TC-22, BP-22 and EIM Phase III Customer Workshop

June 24, 2020

AGENDA REVIEW

Agenda

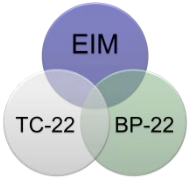
Day 2 – June 24, 2020		
TIME*	**TOPIC**	**Presenter**
9:30 to 9:40 a.m.	EIM Losses Update	Todd Kochheiser
9:40 to 10:30 a.m.	Transmission Losses • Settlement mechanisms • Methodology • Pricing	Mike Bausch Andy Meyers Katie Sheckells Daniel Fisher
10:30 to 10:45 a.m.	BREAK	
10:45 to 11:45 a.m.	Transmission Losses (con't) • Settlement mechanisms • Methodology • Pricing	Mike Bausch Andy Meyers Katie Sheckells Daniel Fisher
11:45 to 12:45 p.m.	**LUNCH**	
12:45 to 1:30 p.m.	Generator Interconnection • Steps 3-4	Tammie Vincent Ava Green Cherilyn Randall
1:30 to 2:15 p.m.	Power Rates • Exploring the Amount of Net Secondary Revenue in Base Rates	Daniel Fisher
2:15 to 3:00 p.m.	TC-20 Topics • Hourly Firm	Kevin Johnson Katie Sheckells
3:00 to 3:45 p.m.	TC-20 Topics • Short Term ATC	Margaret Olczak

** Times are approximate*

EIM Priority Issues

EIM
TC-22
BP-22

#	Issue	BP-22	TC-22	Future BP/TC
1	EIM Charge Code Allocation	X	?	X
2	EIM Losses	X	X	?
3	Resource Sufficiency	X	X	?
3a	- Balancing Area Obligations	X	X	?
3b	- LSE Performance & Obligations	X	X	?
3c	- Gen Input Impacts	X	X	?
4	Development of EIM Tariff Changes		X	?
5	Transmission Usage for Network	X	X	?
6	Requirements for Participating & Non-Participating Resources	X	X	?
6a	- Participating Resources: Base Scheduling Timeline			
7	Metering & Data Requirements		X	?
8	Evaluation of Operational Controls	X	X	?



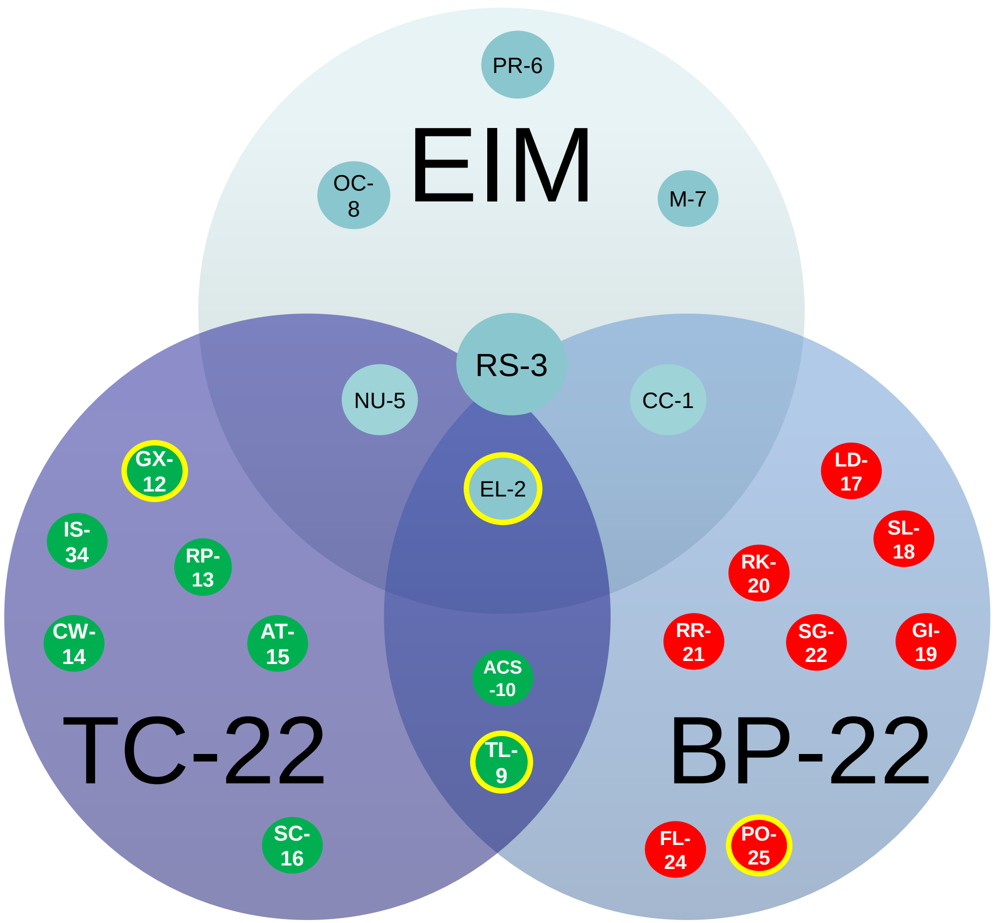
Rates & Tariff Topics

#	Topics	BP-22	TC-22	Future BP/TC
9	Transmission Losses	X	X	
10	Ancillary Services	X		?
11	Debt Management (Revenue Financing)	X		
12	Generator Interconnection		X	
13	Regional Planning		X	
14	Creditworthiness		X	
15	Incremental/Minor Changes to Agreement Templates		X	
16	Seller’s Choice		X	
17	Loads	X		
18	Sales	X		
19	Generator Interconnection (assumed for BP-22)	X		
20	Risk	X		
21	Revenue Requirements	X		
22	Review of Segments	X		
23	Review of Sale of Facilities	X		
24	Financial Leverage Policy Implementation	X		
25	Power-Only issues	X		

Potential Future Rates & Tariff Issues

#	Issue	BP-22	TC-22	Future BP/TC
26	Simultaneous Submission Window			?
27	Study Process			?
28	Attachment C (Short-term & Long-term ATC)			?
29	Hourly Firm (TC-20 Settlement – Attachment 1: section 2.c.ii)			?
30	Required Undesignation			?
31	Reservation window for Hourly non-firm			?
32	Non-federal NT Redispatch			?
33	PTP/NT Agreement Templates			?
34	Intertie Studies			?
35	De minimus (TC-20 Settlement)			?

BP-22, TC-22 & EIM Integrated Scope



TC	
TL-9	Transmission Losses
ACS-10	Ancillary Services
GX-12	Generator Interconnection
RP-13	Regional Planning
CW-14	Creditworthiness
AT-15	Agreement Templates
SC-16	Seller's Choice
IS-34	Intertie Studies

BP	
LD-17	Loads
SL-18	Sales
GI-19	Gen Inputs
RK-20	Risk
RR-21	Revenue Requirements
SG-22	Segmentation
FL-24	Financial Leverage
PO-25	Power-only

EIM	
CC-1	Charge Code Allocation
EL-2	EIM Losses
RS-3	Resource Sufficiency
NU-5	Network Usage
PR-6	Participating Resources
M-7	Metering
OC-8	Operational Controls

XX-#
Yellow Outline Denotes
6/24 Workshop Topics

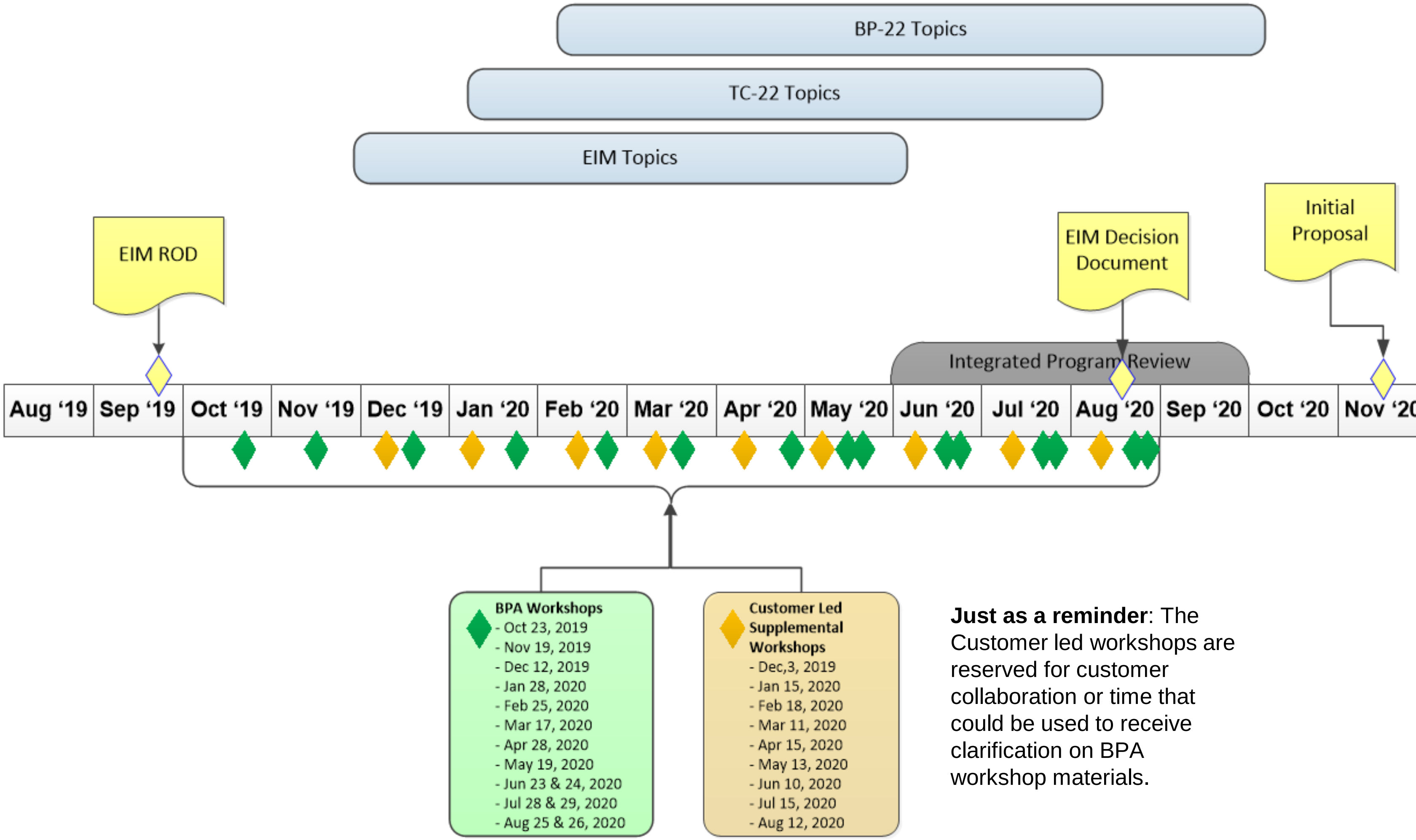
WORKPLAN AND PROPOSAL

Engaging the Region on Issues

- After every workshop, BPA will provide a two-week feedback period for customers.
  - Input can be submitted via email to techforum@bpa.gov. Please copy your Power or Transmission Account Executive on your email.
- Issues will be presented according to the following process at workshops (multiple steps might be addressed in a single workshop):

Phase One: Approach Development	Phase Two: Evaluation	Phase Three: Proposal Development
Step 1: Introduction & Education Step 2: Description of the Issue	Step 3: Analyze the Issue Step 4: Discuss Alternatives	Step 5: Discuss Customer Feedback Step 6: Staff Proposal

BP/TC-22 Proposed Workshop Timeline



Just as a reminder: The Customer led workshops are reserved for customer collaboration or time that could be used to receive clarification on BPA workshop materials.

TC-22, BP-22 and EIM Workshop Topics

June 23-24, 2020

- Resource Sufficiency (RS-3)
  - Steps 5-6
- Ancillary Services: Generation Inputs (ACS-10)
  - Steps 1-4
- EIM Transmission Usage for Network (NU-5)
  - Steps 5-6
- Requirements for Participating Resources & Non-participating Resources (PR-6)
  - Steps 3-4
- EIM Losses (EL-2)
  - Steps 5-6
- Transmission Losses (TL-9)
  - Steps 5-6
- Generator Interconnection (GX-12)
  - Steps 3-4
- Participating Resources: Base Schedule Timeline (PR-6)
  - Steps 3-4
- Agreement Templates (AT-15)
  - Steps 5-6
- Regional Planning Organization (RP-13)
  - Steps 5-6
- Review Tariff red line
- Transmission Rates (GI-19)
  - Gen Inputs
- *TC-20 Topics*
  - Hourly Firm – share results (2.d) FINAL
  - Short Term ATC
- *Power Rates*

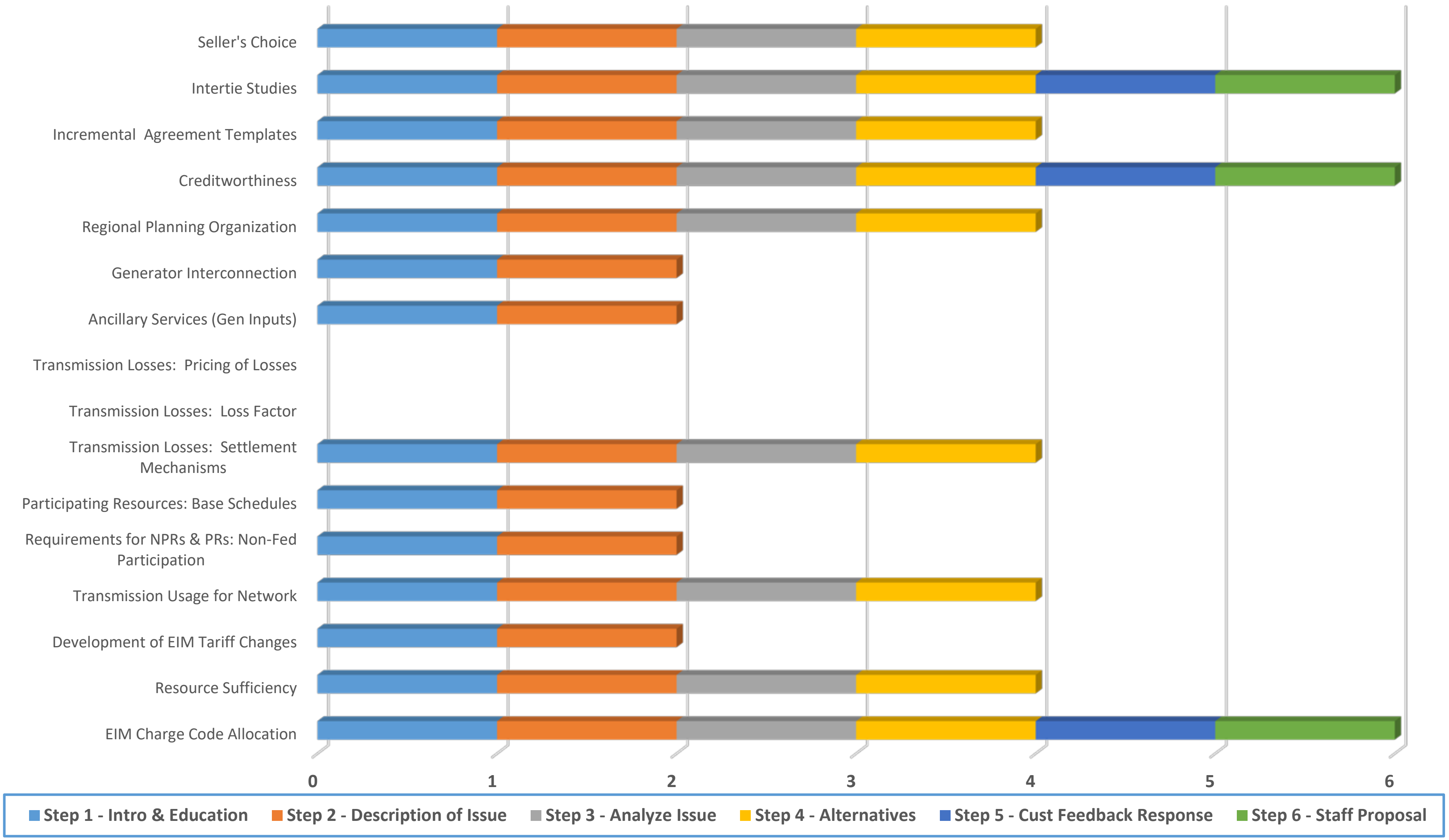
July 28-29, 2020

- Seller's Choice (SC-16)
  - Steps 5-6
- Generator Interconnection (GX-12)
  - Steps 5-6
- Ancillary Services: Generation Inputs (ACS-10)
  - Steps 1-4 – EI/GI Service Rates and Penalties
- Requirements for Participating Resources & Non-participating Resources (PR-6)
  - Steps 5-6 – Enabling Agreement
  - Steps 5-6 – Transmission Reservations
- Participating Resources: Base Schedule Timeline (PR-6)
  - Steps 5-6
- Transmission Rates (GI-19)
  - Gen Inputs
- Review Tariff red line
- Transmission Rates
  - Sales (SL-18)
  - LGIA
  - EIM Charge Code Implementation (LD-17)
  - Cost Recovery of Losses (RR-21)
- Power Rates

August 25-26, 2020

- Summary of Topics & Policy – Staff Leaning through the end of August
- Transmission Rates
  - Rate Schedules (RK-20)
  - Rates Modeling
  - Follow-up: EIM Charge Code Implementation (RR-21)
  - Follow-up: Cost Recovery of Losses (SG-22)
- Ancillary Services: Generation Inputs (ACS-10)
  - Steps 5-6 EI/GI Service Rates and Penalties
  - Steps 5-6 BR Capacity Forecast
  - Steps 5-6 Scheduling Elections
  - Steps 5-6 Pricing
- Power Rates
  - Loads & Resources
  - Gas and Market Price Forecasts
  - Secondary Revenue Forecast
  - Transfer Service
  - Follow-up: Treatment of EIM Charge Codes

Status of Topics as of 6/22/20



EIM Losses Update

EIM Losses-Timeline

- BPA discussed EIM Losses at the12/12/2019 Customer Workshop (slides 28-39) where step 1 (identification of the issue) was covered
- There was a subsequent customer led workshop on 01/15/2020 where additional clarification was provided

EIM Losses Text from the ROD

"Bonneville will discuss with stakeholders the extent to which the EIM's handling of losses should lead to changes in Bonneville's current practices regarding transmission losses, or what new opportunities are available for more efficient repayment of losses. This may include the potential for moving to a practice which losses are only settled financially instead of a physical repayment. Decision in this process will likely influence and/or be memorialized in the BP-22 and TC_22 cases."

EIM Losses - Summary

- The EIM does not provide system or BAA losses, but takes them into consideration when ensuring each BAA is balanced prior to the hour
- The EIM also takes into consideration marginal (a.k.a. incremental) losses that result from market awards and dispatches
- Losses are embedded in load Uninstructed Imbalance Energy (UIE), Unaccounted For Energy (UFE), and Real Time Imbalance Energy Offset (RTIEO) charge codes
- Bonneville will need to determine the loss percentages used by the EIM

EIM Losses-Findings/Conclusions

- No “new opportunities” have been identified for more efficient repayment of losses in the EIM
- The net settlement of UIE for load, UFE, and RTIEO does not changed based on the loss percentage chosen
- The determination of the loss percentage used by the EIM is an implementation issue.
- The settlement of UIE, UFE and RTIEO will be discussed as part of the TC-22/BP-22 cases

ISSUE #9: TRANSMISSION LOSSES

Network Loss Factor (Steps 1-4)

Line Loss Settlement (Steps 5-6)

Pricing of Losses (Steps 1-4)

Topic - Line Losses

1. Network Loss Factor

2. Line Loss Settlement

3. Pricing Losses

Network Loss Factor - Agenda

- Introduction and Education (Step 1)
- Description of the Issue (Step 2)
- Data/Analysis that Supports the Issue (Step 3)
- Discussions on Possible Alternatives to Solve Issue (Step 4)

Introduction and Education – Step 1

- Current Network Loss Factor is 1.9%
  - Value has remained unchanged for last 20 years

- Recent studies evaluated the Loss Factor

Description of Issues – Step 2

- Two Issues regarding Loss Factor
  - A) Recent studies support updating the Loss Factor
  - B) How granular should the Loss Factor be?

Description of Issue A (Factor Accuracy) – Step 2

- Current Loss Factor does not accurately reflect current network transmission system
  - New lines have been added to system
  - Regional loads have increased over last 20 years
- Loss Factor is being analyzed to reflect current system loading

Description of Issue B (Factor Granularity) – Step 2

- System losses change over time
  - Different during different seasons
  - Different during HLH and LLH

Data/Analysis – Step 3

Seasonal Average Loss Factors

Season	**MW Avg. Hour**	**Avg. Network Loss Factor**
Spring	21,691	1.98%
Summer	22,632	2.30%
Fall	19,414	1.88%
<u>Winter</u>	<u>22,962</u>	<u>1.94%</u>
Annual Average Loss Factor	**N/A**	**2.03%**

Spring=April-May
Summer=June-September
Fall=October-November
Winter=December-March

Data/Analysis – Step 3

Seasonal HLH & LLH Loss Factors

Season	Hour Type	Avg. MW Hour	Avg. Network Loss Factor
Spring	HLH	22,328	2.00%
Spring	LLH	20,871	1.94%
Summer	HLH	24,169	2.39%
Summer	LLH	20,643	2.18%
Fall	HLH	20,699	1.94%
Fall	LLH	17,797	1.81%
Winter	HLH	24,043	2.02%
Winter	LLH	21,608	1.86%
Annual HLH Loss Factor	**HLH**		**2.10%**
Annual LLH Loss Factor	**LLH**		**1.95%**

Options for Issue A (Factor Accuracy) - Step 4

- Leave Loss Factor unchanged

- Change Loss Factor

Options for Issue B (Factor Granularity)-Step 4

- Flat yearly loss factor
- Bifurcated yearly loss factor (HLH/LLH)
- Seasonal loss factor
- Seasonal bifurcated loss factor (HLH/LLH)

Line Loss Settlements - Agenda

- Step 6 - Staff proposal for loss returns alternatives

Alternatives

Alternative	Time to Return In-Kind	Settle Delivery Errors Financially?	Financial Rate Set by
1. **Keep** Status quo	168 hours	No	Trading Floor
2. **Keep** in-kind at 168 hours + implement financial settlement only for inaccurate return of energy (“Financial for inaccuracy - FFI”)	168 hours	Yes	Trading Floor
3. **Keep** in-kind at 168 hours + **change** financial rate to be set in rate case + **implement** FFI	168 hours	Yes	Rate Case
4. **Change** in-kind to concurrent only + **implement** FFI	Concurrent	Yes	Trading Floor
5. **Change** in-kind to concurrent only + **change** financial rate to be set in rate case + **implement** FFI	Concurrent	Yes	Rate Case
6. **Change** to financial settlement only	N/A	N/A – No delivery	Rate Case

Staff Recommendation

- Recommendation – phased implementation
  - Propose Alternative 3 for BP/TC-22
    - Continue to allow In-kind and Financial settlements for BP-22 rate period (FY 22-23)
    - Business Practice change
      - FFI starts 10/1/21
      - Customers will be allowed to make a single loss settlement election for the rate period
  - Propose Alternative 6 for BP/TC-24
    - Financial-only settlement starts 10/1/23
  - Benefits of phased implementation
    - Provides customers time to make adjustments to their business practice
    - Introducing FFI in BP/TC-22 mitigates scheduling concerns sooner
    - Customers participate in process to determine financial rate
  - “Stair-Step Approach" allows BPA to modernize losses program and allow customers time to implement changes
    - BPA achieves efficiencies and captures the value of capacity
    - TC proceedings give customers ability to provide feedback

Options

- Option 1 of 2 – Staff Recommendation
  - Implement Alternative 3 for BP/TC 22
    - In-Kind remains at 168 hours
    - Financial rate developed in Rate Case
    - FFI implemented
  - Transition to Alternative 6 over time – anticipated to occur in BP/TC 24
    - Financial settlement only
    - Financial rate developed in Rate Case

Options

- Option 2 of 2 – Keep In-Kind and Financial Settlement
  - Implement Alternative 5 for BP/TC 22
    - In-Kind changes to concurrent
    - Financial rate developed in Rate Case
    - FFI implemented

Concurrent Loss Return Methodologies

- Currently used industry methods
  1. Self supply of losses on a separate e-Tag for each transaction
     - Require a separate OASIS reservation for each loss delivery e-Tag
  2. Self supply of losses by reducing the amount of energy delivery
     - e-Tag reflects a reduction to the energy profile as the transaction wheels across the BAA
     - Example – energy value of 100 MW’s at interchange POR -> energy value of 98 MW’s at interchange POD (assuming 2% loss factor)

       OR

     - Example – energy value of 102 MW’s at interchange POR -> energy value of 100 MW’s at interchange POD (assuming 2% loss factor)
  3. Failure to self supply losses or reduce energy delivery results in financial settlement

Concurrent Loss Return Methodologies

- Other methods for consideration (not currently implemented)
  1. Day Ahead -- aggregation of all tagged schedules just prior the end of the preschedule day
     1. Separate e-Tag submitted for loss return energy to the BAA prior to preschedule checkout (3 PM PPT)
     2. Scheduler to make a separate OASIS reservation for loss delivery to BAA
  2. RT adjustments – aggregation of e-Tags created after preschedule checkout (including any adjustments to preschedule e-Tags)
     1. Adjustment either (+ or -) to separate loss e-Tag
     2. Scheduler to ensure adequate OASIS reservation for loss delivery to BAA
        1. RT adjustments may require an additional reservation(s) in OASIS if loss delivery exceeds Preschedule value
     3. Adjustments to Loss return e-Tag submitted by T-20
  3. Imbalance settled financially

Anticipated Business Practice Changes

- FFI – Financial for Inaccuracy
  - Implements at start of TC-22 cycle
- Loss Return Elections
  - Modified from 4 per year to once per rate period
  - implements TC-22 cycle

Financial for Inaccuracy (FFI)

- New term pertaining to inaccurate scheduling of in-kind losses

- Description
  - Inaccurate in-kind loss schedules count as strikes.
  - The imbalance continues to be carried forward per current practice
  - At this point the customer has the opportunity to correct their scheduling issues
  - After a predetermined number of strikes, the following occurs
    - Customer is automatically be converted to fully financial loss settlements
    - Any outstanding imbalances would be settled financially
    - This conversion would remain in place until the end of that rate period.

