Lyons
IRP Generation Option Transmission Planning Studies	12:40	Dean Spratt
Distribution System Planning within the IRP	1:45	Damon Fisher
Break		
Social Cost of Greenhouse Gas for Energy Efficiency (WA only)	3:00	James Gall
Avoided Cost Rate Methodology	3:15	Clint Kalich
Adjourn	4:00	

2023 IRP Introduction

2023 Avista Electric IRP

TAC 5 – September 7, 2022

John Lyons, Ph.D. Senior Resource Policy Analyst

Meeting Guidelines

- IRP team is working remotely and is available for questions and comments
- Stakeholder feedback form
  - Responses shared with TAC at meetings, by email and in Appendix
  - Would a form and/or section on the web site be helpful?
- IRP data posted to web site – updated descriptions and navigation are in development
- Virtual IRP meetings on Microsoft Teams until able to hold large meetings again
- TAC presentations and meeting notes posted on IRP page
- This meeting is being recorded and an automated transcript made

Virtual TAC Meeting Reminders

- Please mute mics unless commenting or asking a question
- Raise hand or use the chat box for questions or comments
- Respect the pause
- Please try not to speak over the presenter or a speaker
- Please state your name before commenting
- Public advisory meeting – comments will be documented and recorded

Integrated Resource Planning

The Integrated Resource Plan (IRP):

- Required by Idaho and Washington* every other year
  - Washington requires IRP every four years and update at two years
- Guides resource strategy over the next twenty + years
- Current and projected load & resource position
- Resource strategies under different future policies
  - Generation resource choices
  - Conservation / demand response
  - Transmission and distribution integration
  - Avoided costs
- Market and portfolio scenarios for uncertain future events and issues

Technical Advisory Committee

- Public process of the IRP – input on what to study, how to study, and review of assumptions and results
- Wide range of participants involved in all or parts of the process
  - Please ask questions
  - Always soliciting new TAC members
- Open forum while balancing need to get through topics
- Welcome requests for new studies or different modeling assumptions.
- Available by email or phone for questions or comments between meetings
- Due date for study requests from TAC members – October 1, 2022
- External IRP draft released to TAC – March 17, 2023, public comments due – May 12, 2023
- Final 2023 IRP submission to Commissions and TAC – June 1, 2023

Remaining 2023 IRP TAC Meeting Schedule

- TAC 5: September 7, 2022
- TAC 6: September 28, 2022, 12:30 – 4:00 pm
- Public Participation Partners opportunity to comment on Avista's advisory groups
  - September 12, 2022, 11:00 am to 12:00 pm or September 13, 2022, 9:00 am to 10:00 am
- TAC 7: October 11, 2022, 9 am – 3:30 pm
- Technical Modeling Workshop: October 20, 2022
- Washington Progress Report Workshop: December 14, 2022
- TAC 8: February 16, 2023
- Public Meeting Gas & Electric IRPs: March 8, 2023
- TAC 9: March 22, 2023

Today’s Agenda

12:30	Introductions, John Lyons
12:40	IRP Generation Option Transmission Planning Studies, Dean Spratt
1:45	Distribution System Planning within the IRP, Damon Fisher
	Break
3:00	Social Cost of Greenhouse Gas for Energy Efficiency (WA Only), James Gall
3:15	Avoided Cost Rate Methodology, Clint Kalich
4:00	Adjourn

Integrated Resource Plan (IRP) Transmission Planning Studies

Dean Spratt, Transmission Planning

Technical Advisory Committee Meeting

September 07, 2022

FERC Standards of Conduct

Summary of requirements

- Non-public transmission information can not be shared with Avista Merchant Function employees.
- There are Avista Merchant Function employees attending today.
- We will not be sharing any non-public transmission information. Avista's OASIS is where this information is made public.

Agenda

- Introduction to Avista System Planning
  - Useful information about Transmission Planning
  - Overview of recent Avista projects

- Generation Interconnection Study Process
  - Integrated Resource Plan (IRP) Requests
  - Large Generation Interconnection Queue
  - Transition to Cluster Study Process

Introduction to Avista System Planning

Avista's System Planning Group includes:

- Distribution Planning
- Transmission Planning
  - Focus on reliable electric service
    - Federal, regional, and state compliance
    - Regional system coordination
  - Provide transmission service and system analysis
    - Planned load growth and changing generation mix/dispatch
    - Interconnection of any type of generation or load
      - We are ambivalent about type (must perform though)

Information About Transmission Planning

- Our focus is the Bulk Electric System (BES)
  - Avista's 115 kV and 230 kV facilities (>100 kV)
- We identify issues where Avista's BES won't reliably deliver power to our customers
- Then we develop plans to fix it
  - "Corrective Action Plans"
  - Mandated and described in NERC TPL-001-4
- We live in the world of NERC Mandatory Standards
  - Energy Policy Act of 2005

NERC Standard TPL-001-4

- Describes outage conditions we must study
  - P0: everything online and working
  - P1: single facility outages, like a transformer
  - P2, P4, P5 & P7: multiple facility outages
  - P3 & P6: overlapping combination of two facilities

Standard TPL-001-4 — Transmission System Planning Performance Requirements

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
d. Simulate Normal Clearing unless otherwise specified.
e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.
g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.
h. Planning event P0 is applicable to steady state only.
i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Standard TPL-001-4 — Transmission System Planning Performance Requirements

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]
		5. Single pole of a DC line	SLG		
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]
				HV	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]
				HV	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes

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TPL-001-4, cont.

- A couple of NERC directives for the above faults
  - “The System shall remain stable”
    - Cascading and uncontrolled islanding shall not occur
  - “Applicable Facility Ratings shall not be exceeded”
    - Equipment ratings, voltage, fault duty, etc
  - “An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events”

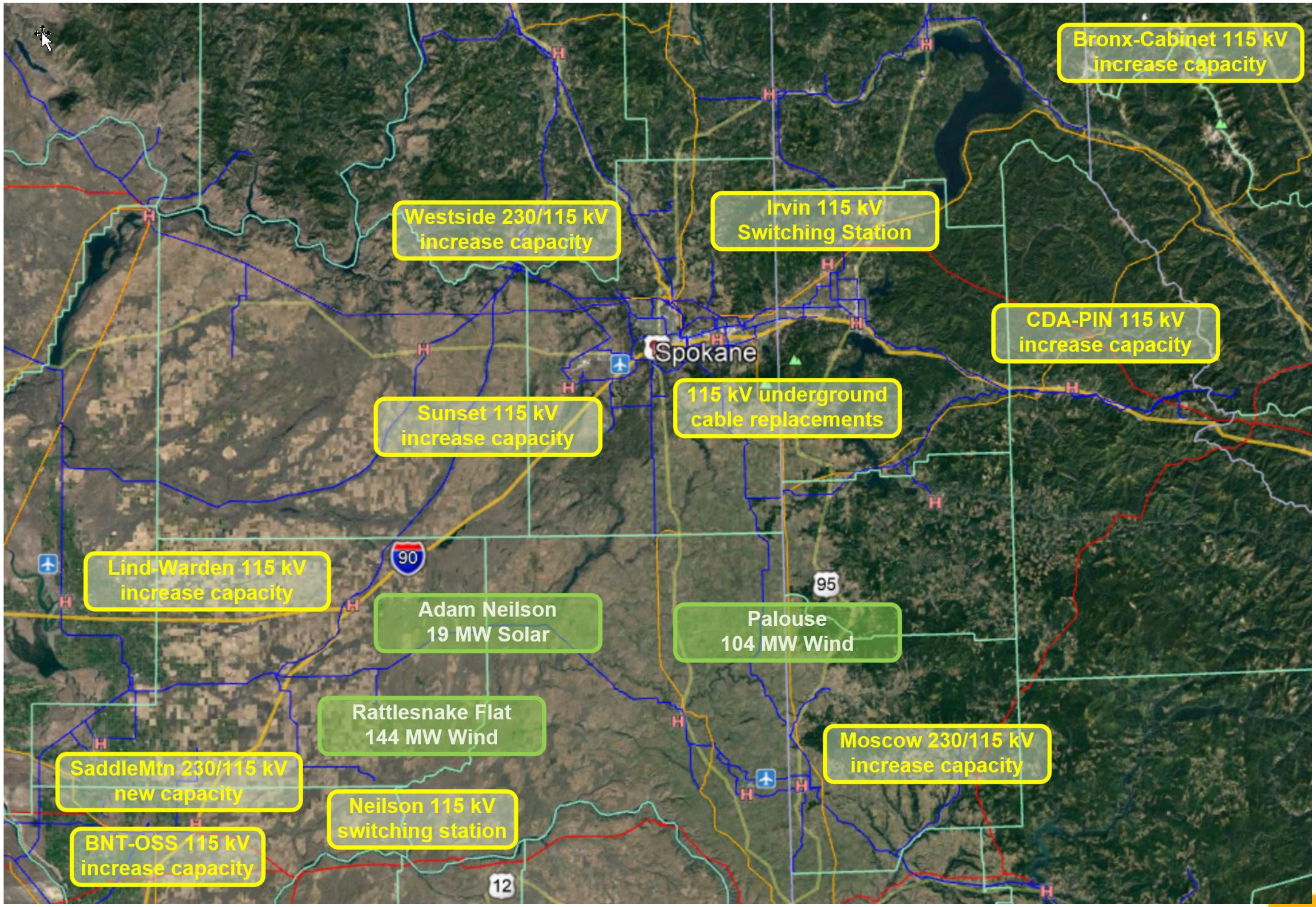
Two Approaches to Reliability Issues

- Transmission Operations (TO) are guided by *significantly* different standards than Transmission Planning (TP).
- TO standards provide *flexibility* that TP standards do not allow
  - Operators can push system limits to ***SAVE*** the interconnected system
    - Shed load, overload equipment, etc – all short term
    - The planned system should give them the tools to do this
    - The standards continue to define this balance