Pricing Losses

Topics

Agenda

- Capacity component of BPA’s loss return program
- Methodologies to value the amount of capacity provided by the FCRPS
- Cost estimates of the capacity provided to support loss returns
- Cost recovery options

Current Loss Return Options

- BPA currently offers two options for loss provision:
  - Financial Loss Returns
    - Losses are not returned, but instead paid for at a rate set by the trading floor.
  - Physical (In-Kind) Loss Returns
    - Losses are returned 168 hours later as energy

- Additionally, BPA assumes the loss factor for loss returns (financial or in-kind) is 1.9%

Capacity Issues with Status Quo

Power Services provides capacity to support the current loss return program in the following three ways:

1. Financial Loss Returns
    - The current rate is set by the trading floor as a Monthly HLH index price plus 15%. Using the HLH Index and Percentage adder capture the capacity value.
    - Because most customers think this rate is set too high, most do not elect it. This means that most loss return service provides Power Services no compensation for capacity used.
2. Physical Loss Returns – 168-hour delay
    - Since losses are returned 168 hours later, the amount of power being returned is usually different that the amount of losses being currently provided by Power Services. Power Services has to use capacity to manage this difference and is not currently being compensated for that.
    - The 168 hours return paradigm creates a mismatch in value between losses supplied and losses returned.
3. Flat Loss Factor
    - This loss factor is assumed for all hours and does not take into account the seasonal and diurnal impact to loss factors. This results in Power Services providing more capacity than is returned in months and diurnal periods with higher effective loss factors.

A Capacity Component to Losses

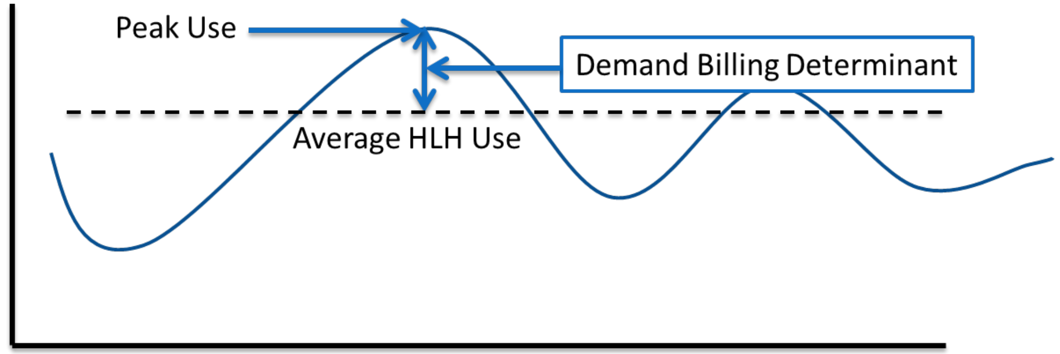
- BPA staff believes there should be a capacity component for loss returns because:
  - Real power losses consume power generation the same as any other load on the system.
  - Utilities must, and do, plan for losses when they plan their systems, run loss of load probabilities, and determine how much conservation and generation needs to be acquired to reliably meet load obligations.
  - If BPA provides transmission losses, utilities' IRPs will reflect the reduced load obligation and cause those utilities to acquire less capacity.
    - However, since this regional capacity obligation did not go away, BPA would be taking on this capacity obligation and see it reflected in its resource planning.
  - If BPA has surplus capacity, taking on this obligation reduces BPA's ability to sell capacity products.

Determining a Methodology

- Staff recommends that the energy component of loss returns be priced at an hourly index price.
- For determining the capacity component there are two main decisions to be made:
  - What metric would be used to determine the size of the capacity component?
  - What capacity price would be used to value it?

Capacity Quantity Methods: Method A

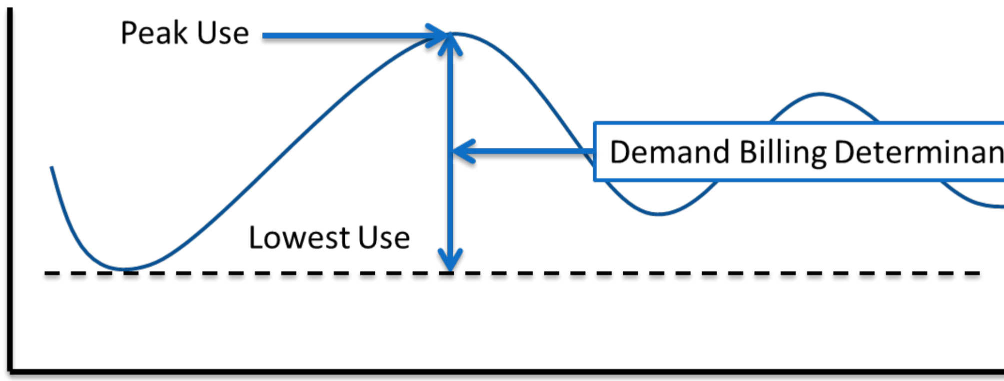
- Method A would set the capacity quantity based on the difference between the average load in HLH and peak load:



- Pros:
  - effectively bifurcates transaction into an energy component which could be purchased ahead as a flat block and a capacity component which requires FCRPS flexibility. Similar to how Power Services assesses the demand charge for PF, NR, and IP.
- Cons:
  - Does not work well for products with unpredictable power requirements. Requires adders to account for the cost of acquiring a forward block of power, and the cost of storing energy.

Capacity Quantity Methods: Method B

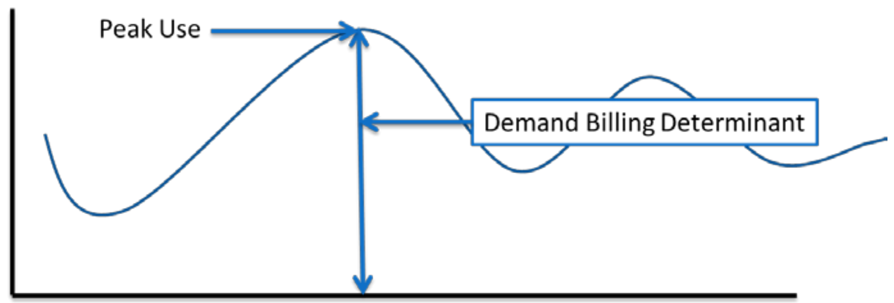
- Method B would set the capacity quantity based on the difference between the minimum and maximum load (this is how the trading floor prices capacity products today):



- Pros:
  - Effectively bifurcates transaction into an energy component which could be purchased ahead as a flat block and a capacity component which requires FCRPS flexibility.
- Cons:
  - Requires an adder to account for the cost of acquiring a forward block of power

Capacity Quantity Methods: Method C

- Method C would set the capacity quantity based on the maximum load:



- Pros:
  - works well for capacity-only products with unpredictable power requirements
- Cons:
  - may assess too large of a capacity charge when there is a portion of the load which can be reasonably forecast in advance.

Capacity Price Options

- Embedded Cost:
  - This is the capacity cost used in calculating balancing reserves rates which reflects only the fixed costs of the FCRPS. It is around $6/kW-month.
- Average Capacity Cost:
  - This is the capacity cost used in calculating balancing reserves rates which reflects both the fixed costs of the FCRPS and the variable costs of standing ready. It is around $7.30/kW-month.
- Marginal Capacity Cost (Demand Rate):
  - This is the capacity cost used in calculating the PF/NR/IP demand rate which reflects the cost to build a new thermal resource. It is around $10.29/kw-month.

Example Valuations for Financial Loss Return rate

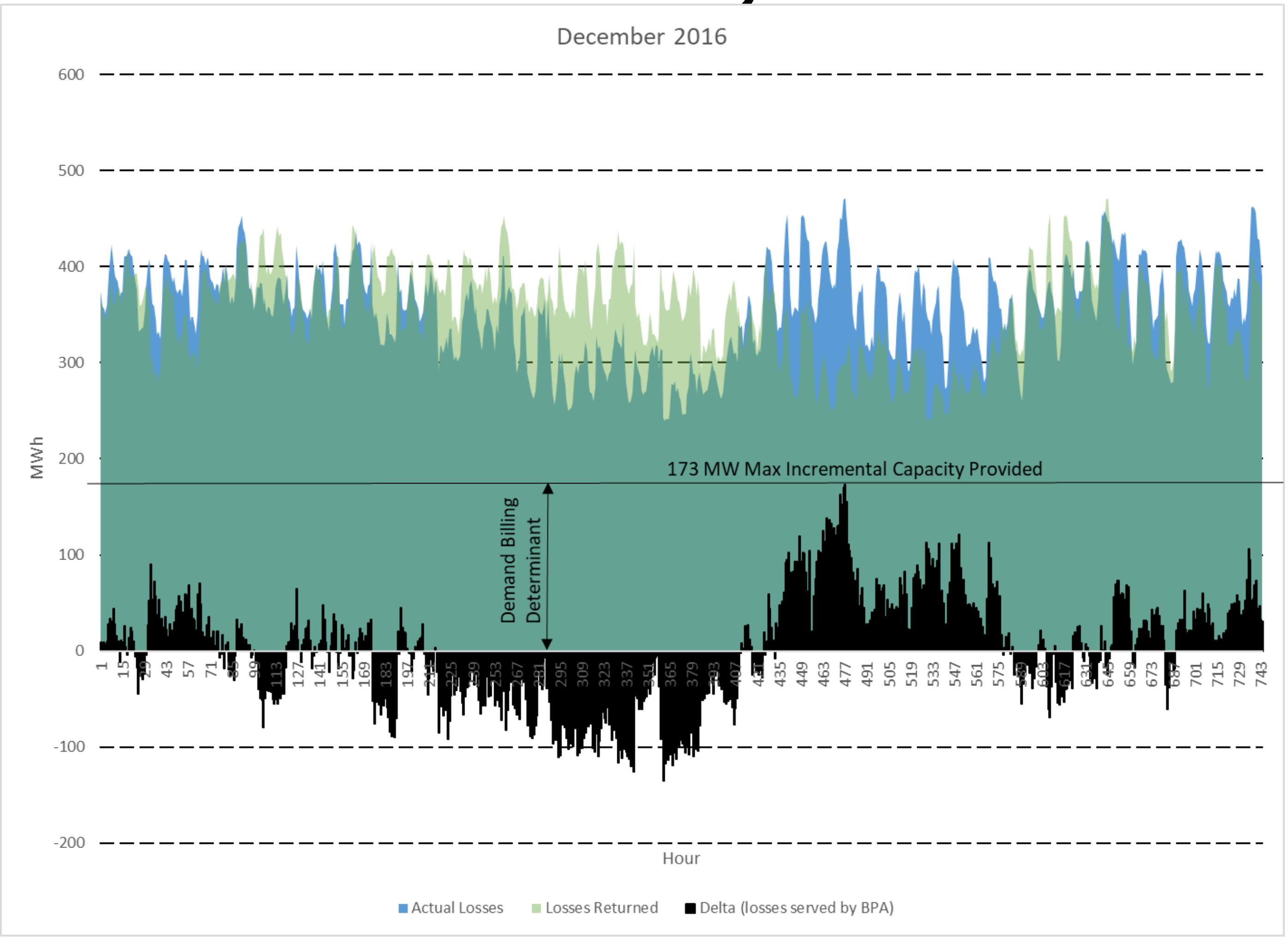
- The table below does not include all possible combinations of methods and prices, for simplicity the middle price of ~$7.30/kW/mo was not included.
- $1/MWh adder for spot-to-forward price differential is shown for Methods A and B, a $3/kW/mo adder for DEC value is added to Method A.

Capacity Valuation	Capacity Cost	Forward to Spot Differential	DEC Value	Capacity Cost in $/MWh (based on average load shape)	Expected Annual Power Capacity Revenue (for all wheeling losses)
Method A	$6/kW/mo	$1/MWh	$3/kW/mo	$4.99	$15,000,000
Method A	$10.29/kW/mo	$1/MWh	$3/kW/mo	$7.19	$21,620,000
Method B	$6/kW/mo	$1/MWh	N/A	$6.85	$20,590,000
Method B	$10.29/kW/mo	$1/MWh	N/A	$11.74	$35,320,000
Method C	$6/kW/mo	N/A	N/A	$11.29	$33,980,000
Method C	$10.29/kW/mo	N/A	N/A	$19.37	$58,270,000
Today's Financial Method	N/A	N/A	N/A	$22.88	$68,830,000

Capacity being provided to support losses

- Power Services provides capacity to support the current loss program and does not receive compensation for such capacity. This includes providing capacity to support:
  - 168-hour delayed physical returns
  - Flat 1.9% loss factor.
- If BPA were to keep its current loss program, Power Services should pass the costs of providing such capacity onto Transmission Services.
  - If BPA replaced the 168-hour delay with concurrent physical returns, then Power Services would not need to assess a capacity charge for supporting delayed returns.
  - If BPA were to update its current loss factor to monthly/diurnal loss factors, then Power Services would not need to assess a capacity charge for supporting the flat 1.9% loss factor.

Capacity provided to support 168-hour delay returns



- The cost of this service is based on the amount of capacity that is used in managing the difference between the amounts of losses provided during the hour and the energy being delivered from losses provided 168 hours ago.
- Pricing construct for Inc capacity. Decs are not valued.

Capacity costs of 168-hour delay returns

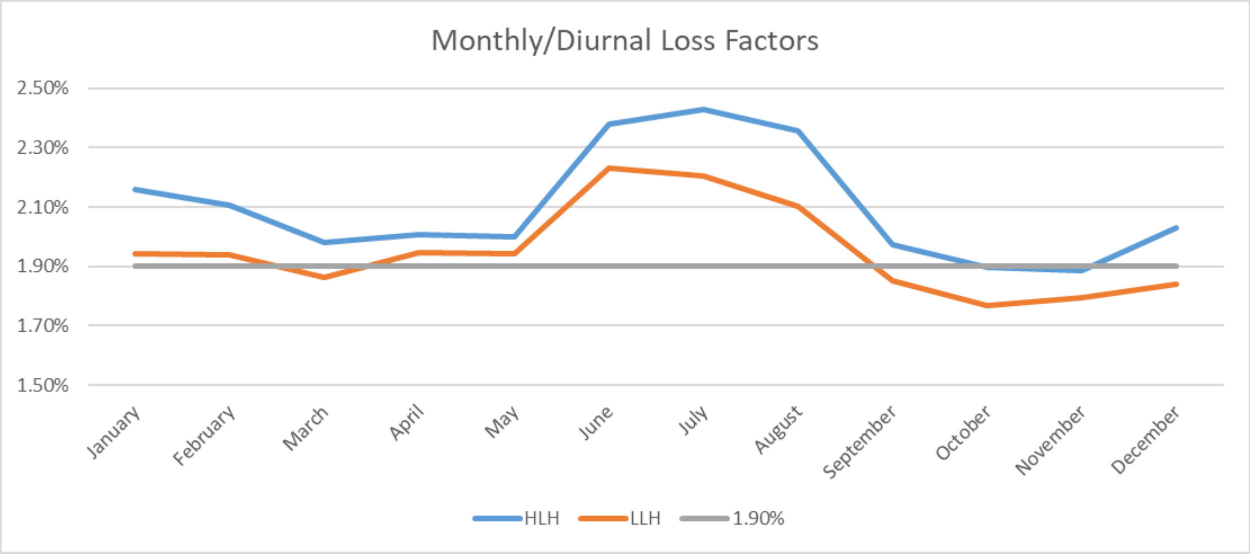
- Based on FY 2017 through FY 2019 PTP wheeling loss returns, the average monthly capacity provided to support 168-hour delay returns was about 146 MW.

Average Quantity (MW)	Capacity Price ($/kW/mo)	Estimated Annual Cost
146	$6.00	$10,512,000
146	$7.30	$12,790,000
146	$10.29	$18,028,000

- The difference between the amounts of losses provided during the hour and the energy being delivered from losses provided 168 hours ago does result in small amount of average HLH energy, about 4 annual aMW. If considering capacity quantity Method A the estimated annual cost above would decrease by about $400,000.

1.9% loss factor vs updated loss factors

- The cost of this service is based on the difference between losses with a flat 1.9% applied loss factor and losses recalculated with shaped monthly/diurnal loss factors.
- This capacity is provided with financial loss returns, physical concurrent loss returns, and 168-hour physical loss returns
- Currently the pricing construct only considers inc capacity. Decs are not valued.



Capacity costs with 1.9% loss factor

Method	Capacity Quantity Valuation	Average Quantity (MW)	Capacity Price ($/kW/mo)	Estimated Annual Cost
A	Peak less aHLH	6	$6.00	$432,000
A	Peak less aHLH	6	$7.30	$526,000
A	Peak less aHLH	6	$10.29	$741,000
B	Peak less Min	22	$6.00	$1,584,000
B	Peak less Min	22	$7.30	$1,927,000
B	Peak less Min	22	$10.29	$2,717,000
C	Peak	26	$6.00	$1,872,000
C	Peak	26	$7.30	$2,278,000
C	Peak	26	$10.29	$3,210,000

- These capacity estimates were calculated with shaped loss factors that were reduced proportionally to an annual average 1.9%.
- Assumes all PTP wheeling losses are returned concurrently.

Capacity costs with 168-hour delay and 1.9% loss factor

- There is a diversity factor benefit when considering the capacity it takes to support 168-hour delay return of physical losses and using a flat 1.9% loss factor.

- The capacity amount is calculated by recalculating hourly losses assuming the shaped loss factors and then subtracting the amount of 168-hour delayed return losses (which were based on the flat 1.9% loss factor.)

Average Quantity (MW)	Capacity Price ($/kW/mo)	Estimated Annual Cost
154	$6.00	$11,088,000
154	$7.30	$13,490,000
154	$10.29	$19,016,000

Cost Recovery Options

After determining the method for valuing the capacity, how to collect those costs from Transmission Services must be decided. Two general options have been identified, either as classic capacity cost recovery or through folding the capacity cost into the energy component.

- Classic fixed capacity cost recovery – charging a stand-alone capacity price
  - Pros.
    - Classic method of billing for capacity. Clean distinction between capacity and energy.
  - Cons.
    - More complex billing if passed on to customers.
    - Can complicate hop-on/hop-off services. If customers are required to maintain an election for a whole rate-period, this problem goes away.

Cost Recovery Options (cont.)

- Folding the capacity cost into the energy cost
  - Pros.
    - Can simplify billing and may be the best option for hop-on/hop-off services.
  - Cons.
    - If a percent adder to the energy rate is used to determine the total losses price, an assumed market price is required. A fixed $/MWh approach based on a forecast energy price can be used to overcome the disadvantage of using a percent adder.
    - Not the preferred method for billing for capacity because it uses an energy model of billing. This undermines the importance of capacity and can cause confusion as customers compare the price paid for a service with capacity to the market price of energy only.

Summary

- Power Services is currently providing services which it isn’t being compensated for except for customers which elect financial losses.
  - However, most customers do not elect to purchase losses from Power Services.
- Staff proposes three ways which would correct this:
  - 1) 168-Hour Delayed Physical Returns with compensation to Power Services for managing 168 hour delay and the difference between the average annual loss factor and the actual loss factor (or add a shape to the applied loss factor).
  - 2) Concurrent Physical Returns with compensation to Power Services for managing the difference between the average annual loss factor and the actual loss factor (or add a shape to the applied loss factor).
  - 3) Updated Financial Returns

Next Steps

- Network Loss Factor
  - Workshop on July 28, 2020
  - Anticipate discussions for Network Loss Factor
    - Step 5: Discussion of Customer Feedback to Alternatives and BPA's Response
    - Step 6: Staff Proposal for Solution
- Line Loss Settlement
  - Anticipate decision to be made in August 2020
- Pricing Losses
  - We plan to come back in July for the pricing and loss factor discussion for steps 5-6.
- Please provide comments by July 8, on the loss factor, settlement and pricing to techforum@bpa.gov.

ISSUE #12: GENERATOR INTERCONNECTION

- Repower & Replacement
  - Step 3: Analyze the Issue
  - Step 4: Discuss Alternatives
- Key Tariff Revisions to Attachments L & N

Objectives

- Walkthrough proposed alternatives for repower and replacement provisions of Attachment L of the Tariff
  - Please see redline in strawman proposal

- Walk through key revisions to Tariff Attachments L and N

Analyzing the Issue

- Interconnection Customers' generating facilities are aging and some are finding it necessary to replace/update equipment.
- Bonneville has an opportunity to create a streamlined process to facilitate these efforts.

Alternative #1 – Status Quo

- Interconnection Customer (IC) requesting a repower of an existing Generating Facility must submit a new Interconnection Request (IR) and complete the process outlined in the LGIP (e.g., feasibility study, system impact study, facilities study, etc.).

Alternative #2 - Repower

- Update the Tariff Attachment L to include Generating Facility Repower (replacement of the components of a Generating Facility Identified in an executed LGIA).
- *NOTE: Streamlined Repower Process does not include general maintenance, an increase in Interconnection Service or no new Point of Interconnection;*
    - No need to submit an IR;
    - IC notifies Transmission Provider (TP) of the Repower;
    - Scoping meeting is held to discuss the Repower;
    - IC must demonstrate that repower will not degrade the Transmission System;
    - TP will determine whether the Repower is a potential Material Modification;
        - If the Repower is a potential Material Modification then an IR is required.
            - Once the IR is received the IC may bypass the Feasibility Study and Impact Study (if mutually agreed to by the IC and TP).
        - If not Material Modification TP will require the Repowered Generating Facility meet all of TP's current operational and technical standards;
    - IC will move to Facilities Studies and environmental studies as needed.
    - Existing LGIA is amended to reflect the new Repowered Generating Facility;

Alternative #3 - Replacement

- Update the Attachment L to include Generating Facility Replacement (any Replacement Generating Facility must connect to the Transmission System at the same electrical Point of Interconnection [i.e. same voltage level at the interconnecting substation] as the Existing Generating Facility). No increase in Name Plate and Interconnection Service, no new Point of Interconnection.
  - IC submits an IR consistent with the terms of the LGIP, pays deposit, and enters the Interconnection Queue;
  - The request must be submitted to TP by the IC for its Existing Generating Facility at least one (1) year prior to the date that the Existing Generating Facility will cease operation;
  - The IC shall request only ER Interconnection Service for the Replacement Generating Facility, if the Existing Generating Facility has only ER Interconnection Service;
  - The IC may request either ER Interconnection Service or NR Interconnection Service for the Replacement Generating Facility, if the Existing Generating Facility has NR Interconnection Service;
  - TP will conduct Interconnection Facilities Study and necessary environmental studies.
  - TP may also conduct a Replacement Impact Study and a Reliability Assessment Study.
  - Existing LGIA is amended to reflect the Generating Facility Replacement.

Alternative #4: Repower and Replacement

- Update Attachment L to the Tariff to include both Generating Facility Repower and Replacement provisions (Alternatives 2 and 3).

Key Revisions to Attachments L and N

- Repowers & Replacements
- Order 845, 845-A
  - Interconnection Customer's Option to Build
  - Identification and Definition of Contingent Facilities
  - Utilization of Surplus Interconnection Service
  - Material Modification and Incorporation of Advanced Technologies
- Revised GIAs to allow for electronic signatures, and to align the notice provisions with the rest of the Tariff.
- Clean up of Attachment L and N (e.g., remove references to filing with FERC and made other revisions to align with our status as a federal entity, removed errors in pro forma Tariff language).

FERC Order 845, 845-A

- Order No. 845, 845-A: Revised the *Pro Forma* LGIP and LGIA to improve certainty for interconnection customers and promote more informed interconnection decisions and enhance the interconnection process. FERC adopted ten reforms:
  - **Interconnection Customer's Option to Build;**
  - Dispute Resolution;
  - **Identification and Definition of Contingent Facilities;**
  - Transparency Regarding Study Models and Assumptions;
  - Definition of Generating Facility in the Pro Forma LGIP and LGIA;
  - Interconnection Study Deadlines;
  - Requesting Interconnection Service Below Generating Facility Capacity;
  - Provisional Interconnection Service;
  - **Utilization of Surplus Interconnection Service; and**
  - **Material Modification and Incorporation of Advanced Technologies.**

Next Steps

- Provide feedback on all Repower & Replacement alternatives by July 8 send to techforum@bpa.gov (with a copy to your Transmission Account Executive).
- July Customer Workshop
  - Steps 5 and 6 for Repower and Replacement Tariff Alternatives and redline Tariff language
  - BPA will share final draft of Tariff language at this workshop.

POWER RATES: EXPLORING SECONDARY REVENUE IN BASE POWER RATES

Purpose

- We want to discuss, yes again, how BPA accounts for secondary revenue in its base rates.
- We've explored the concept of including less secondary revenue in base rates as recently as two years ago and have regularly revisited this topic over the past decade or more.
- It's a concept that has a lot of expressed appeal outside the rate setting process, but that appeal historically loses its luster once the immediate rate impacts are considered.
- We believe we may have a construct that could harness the appeal while maintaining its shine through the rate setting process.

The Objective

- Objective: Design a construct that decreases over time BPA's dependence on its secondary revenue for purposes of recovering its costs.
- Construct must not create additional rate pressure when the secondary revenue forecast is the same or less than the amount of secondary included in previous rate period's base rates.

Why?

- The secondary revenue forecast is the largest source of revenue recovery risk for BPA power rates.
- Including this risk in our base rates causes us to rely heavily on risk provisions that extract additional revenue from BPA's customers during difficult financial times.
- We want to try to flip the equation and put BPA and its customers in the position of delivering good news (through rebates) rather than delivering bad news (through added charges).
- It's a more robust solution that over time will lend itself to a better financial situation than the current construct and do so while keeping base rates stable all else equal.

High-Level Concept

Set the forecast secondary revenue included in base rates equal to the lower of the previous rate period's secondary revenue amount and the updated secondary revenue forecast.

$$BP22_{Base} = Minimum(BP20_{Base}, BP22_{Forecast})$$

Where:

$BP22_{Base}$ is the amount of secondary revenue included in the calculation of BP-22 base rates.

$BP20_{Base}$ is the amount of secondary revenue included in the calculation of BP-20 base rates.

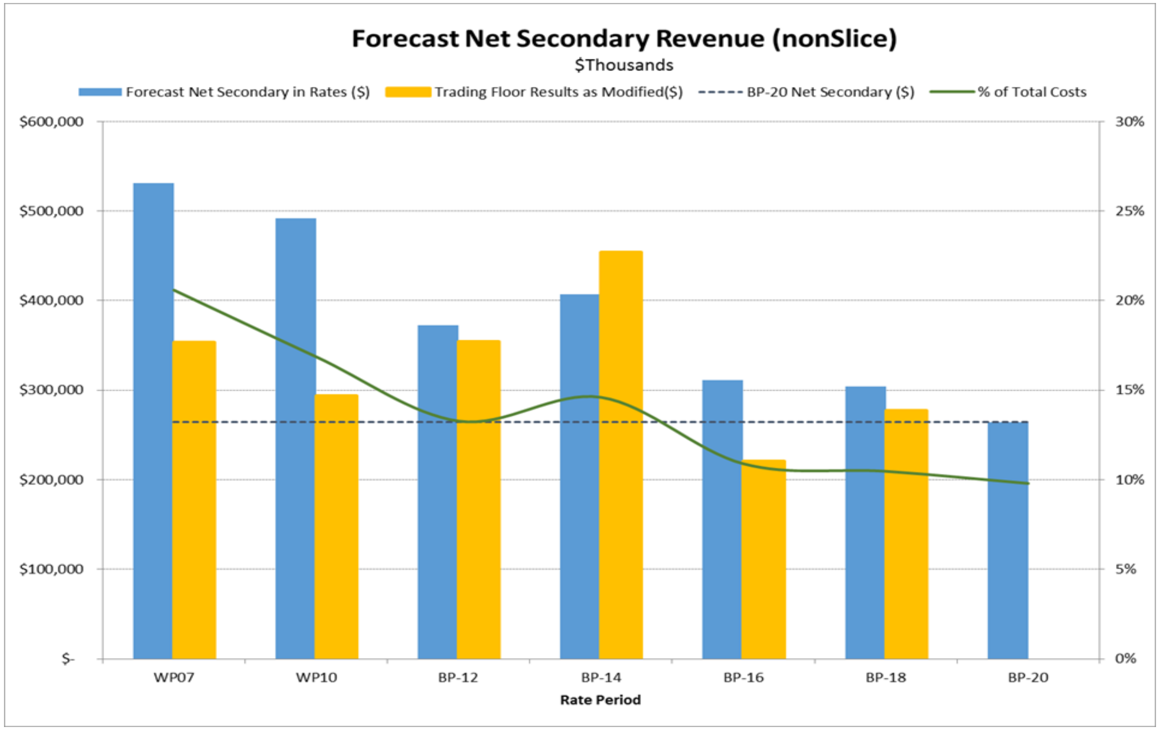
$BP22_{Forecast}$ is the forecast expected secondary revenue in the BP-22 rate studies.

Details to Workout

- What is included in "secondary revenue" for purposes of this calculation?
  - Revenue forecast from sales served with energy that is forecast to be available above critical water levels.
  - Probably should not include capacity sales.
  - Should not include firm surplus (forecast or actual sales served with critical water inventory).
- How do we adjust to account for shifts in critical and average energy inventory?
  - Calculation would likely need to be proportional to MWhs so that it scaled with more or less inventory.
- How is it modeled in the Rates Analysis Model?
  - Likely a post-process adjustment to rates subject to risk mechanisms. Meaning, set rates first assuming expected secondary the status quo way and then back out secondary revenue by adjusting applicable rates.

Conclusion

- We have been talking about this for a long time and now is an opportune time to act given the relatively low level of secondary revenue included in BP-20 rates. Let's not move backwards from this worthy goal of reducing BPA's dependence on its secondary revenue for purposes of recovering its costs.



ISSUE #29: TC-20 – HOURLY FIRM

Today’s Objective

- Provide an update on open HF settlement items
  - 2.c. TC-22 Language
  - 2.f. Preemption and Competition
  - 2.k. NT Redispatch Cost Allocation
  - 2.i. Product Conversion

- As committed in the TC-20 settlement, BPA will provide an update and share results of the evaluation of Hourly Firm based on the Monitoring and Evaluation Plan.

TC-22 Proposed Hourly Firm Language

2.c. TC-22 Hourly Firm Language

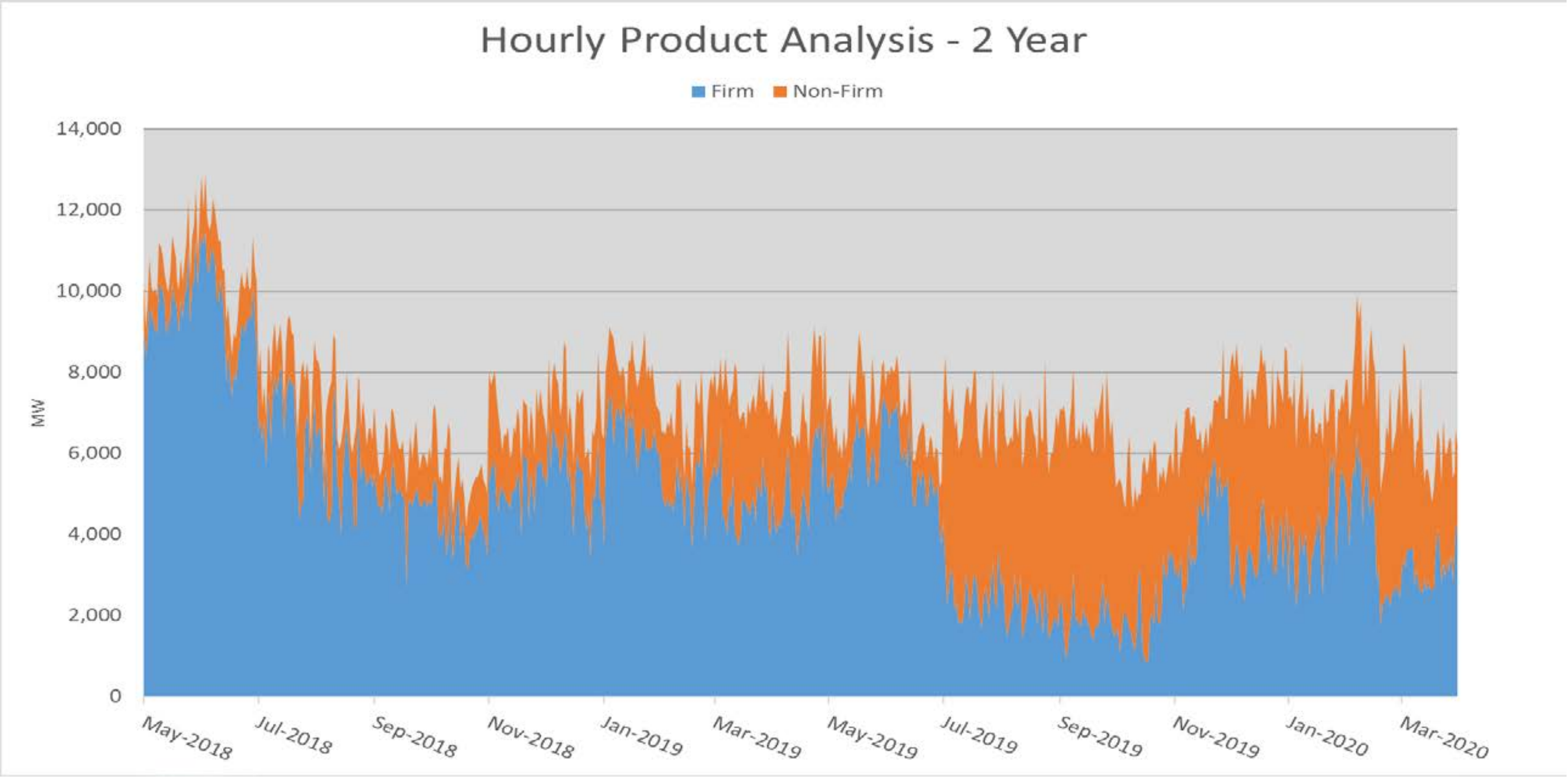
Objective: Determine whether BPA should propose changes to *status quo*. Currently, Hourly Firm service is offered according to limits based on ATC, and the service may be reserved until the day prior to the operating day at 2340 for the TC-22 proceeding.

Background: BPA currently provides Hourly Firm service that may be reserved until the day prior to the operating day at 2340. BPA has agreed to maintain this offering through the TC-22 Period (October 1, 2021 –September 30, 2023).

As agreed in the TC-20 settlement, BPA may propose a change from this *status quo* during the TC-22 proceeding after:

- Bonneville identifies Hourly Firm service as:
  - A demonstrable adverse reliability risk
  - A more than *de minimis* adverse impact to firm transmission service
  - In conflict with the then applicable market rules
- Bonneville engages in best efforts to come to a collaborative solution that mitigates the identified risks/impacts of hourly firm service with customers.

Impact on Customer Use of Hourly Firm



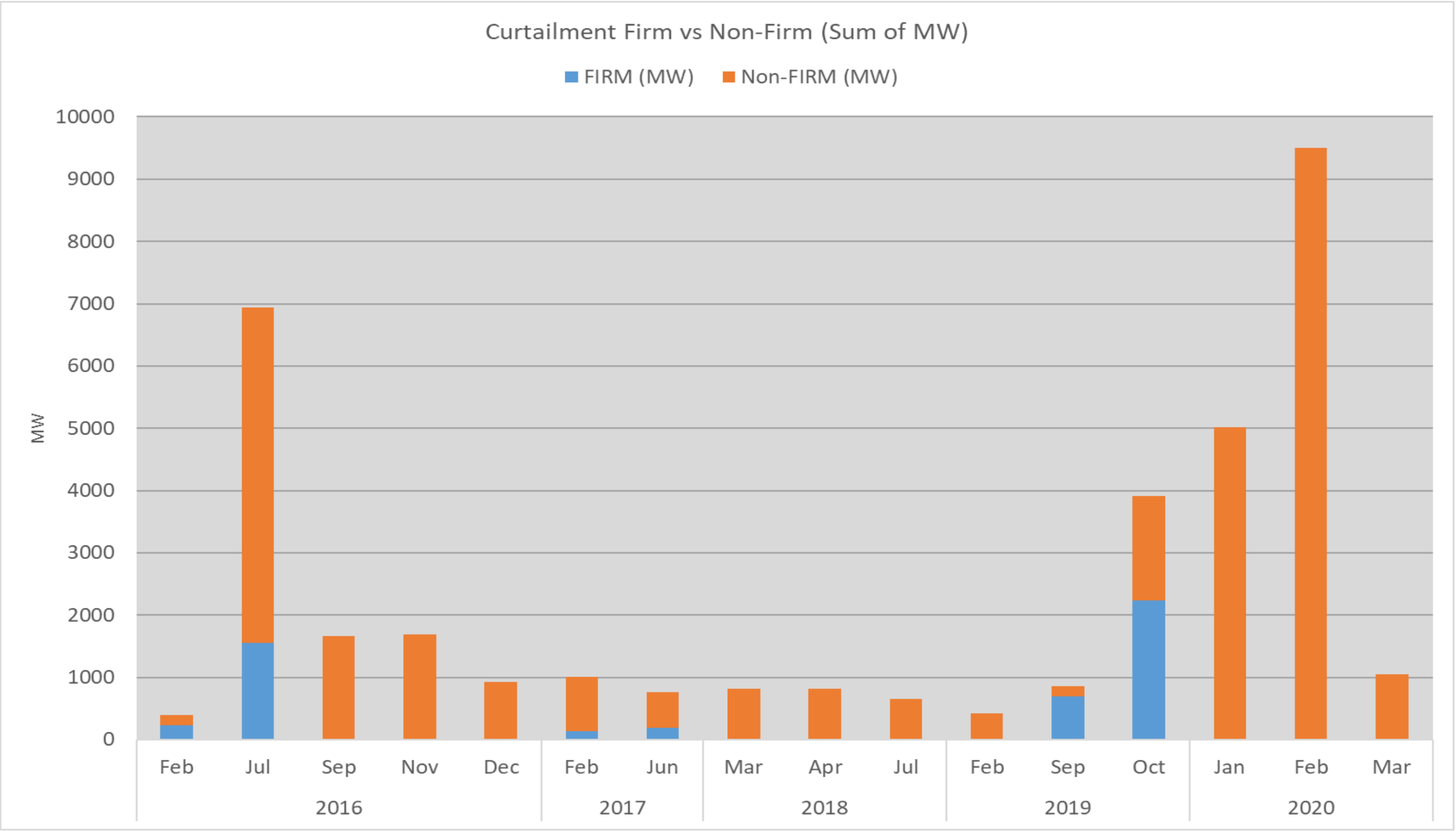
	Hourly - Firm (MW)	% Change	Hourly - Non-Firm (MW)	% Change	% of TSRs - Hourly Firm
Before HF Limitation*	6,023.52	-	1,559.18	-	79.44%
After Limitation**	3,731.89	-38%	3,204.58	106%	53.80%

*"Before Limitation" review period May '18 - June '19

**"Limitation" is defined as both July '19 and January '20 changes.

Figures are systemwide average MW used per hour of products with an hourly duration.

Impact of Firm Curtailments



	Priority1 MW:	Priority2 MW:	Priority6 MW:	% NF:	Priority7 MW:	% F:
Before HF Limitation	51,252	1,755	4,830	79%	15,605	21%
After Limitation*	15,312	262	0	100%	0	0%

*"Before Limitation" review period March '12 - June '19

**"Limitation" is defined as both July '19 and January '20 changes.

There were firm curtailments between July and January that were outage related that have been excluded from this dataset.

Customer Experience

Feedback Themes:

- Increased operational difficulty
- Decreased value of transmission products
- Increased costs
- Issues with offering real-time hourly operating reserves
- Increased chance of UIC violations with persistent alterations to the parent TSRs firm transmission allocation

Customer comments posted here

TC-22 Proposed Language

To date, analysis has not demonstrated that Hourly Firm is:

- A demonstrable adverse reliability risk
- A more than *de minimis* adverse impact to firm transmission service
- In conflict with the then applicable market rules

Therefore BPA proposes to maintain the ***Status Quo:*** Hourly Firm service that may be reserved until the day prior to the operating day at 2340 as in the TC-20 proceeding.

Preemption and Competition Update

2.f. Preemption and Competition

As soon as practicable, Bonneville will apply preemption and competition to daily and hourly firm, including redirects, if OATI implements NAESB standards to adopt FERC policy under *Entergy Services Inc.* 148 FERC ¶ 61,209. If FERC has not directed OATI to adopt such NAESB standards or if OATI has not made the changes prior to the start of the TC-22 proceeding, then the issue of whether to apply preemption and competition to daily and hourly firm in the absence of such action will be reevaluated as part of the TC-22 proceeding. The Parties will discuss the conditional window in Tariff section 13.2(iv) in workshops before the TC-22 proceeding.

2.f. Preemption and Competition

FERC has issued Order 676-I which includes new standards that will introduce some large changes to preemption and competition as well as standards to address Entergy *Services Inc.*

Bonneville affirms that it will implement preemption and competition for hourly, daily and redirects **as soon as practicable** after the testing and implementing the necessary software, once it is delivered by OATI.

Bonneville is not proposing any changes to 13.2(iv) in our tariff.

2.k. NT Redispatch Cost Allocation

Bonneville forecasts NT Redispatch costs in Bonneville rate cases based on historic usage of NT Redispatch (“NT Redispatch Cost Methodology”). For the BP-20 rate period and for any rate period thereafter during which Bonneville offers the hourly firm product, the costs for NT Redispatch under Bonneville’s Redispatch and Curtailment Business Practice, will be allocated based on the principle that NT customers should not incur additional NT Redispatch costs that are attributable to the Point-to-Point hourly firm product.

Notwithstanding section 2.k.i above, if Bonneville forecasts NT Redispatch costs below $4 million:

- In BP-20, Bonneville shall use historical usage to forecast the cost for NT Redispatch and allocate such costs to the network segment generally; and
- In BP-22 and BP-24, Bonneville shall include in its Initial Proposal that any forecast NT Redispatch costs will be allocated to the network segment generally.

If Bonneville forecasts NT Redispatch costs to exceed $4 million in the BP-22 or BP-24 rate periods, the Parties have the right to support and challenge any alternative approaches to allocate the costs for NT Redispatch in the respective rate proceeding in a manner consistent with the principle set forth in section 2.k.i above.

2.k. NT Redispatch Cost Allocation

Bonneville forecasts NT Redispatch costs below $4 million:

- Total costs for redispatch by the Federal System from July 2019 through March 31, 2020 = $9,100 (reports available here)
- Total costs for redispatch by transmission purchases for the same period was roughly $300,000

Since Bonneville forecasts NT Redispatch costs below $4 million:

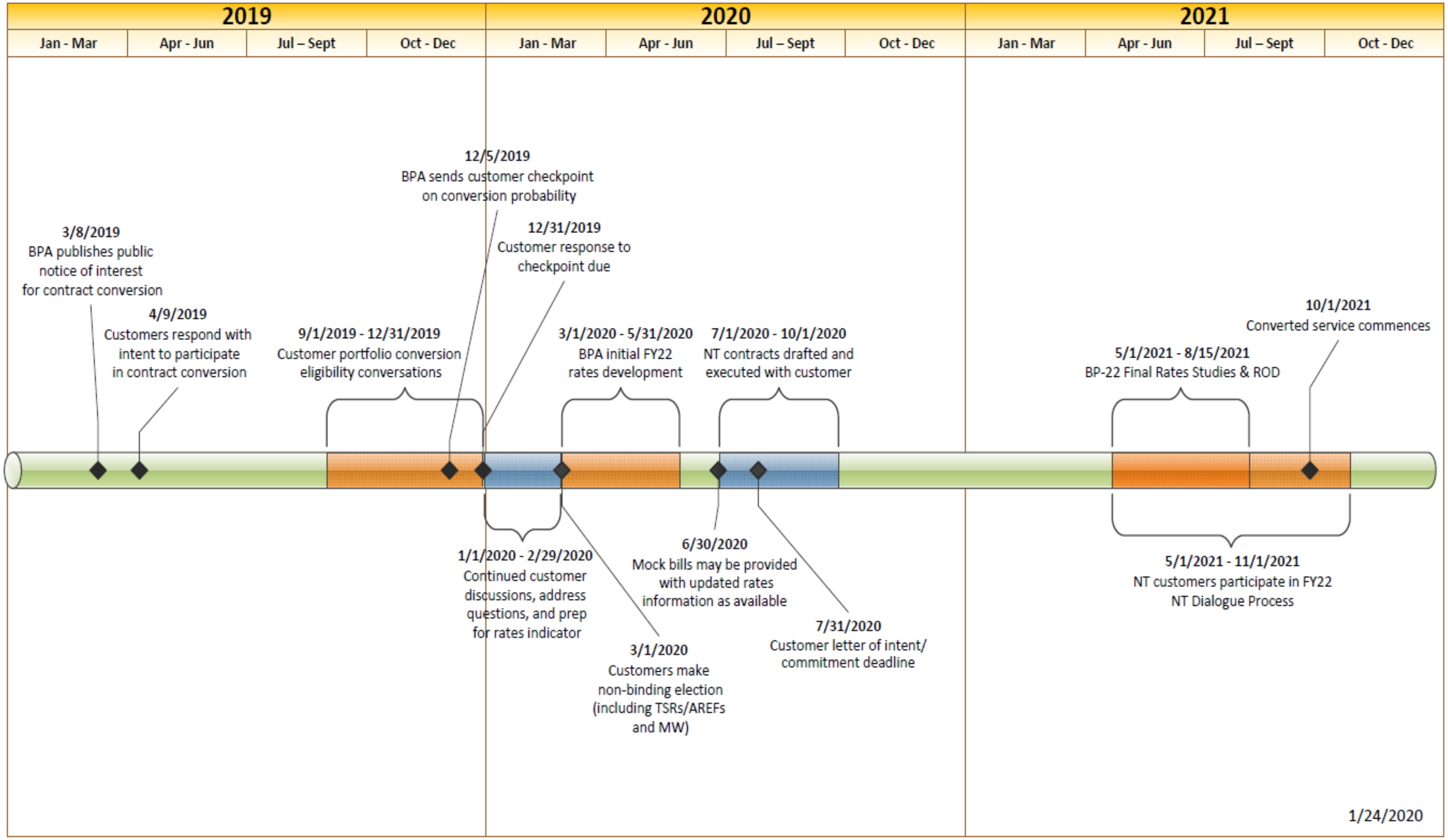
- In BP-22, Bonneville shall include in its Initial Proposal that any forecast NT Redispatch costs will be allocated to the network segment generally.

2.i. Product Conversion

Conversion Window 1 update:

- Initial MW considering to convert: 2894 MW
- Remaining MW for the two customers pending: 1262 MW (1118 MW, 143 MW)
- Second window expected to begin Q2 FY21

2.i. Product Conversion



Information Availability

- Reports and raw data will be generated per the Hourly Firm Monitoring and Evaluation Plan
- Bonneville will post the updated and generated reports on a quarterly basis on BPA's external website
- Available starting June 10, 2020 https://www.bpa.gov/transmission/Reports/Pages/Hourly-Firm-Data-Monitoring-and-Evaluation.aspx
- Data will be posted from Quarter 2, Calendar Year 2018 to current

Proposed Timeline & Next Steps

1. Future congestion management information (TLR avoidance and curtailment events) will be provided at quarterly ST ATC workshops going forward

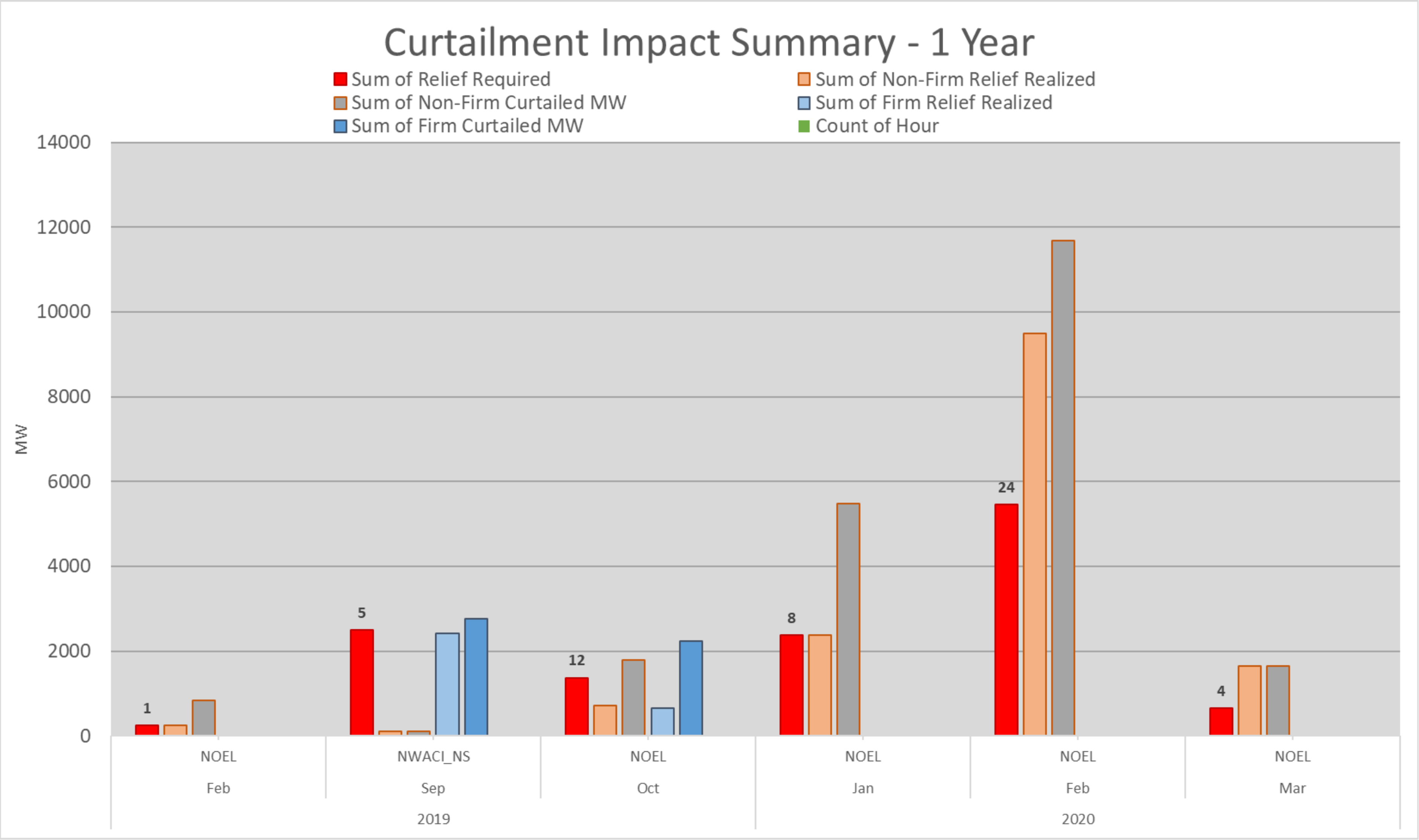
2. Comments on the Hourly Firm TC-22 proposed language are due 7/8/20

3. After the TC-22 proceeding, Bonneville and customers will evaluate options for the post-TC-22 period for the hourly firm product based on the results of the neutral evaluation described in section 2.d.

Hourly Firm – Quarterly Update

Overall Events

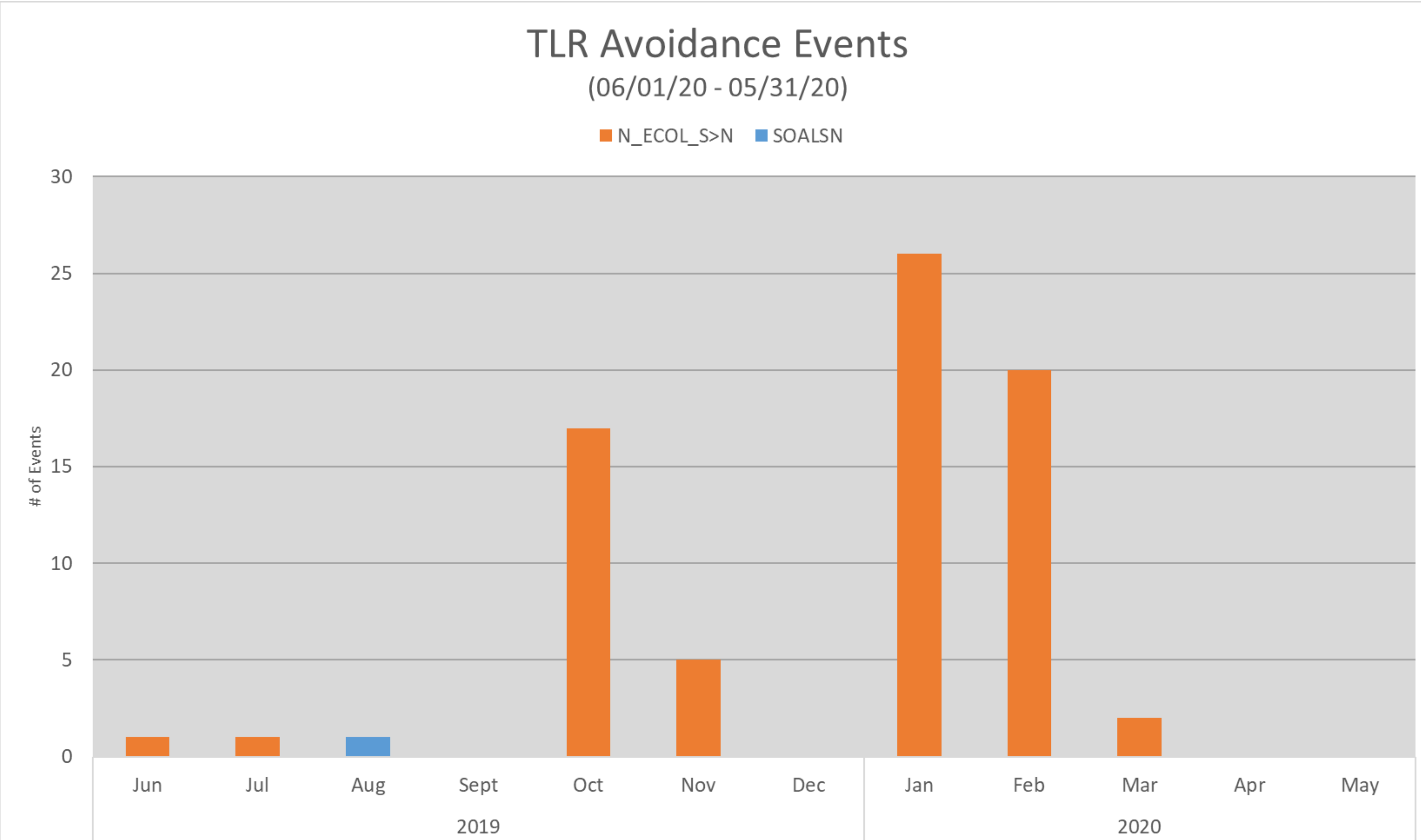
- Curtailments:
  - 4 events over 1 individual day (03/01 – 05/31)
- TLR Avoidance Events:
  - 2 events over 1 individual day (03/01 – 05/31)
- Refused TSRs due to TLR Avoidance:
  - 33 (33 on NOEL) (03/01 – 05/31)
- Percentage of hours where actual flows were within 20% of TTC:
  - 1.32% - System-wide (14.94% - NOEL only)


Curtailment Impact Summary - 1 Year
Sum of Relief Required
Sum of Non-Firm Relief Realized
Sum of Non-Firm Curtailed MW
Sum of Firm Relief Realized
Sum of Firm Curtailed MW
Count of Hour
14000
12000
10000
8000
6000
4000
2000
0
MW
1
5
12
8
24
4
NOEL
Feb
NWACI_NS
Sep
NOEL
Oct
2019
NOEL
Jan
NOEL
Feb
NOEL
Mar
2020

TLR Avoidance Events – June 2019-May 2020

Count of TLR Avoidance Events	Days/ Hours Impacted	Refused TSRs	Flowgate	Annotation	Initial Start	Final Instance
Total: 73	**Total: 195/ 1798**	**Total: 1548**	**-**	**-**	**2019-06-10 10:00:00 PS**	**2020-03-16 09:00:00 PS**
68 Firm / 4 Non-Firm	64 / 1023	1530	N_ECOL_S>N	North of Echo Lake Mitigation	2019-06-10 10:00:00 PS	2020-03-16 09:00:00 PS
1 Firm	1/4	18	SOALSN	South of Allston Mitigation	2019-08-06 16:00:00 PD	2019-08-06 20:00:00 PD

*Days and Hours impacted count is not mutually exclusive.