Standards are a Roadmap

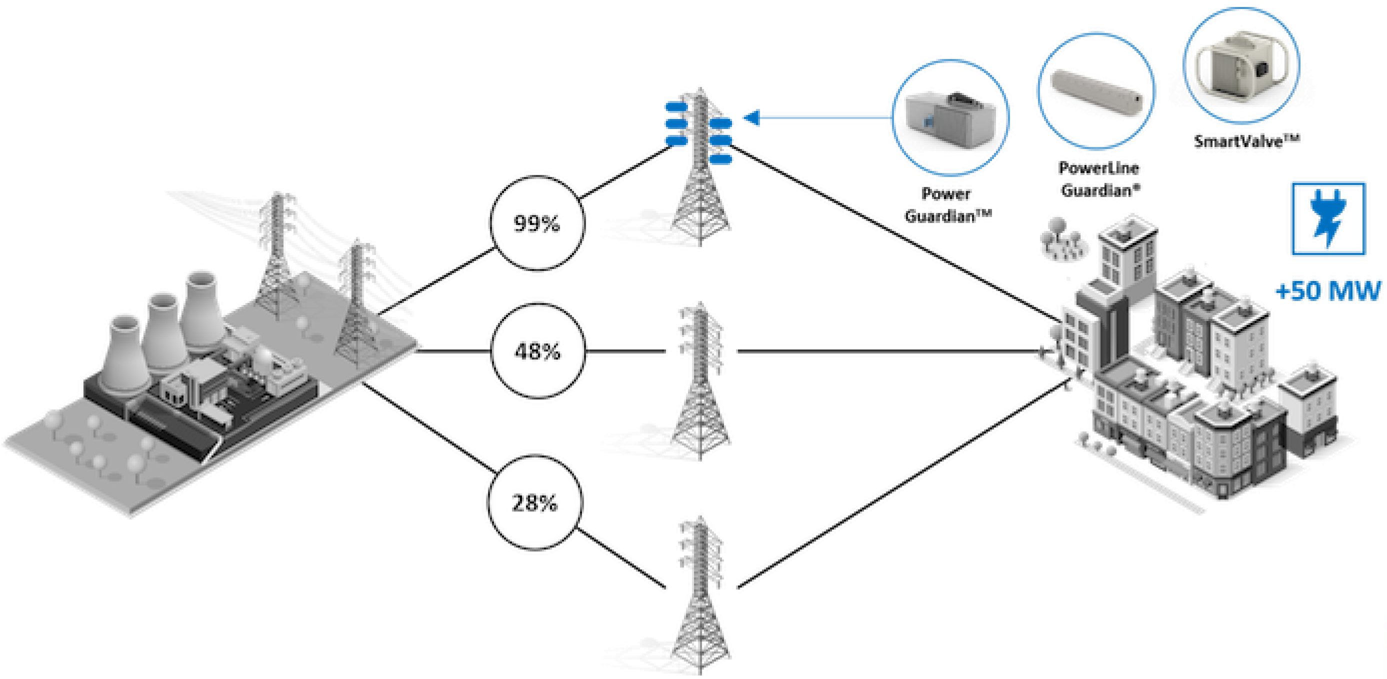
- Western Systems Coordinating Council (WSCC)
  - Ensure that disturbances in one system do not spread to other systems.
    - Operating agreement with 40 electric power systems established in 1967
- Western Electricity Coordinating Council (WECC)
  - Responsible for coordinating and promoting electric system reliability established in 2002
- North American Electric Reliability Council (NERC)
  - Ensure the reliability of the North American bulk power system reformed in 2006; Corporation in 2007
    - Established as a voluntary organization in 1968

Recent Transmission Projects



Non-Wire Alternatives are Considered

- We are documenting this with more clarity
- Non-wire options require robust wires to perform
  - Avista is working on the transmission fundamentals



Evaluated Batteries for T-1-1

- TPL-001-4 ~ T-1-1 for long lead equipment
  - Double transformer outages
    - Shawnee 230/115 kV outage followed by a concurrent outage of Moscow 230/115 kV transformer.
  - Could we mitigate performance issues with storage?
    - Yes…but… We would need a 125 MW battery
      - Typical charge is 8 hours, discharge for 12 to 16 hours
      - Transformer outage is weeks to months
    - A third transformer is a better solution
      - Robust performance and much less $$$$

Requisitions: Requisitions >

Requisition 162964

Description	**M08 - Westide 250/280MVA, 230-115-13.8kV, three phase auto transformer.**	Status	Approved
Created By	**Wilson, Barnes Scott (Scott)**	Change History	**No**
Creation Date	**12/06/2017 12:49:35**	Urgent Requisition	**No**
Deliver-To	**One Time Ship To**	Attachment	View
Justification	**This is the second transformer associated with the Westside Substation rebuild.**	Note to Buyer	**Quote attached. Bid evaluation sheet pre Shelly Campbell.**

Details

Line	Description	Need-By	Deliver-To	Unit	Quantity	Qty Delivered	Qty Cancelled	Open Quantity	Price	Amount (USD)
1	250/280MVA, 230-115-13.8kV, three phase auto transformer.	10/03/2018 12:51:34	One Time Ship To	Each	1	1	0	0	2397826 USD	2,397,826.00
2	SFRA Testing at factory and field	10/03/2018 12:51:34	One Time Ship To	Each	1	1	0	0	5400 USD	5,400.00
									Total	**2,403,226.00**

Generation Interconnection Study Process

Process for Generation Requests

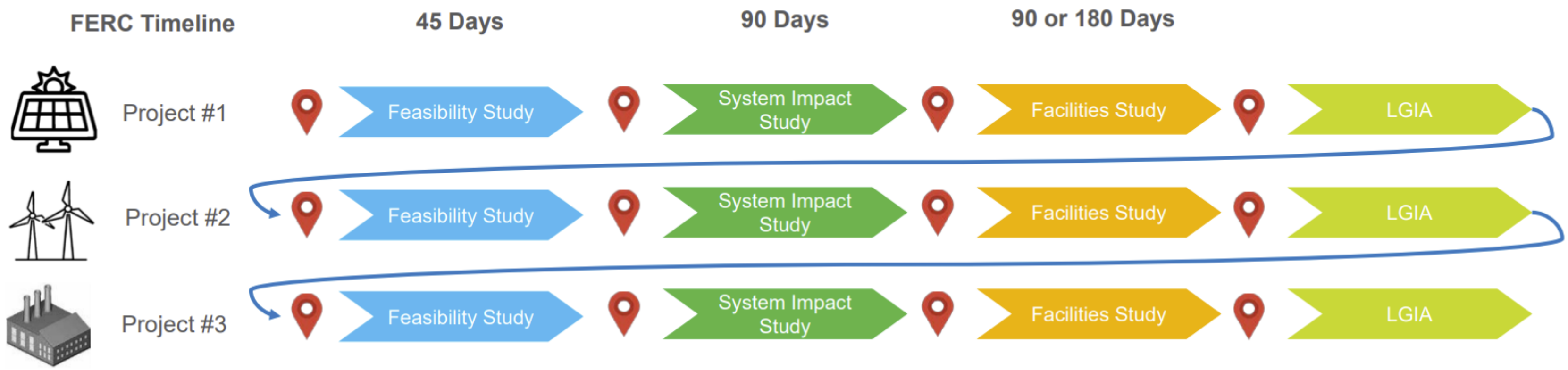
- Two sources:
  - External developers
    - Enter via the OATT
  - Internal IRP requests
    - Feasibility Light Study…then OATT
      - AVA Merchant MUST follow the OATT just like external parties
- Typical process:
  - Hold a scoping meeting to discuss particulars
  - Outline a study plan
  - Augment WECC approved cases for our studies
  - Analyze the system against the standards
  - Publish our findings and recommendations

Transition - Serial to Cluster Study Process

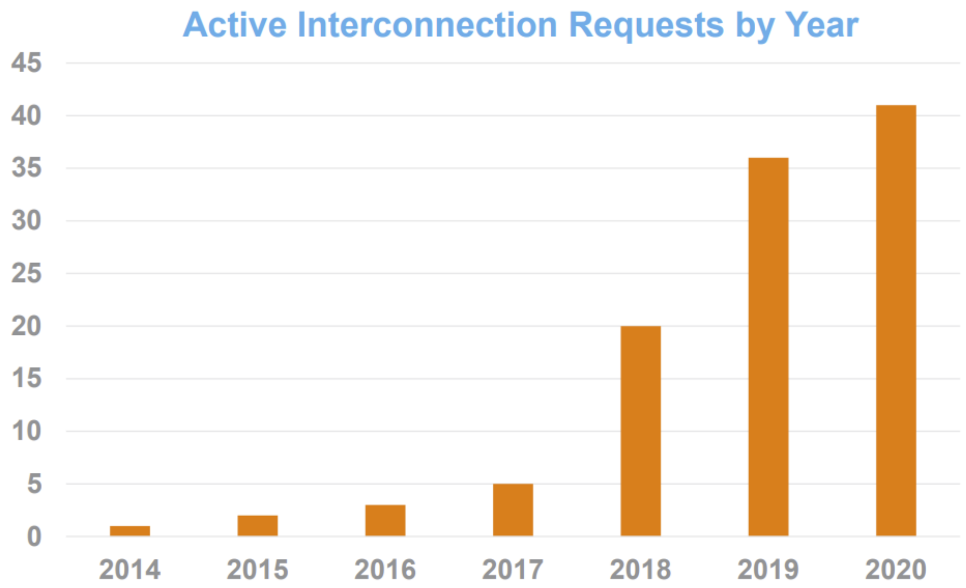
Challenges with Serial Interconnections

- Large serial queues become difficult to process efficiently
- Interdependency of projects becomes complicated
  - Studying single projects is inefficient compared to studying projects in a group
  - Projects that do not reach commercial operation may cause re-studies
  - System Upgrade allocation
- The serial process is difficult for the developers and the utility

Serial Process was Complex and Slow



Interconnection Requests necessitated a better Process



Two-Phase Cluster Study Process

Benefits and Objectives

- Create a more efficient process
- Design a process with definitive timelines that can be consistently met
- Allocate System Upgrades proportionally
- Ensure commercially viable projects have a clear path for development
- Alleviate the backlog in the queue