TLR Avoidance Events
(06/01/20 - 05/31/20)
N_ECOL_S>N
SOALSN
30
25
20
15
10
5
0
# of Events
Jun
Jul
Aug
Sept
Oct
Nov
Dec
Jan
Feb
Mar
Apr
May
2019
2020

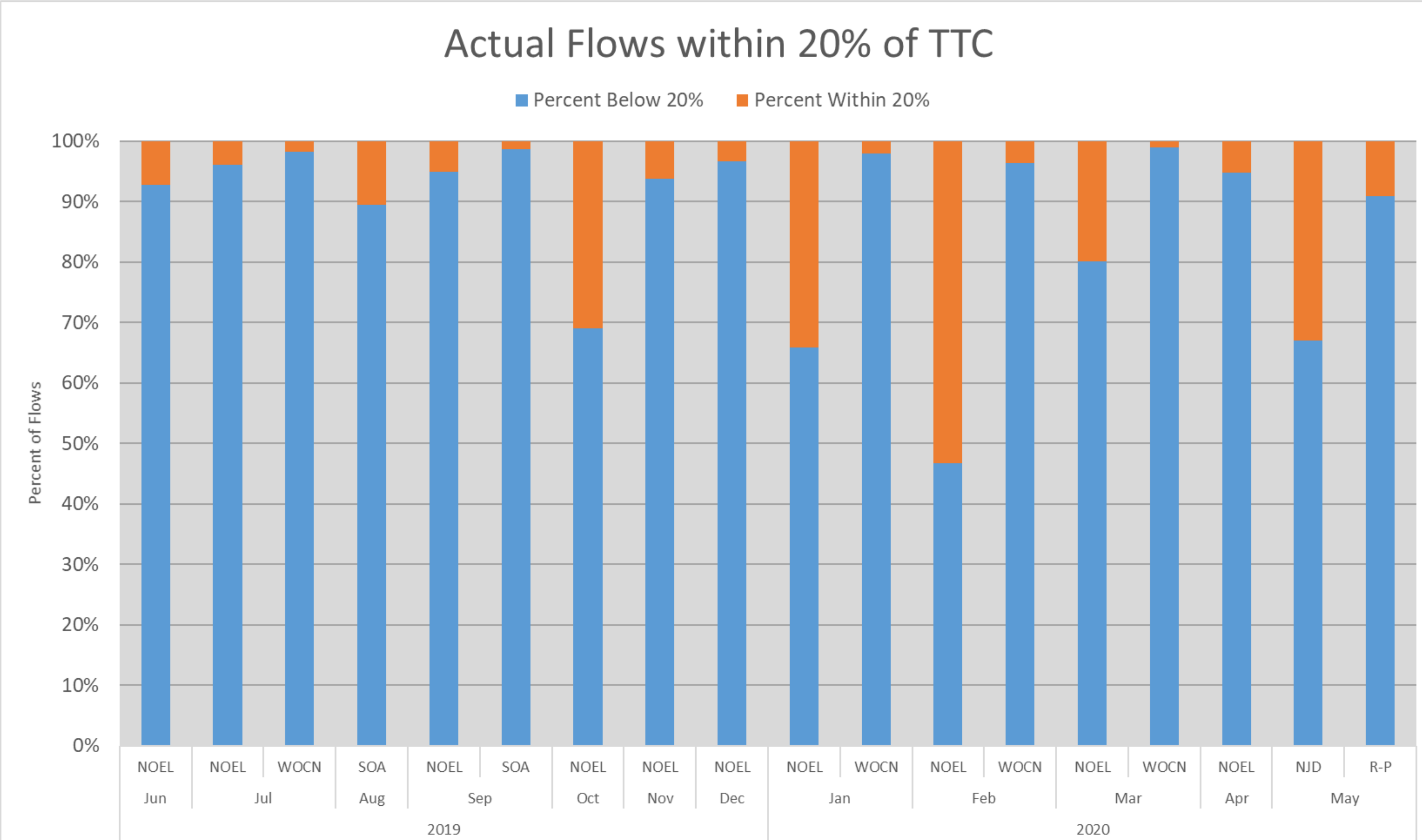


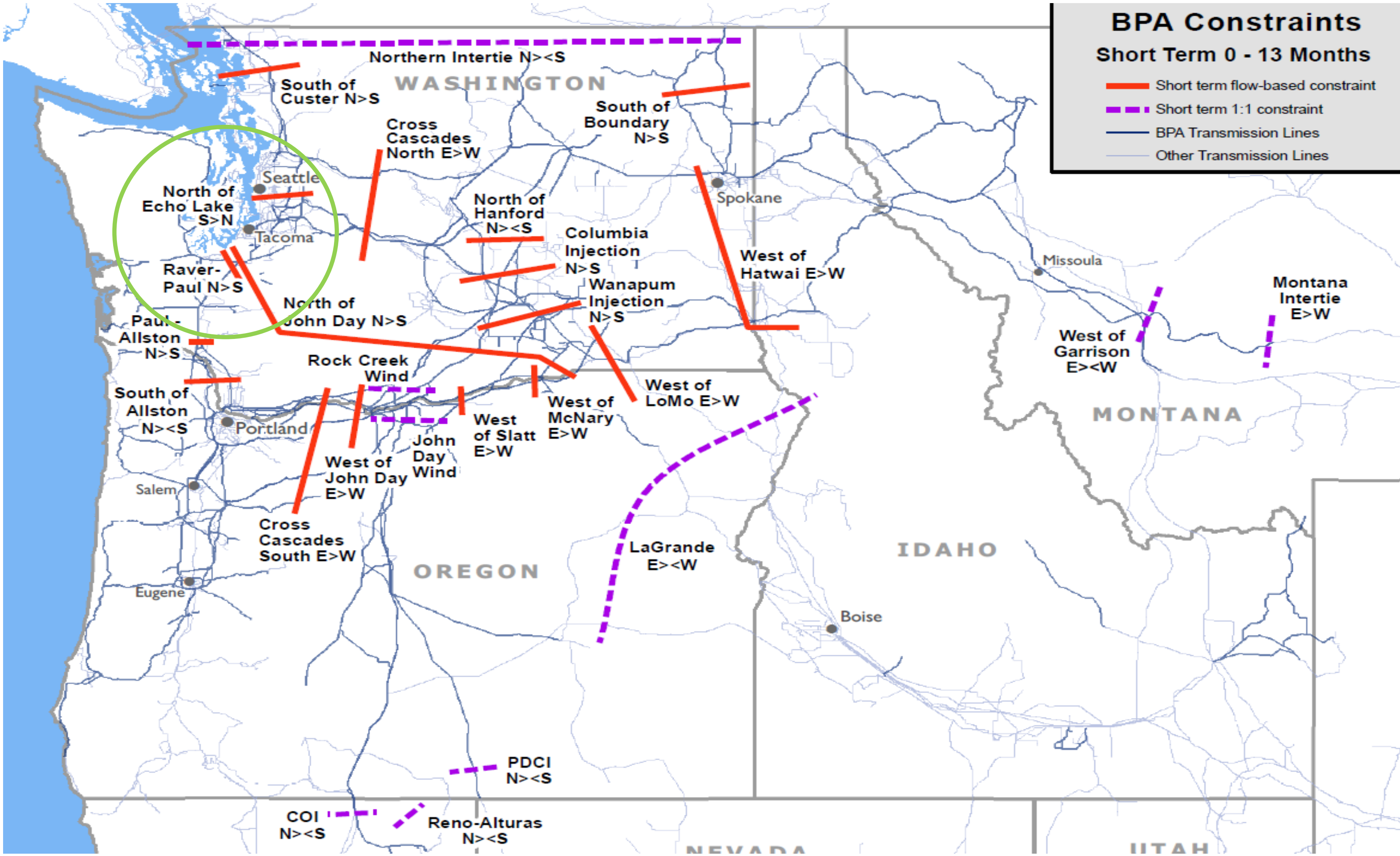
**Chart includes information for flowgates with greater one percent of hours where actual flows were within 20% of TTC.*

DEEP DIVE

MARCH 2020

NORTH OF ECHO LAKE

ATC Short Term Constraints



Deep Dive Conditions

- Timeframes – **March 1-3, 2020**
- Curtailment Events – **4 (1 Day, NOEL Flowgate)**
- TLR Avoidance Events – **0**
- Planned Outages – (detailed on following slide)
- Weather Impacts – **N/A**

Dispatcher Actions

- DUE TO MONROE PCB 4522 BFR POST CONTINGENCY CAUSING FLOWS ABOVE 100% OF EMERGENCY RATING ON THE MAPLE VALLEY-SNOKING #1230KV LINE,INITIATED 200MW CURTAILMENT ON NOEL (TOTAL 493MW NF) ICRS ID 8661 FOR HE13 .NTERVAL D. TMS NOTIFIED. DSOA SENT. RC NOTIFIED.

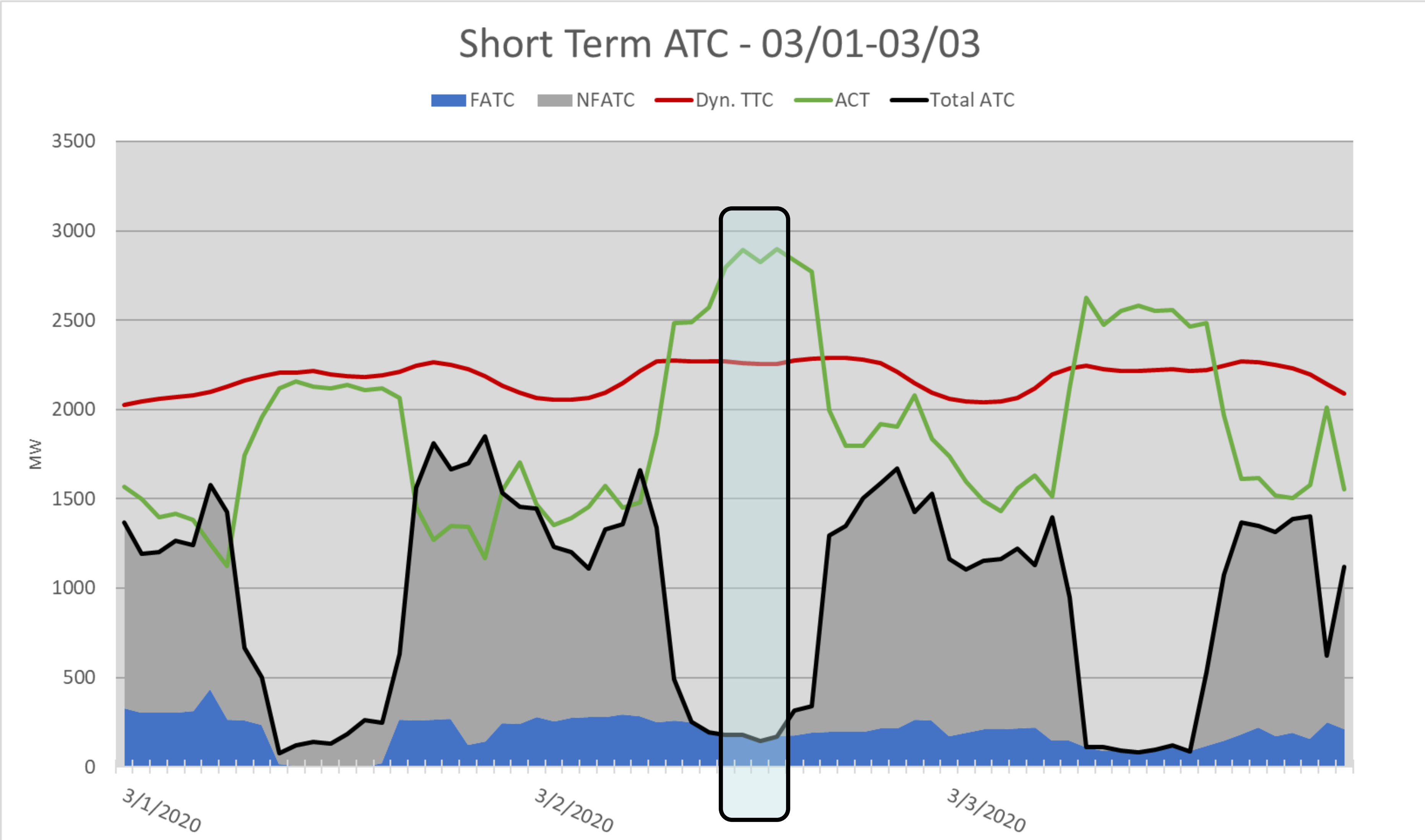
- Due TO MONROE PCB 4522 BFR POST CONTINGENCY CAUSING FLOWS ABOVE 100% OF EMERGENCY RATING ON THE MAPLE VALLEY-SNOKING #1 230KV LINE,INITIATED 200MW CURTAILMENT ON NOEL (TOTAL 483MW NF) ICRS ID 8662 FOR HE14. TMS NOTIFIED. DSOA SENT. RC NOTIFIED.

- INITIATED 100MW CURTAILMENT ON NOEL (TOTAL 291MW NF) ICRS ID 8666 FOR REMAINDER OF HE16. TMS NOTIFIED. DSOA SENT. RC NOTIFIED.

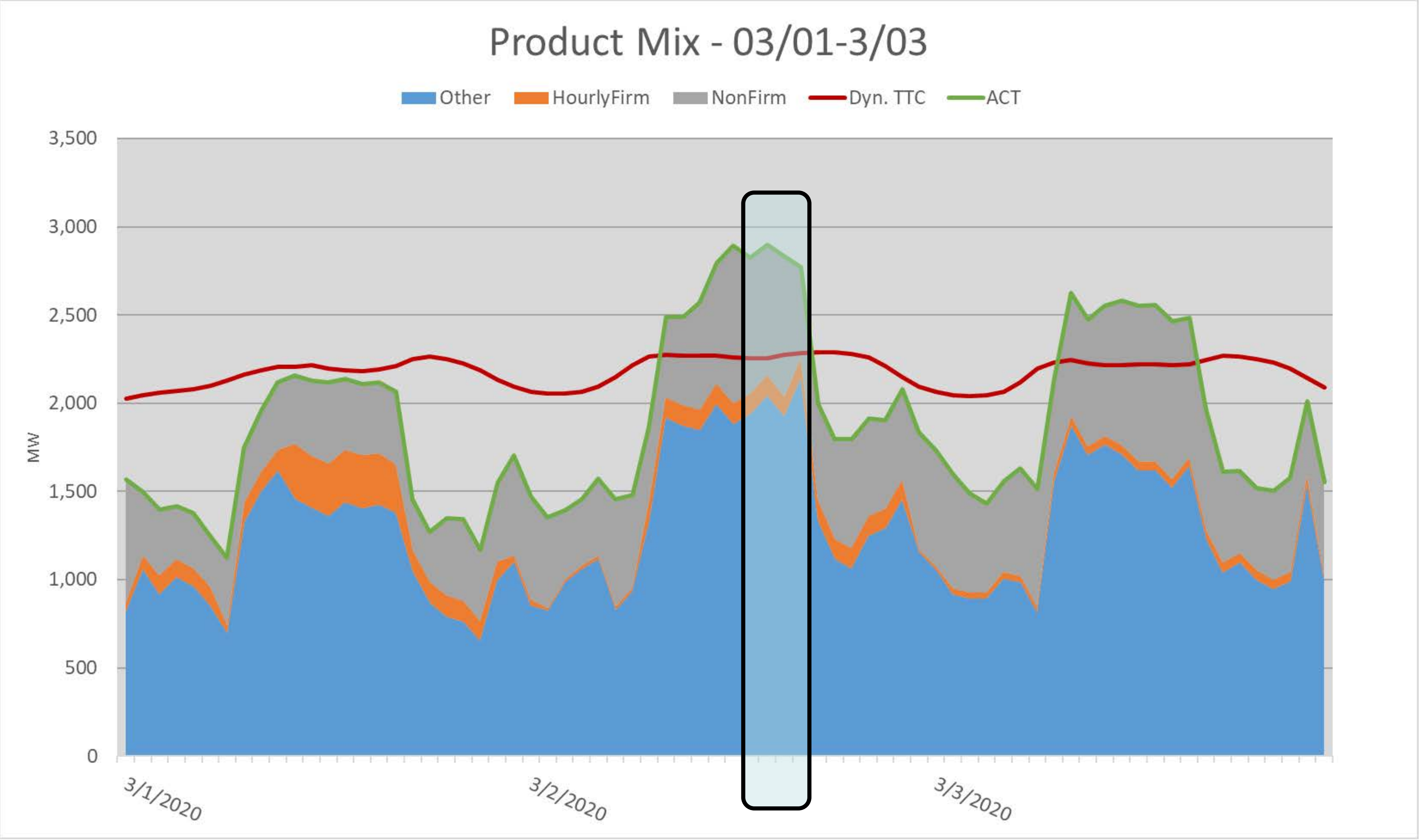
Key NOEL Outage Summary

N_ECOL_S>N

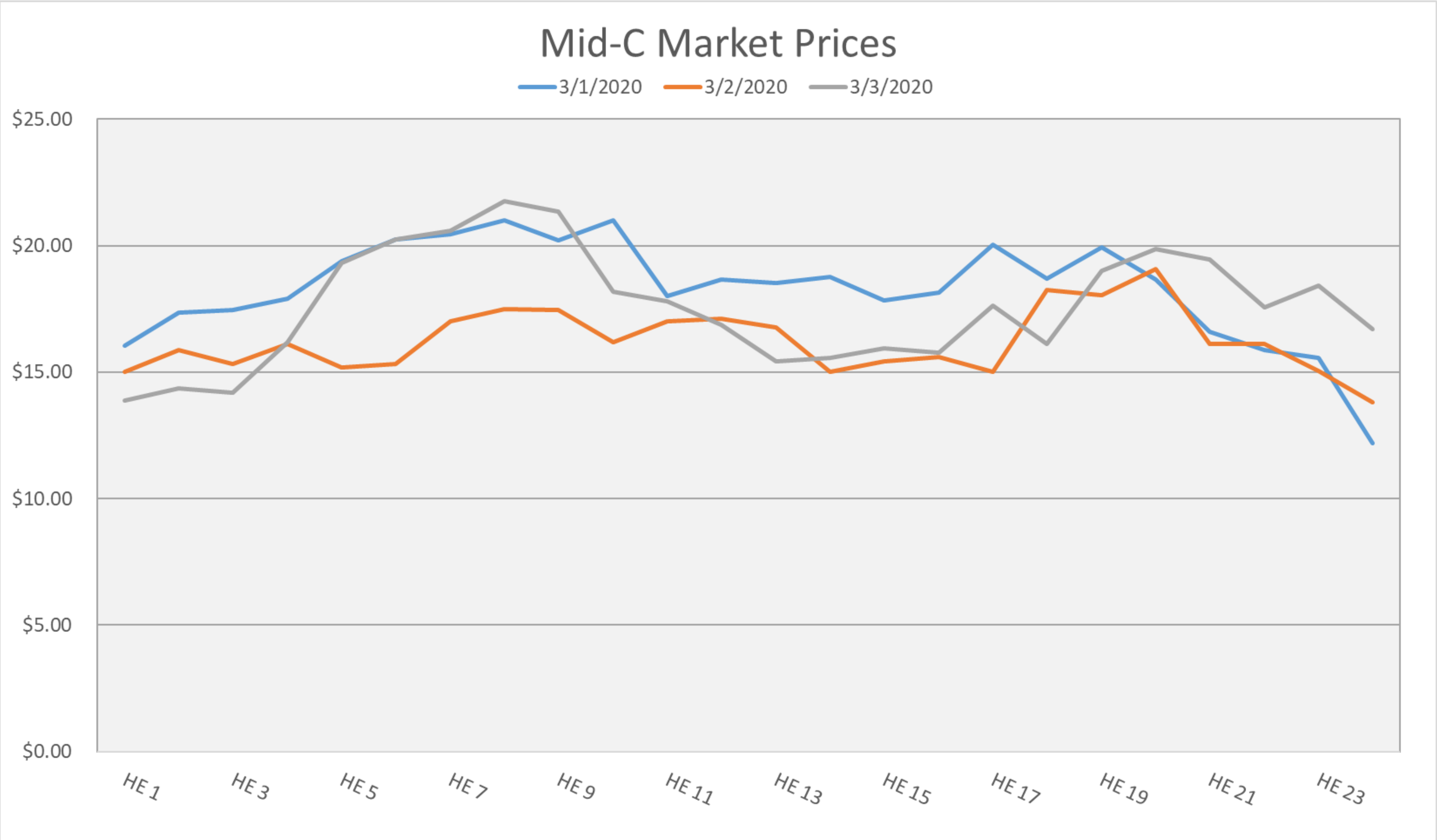
Event (from previous slide)	TTC Variance	Annotation	Start (order by start)	Stop
3	1298	SCSTER & N_ECOL Long-term limit	2015-11-01 00:00:00 PD	2025-01-01 00:00:00 PS
3	(697)	NOEL-Winter Seasonal Limit for 2020	2019-11-01 00:00:00 PD	2020-06-01 00:00:00 PD
3	(5014)	BPA-CHIEF JOSEPH-MONROE 1 500kV LINE (SLIM 641 R3)	2020-02-22 17:00:00 PS	2020-03-1317:00:00 PD



*TLR and Curtailment representations are approximations of their actual start and end times.

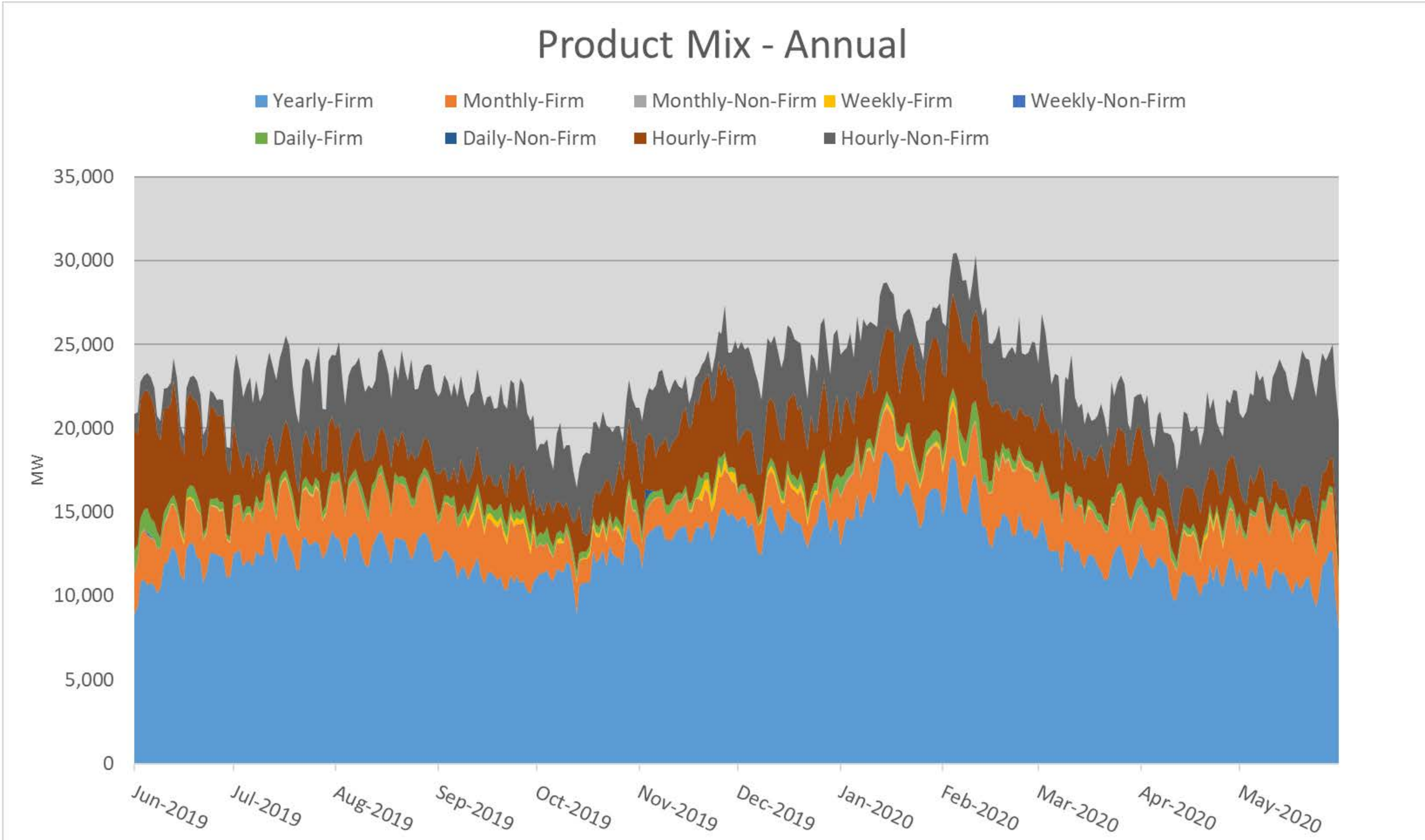


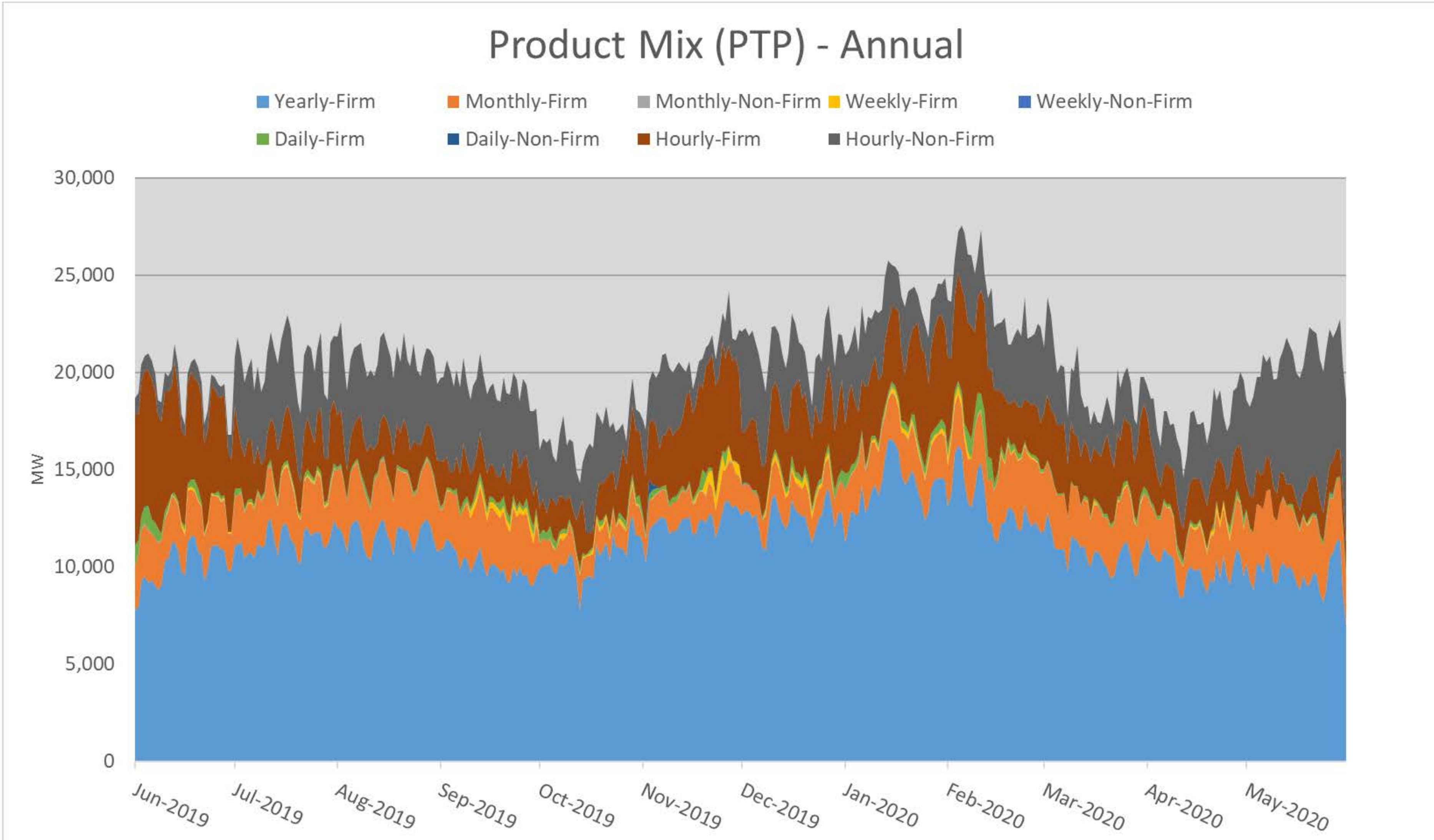
*TLR and Curtailment representations are approximations of their actual start and end times.

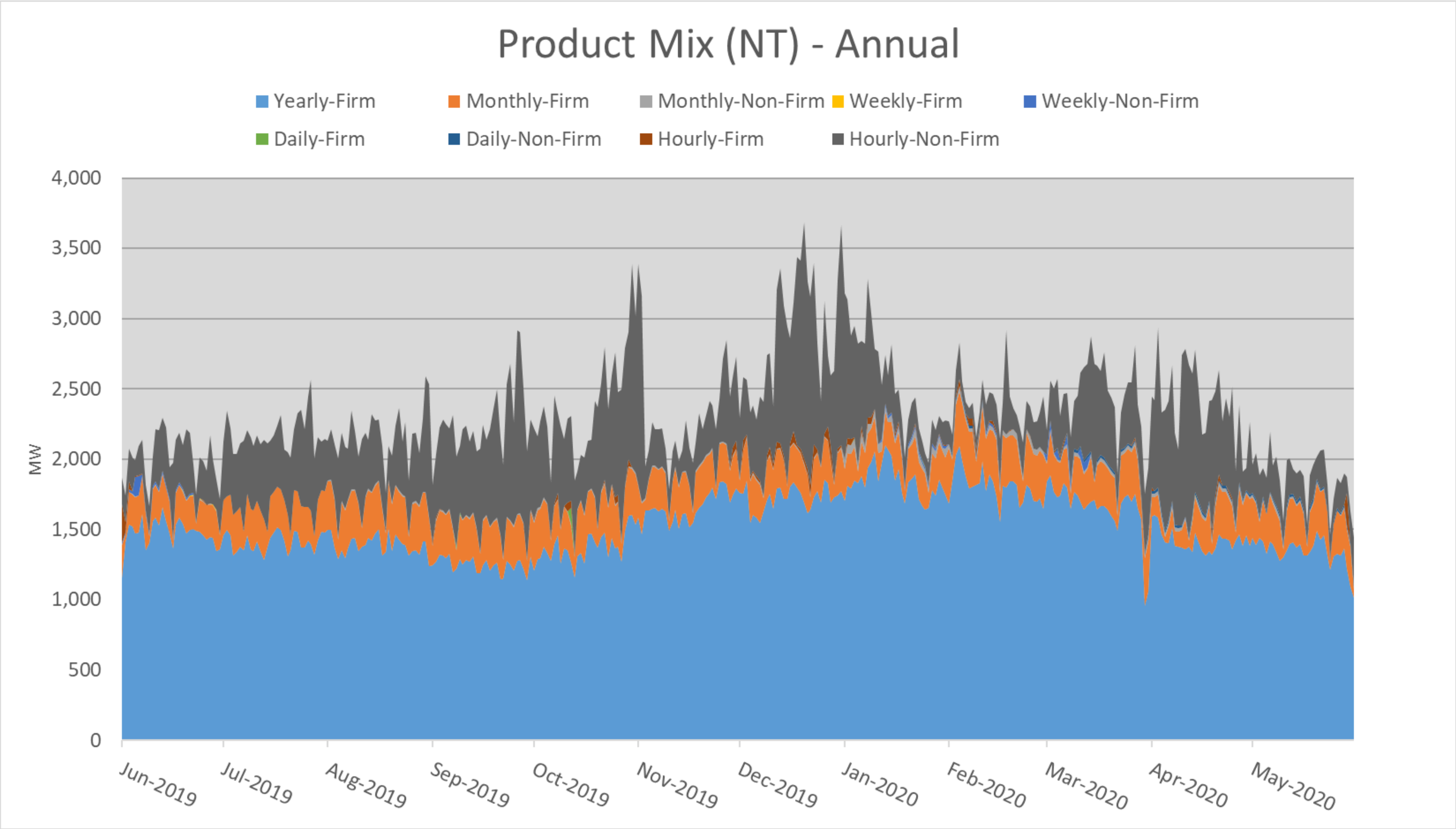

Mid-C Market Prices
3/1/2020
3/2/2020
3/3/2020
$25.00
$20.00
$15.00
$10.00
$5.00
$0.00
HE 1
HE 3
HE 5
HE 7
HE 9
HE 11
HE 13
HE 15
HE 17
HE 19
HE 21
HE 23

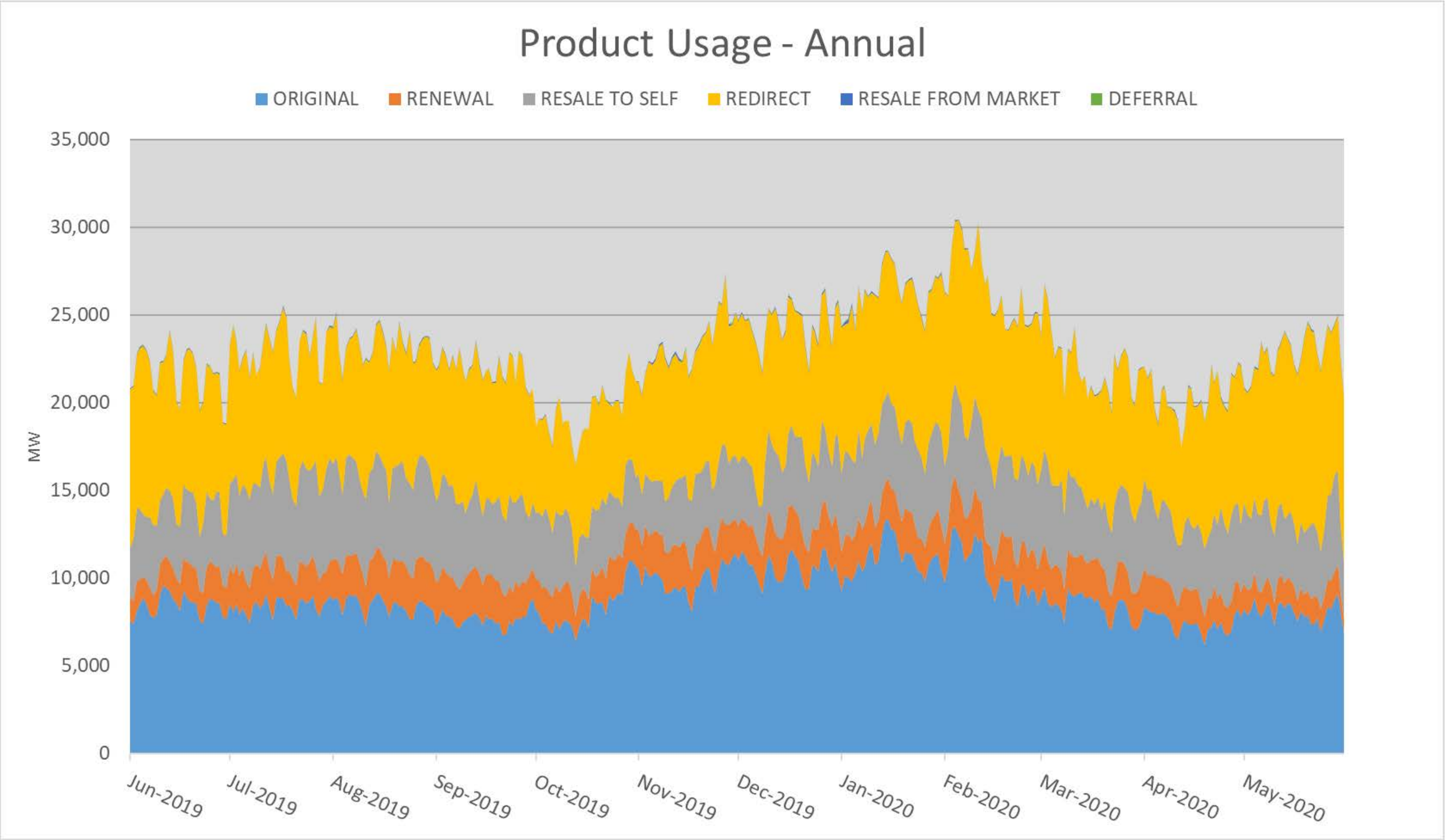
PRODUCT USAGE

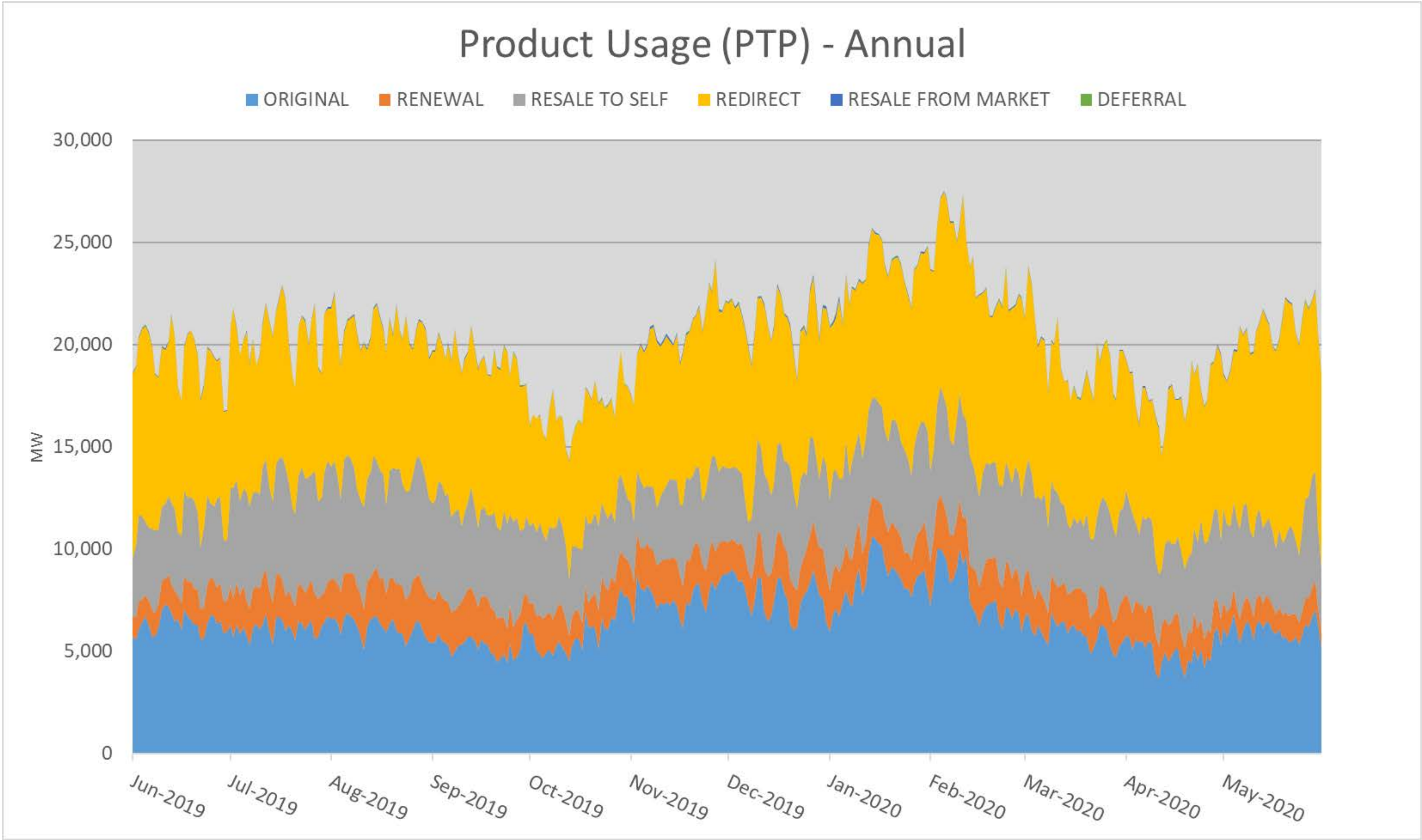
New charts reflected with ☆

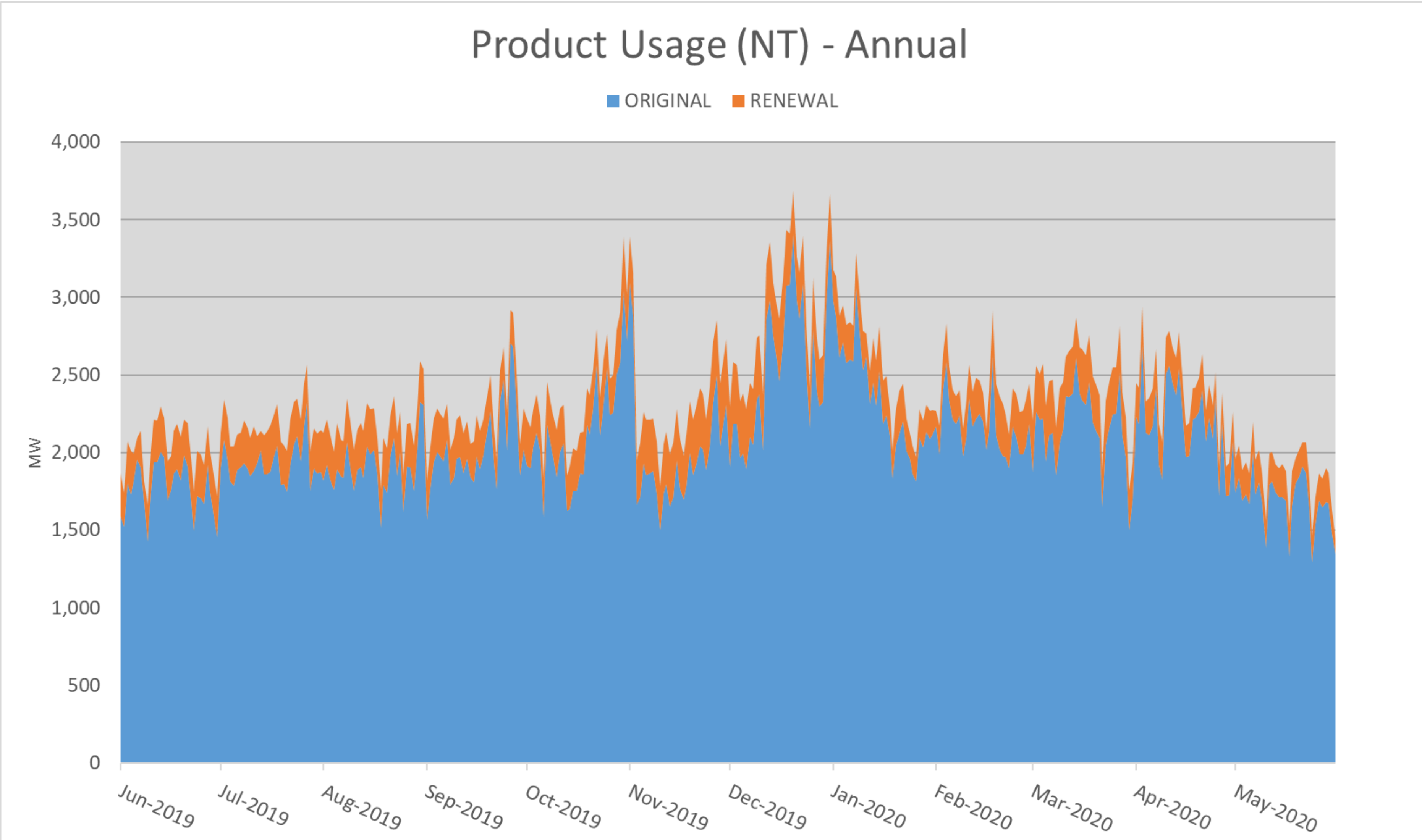

Product Mix - Annual
Yearly-Firm
Monthly-Firm
Monthly-Non-Firm
Weekly-Firm
Weekly-Non-Firm
Daily-Firm
Daily-Non-Firm
Hourly-Firm
Hourly-Non-Firm
MW
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
Jun-2019
Jul-2019
Aug-2019
Sep-2019
Oct-2019
Nov-2019
Dec-2019
Jan-2020
Feb-2020
Mar-2020
Apr-2020
May-2020

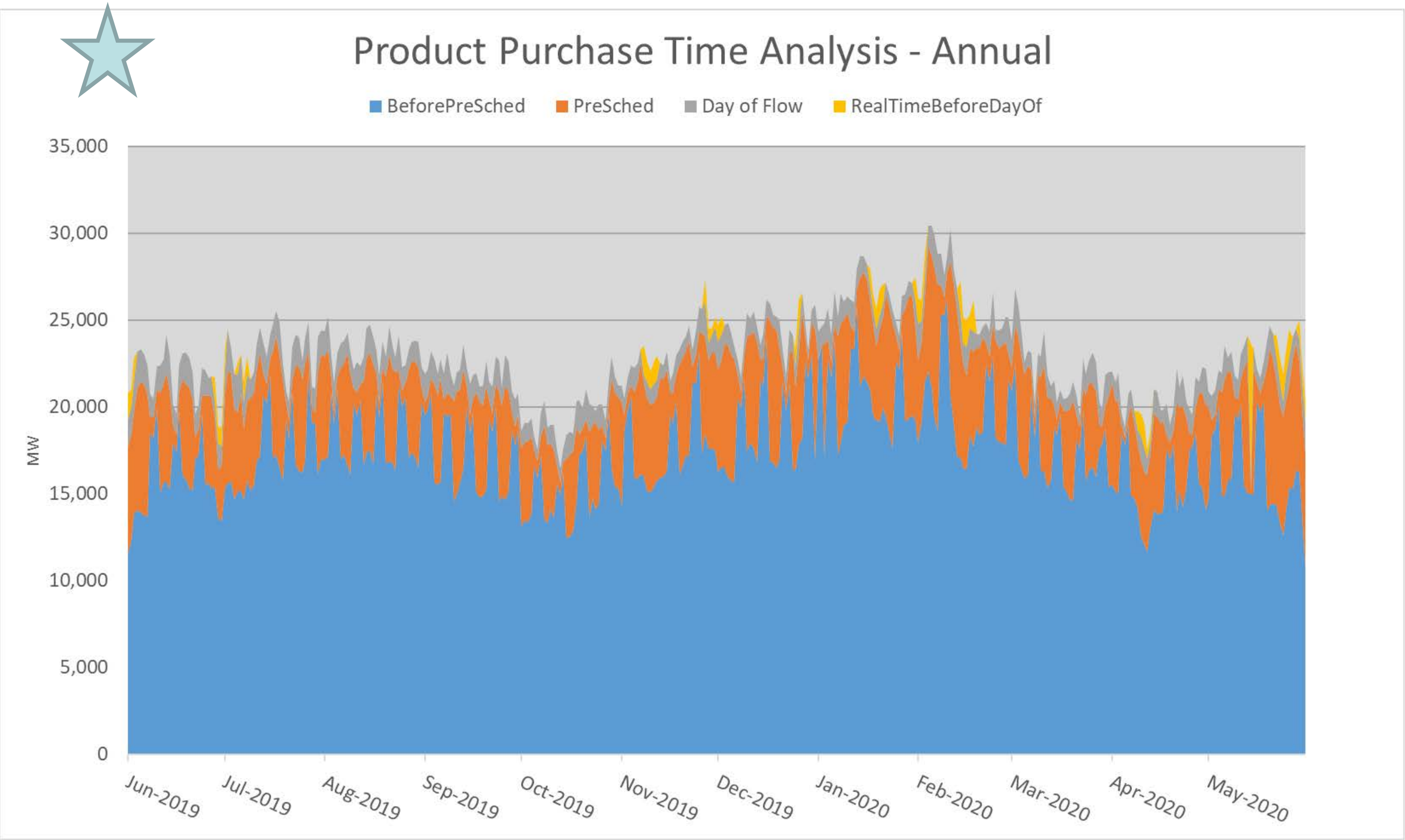

Product Mix (PTP) - Annual
Yearly-Firm
Monthly-Firm
Monthly-Non-Firm
Weekly-Firm
Weekly-Non-Firm
Daily-Firm
Daily-Non-Firm
Hourly-Firm
Hourly-Non-Firm
MW
30,000
25,000
20,000
15,000
10,000
5,000
0
Jun-2019
Jul-2019
Aug-2019
Sep-2019
Oct-2019
Nov-2019
Dec-2019
Jan-2020
Feb-2020
Mar-2020
Apr-2020
May-2020

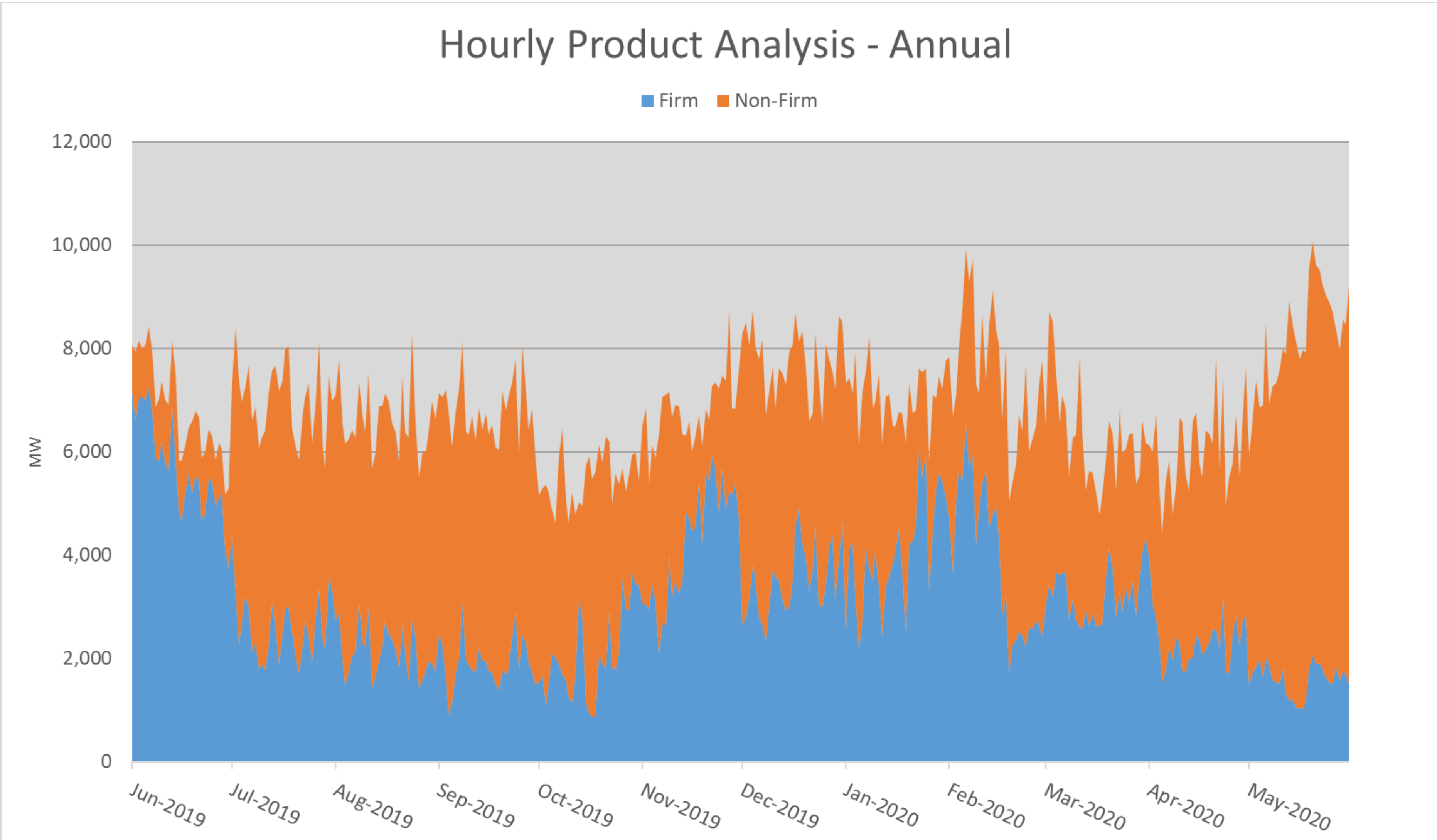

Product Mix (NT) - Annual
Yearly-Firm
Monthly-Firm
Monthly-Non-Firm
Weekly-Firm
Weekly-Non-Firm
Daily-Firm
Daily-Non-Firm
Hourly-Firm
Hourly-Non-Firm
MW
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Jun-2019
Jul-2019
Aug-2019
Sep-2019
Oct-2019
Nov-2019
Dec-2019
Jan-2020
Feb-2020
Mar-2020
Apr-2020
May-2020