Current Interconnection Queue

Serial or Cluster Number	Project Name	Former Queue Number	Max MW Output	Type	County	State
LGIA	Saddle Mountain	46	126	Wind	Adams	WA
LGIA	Taunton	52	100	Solar	Adams	WA
LGIA	Asotin	60	150	Solar	Asotin	WA
LGIA	Kettle Falls	66	71	Wood Burner/ CT	Stevens	WA
Senior	Aurora	59	116	Solar/Storage	Adams	WA
Senior	Post Falls	63	26	Hydro	Kootenai	ID
Senior	Elf II	79	2.1	Solar	Spokane	WA
Senior	Elf I	80	19	Solar	Spokane	WA
Senior	Acadia	84	5	Solar	Stevens	WA
Senior	Lolo Solar	97	100	Solar/Storage	Nez Perce	ID
TCS-02	Rattlesnake II	62	123.2	Wind	Adams	WA
TCS-03	Old Milwaukee	67	80	Solar/Storage	Adams	WA
TCS-04	Sprague	73	94	Solar/Storage	Adams	WA
TCS-05	Royal City	76	114.12	Solar	Grant	WA
TCS-06	Ralston	81	94	Solar/Storage	Adams	WA
TCS-07	Rainier	85	5	Solar	Adams	WA
TCS-08	Wahatis	99	200	Solar/Storage	Franklin	WA
TCS-09	Stringtown	100	100	Solar/Storage	Spokane	WA
TCS-10	Harrington	103	40	Solar	Lincoln	WA
TCS-11	Latah	104	120	Wind	Spokane	WA
TCS-12	Orin	105	5	Solar	Stevens	WA
TCS-14	Cloudwalker	110	375	Wind/Solar/Storage	Garfield	WA
TCS-16	Daydreamer	112	125	Solar/Storage	Lincoln	WA
TCS-18	Dry Falls	119	200	Solar/Storage	Grant	WA

Transmission Integration Cost Estimates

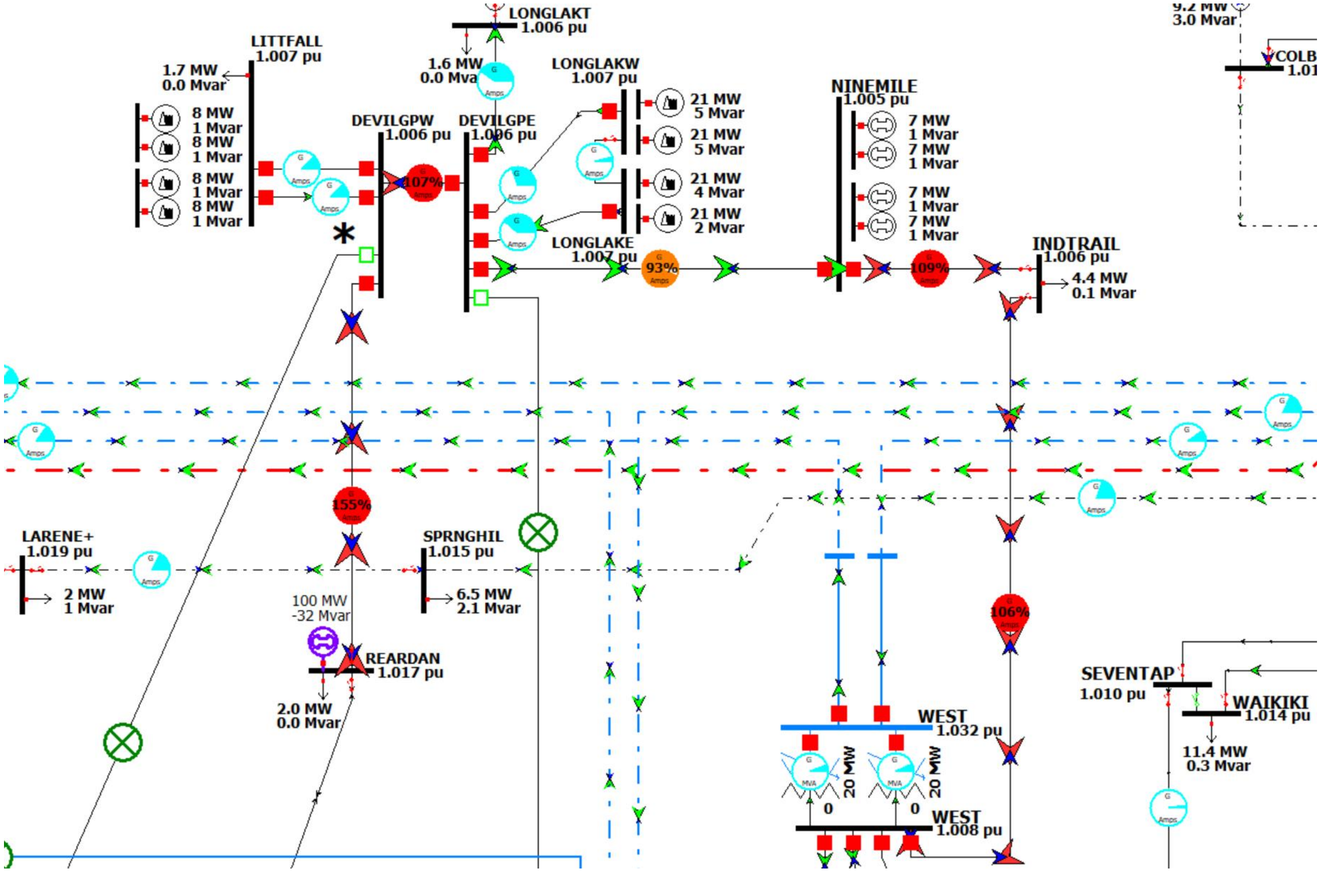
POI Station or Area	Requested (MW)	POI Voltage	Cost Estimate ($ million)
Big Bend area near Lind (Tokio)	100/200	230kV	138.2
Big Bend area near Odessa	100	230kV	167.1
Big Bend area near Odessa	200/300	230kV	168.0
Big Bend area near Othello	100/200	230kV	222.2
Big Bend area near Othello	300	230kV	262.4
Big Bend area near Reardan	50	230kV	9.7
Big Bend area near Reardan	100	230kV	10.3
Clarkston/Lewiston area	100/200/300	230kV	1.9
Kettle Falls substation, existing POI	12/50	115kV	1.8
Kettle Falls substation, existing POI	100	115kV	24.9
Lower Granite area	100/200/300	230kV	2.9
Northeast substation, existing POI	10	115kV	1.6
Northeast substation, existing POI	100	115kV	6.7
Palouse area, near Benewah (Tekoa)	100/200	230kV	2.4
Rathdrum substation, existing POI	25/50	115kV	11.5
Rathdrum substation, existing POI	100	230kV	16.7
Rathdrum substation, existing POI	200	230kV	27.0
Rathdrum Prairie, north Greensferry Rd	100	230kV	32.7
Rathdrum Prairie, north Greensferry Rd	200	230kV	43.0
Rathdrum Prairie, north Greensferry Rd	300	230kV	54.4
Rathdrum Prairie, north Greensferry Rd	400	230kV	91.5
Thornton substation, existing POI	10/50	230kV	1.9
West Plains area north of Airway Heights	100	115kV	2.4
West Plains area north of Airway Heights	200/300	115kV	4.7

Assume anti-islanding scheme is in place, but no remedial Action Scheme (RAS)