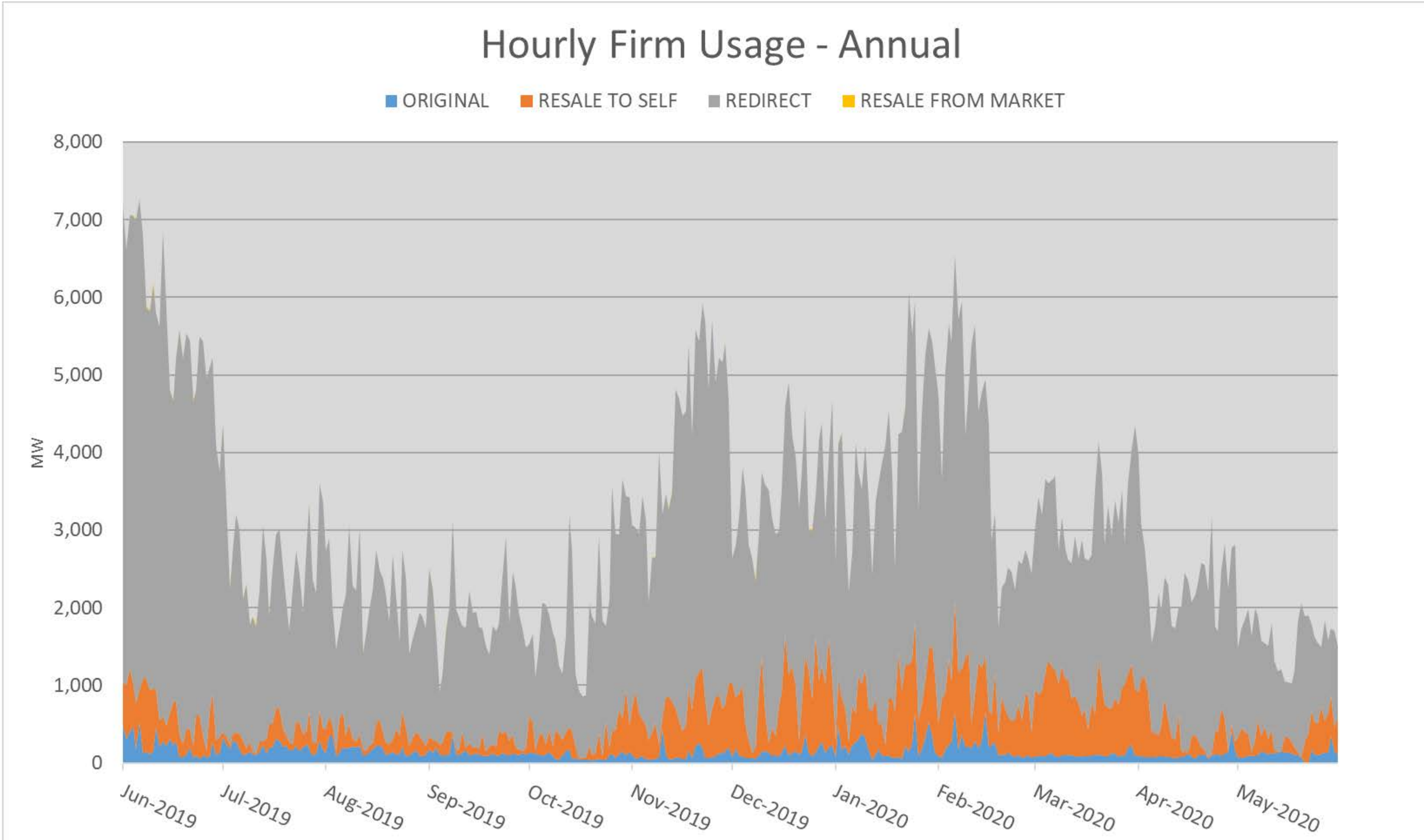

Product Usage - Annual
ORIGINAL
RENEWAL
RESALE TO SELF
REDIRECT
RESALE FROM MARKET
DEFERRAL
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
MW
Jun-2019
Jul-2019
Aug-2019
Sep-2019
Oct-2019
Nov-2019
Dec-2019
Jan-2020
Feb-2020
Mar-2020
Apr-2020
May-2020

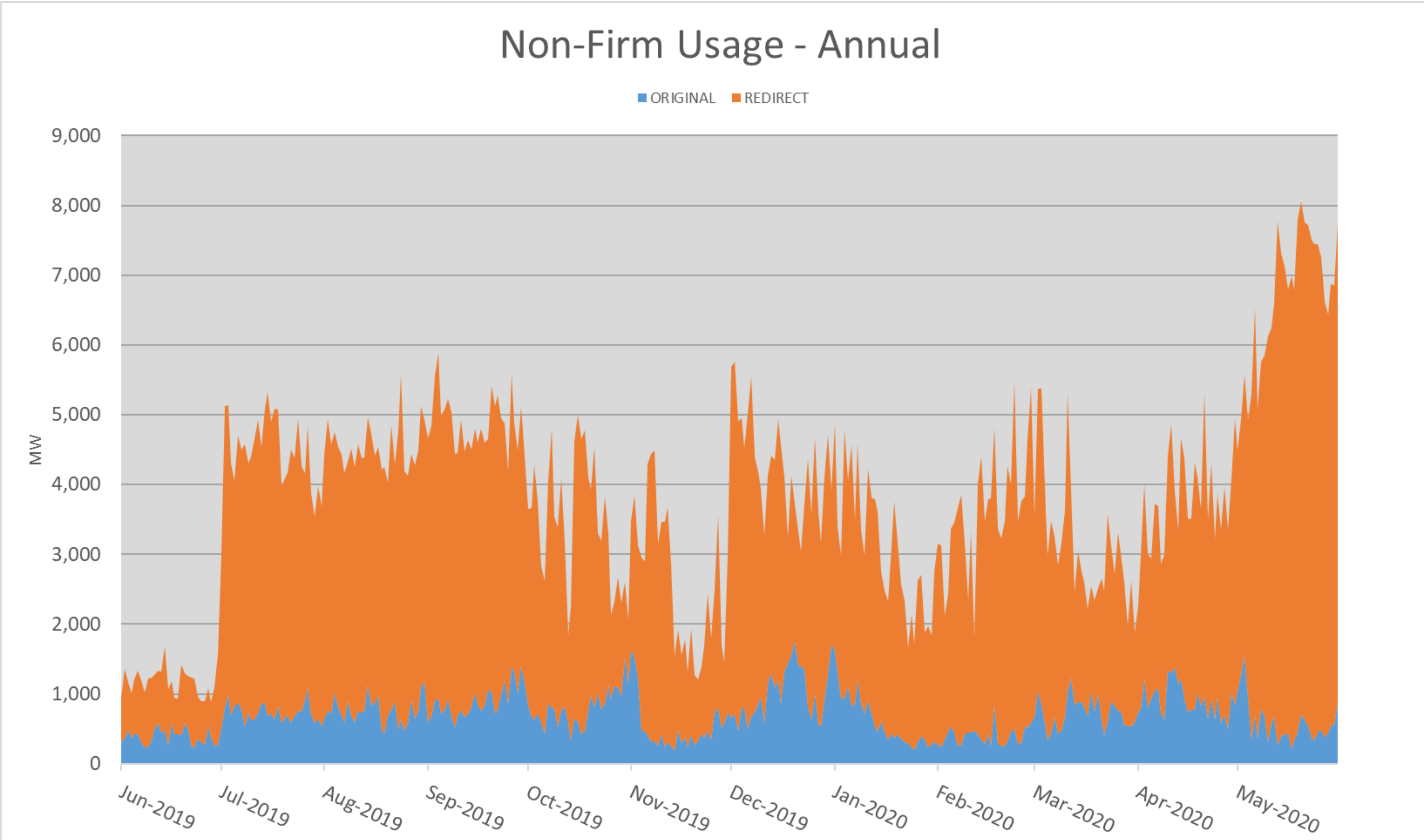

Product Usage (PTP) - Annual
ORIGINAL
RENEWAL
RESALE TO SELF
REDIRECT
RESALE FROM MARKET
DEFERRAL
MW
30,000
25,000
20,000
15,000
10,000
5,000
0
Jun-2019
Jul-2019
Aug-2019
Sep-2019
Oct-2019
Nov-2019
Dec-2019
Jan-2020
Feb-2020
Mar-2020
Apr-2020
May-2020

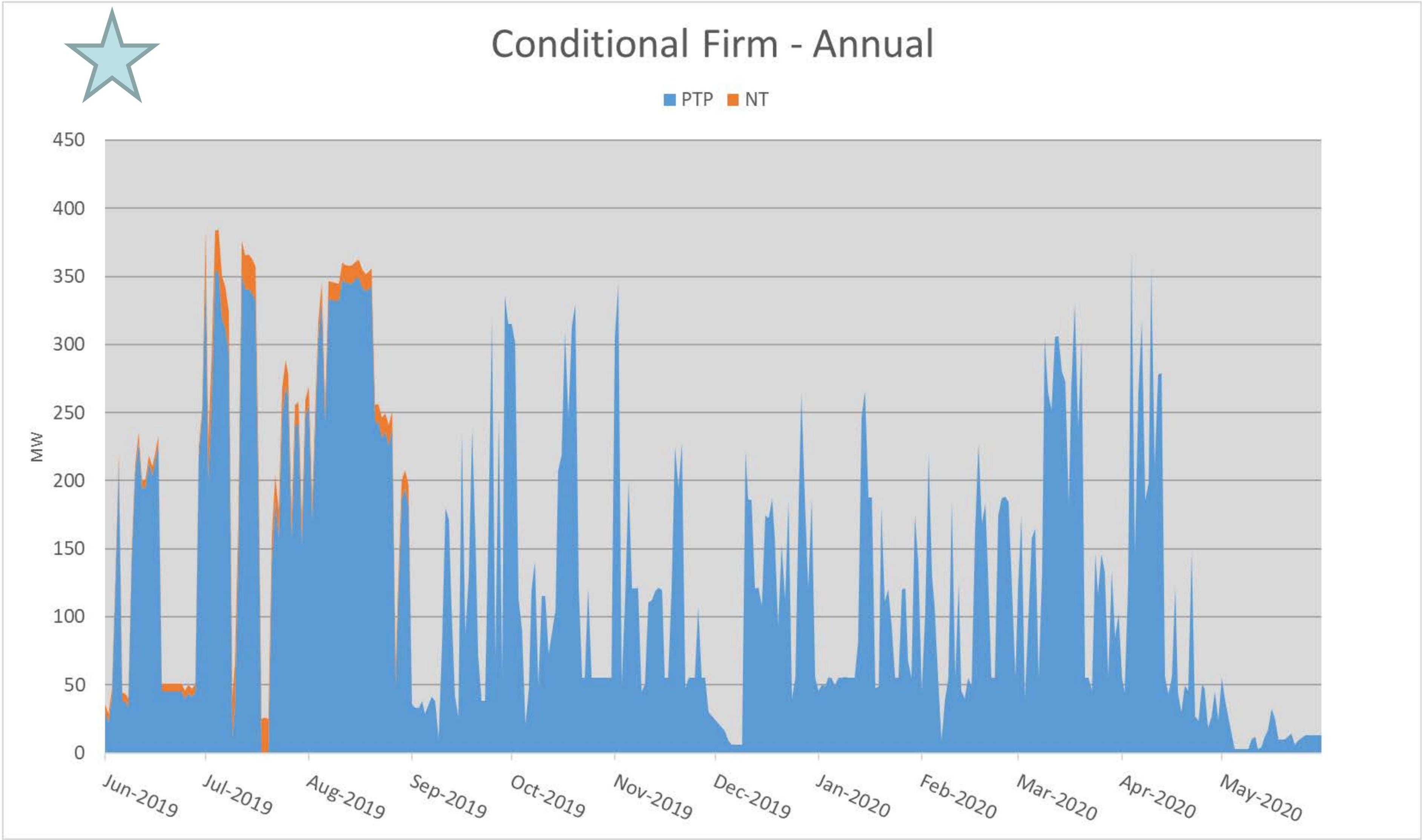

Product Usage (NT) - Annual
ORIGINAL
RENEWAL
MW
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Jun-2019
Jul-2019
Aug-2019
Sep-2019
Oct-2019
Nov-2019
Dec-2019
Jan-2020
Feb-2020
Mar-2020
Apr-2020
May-2020


Product Purchase Time Analysis - Annual
BeforePreSched
PreSched
Day of Flow
RealTimeBeforeDayOf
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
MW
Jun-2019
Jul-2019
Aug-2019
Sep-2019
Oct-2019
Nov-2019
Dec-2019
Jan-2020
Feb-2020
Mar-2020
Apr-2020
May-2020

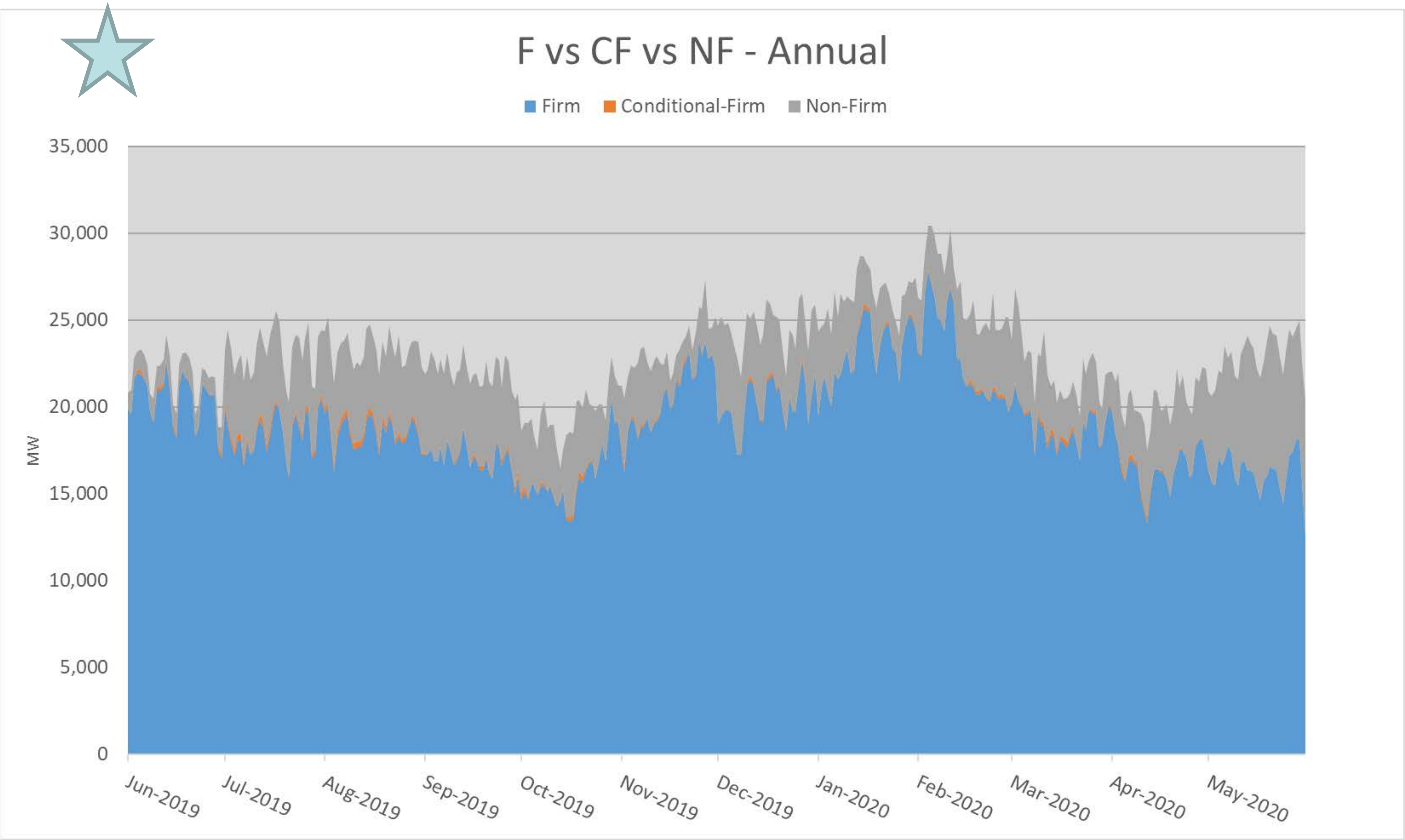

Hourly Product Analysis - Annual
Firm
Non-Firm
MW
12,000
10,000
8,000
6,000
4,000
2,000
0
Jun-2019
Jul-2019
Aug-2019
Sep-2019
Oct-2019
Nov-2019
Dec-2019
Jan-2020
Feb-2020
Mar-2020
Apr-2020
May-2020

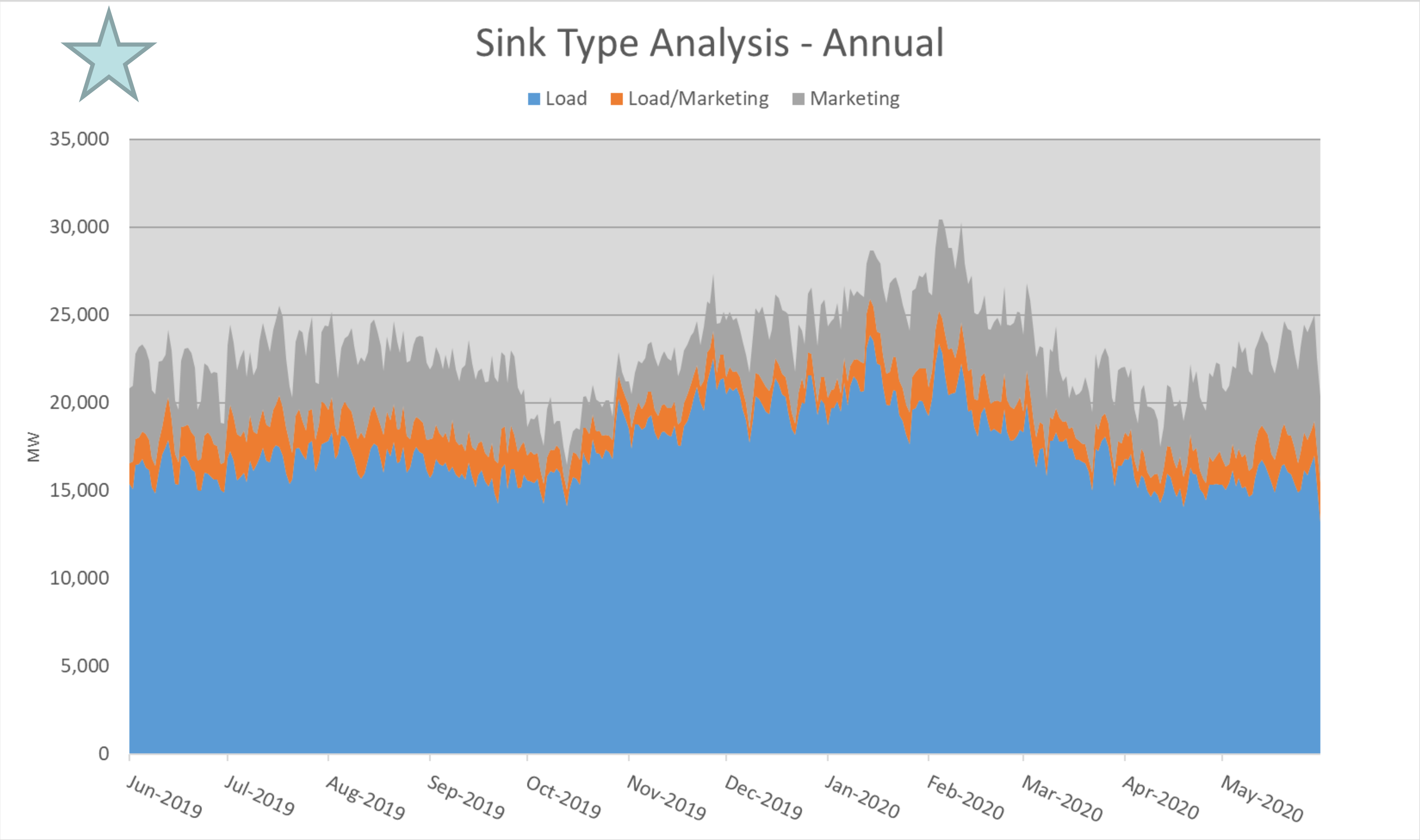

Hourly Firm Usage - Annual
ORIGINAL
RESALE TO SELF
REDIRECT
RESALE FROM MARKET
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
MW
Jun-2019
Jul-2019
Aug-2019
Sep-2019
Oct-2019
Nov-2019
Dec-2019
Jan-2020
Feb-2020
Mar-2020
Apr-2020
May-2020

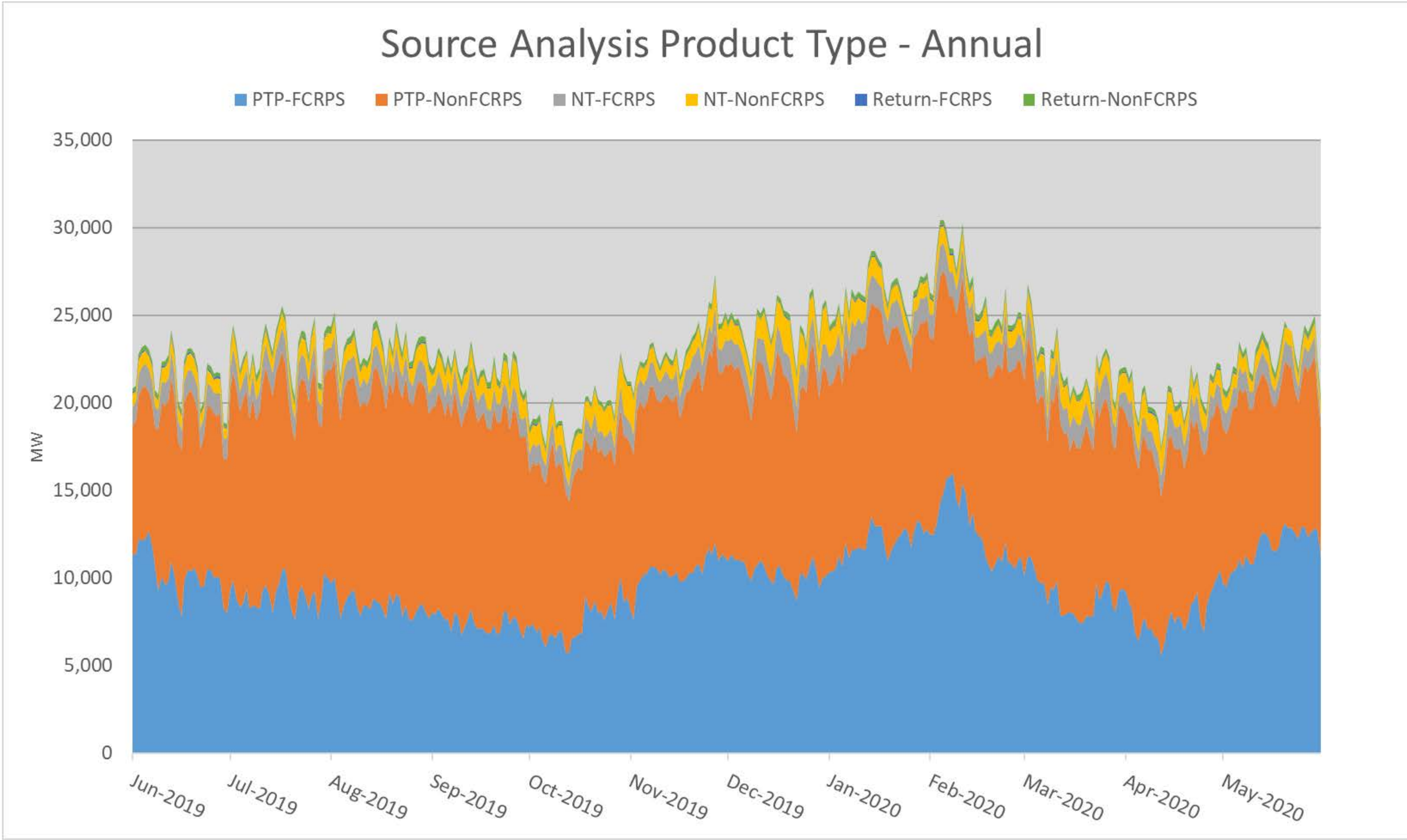

Non-Firm Usage - Annual
ORIGINAL
REDIRECT
MW
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
Jun-2019
Jul-2019
Aug-2019
Sep-2019
Oct-2019
Nov-2019
Dec-2019
Jan-2020
Feb-2020
Mar-2020
Apr-2020
May-2020



Conditional Firm - Annual
PTP
NT
MW
450
400
350
300
250
200
150
100
50
0
Jun-2019
Jul-2019
Aug-2019
Sep-2019
Oct-2019
Nov-2019
Dec-2019
Jan-2020
Feb-2020
Mar-2020
Apr-2020
May-2020

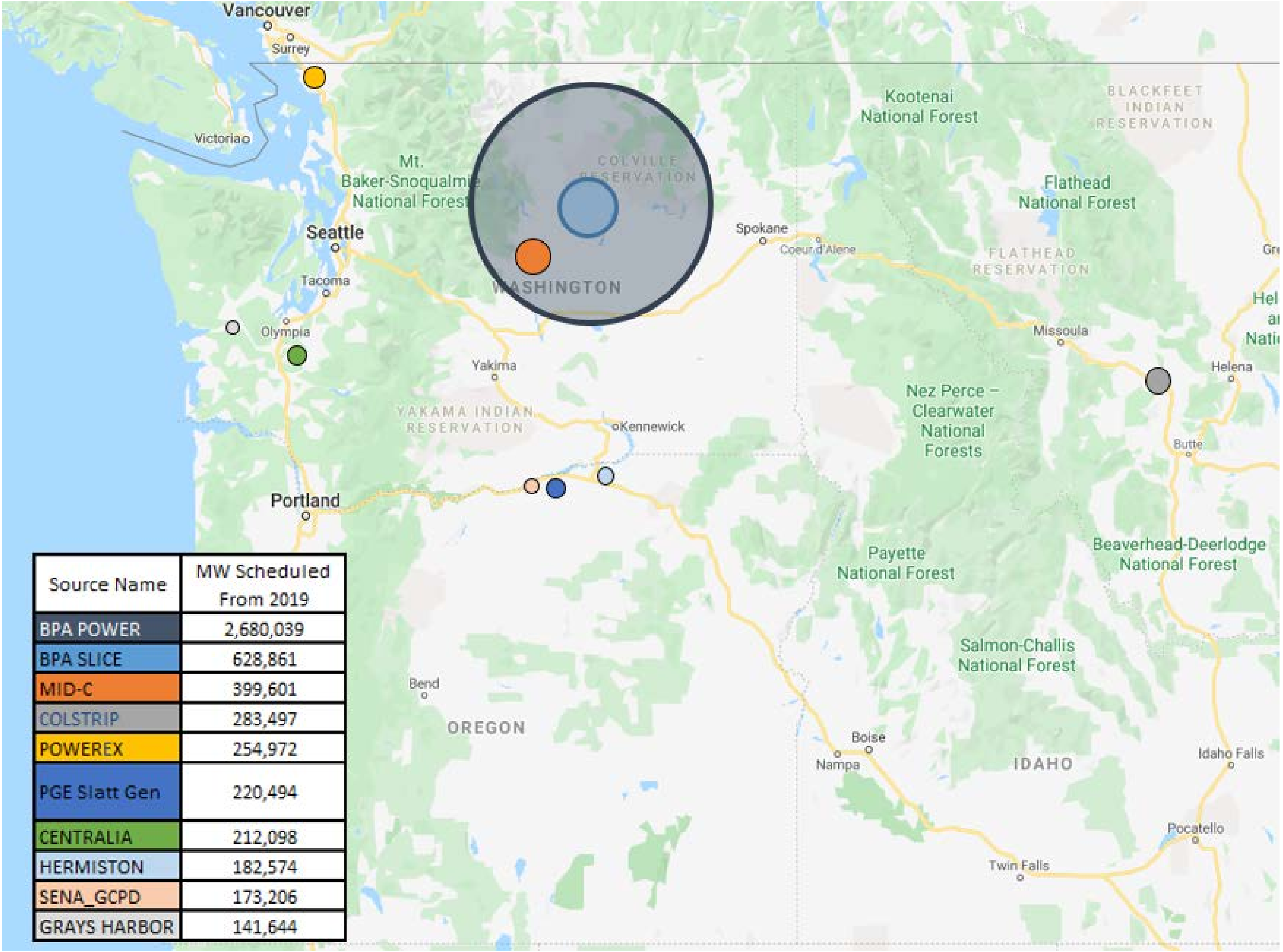

F vs CF vs NF - Annual
Firm
Conditional-Firm
Non-Firm
MW
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
Jun-2019
Jul-2019
Aug-2019
Sep-2019
Oct-2019
Nov-2019
Dec-2019
Jan-2020
Feb-2020
Mar-2020
Apr-2020
May-2020


Sink Type Analysis - Annual
Load
Load/Marketing
Marketing
MW
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
Jun-2019
Jul-2019
Aug-2019
Sep-2019
Oct-2019
Nov-2019
Dec-2019
Jan-2020
Feb-2020
Mar-2020
Apr-2020
May-2020



Source Analysis Product Type - Annual
PTP-FCRPS
PTP-NonFCRPS
NT-FCRPS
NT-NonFCRPS
Return-FCRPS
Return-NonFCRPS
MW
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
Jun-2019
Jul-2019
Aug-2019
Sep-2019
Oct-2019
Nov-2019
Dec-2019
Jan-2020
Feb-2020
Mar-2020
Apr-2020
May-2020

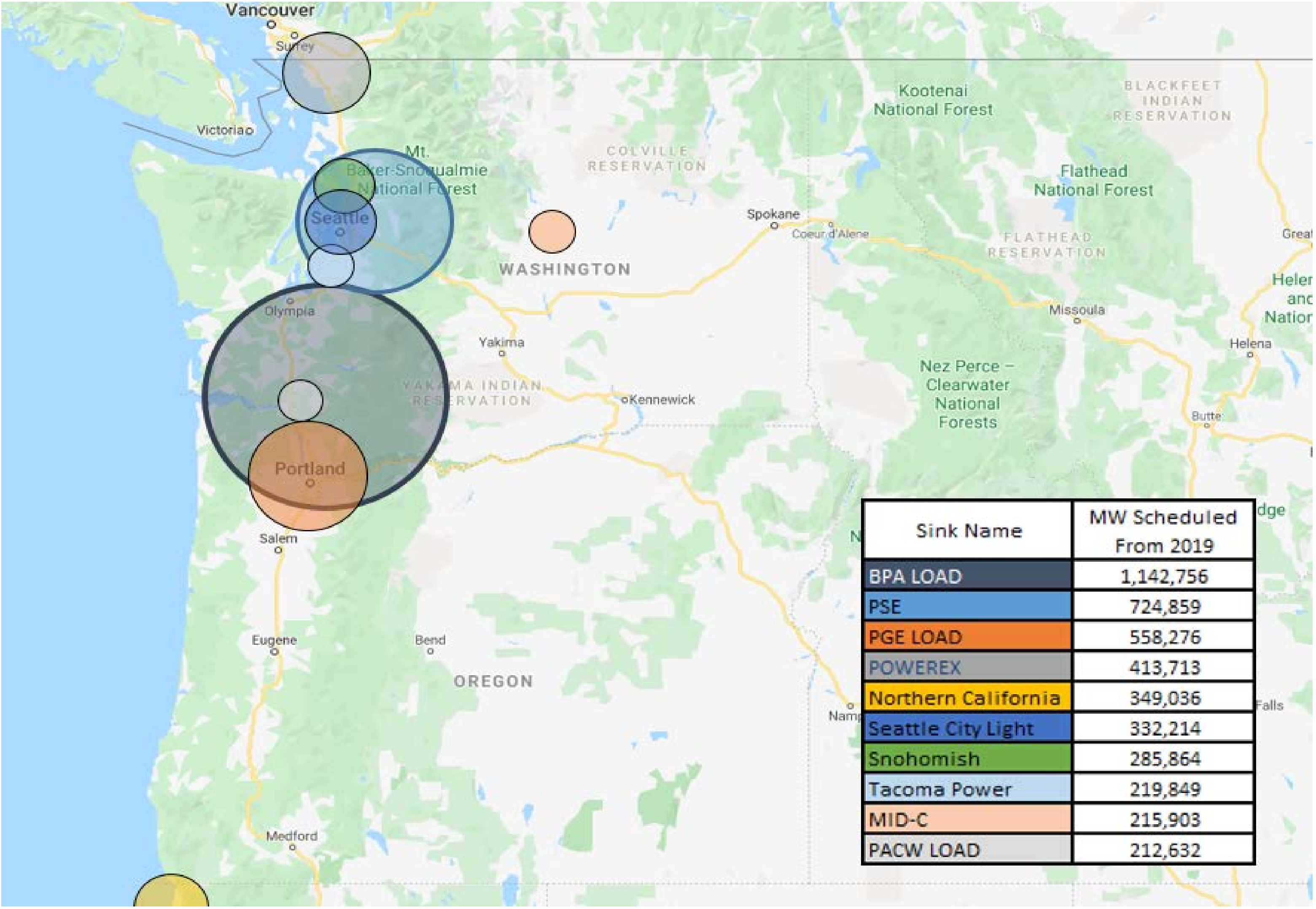
Top Ten Sources (Scheduled MW 2019):



Source Name	MW Scheduled From 2019
BPA POWER	2,680,039
BPA SLICE	628,861
MID-C	399,601
COLSTRIP	283,497
POWEREX	254,972
PGE Slatt Gen	220,494
CENTRALIA	212,098
HERMISTON	182,574
SENA_GCPD	173,206
GRAYS HARBOR	141,644

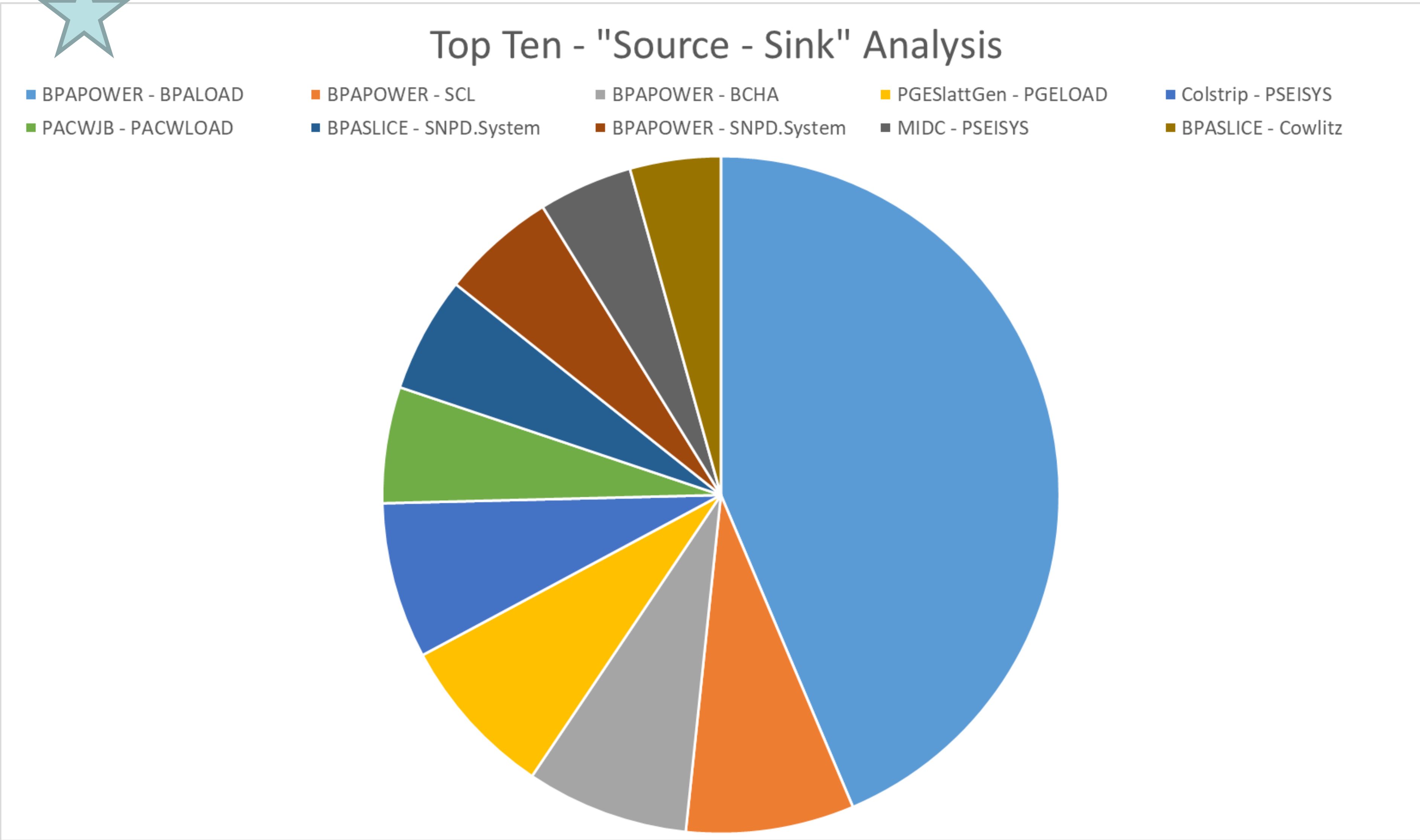
* Top ten sources make up roughly 64% of MWs scheduled in calendar year 2019.

Top Ten Sinks (Scheduled MW 2019):



Sink Name	MW Scheduled From 2019
BPA LOAD	1,142,756
PSE	724,859
PGE LOAD	558,276
POWEREX	413,713
Northern California	349,036
Seattle City Light	332,214
Snohomish	285,864
Tacoma Power	219,849
MID-C	215,903
PACW LOAD	212,632

* Top ten sinks make up roughly 55% of MWs scheduled in calendar year 2019.



* Top ten source-sink combinations make up roughly 29% of MWs used in calendar year 2019.

ISSUE #28: TC-20 – SHORT-TERM AVAILABLE TRANSFER CAPABILITY (ST ATC) PROJECT UPDATE

Objectives

1. TC-20 Settlement Status for ST ATC
2. ST ATC Project Timeline
3. Latest Completed ST ATC Improvements
4. Proposed ST ATC Improvement
5. Additional Work on ST ATC
6. Wrap up

TC-20 Settlement Status for ST ATC

BPA's TC-20 Settlement commitments on ST ATC were:

1. Begin evaluation in the second quarter of 2019 and identify any potential improvements to short-term ATC that could be implemented before October 1, 2021
   a. Status: on-track
   b. BPA proposed its initial ST ATC improvements to customers on June 13, 2019, and improvements have been implemented regularly over the last year (transition to monthly base cases, more frequent PDTFs, many others)

TC-20 Settlement Status for ST ATC (cont.)

2. Hold a short-term ATC workshop in the fourth quarter of 2019, and the second and fourth quarter of each fiscal year until October 1, 2021

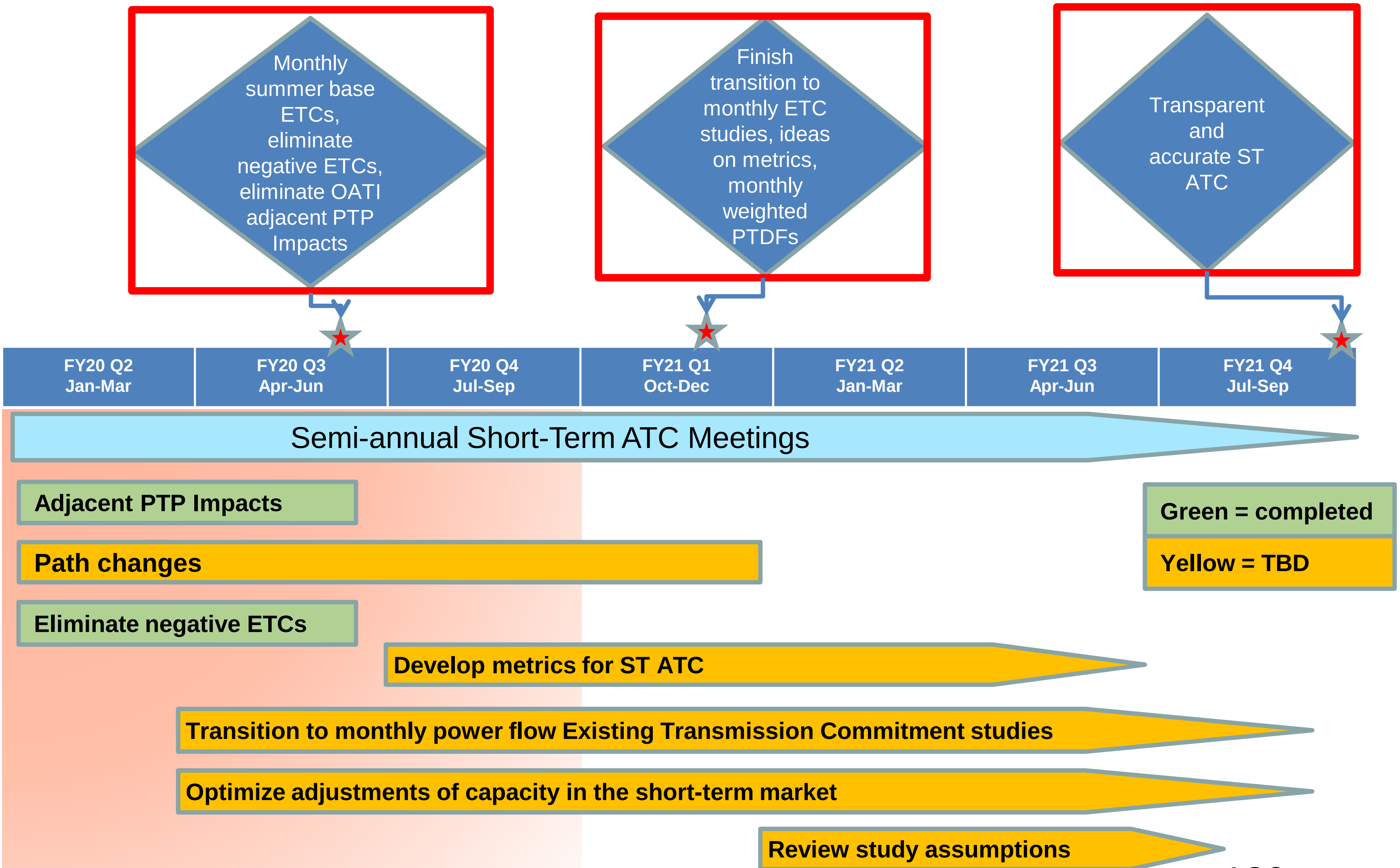
   a. Status: ST ATC workshops to date have exceeded the required frequency

   b. Workshops have been held in June 2019, August 2019, September 2019, November 2019, December 2019, January 2020, March 2020

TC-20 Settlement Status for ST ATC (cont.)

3. Provide a review of timelines and parameters for making specific changes to ATC/available flowgate capability ("AFC") methodology to improve accuracy in the short-term ATC workshops
   a. Status: on-track
   b. Timelines presented in customer workshops and additional details communicated via Tech Forum notices
4. Continue to calculate and post hourly ATC/AFC values
   a. Status: stable ongoing process
   b. BPA is continuing to calculate and post hourly ATC/AFC values in accordance with regulatory requirements and the TC-20 Settlement

Short-Term ATC Project Timeline



Latest Completed ST ATC Improvements

1. Transitioned from one heavy load base Existing Transmission Commitment (ETC) study for Summer season to monthly heavy load base ETC studies for June through October
   a. Monthly studies enable BPA to use monthly load and generation forecasts for our Balancing Authority (versus seasonal peaks)
   b. Monthly studies also allow for more timely updates to system topology and generation energizations
2. Final set of monthly heavy load ETC cases will be released in late October and will cover the months of November through March

Latest Completed ST ATC Improvements (cont.)

3. The table below illustrates BPA's transition to monthly heavy load ETC cases:

POSTED TO OASIS	HEAVY ETC BASE CASE STUDIES PERFORMED											
Prior to Mar-20	SPRING		SUMMER					WINTER				
Mar-20	APR	MAY	SUMMER					WINTER				
May-20	APR	MAY	JUN	JUL	AUG	SEP	OCT	WINTER				
Oct-20	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR

4. BPA will evaluate whether to transition to monthly light load ETC cases after the heavy load ETC cases are all transitioned to a monthly granularity

Latest Completed ST ATC Improvements (cont.)

5. Began using zero as base ETC when power flow studies result in a negative base ETC
6. Eliminated the impacts of adjacent Transmission Service Provider impacts calculated by OATI from BPA's ETC calculation
7. The system update to incorporate the above changes occurred on May 20, 2020
   a. Changes updated ATC for the NERC horizon, starting with June 1, 2020

Latest Completed ST ATC Improvements (cont.)

8. BPA has consolidated all information about ST ATC on its ATC Methodology page
   a. The ATCID, past workshop presentations, customer comments and other related documents can be found on this page
   b. The link for the ATC Methodology page is: https://www.bpa.gov/transmission/Doing%20Business/ATCMethodology/Pages/default.aspx

Proposed ST ATC Improvement #1

Description: Increase accuracy of weighted BPAPower, FCRPS and BPAPUNSCHD Power Transfer Distribution Factors (PTDFs) by using generation and load profiles from each monthly ETC base case

1. Current process
   a. BPA calculates weighted PTDFs by using generation and load profiles from a proxy ETC base case for several months
   b. May ETC case is used to calculate weighted PTDFs for April and May
   c. August ETC case is used to calculate weighted PTDFs for June through October
   d. January ETC case is used to calculate weighted PTDFs for November through March

Proposed ST ATC Improvement #1 (cont.)

2. Proposed process
    a. BPA would like use the generation and load profiles from individual monthly ETC cases to calculate the weighed PTDFs for each individual month
    b. Generation and load profiles from the January ETC case would be used to calculate the weighted PTDFs for January, generation and load profiles from the February ETC case would be used to calculate the weighted PTDFs for February and so on
3. Benefits of change
    a. Weighted PTDFs will better represent the time period that ETC is being calculated for
    b. Improved accuracy of the resulting ST ATC
4. Anticipated implementation date: Summer/Fall 2020

Additional Work on ST ATC

Description: BPA has completed an evaluation on whether BPA's current Pending ETC methodology can be modified to release capacity encumbered for requests in BPA's long-term pending queue to the short-term market sooner

1. Pending ETC is the capacity that BPA encumbers for Original and Redirect requests in BPA's long-term pending queue
   a. BPA processes TSRs in order of queue time, with earlier queued requests having priority to ATC
   b. TSRs in the long-term pending queue have an earlier queue time than short-term TSRs
2. In the 0 to 4 month time frame, BPA releases capacity that is encumbered for requests in the long-term pending queue, unless an offer is in process

Additional Work on ST ATC (cont.)

3. In the 4 to 13 month time frame, BPA encumbers 100% of capacity needed to enable Original and Redirect requests in the long-term pending queue

4. BPA analyzed historical data to determine what percentage of Pending ETC was being used to enable Original and Redirect long-term offers in the 4 to 13 month time frame

   a. BPA performed this evaluation to ensure BPA is not encumbering capacity in the 4 to 13 month time frame that could be released to the ST market without impacting queue priority

5. BPA found that there were times where close to 100% of the Pending ETC had been needed to enable offers in the 4 to 13 month time frame

Additional Work on ST ATC (cont.)

6. BPA does not plan to change its Pending ETC process based on analysis of the historical data
7. BPA will periodically evaluate data on Pending ETC usage to see if the Pending ETC process should be updated

Additional Work on ST ATC (cont.)

Description: Evaluate what type of controls are needed in the Satsop 230 kV substation area in the 0 – 13 month NERC horizon

1. At the ST ATC update on December 12, 2019, BPA also it was evaluating what type of controls were needed in the in the Satsop 230 kV substation area

2. BPA has completed this evaluation and concluded that both congestion management tools and an ATC Path are needed to manage this area

3. BPA will first add congestion management tools in this area

   a. Congestion management tools will allow BPA will to monitor the Satsop 230 kV substation area for curtailments

Additional Work on ST ATC (cont.)

4. Once congestion management tools are in place, BPA will work on adding a full ATC Path in this area for the NERC horizon
5. Once this ATC Path is created, the following changes will occur:
   a. BPA will calculate and post ATC for this new path for 0 – 13 months
   b. TSRs will require ST ATC across this path
6. Additional details on the cutover dates for both the addition of the Satsop 230 kV substation congestion management tools as well the full ATC Path addition will be communicated when they are known

Additional Work on ST ATC (cont.)

Description: Develop metrics for ST ATC

1. BPA is beginning to work on metrics for ST ATC
2. The ST ATC team is compiling ideas and will share these with customers
3. Team will be building upon the data already being collected on ST ATC in the TC-20 settlement

Wrap up

1. BPA continues to work on the proposed ST ATC changes and will update its ATCID prior to implementation of any changes
2. Comments on the ST ATC proposed improvements discussed today are due in 2 weeks – comments will close July 8, 2020
3. Please send Questions/Comments to techforum@bpa.gov, with a copy to your Account Executive
4. Next ST ATC meeting is being planned for September 2020
   a. BPA will send out a Tech Forum when the date is finalized and the information will be posted on the ATC Methodology page under Meetings (https://www.bpa.gov/transmission/Doing%20Business/ATCMethodology/Pages/default.aspx)

Wrap up and Next Steps

- Comment period
  - Customers should submit comments by July 8, 2020 to the techforum@bpa.gov

Summary of Customer Feedback

APPENDIX

4/28 Workshop - Customer Comments

Customer	Comment Summary	BPA Response
Charge Code Allocation	• Existing transmission usage should be preserved to the extent possible to minimize unintended consequences of existing use of the FCRTS and BPA's transmission business model • Per BPA's own criteria, to the extent possible, maintain alignment with FERC-approved allocation methods, particularly to avoid seams issues • Allocation of charges/credits should be consistent with cost causation to avoid uneconomic price signals and increased costs and included in evaluation criteria • Clarify how charges attributable to load following customers will be allocated and accounted for. • Concerned with unintended shift of costs to transmission customers and with revenues only benefiting BPA Power • Revenues should be allocated to transmission customers to offset costs with any surplus to Power • Request further clarification on certain charge codes that are excluded from initial sub-allocation (bid cost recovery, flexible ramp, grid management, enforcement protocol, administrative) • Operational experience will mitigate inappropriate allocation of charges/credits. Until such experience is attained, consider no sub-allocation. • If proceeding with sub-allocation, develop a framework to guide charge/credit allocation. • If proceeding with sub-allocation, all charge codes should be well understood	• Thank you for your comments. BPA will continue to evaluate the impacts and consider the concerns expressed as we approach the implementation phase.

4/28 Workshop - Customer Comments (Cont.)

Customer	Comment Summary	BPA Response
Proposed Workplan	• Provide clarification on status of 7(f) options and grandfathered Green Exception • Undesignation of DNR should be addressed in TC-22	• See BP-22 Rate Case Kickoff presentation. • BPA does not calculate its ST ATC frequently enough for ST undesignations to be reflected in ST ATC. • The systems are not in place at this time to recognize ST undesignations of NT resources and release the corresponding ST ATC to the market. • The full implementation of NITS on OASIS will include this functionality. However, the recent FERC Order 676-I makes extensive changes to the NITS on OASIS module that OATI needs to build over the next several months. • BPA still offers unlimited non-firm transmission, which mitigates the impact of not releasing ST ATC to the non-firm market after ST undesignation of a network resource.

4/28 Workshop - Customer Comments (Cont.)

Customer	Comment Summary	BPA Response
Solar Study (BP-20 Settlement)	• Don't support decision to delay development of a shaped quantity of reserves • Study should be expanded to include wind resources • BPA should be prepared to revisit should circumstances change	• Thank you for your comment. Should circumstances change significantly, BPA is prepared to revisit.
Creditworthiness	• Support alignment with structure of pro forma approach	• Thank you
Agreement Templates	• Proposed clarifying language regarding service commencement	• Thank you. We will review consider it our next workshop in June
Tariff Language Review	• Inter-related issues should be presented together to ensure complete picture of tariff edits is understood	• BPA will share tariff language with customers as it's available. At the final workshop a complete draft tariff will be shared with customers with an opportunity to provide feedback before that language goes into the Initial Proposal.
General Comments	• EIM must support the Northwest's current shift to low carbon resources and not result in negative financial impact to VERS • Requests a workshop to educate CAISO on tools that BPA and renewables have used to reduce integration costs	• Thank you
Timeline for Base Schedules	• T-57 scheduling deadline may increase VERBS exposure to balancing reserves • Supports exploration of possibly reducing balancing reserve requirements • Entities may be forced to make decisions to use transmission to support within hour scheduling versus EIM participation.	• This will be considered in the June presentation

3/17 Workshop - Customer Comments

Customer	Comment Summary	BPA Response
Work Plan & Workshops	• More information and clarity needed on EIM Phase III Decision Document • Clarify where all policy issues will be documented • Identify topics that could be delayed or simplified to allow focus on priority issues • Support additional workshops • Continue to use the VENN diagram to highlight topics	• BPA has included a detail policy questions and proposal on where those decisions will be made in the presentation
Seller's Choice	• Support access to non-federal resources at Mid-C • Clarify whether there is an impact to ATC due to NT encumbrance. • Be careful with any policies that deviate from the OATT. • Provide additional analysis of reservations/schedules/flow impacts at Mid-C.	• These concerns will be considered and addressed in May, when Seller's choice will be discussed
Transmission Losses	• General support for Alternative 3 and 5, maintain both options with financial rate developed in rate case. • This issue should be able to be resolved quickly • Support financial for inaccuracy charge • Additional details needed on financial pricing including impacts by customer type • Additional details needed on customer impacts/benefits • Administrative costs may be worthwhile/appropriate • Consider additional decision criteria (per submissions)	• Thank you for your feedback. These comments will be considered and addressed in the May workshop
EIM Transmission Usage	• Support for modifications to scope and objective • Support non-firm donations • Concerns with donation deadlines misaligned with market intervals • Evaluate impacts to dynamic transfers as compared to ETSRs. • Cost recovery mechanisms must be in place to follow cost-causation principles	• Thank you for your feedback, your concerns will be considered and addressed in the June workshop
Intertie Studies	• Support updating the tariff • Maximize flexibility and minimize financial exposure • Work with customers, regional stakeholders and partners on expansion needs	• Thank you for your comments. BPA staff will consider these comments as we address the tariff discussion for the Intertie studies at the May workshop.