Preliminary estimates are given as -25% to +75%

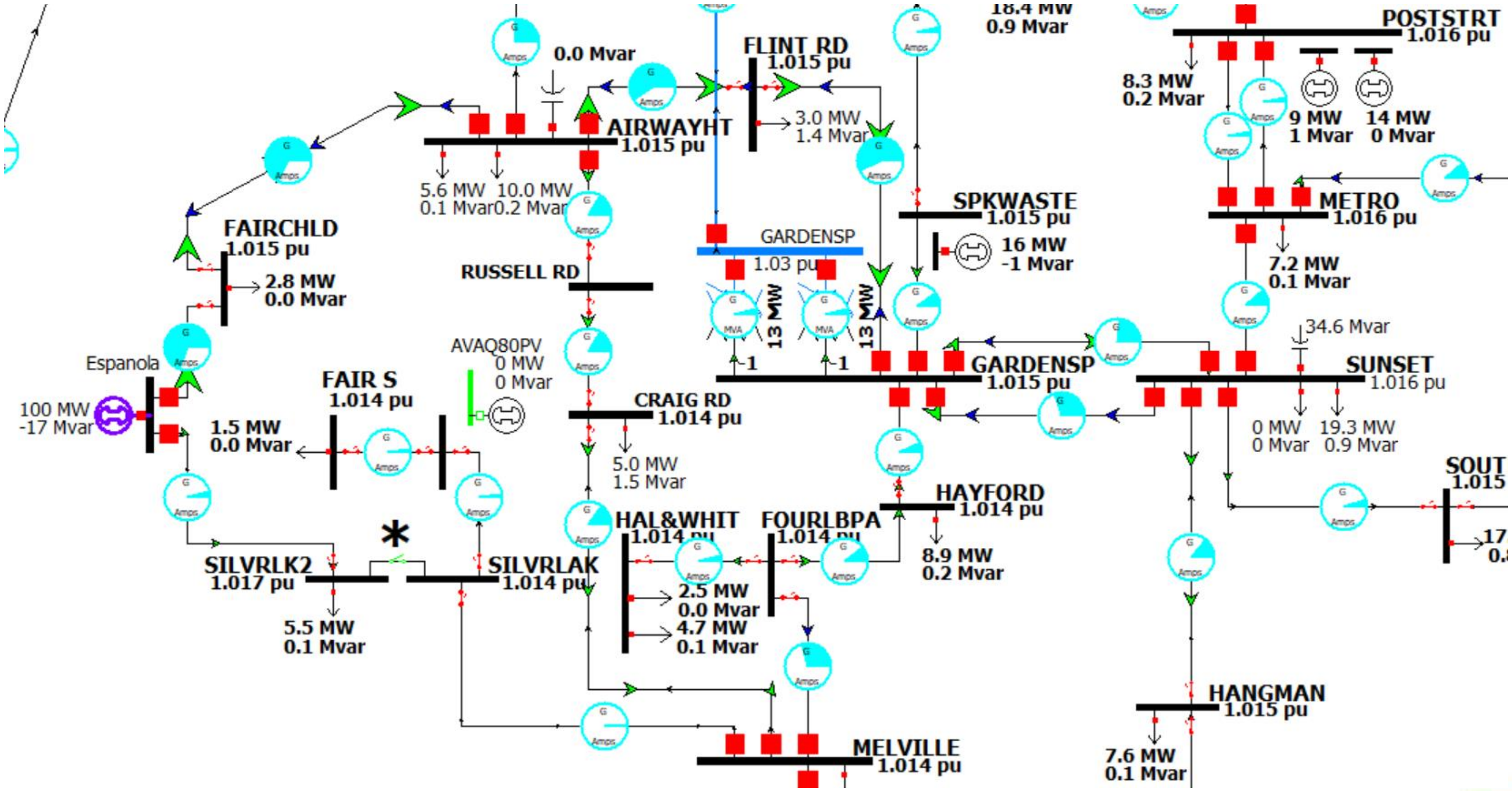
Reardan: 100 MW

Choice of interconnection point may result in extensive system reinforcements



Espanola: 100 MW

Optimizing the interconnection point is a key benefit of the Cluster Study process



Questions?

Refer to Avista’s OASIS link for information regarding System Planning and the Interconnection Process:

http://www.oasis.oati.com/avat/index.html

- Generation Interconnection
- Generation Interconnection Queue Reform
  - Application Documents
  - Draft Tariff
  - Phase One Reports
  - Stakeholder Meeting Presentations
  - TCS Queue, Plan, Map and Base Cases
  - FERC Filing

Distribution Resource Planning

Damon Fisher, System Planning
Fifth Technical Advisory Committee Meeting
September 7, 2022

Goals of Electric Distribution Planning

- Ensure electric distribution infrastructure to serve customers now and in the future with a focus on:
  - Safety
  - Reliability
  - Capacity
  - Efficiency
  - Level of service
  - Operational flexibility
  - Corporate/Regulatory goals
  - Affordability

Primary Goal of Distribution Resource Plan

- Where possible, solve distribution grid deficiencies using distributed energy resources (DER) that also contribute to system resource needs as identified in the Integrated Resource Plan.

Can IRP resource needs and distribution "fixes" be aligned? Certainly.

- Not without challenges.
  - Temporal need
  - Grid operation and flexibility
  - Resource adequacy- a new distribution definition?
  - System Protection

Typical Distribution System Deficiencies

- Low Voltage
- Capacity (Substation/Feeder)
- Asset Condition
- Contingency Switching Limits

What are DER's? – Distribution's Perspective

- Anything that can reduce demand or support voltage

Real

Targeted Energy Efficiency

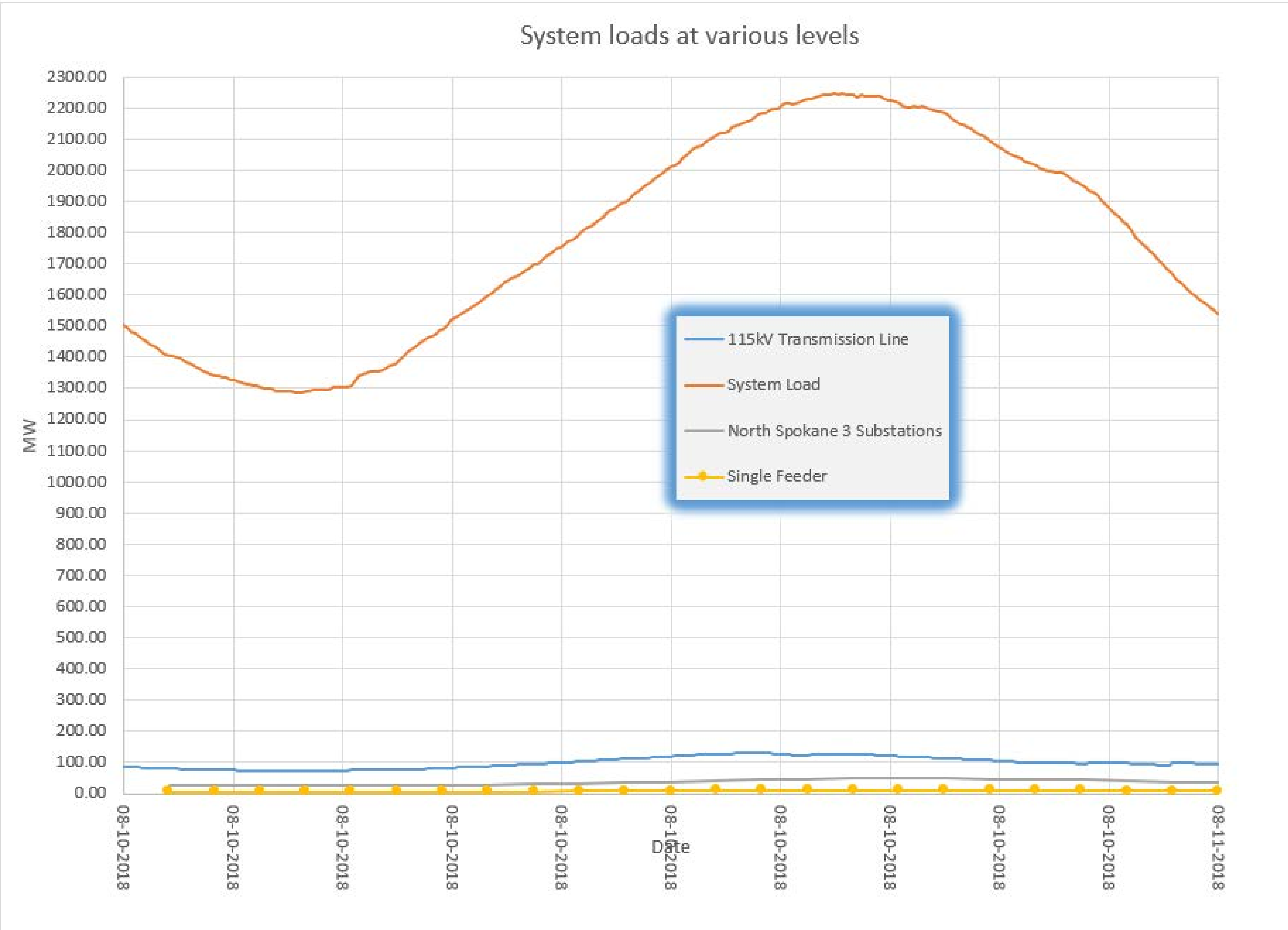
Targeted Demand Response

Apparent

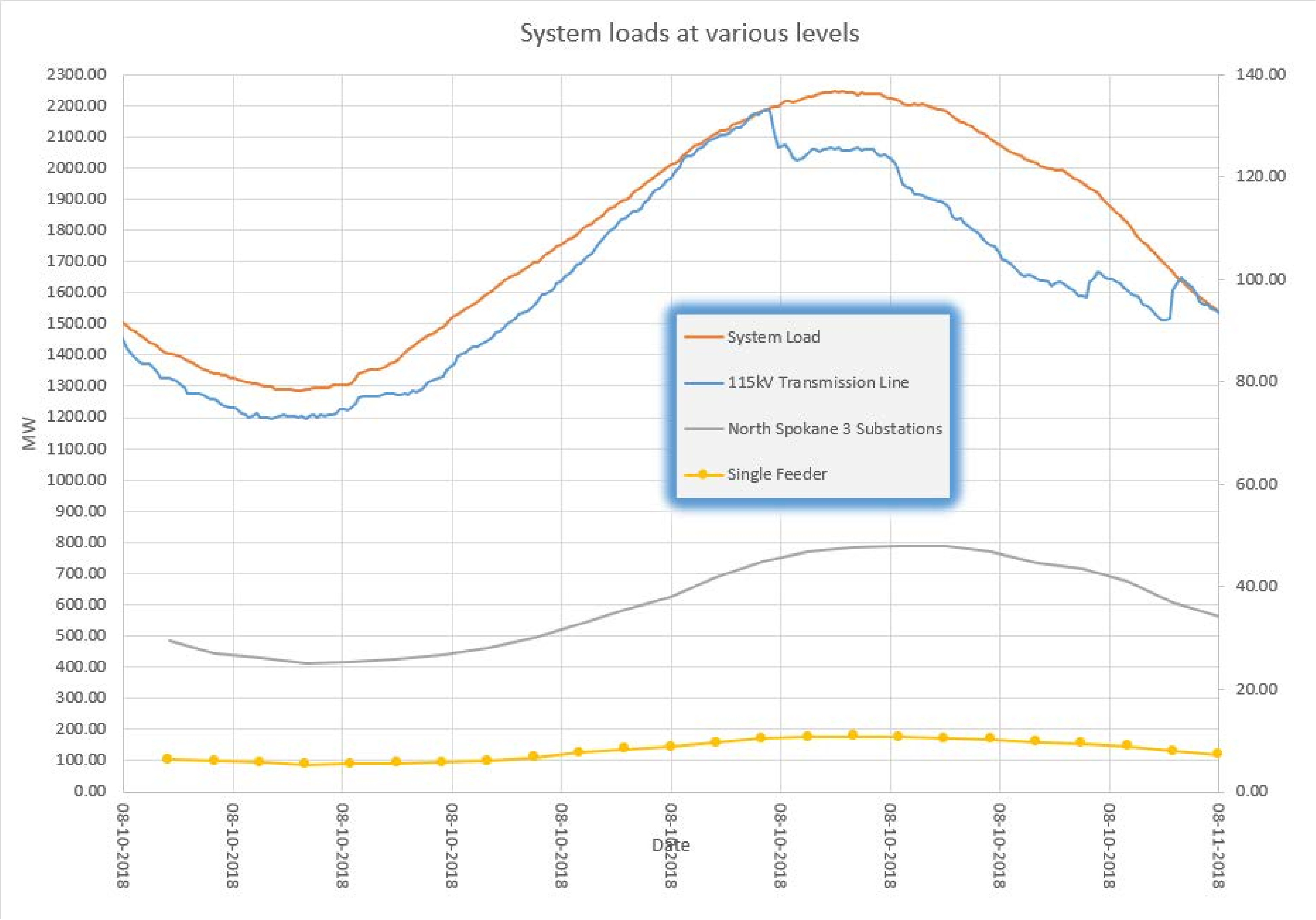
Storage (Load shifting)