2/25 Workshop - Customer Comments

Customer	Comment Summary	BPA Response

Charge Code Allocation	• Comments received reflected support for both a phased in sub-allocation approach as well as a "direct-assigned" approach that would utilize CAISO charge codes.
	  • Develop more examples of how different customer types would be treated under the different alternatives.
	  • Provide additional estimates on the administrative costs.
	  • Provide a cost-benefit analysis for each alternative that weighs benefits against administrative costs.
	• If no sub or sub-allocation:
	  • Balance cost-causation with simplicity
	  • Imbalance service should be developed as a separate rate
	  • Will better ensure existing transmission rights are respected
	  • Focus on Base Codes and Scheduling Entity Codes
	• If direct assigned (FERC-approved allocation method):
	  • Maintain incentives for customers to schedule accurately within the BAA
	  • Consistency across EIM footprint
	  • Maintains consistency with FERC, one of BPA's tariff principles
	  • Insulation of costs will create risk of hiding EIM market signals
	  • A phased in approach could be applied
	  • Concerned that development of rate mechanisms will not capture granularity
	  • Experiences with EIM suggest more administrative burden up front but ease of that burden moving forward.
	  • Administrative burden to insulate customers is not a justifiable argument and eventually will be same level as other EIM entities
	  • Customers need transparency for market signals and disputes
	  • Ensures better adaptability and response to future changes from CAISO instead of every two years.
		• Direct assignment, sub allocation will be discussed in the alternatives in Steps 5 and 6 on April 28.

2/25 Workshop - Customer Comments (Cont.)

Customer	Comment Summary	BPA Response
Resource Sufficiency	• Don’t establish a target • Develop financial mitigation for the t-20 to t-55 window • Develop a matrix of 4 alternatives for better comparative capability	• The target and the alternatives will be discussed in steps 5 and 6 in the April 28 workshop.
Gen Inputs	• Develop principles for Gen Inputs • EIM benefits should be part of Gen Input rate design • Maintain close association with Charge Code discussion • Schedules 9 and 10 might benefit from transitioning to EIM methodology • Need a more robust conversation about ID, PD, EI, and GI rates relative to the charge code sub-allocation alternatives • Eliminating the 30/60 and 30/15 committed scheduling elections options will increase the capacity that BPA must set aside for reserves and increase the rates that ancillary services customers will have to pay	• The team will consider the customer request and respond at the April workshop • The alternatives will be considered in the development of steps 3 and 4 in the April workshop.
Creditworthiness	• Attachment to the OATT	• Attachment to the OATT will be considered the review of the alternatives in steps 3 to 4 in the April workshop
Section 7(f) Power Rates	• Customers have requested we explore contractual solutions such as the grandfathered Green Exception.”	• The team will address this in our next workshop on service under 7(f).
Regional Planning	• Revise Attachment K to ensure future changes must go through tariff process	• We will consider this alternative in steps 3 and 4 which will be reviewed in the May workshop
Generator Interconnection	• Support for implementation of Order 845 • Need more information regarding “streamlining” proposal to ensure no queue discrimination	• Thank you

1/28 Workshop - Customer Comments

Customer	Comment Summary	BPA Response
Objective Statement	• Clarify that BPA will not negatively impact existing rights or existing uses in favor of EIM • Costs associated with EIM should be allocated to those benefiting • Alternatives should consider the sub-elements of the objective statement.	• These suggestive changes to the objective statement will be considered
Network Usage	• Concerns that EIM will reduce capacity used to support bilateral transactions • Encourage BPA to pursue solutions that would allow use of ATC Methodology. Admittedly may be most appropriate in EDAM • BPA needs to ensure rights and expectations of existing customers under the tariff and in some cases may need to eliminate adverse commercial impacts. • EIM reciprocity transmission framework is an essential principle. Align with requirements utilized by other EIM entities	• The concerns and considerations will be evaluated in steps 3 and 4. Some of these concerns were addressed in the other forums and we will address these concerns in our evaluation.
Deviation Policies	• Evaluate persistent deviation and intentional deviation penalties with respect to EIM dispatch • How does EIM dispatch impact Intentional Deviation policies?	• The penalties are discussed in the presentation 2/25 and will be evaluated in steps 3 and 4
Ancillary Services	• NIPPC posed several questions addressing concerns around how BPA will address ancillary services in EIM. • Penalties/Negative Prices: Review ACS rate schedules for appropriate modifications	• The ancillary services questions as it relates to rates are discussed in the Gen Inputs of the 2/25 workshop and will continue the discussion in future rate case workshops

1/28 Workshop - Customer Comments (Cont.)

Customer	Comment Summary	BPA Response
Participating & Non-participating Resources	• Non-participating Resources: Concerned with requirements for co-gen resources • Participating Resources: BPA should present preliminary evaluation along with pros and cons on what types of transmission products for EIM transfers. • External-BA Resources: will BPA allow dynamic schedules? • Participating Resources: NIPPC poses several questions regarding type of transmission donations and the donation process. o Survey and share findings of how existing EIM participant approaches to these questions. o How will BPA manage exposure to EIM prices?	• The concerns and the evaluation will be discussed during the steps 3 and 4
Un-designation of DNR	• Un-designation of DNR o Require the Un-designation of DNRs being used to make Firm network sales o Address this issue in TC-22 including review of the NT MOA	• The NT team is reviewing these comments and will have a response at the next TC-20 settlement workshop.
Solar Study (BP-20)	• Solar Study (BP-20): Material value to exploring shaped reserve option. • Gen Inputs: limited input to reach conclusions	• The concerns and considerations will be evaluated in steps 3 and 4

1/28 Workshop - Customer Comments (Cont.)

Customer	Comment Summary	BPA Response
7f Rate Design	• Clarify the timing, availability and market risk as a discretionary Tier 1 obligation o Also include terms & conditions, methodology for new rate and customer obligations o New firm surplus rate could be explored with similar clarification per above • Support continued exploration as long as available to all preference customers among other considerations. • Any new proposal for serving load following customers should be win-win for all preference customers and not create any new material risks or cost shifts • There is potential merit deserving further exploration based on initial customer benefits and BPA revenues	• The 7f rates team are reviewing these comments and will consider them as part of their evaluation and alternatives in upcoming rates workshop
Financial Planning	• Concerned of disproportionate burden on transmission • use of MRNR per previous filings and testimony o Accounting policies should be considered outside of a rate case o Amortize short-lived regulatory assets for greatest ratepayer benefits o More strategic approach at regulatory accounting and MRNR • include long-term cost and rate forecasting. Customers will want greater visibility	• These concerns and comments were forwarded to the financial planning process
General Comments	• BPA should demonstrate how it will track how the new processes will affect other topics. • EIM charges: incremental transmission charges would be problematic and upset the reciprocity transmission framework o FERC expressly disapproved of PAC's proposal of an incremental transmission rate for EIM • VERBS: 30/15 option will most likely be eliminated. What other changes might be needed? • In general, avoid seams issues • Encourage BPA to work with stakeholders across EIM footprint	• These comments will be considered by the affected teams moving forward

12/12/19 Feedback Summary

Themes	BPA's Response
Transmission Losses concerns on pricing and capacity adder	The review of the pricing and the value for transmission losses will be discussed in the rate case
Customers would like to have a better understanding of the objective and reason for change for Transmission Losses.	Losses will return in the March workshop to address this request.
Customers would like to have choices for settling transmission losses (i.e. physical vs financial). For example one choice could be to consider an option of returns in like kind with a penalty for customers who fail to return the loss obligation	Losses will return in the March workshop to begin sharing options.
Transmission loss factor should be established in Tariff proceedings	The Tariff does contain the annual average system loss factor for the network and intertie. We do not intend to suggest removing it from the Tariff.
Transmission losses should be included in the Transmission rates and rates schedule and should be equitably allocated	Bonneville intends to have any rate discussions during the upcoming rate case proceedings. Any discussion regarding the location (i.e. Power or Transmission Rates Schedules) will be discussed during the rate proceeding. Options of transmission losses pricing will be discussed in the rate case in steps 4 and 5.
The EIM losses are important and BPA is in the the best position to determine the appropriate transmission loss percentage for OATT service	In the workshops, steps 4 and 5 will discuss the option for the EIM Losses
Provide more information on the value lost to BPA from a customer's failure to deliver In Kind	This will be addressed in steps 4 and 5.
Costs are inevitable so develop cost/benefit analysis (administrative burden) for financial returns (similar to what was developed for In Kind). In other words, realize that certain administrative costs may be worthwhile due to the market value they deliver – such costs should be appropriately allocated.	This will be addressed in steps 4 and 5
Be clearer of the strategic interplay between EIM Losses and Transmission Losses both in implementation and long-term	We will continue to look for opportunities to share interplay between EIM losses and Transmission losses if applicable. At this point, we do not see any interplay between EIM Losses and Transmission Losses.
Maintain separation between EIM Losses and Transmission Losses	We agree there is a separation of EIM Losses and Transmission Losses

12/12/19 Feedback Summary (cont.)

Themes	BPA's Response
Customer proposed changes to EIM Charge Code principles	The team will consider the proposed principles and will give feedback to customers at the February workshop
Include a glossary of EIM charge codes and a crosswalk to current BPA rates where applicable	We will continue discussing the EIM charge code s and cross walk to current BPA rates where applicable in the February workshop materials
EIM charge code cost allocation should include wheel through , preference customers and interchange and non-participating resources. How are customers outside the BA considered?	Analysis and alternatives will be discussed in steps 4 and 5.
EIM charge code cost allocation should be initially based on cost causation and should be phased in with a partial insulation	Cost allocation is an important issue and the feedback on a phased in and partial insulation will be considered in the alternatives development
As the EIM charge code cost allocation (and other EIM policy issues) is discussed, one consideration is to ensuring customers existing OATT rights are fully respected and that customers maintain the ability to use their rights without facing new costs.	In the evaluation phase, there will be consideration of OATT rights and how to recover new costs . In the steps 5 and 6 the consideration of OATT rights will be evaluated
More clearly tie Ancillary Services to EIM Charge Codes	In the rates discussion, there will be an in-depth discussion of tying the Ancillary Services to EIM Charge Codes where it is applicable.

12/15/19 Feedback Summary

Themes	BPA's Response: Updated 1/28
Provide a detailed summary timeline with topics for each workshop	We will keep an agile schedule and adjust as we hear feedback from customers.
Customers concurred with BPA's proposal for engagement for certain topics	No change
Customers want early discussions on the following topics: • Transmission Usage • Creditworthiness • EIM Metering and Data Requirements • EIM Non Federal Resources	Based on customer feedback, we have started discussion on the identified topics from customers in Jan. and Feb. This is reflected in the schedule on the Meetings and Workshops page
Provide customers information on where/if there will be changes for Rate Case topics	We recognize rates have dependencies on EIM policy topic decisions and we will stay coordinated with the topics. We also recognize their dependencies on charge code, gen inputs and Priority Firm Load. We have discussions on rate case issue in the Jan workshop and will continue those discussions through the summer.
Provide an explanation of why the proposed future tariff topics are not part of TC-22	The future deferred tariff topics are due to possible changes in industry standards and developing markets. As we discussed in the Oct. 23 workshop, we are focusing on EIM for this proceeding.
Identify early in steps 1 & 2 where there are dependencies for other topics	We will identify the steps and to the extent we know the dependencies, will include them.
Provide a crosswalk of the Tariff issues from TC-20 to TC-22	Please see appendix at workshop in Nov. 19.

12/15/19 Feedback Summary (cont.)

Themes	BPA's Response: Updated 1/28
EDAM impact on rates and tariff	EDAM policy is out of scope in the rates and tariff. Customers have the ability to participate directly in the CAISO's EDAM policy initiative process. Bonneville's evaluation of whether and how to join EDAM is anticipated to be another decision process – much like EIM – including the development of principles for our evaluation. We also anticipate that process would then be followed by rates and tariff cases.
Green House accounting	Green house gas accounting is out of scope in the rates and tariff process. The policy was discussed in the following workshop: https://www.bpa.gov/Projects/Initiatives/EIM/Doc/20190312-March-13-2019-EIM-Stakeholder-Mtg.pdf
EIM governance	EIM governance is out of scope in the rates and tariff process. Customers have the ability to participate in CAISO's governance review process.
Leverage customer led workshops to share experiences and challenges	We worked with other participants to get a better understanding of their experiences and challenges. We also agree the monthly customer led workshops are an excellent forum to share experiences and challenges with other customers. Our first requested customer led workshop was 1/15.
Carry larger ancillary services reserves	This will be addressed in the Gen Inputs discussion.
More discussion is needed on steps 1 & 2 for resource sufficiency. Customers provided several questions to gain a better understanding.	We will look at the schedule and update it to address these questions.

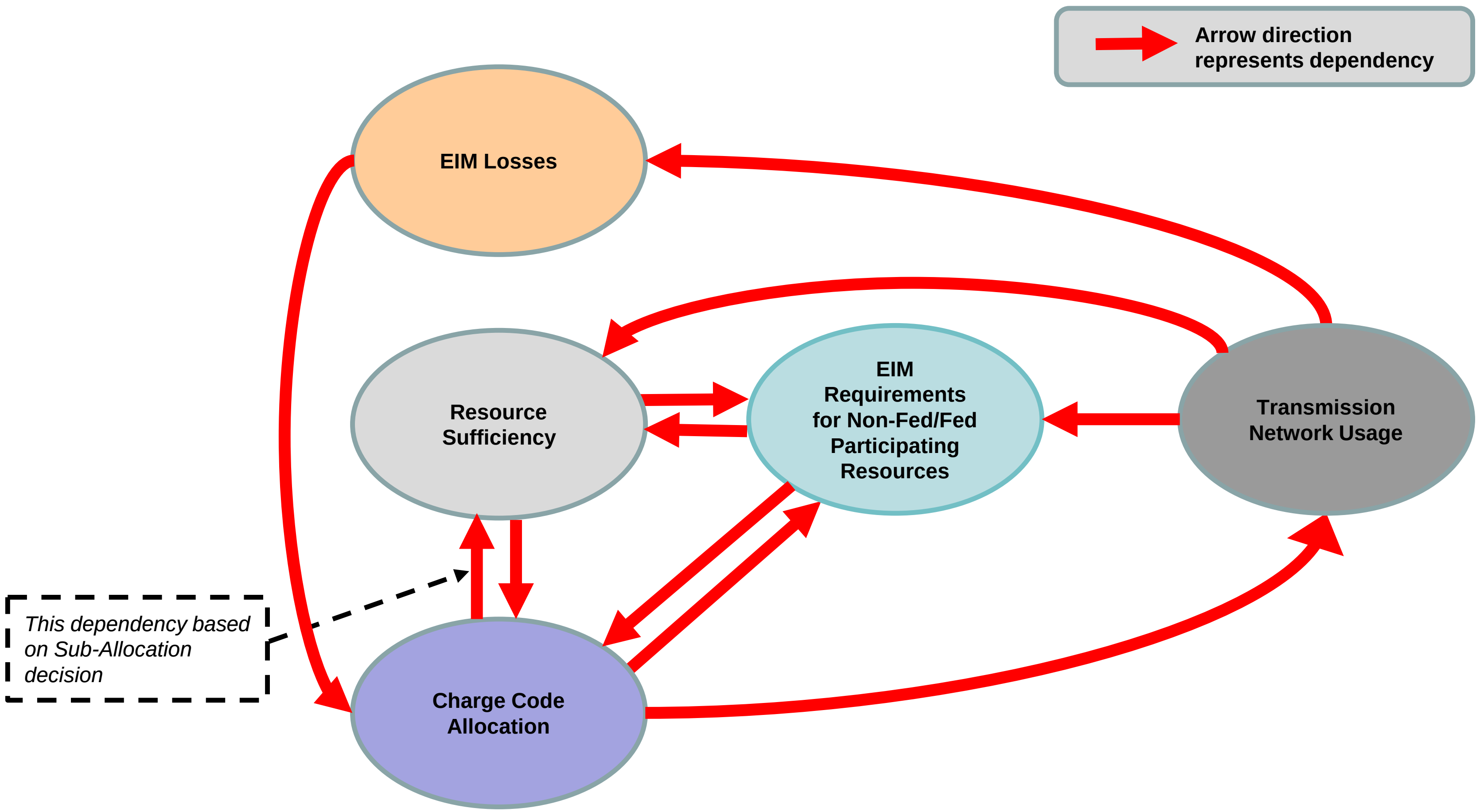
12/15/19 Feedback Summary (cont.)

Themes	BPA's Response: Updated 1/28
Develop a roadmap of how future deferred tariff topics are addressed.	The future deferred tariff topics are due to possible changes in industry standards and developing markets. We don't have roadmaps at this time. We would look to develop roadmaps after the conclusion of TC-22 if warranted.
Regional Planning Organization may have a couple of options	This will be addressed in steps 3-6 of the RPO discussion. An RPO update will be discussed at the 2/25 workshop and step 3 will be addressed in the 4/28 workshop.
Oversupply discussion and if it is needed in EIM	As noted in the EIM discussions at https://www.bpa.gov/Projects/Initiatives/EIM/Doc/20190312-March-13-2019-EIM-Stakeholder-Mtg.pdf BPA believes OMP is compatible with EIM. As we gain experience with EIM operations, we will continue to evaluate implementation and consider any potential changes in future tariff cases.

Customer Led Workshop Protocol

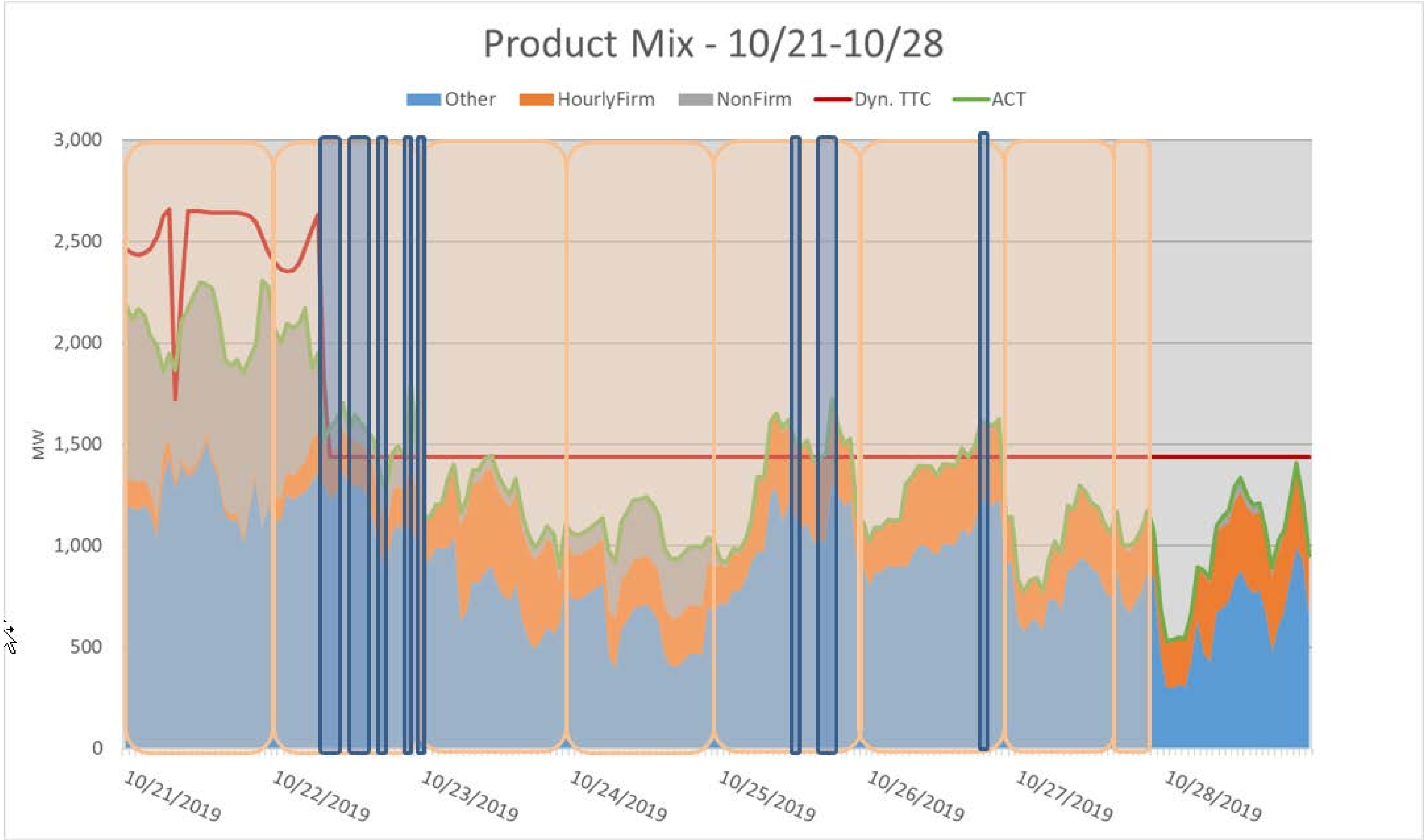
- Submit a workshop request no later than one week before the scheduled date (see slide 4 for dates).
- Requests must include a list of topics/issues you wish to cover if you are requesting Bonneville SME support.
- Discussions/workshops will only cover previously reviewed materials.
- Customers must inform BPA if A/V resources are required to include remote participants and/or present materials **through virtual meeting**.
- BPA will verify that it will staff for the requested topics within three business days via Tech Forum.

EIM Issue Inter-Dependencies Identified



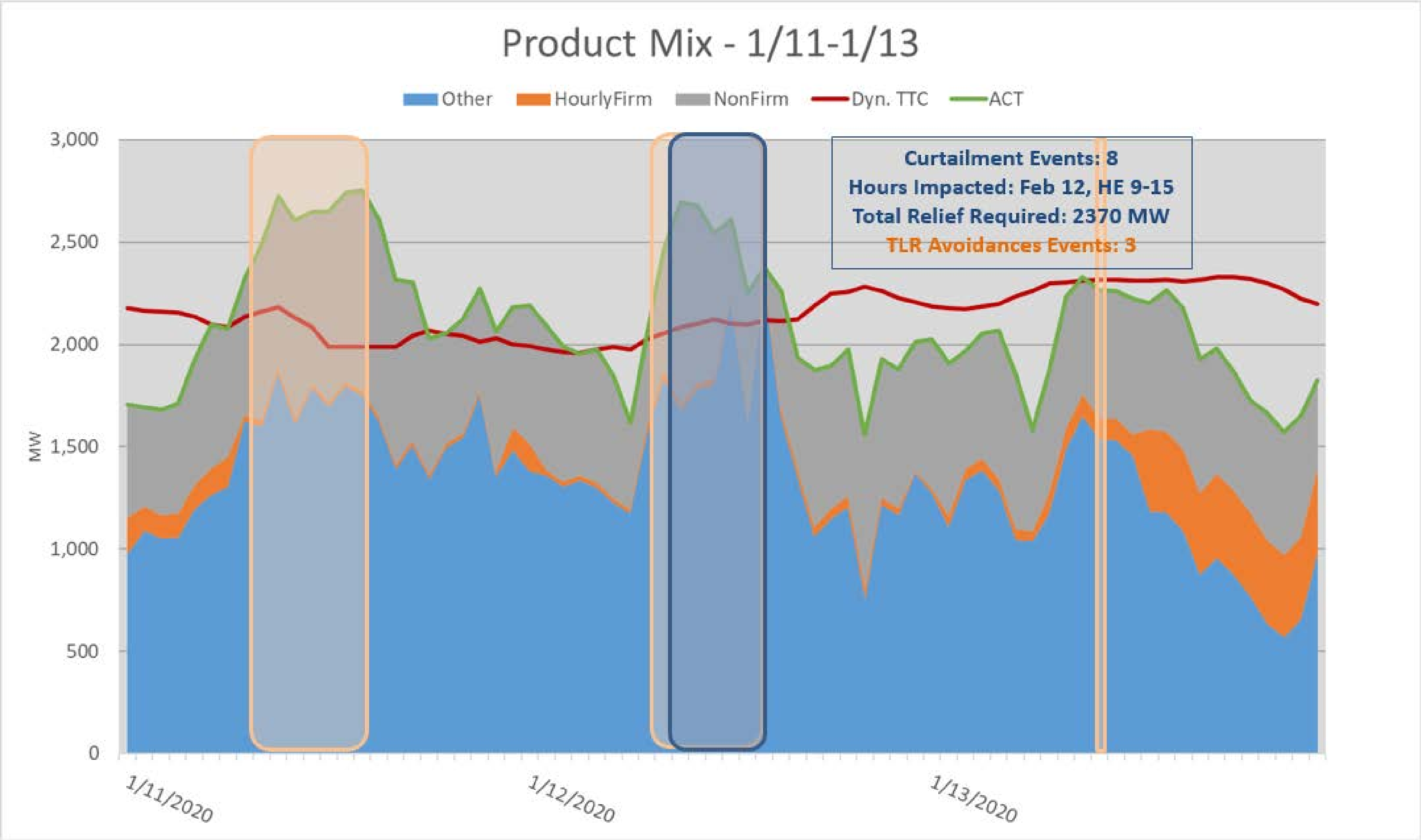
APPENDIX: HOURLY FIRM

Curtailment Event 10/21-28/19



*TLR and Curtailment representations are approximations of their actual start and end times.

Curtailment Event 1/11-13/20



*TLR and Curtailment representations are approximations of their actual start and end times.

Appendix – ATC Formulas (NERC Time Horizon)

The firm ATC formula is:

$$\mathbf{ATC_F = TTC - ETC_F - CBM - TRM + Postbacks_F + Counterflows_F}$$

The non-firm ATC formula is:

$$\mathbf{ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + Counterflows_{NF}}$$

Where:

ATC is the firm Available Transfer Capability for the ATC Path for that period.

TTC is the Total Transfer Capability of the ATC Path for that period.

ETC is the sum of existing firm commitments for the ATC Path during that period.

CBM is the Capacity Benefit Margin for the ATC Path during that period.

TRM is the Transmission Reliability Margin for the ATC Path during that period.

$\mathbf{TRM_U}$ is the Transmission Reliability Margin that has not been released for sale as non-firm capacity

Postbacks are changes to firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

Counterflows are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in their ATCID.

F subscript refers to Firm; **NF subscript** refers to Non-Firm; **S subscript** refers to Scheduled