Generation (Load service)

System Resources vs. Feeder Demand

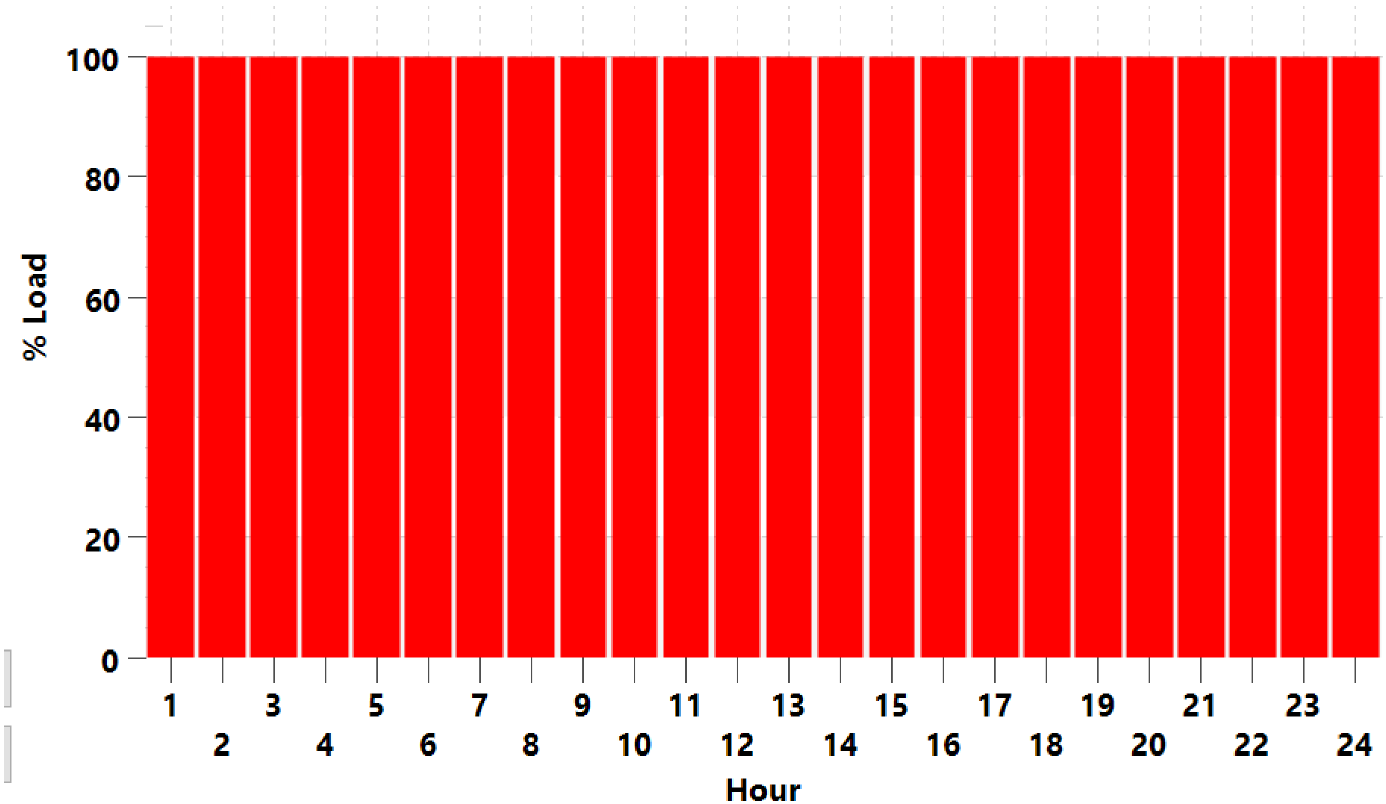


System Resources vs. Feeder Demand



It Is All About Curves

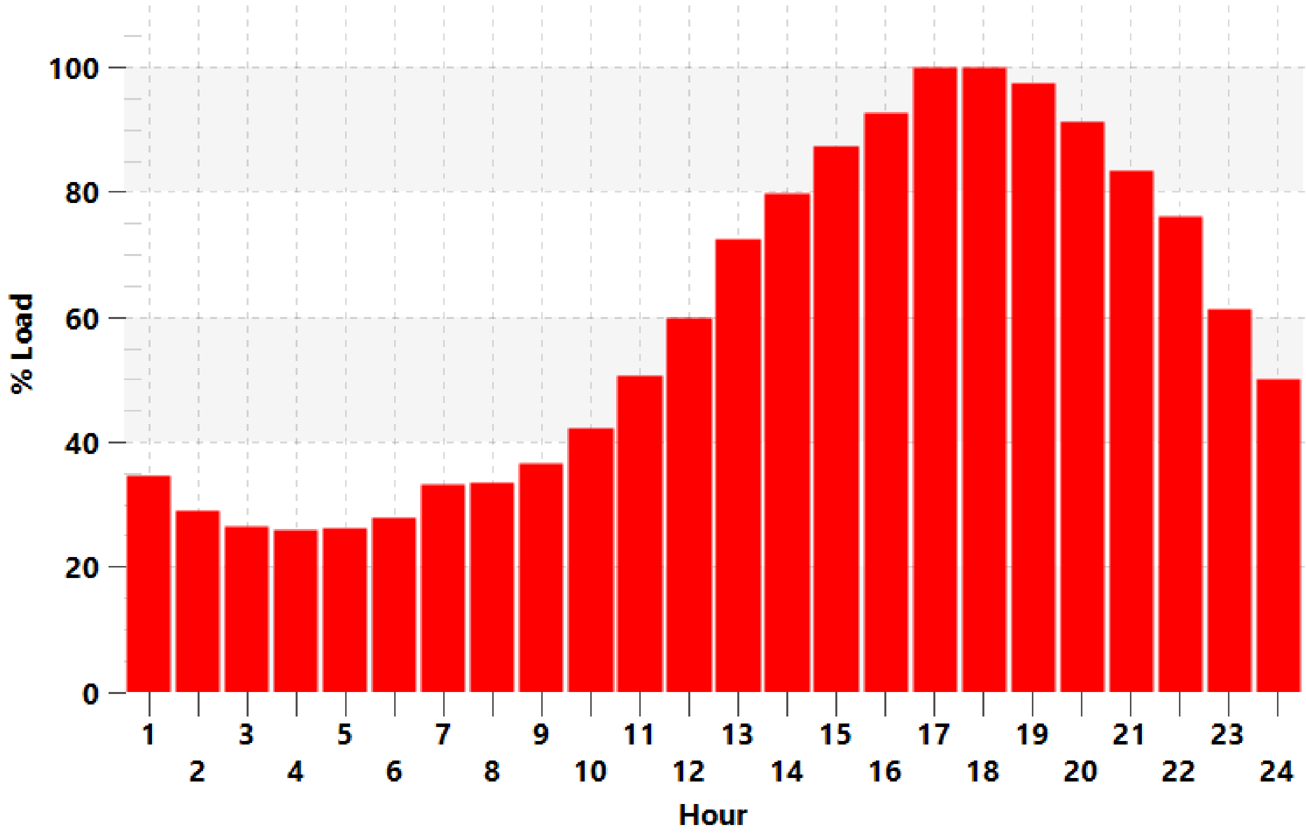
- The ideal curve-



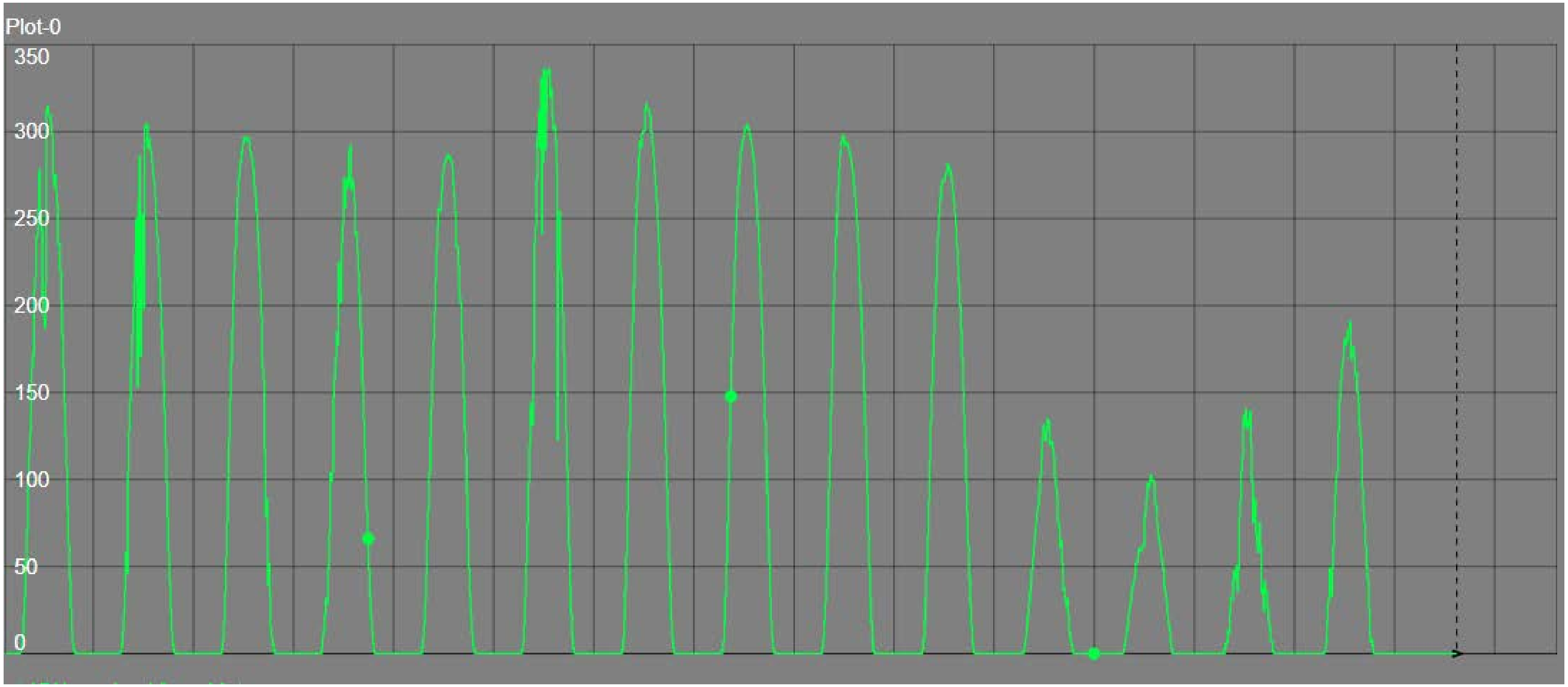
AVISTA

It is all about curves

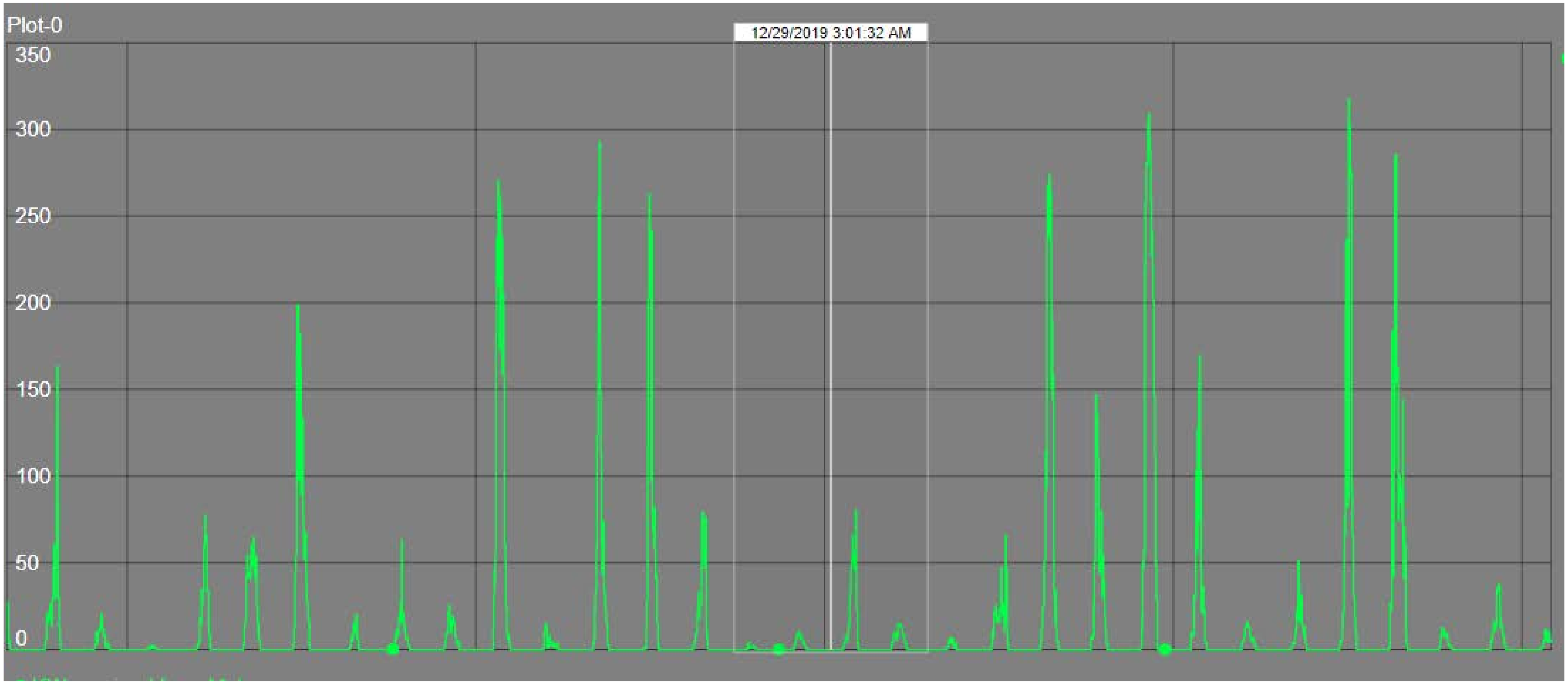
- A real curve (not ideal)-



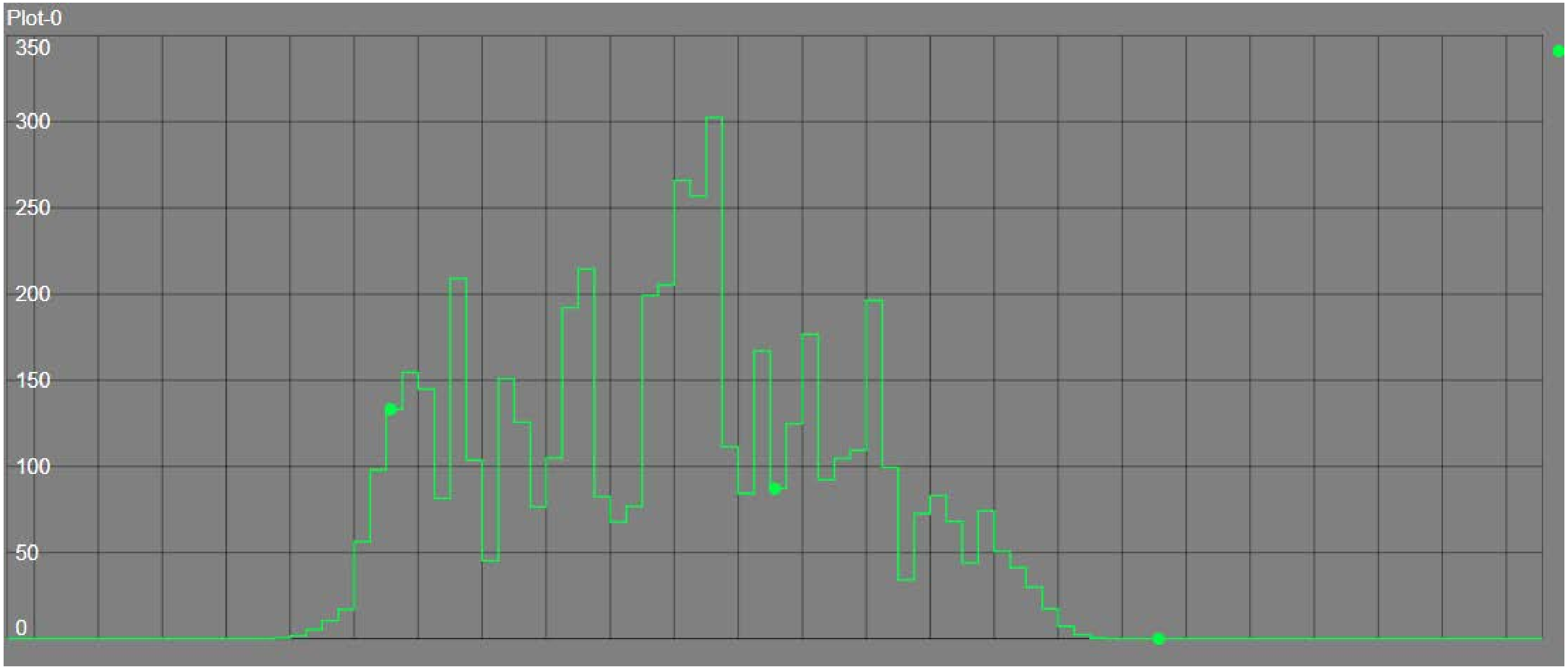
Can We Fix Curves with PV? Community Solar – Summer



Can We Fix Curves with PV?
Community Solar – Winter



Can We Fix Curves with Just PV? Community Solar – Cloudy Day, Battery



DRP Implementation-

- Spatial Load Forecasting
- Spatial DER Forecasting (gap)
- System Performance Criteria
- DER Acquisition and Implementation Processes (in process)
- Engineering/Operational Expertise (in process)
- Time series analysis
- Hosting capacity maps (in process)
- Non-Wired and Wired Playbook (in process)

	Reliability					Safety		Capacity						Power Quality	
	Outages							Load Growth		Peak Support					
	Prevent (SAIFI)	Shorten (SAIDI)	Shorten (CAIDI)	Reduce (CEMI3)	Vulnerable Customer	Mitigate Wildfire	Short Circuit	Transportation Electronification	Electrification (replace gas)	Summer	Winter	8,760 Hours	Voltage	Flicker & Harmonics
Non-Wires Alternatives														
Transmission Connected														
Remedial action schemes												◑		
Dynamic line rating										◑	◑	◑		
Series compensation										◑	◑			
Hydrogen fuel-cell														
Storage														
Short-duration (<=8hrs.) - lithium (NMC, LFP, LTO)														
Medium-duration (>8hrs.& <=72hrs.)								◑	◑	◑	◑			
Long-duration (>72hrs.)								[illegible]	[illegible]	[illegible]	◑			
Distribution Connected														
Natural gas generation		◑	◑		◕					◑	◑			
Distribution automation FDIB (FLISB)	●		[illegible]											
Resource aggregation - virtual power plant										◕	◕	◔		
Automatic feeder reconfiguration (load shif[illegible]g)										◑	◑			
Load balancing										◕	◕		●	◕
Demand response								◕	◕	◕	◕			
Energy efficiency												◕		
Remedial action schemes							◑							
Wind													◑	
Solar										◕		◔	◕	
Hydrogen fuel-cell					◕			◑	◑	◑	◑	◑		
Storage														
Short-duration (<=8hrs.) - lithium (NMC, LFP, LTO)		◑	◑		◕			◕	◑	●	●		◕	
Medium-duration (>8hrs.& <=72hrs.)		◑	◑		◕									
Long-duration (>72hrs.)		◑	◑		◕									
Portable storage					◑					◑	◑			
Immediate response storage (e.g., fly-wheel)					◑								◕	◑
Behind the Meter														
Wind													◑	
Solar										◑		◕	◕	
Natural gas generator					●	◑		◑		◑	◑			
Demand response								◕						
Hydrogen fuel-cell					◕			◑	◑	◑	◑			
Storage														
Short-duration (<=8hrs.) - lithium (NMC, LFP, LTO)		◑	◑		◕			◕		◕	◕		◕	
Medium-duration (>8hrs.& <=72hrs.)		◑	◑							◔	◔			
Long-duration (>72hrs.)		◑	◑											
Microgrid														
Eco-district								◕	●	◕	◕	◕		
Fossil generation					●	◕				◑	◑			
Renewable generation										◑			◑	
Stand-alone Storage					◕					◕	◕		◕	
Fossil generation w/ storage	◑	◑	◑	◑	●	◕				◕	◕		◕	
Renewable generation w/ storage	◑	◑	◑	◑	●	◕		◕	◕	◕	◕	◕	◕	

Generation Integration Costs

- 5MW – assuming dedicated feeder bay and SCADA comms required - $975,000 to $1,350,000
- 1MW – assuming a feeder tap, viper, and SCADA comms required - $170,000 to $254,000
- 500kW - assuming tap the feeder with some upgrades - $24,000 to $36,000
- 100kW - assuming tap the feeder, not a net-metered project - $8,000 to $12,000

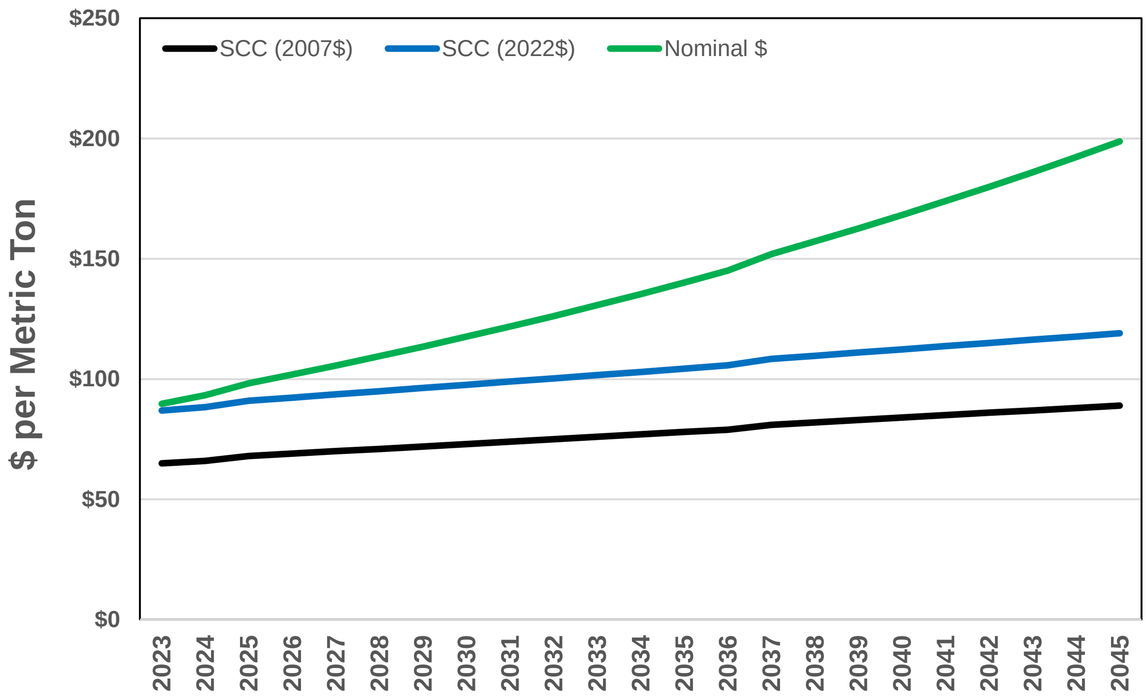
Questions?

Social Cost of Greenhouse Gas for Energy Efficiency (Washington State Methodology)

James Gall, Integrated Resource Planning Manager
Electric IRP, Fifth Technical Advisory Committee Meeting
September 7, 2022

Requesting TAC Input

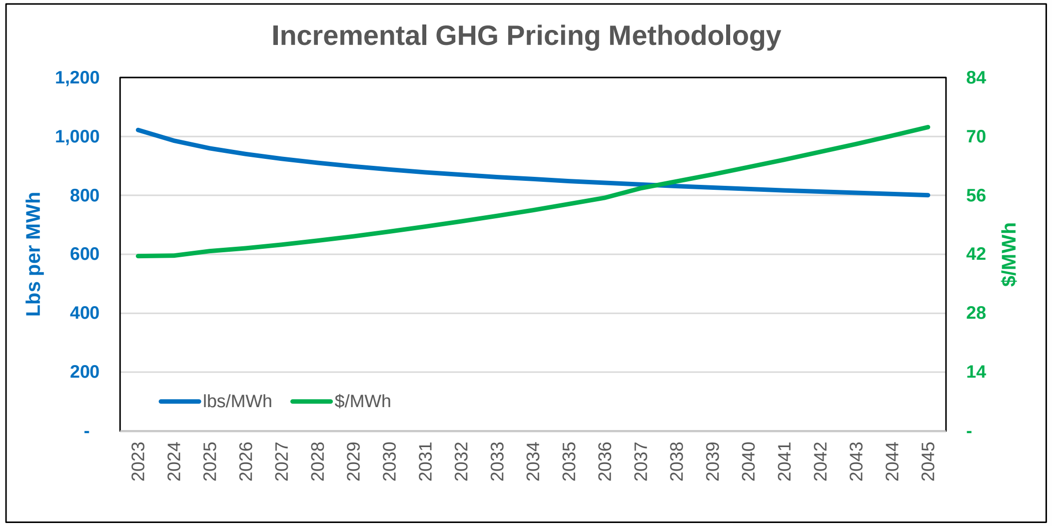
- Avista must include the Social Cost of GHG for Energy Efficiency selected
  - Per Clean Energy Transformation Act (CETA) for Washington customers.
- There are three proposed options to incorporate the non-energy impact into resource planning.
- Levelized SCGHG is estimated at $125.84 per metric ton.
  - Awaiting WUTC’s official pricing.



Methods Studied in the 2021 IRP

1) Incremental Method

– Uses regional GHG incremental emissions rate for the Northwest

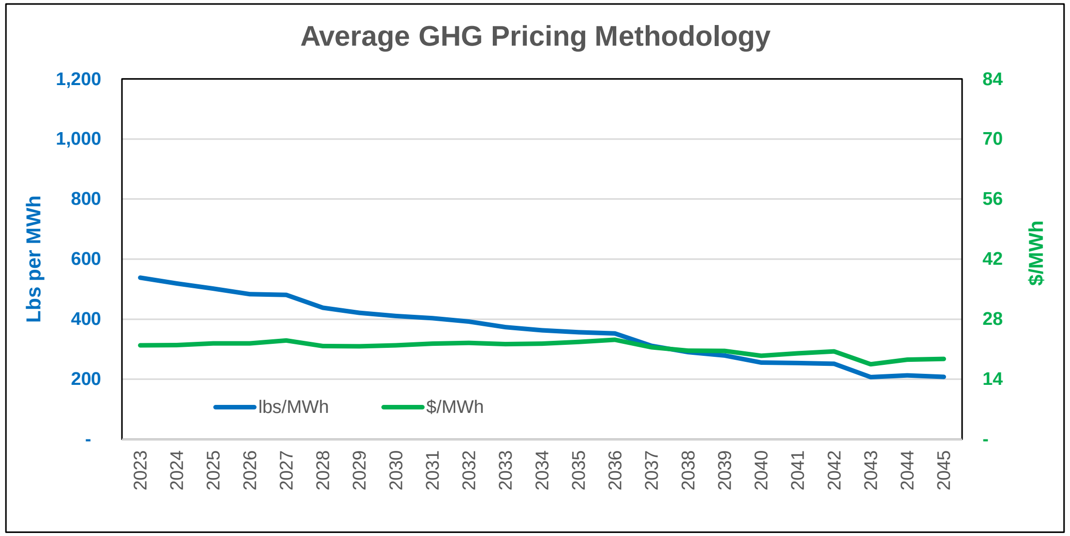


– Each MWh of energy efficiency receives a credit toward avoided cost for savings priced at the SCGHG.

– Results in $50.32/MWh credit

2) Average Method

– Uses regional GHG average emissions rate for the Northwest

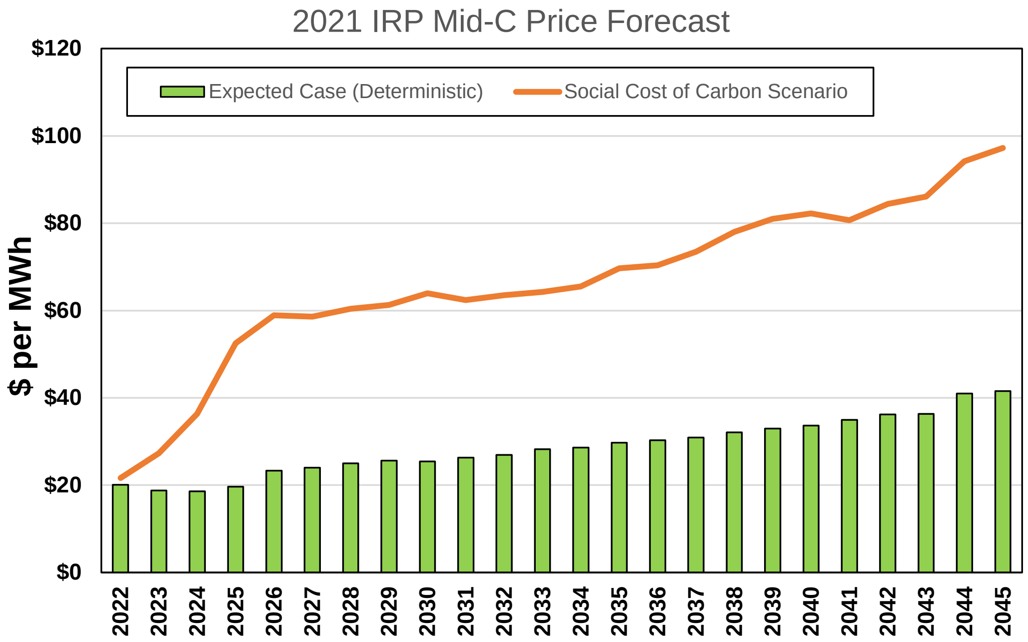


– Each MWh of energy efficiency receives a credit toward avoided cost for savings priced at the SCGHG.

– Results in $21.70/MWh credit

3) Wholesale Price Method

- Apply SCGHG to all resources in the dispatch within Aurora model.
- Creates new wholesale price forecast for energy efficiency avoided cost.
- Caution: some wholesale price forecasts with SCGHG have an overbuild of renewables creating lower wholesale marginal prices.



Results from 2021 Electric IRP Washington only savings (GWh)

GWh Savings	Incremental Method	Average Method	Wholesale Price Method	No SCGHG
10-year savings	507.8	452.4	506.6	370.8
20-year savings	772.4	671.5	769.4	557.9

Options for 2023 IRP

- Incremental Method
  - SCGHG adder will be reduced to account for CCA price already included in dispatch.
- Average Method
  - SCGHG adder will be reduced to account for CCA price already included in dispatch.
- Market Dispatch Method
  - All regional resources dispatched with SCGHG.

Valuing QF Resources (Avoided Costs)

Fifth Electric Technical Advisory Committee

September 7, 2022

Clint Kalich, Senior Manager—Resource Analysis

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Agenda

- Define qualifying facility or QF
- Detail sizes in Federal, Idaho and Washington
- Describe Washington QF methodologies (published vs. IRP method)
- Define Idaho QF Rate methodologies (published SAR vs. IRP method)

PURPA Regulations

For Avista, defined by federal government and two states

- Federal Rules (Public Utilities Regulatory Policy Act of 1978)
  - Buy all cogeneration, and non-cogeneration up to 80 MW, at rates defined by state rules
  - Qualifying non-cogeneration, with a couple of exceptions, defined as renewable resources
  - Rates based on utility-avoided energy and capacity values
- Idaho Implementation
  - Small QF uses “Published SAR Method” rate for up to 10 aMW (100 kW wind/solar)
  - Negotiated rate for larger QFs based on “IRP Methodology”
- Washington Implementation
  - Published rate for QFs up to 5 MW based on IRP Methodology
  - Negotiated rate for larger QFs based on IRP Methodology

QF Published Rate Eligibility
Washington

- Projects up to 5 MW receive payments using a published rate schedule
- Projects over 5 MW receive a negotiated rate
  - Based on conceptual methodologies of published rates
  - Adjustments (up/down) can be applicable to the extent the larger resource differs from the value streams reflected in the published rate schedule

Washington State Avoided Costs

(IRP-Based Methodology)

Washington QF Value Streams

Payment consists of value streams dependent on resource/products offered

- Commodity Energy
- Peaking Capacity Value
- Clean Energy Premium
- Transmission
- Contingency Reserves
- Integration Charge for variable generation resources (wind/solar)
- Others

Commodity Energy – Washington

The most basic value associated with electricity provided to the grid

- Latest-approved IRP energy price forecast
- Priced in two blocks of on- and off-peak periods each month
  - Hours 0700-2200 defined as on-peak
  - Hours 0000-0700 and 2200-2400 are off-peak
- Payment is monthly for each MWh of facility production delivered to grid during that month

Transmission Credits and Charges – Washington

Portfolio savings or costs associated with transporting energy to/from market

- Credit paid in addition to others in hours IRP shows imported market power
- Charge in addition to others in hours IRP shows imported market power
- Rate equals BPA hourly Point-To-Point transmission tariff rate
- Credits and charges billed monthly for each MWh of forecast facility production delivered to grid during a month
  - Not a real-time credit/charge but is determined based on IRP data at the time of contracting
  - Rate escalates with IRP inflation forecast
- For published rates, billed as adjustment to Commodity Energy rate equal to:
  - Delivered energy (MWh) * Transmission credit/charge

Variable Energy Resource Integration Charge – Washington

Cost of incremental capacity services necessary to support grid reliability

- Avista applies variable energy resource (VER) integration charge to all such resources, whether owned or contracted for
- Covers various incremental ancillary services
  - Regulation, load following, forecast error
- Priced at VER integration study rate * QF nameplate capacity
- Discount will not apply until VER study is complete
- For published rates, billed as reduction to Commodity Energy rate equal to:
  - Delivered energy (MWh) * VER integration charge

Peaking Capacity Value – Washington

The value of providing electricity to the grid during times of system peak demands

- Fixed costs from one of two utility options:
  - Fixed costs associated with the last-approved- IRP's first capacity addition fixed cost
  - Fixed costs associated with bids in most recent WAC 480-107 compliant RFP
- Paid based on Qualifying Capacity Contribution (QCC) factor
  - Will update QCC for 2023 IRP to Western Power Pool figures once available
- For published rates, value is paid monthly as a per-MWh rate:
  - Total annual value (TAV) = Nameplate Capacity * QCC * Price
  - Rate equals total annual value divided by annual energy output in MWh

Defining Qualifying Capacity Credit (QCC)

2021 IRP Data will be updated with WPP values once approved (WA & ID IRP Method)

Table 9.12: Peak Credit or Equivalent Load Carrying Capability Credit

Resource	Peak Credit (percent)
Northwest solar	2
Northwest wind	5
Montana wind[11] 100-200 MW	35 to 28
Hydro w/ storage	60-100
Hydro run-of-river	31
Storage 4 hr duration	15
Storage 8 hr duration	30
Storage 12 hr duration	58
Storage 16 hr duration	60
Storage 24 hr duration	65
Storage 40 hr duration	75
Storage 70 hr duration	90
Demand response	60
Solar + 4 hr Storage[12]	17
Solar + 2 hr Storage[13]	12

[11] Net of transmission losses. Montana wind peak credits decline with additional capacity, the first 200 MW is 35 percent, the next 100 MW is 30 percent, and another 100 MW is 28 percent. Avista does not assume any Montana wind beyond 400 MW.

[12] This assumes the storage resource may only charge with solar. This specific option was not modeled within the PRS and is shown as a reference only. Avista only modeled solar plus storage where the storage resource could be charged with non-solar as well to reflect long-term utility operations.

[13] Avista limited solar plus storage to these two scenarios; many other options are likely including different durations and storage to solar ratios. Specific configurations would need to be studied to validate peak credits for those configurations.

From p. 9-28 of 2021 Avista Electric IRP

Contingency Reserves – Washington

Cost of regional obligation to hold capacity in the case of generation outages

- Avista holds 3% of all generation on its grid, irrespective of technology type or ownership
- Charge compensates for this cost
- For published rates, a reduction equal to:
  - Peaking Capacity Value * QF nameplate capacity
- For published rates, billed as a reduction to Peak Capacity Value equal to:
  - Delivered energy (MWh) * Contingency Reserve charge

Clean Energy Premium Value – Washington

Value of providing electricity to the grid that does not contain CO2e

- Latest-approved IRP total resource value less Energy less Peaking Capacity Values
- For published rates, value is added to the commodity energy schedule

Other Value Streams
Washington

- QF payments are based on generic resource type
- Some resources might have values above the generic assumptions
  - e.g., dispatch flexibility, storage, interruption rights, local distribution benefits
  - It is not expected these values will be large for most resources, especially if small in size (i.e., < 5 MW)
- Avista must be able to confirm additional values before a payment is defined

Idaho State Avoided Costs

(SAR-Based Methodology)

Surrogate Avoided Rates (SAR)
Idaho

- Published rate based on IPUC-managed model
  - Based on the fixed and variable costs of a combined-cycle gas turbine
  - Natural gas fuel price updated annually using an EIA gas price forecast
- Different pricing by resource type
  - Wind, solar, hydro, non-seasonal hydro, and other
- On- and off-peak production rates for two seasons of the year
  - Energy and capacity value combined into one figure
  - VER discount per 2007 wind integration study (to be updated with new study)

Surrogate Avoided Rates (SAR), Continued
Idaho

- Note on capacity payments
  - Renewed contracts receive full capacity payment as part of production rate
  - New contracts receive capacity payment starting with first year the utility is capacity deficit
- Renewable energy credits are kept by the QF

Idaho State Avoided Costs

(IRP-Based Methodology)

Differences between Idaho and Washington QF Rates

- Idaho has its own and varying size limits for published QF rates
  - Wind and solar projects <= 100 kW
  - Non-wind, non-solar <= 10 aMW
- Projects ineligible for published rates receive IRP-Methodology rates
  - Same methodology as described for Washington, EXCEPT
  - Peaking capacity value based on portfolio capacity cost rather than a single peaking resource technology
    - Calculated as the difference between PRS and PRS absent the energy and capacity constraints
  - Peaking capacity value is paid on a per-MW rather than per-MWh basis
  - VER charge is billed on a nameplate per-MW basis
  - Large QFs retain 50% of renewable energy credits

Thank You