NWPP

After-the-Fact and System Schedulers Meetings

October 21-22, 2014 – Portland, OR

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Next Meeting…

October 20-21, 2015
– Portland, OR

Stay Tuned:
http://www.nwpp.org/calendar/After-the-Fact-and-System-Schedulers-Meeting-2015.10.20

If you are interested in participating on the Agenda Committee
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(503) 445-1079

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AFTER THE FACT & SYSTEM SCHEDULERS MEETING
October 21-22, 2014
DoubleTree by Hilton – Portland
1000 NE Multnomah Portland, OR 97232

Proposed Agenda

Oct. 21, 2014

1. **Welcome and Arrangements** — ChaRee DiFabio, NWPP

2. **WECC ATF Dispute Report** — Paul Rice, WECC

3. **BAL-002-WECC-2** — Jerry Rust, NWPP

   Introductions & Break

4. **SCE's Decommissioning of San Onofre Nuclear Generating Station (SONGS)** — Tom Botello, SCE

5. **EIM Update**
   - CAISO/PacifiCorp — John Schaffroth PAC; John Apperson, PAC; Don Tretheway CAISO
   - NWPP MC Initiative — Dan Williams, PGE
     - Security Constrained Economic Dispatch (SCED)

6. **Interactive Activity** — All

   Evening Reception - 5:00 p.m. to 8:00 p.m. - Multnomah Grille

Oct. 22, 2014

1. **Welcome Back** — ChaRee DiFabio, NWPP

2. **WECC ISAS Update** — Andy Meyer, BPA – WECC ISAS Chair

3. **PGE Solar Power** — Scott Russell, PGE

4. **WECC - Peak Reliability Update** — Michelle Mizumori, Peak RC

   Break

5. **BPA's Improvement /upgrade project to DC Intertie** — Karl Mitsch, BPA
   - How will it enhance Scheduling?

6. **15 Minute Scheduling – Panel Discussion** — Demetrious Fotiou, PWX; Lou Miranda, BPA; and Matt Richard, PGE
   - How is this new process working?

   Closing & Door Prizes

Presenter Biographies –
After-the-Fact Meetings & System Schedulers
October 21-22, 2014 – Portland, OR

WECC ATF Disputes Report

Paul W. Rice is the Assistant Director of Operations for Western Electricity Coordinating Council. In this capacity he is responsible for coordination and participation on all NERC/WECC RC, BA and TOP certifications. He is also responsible for the NERC Event Analysis program for WECC. He collects, reviews, and posts all Event Reports to both NERC and WECC websites. Paul joined WECC's predecessor, the WSCC, in 2002 as an electronic scheduling specialist. Paul is a 43-year veteran of the electric utility industry having held positions at PacifiCorp and Nevada Power working in transmission (pre-scheduling and e-Tagging) and sub-transmission and in AGC. In addition, he worked on the implementation of the OASIS program at PacifiCorp. Paul began his career with Pacific Power & Light as a meter reader in 1971 and held various positions within the organization, including journeyman lineman and serviceman positions in Rock Springs, Wyoming and in dispatch at the company's Jim Bridger Plant in Wyoming. He has been in Operations, holding many managerial positions since. Paul retired from Nevada Power Company in 1996 after 15 years and from PacifiCorp in 2002 after 15 years, both in Operations. Paul graduated BS Social Sciences (Double Major in Psychology and Sociology) August 1971.

WECC Standard BAL-002-WECC-2

Jerry D. Rust joined the Northwest Power Pool January 1, 2001 as President. For the majority of 2000, Jerry consulted on power issues for several software companies. Prior to that, he worked at PacifiCorp for 23 years, where he served as managing director of PacifiCorp's revenue organization and managing director of the transmission systems group. Jerry joined PacifiCorp in 1977 as an engineer and held positions in power resources, financial analysis, field operations, customer service, sales support and national sales.

Mr. Rust was graduated from the University of Wyoming with a degree in electrical engineering. He has furthered his education with numerous courses from various schools (University of Washington, Washington State University, Colorado School of Mines, and others). Jerry is one of the Western Electricity Coordinating Council's North American Electric Reliability Council Operating Committee Representatives.

SCE's Decommissioning of San Onofre Nuclear Generating Station (SONGS)

Thomas J. Botello is a principal manager with SCE responsible for an organization that directs electric system grid operations and engineering by monitoring, planning, analyzing and directing 24/7 operations of the grid, and ensuring compliance with mandatory reliability standards. He has a staff of 40, and has been in with SCE for 32 years holding numerous management positions with increasing responsibility. He is the current SCE member representative with Peak Reliability and the Operating Committee representative with WECC. He has served in numerous capacities in the electric industry including; WECC Operating Committee Chair; Operating Issues Work Group Chair; PacifiCorp Disturbance Investigation Team Chair; Operating Practices Subcommittee Member; Reliability Issues Task Force Member, Reliability Coordination Task Force Member; WECC Reliability Coordinator NERC Review Certification Team Member, and 2003 Northeast Blackout Readiness Review Teams. He has completed executive training courses at Pepperdine Graziadio School of Business and the University of Idaho.

EIM Update - CAISO/PacifiCorp

John Schaffroth has been at PacifiCorp for 12 years. He started on the Balance & Interchange Desk where he worked for about five years, moved to the Transmission Preschedule group for two years, supervised the B&I desk for about three years, and is currently assigned to the EIM Implementation team. He has a wife and two kids and currently resides in Vancouver, WA.

EIM Update - CAISO/PacifiCorp

John Apperson has been the trading director at PacifiCorp located in Portland, Oregon, since 2000 and is responsible for real-time, short-term and long-term trading, scheduling and operations for electricity and natural gas. Mr. Apperson has experience in many aspects of the utility industry from transmission planning to wholesale marketing. He has been actively involved in the design and implementation of the California ISO energy imbalance market.

EIM Update - CAISO/PacifiCorp

Don Tretheway is the Lead Market Design and Regulatory Policy Specialist at the California ISO. He led the stakeholder initiative at the ISO to design the Energy Imbalance Market which leverages the ISO's real-time market. He was also responsible for the ISO's FERC Order No. 764 compliance and associated real-time market design changes including the introduction of the fifteen minute market and advanced scheduling and bidding for variable energy resources. He will also be leading the Flexible Ramping Product stakeholder initiative which will be recommencing the end of May.

EIM Update – NWPP MC Initiative

Dan Williams, NWPP MC Initiative Lead – Power Operations, Portland General Electric: Dan joined PGE's Power Supply Operations group in late 2012, where his diverse background in real-time trading (PSE and Tri-State Energy), back-office (PPM/Iberdrola), and FERC policy and compliance (PSE) has been put to use on a number of projects. He currently leads PGE's internal and external participation in the NWPP MC Initiative, and is the Chair of the NWPP MC Initiative Leadership Committee for 2014.

WECC ISAS – Status Update & WIAB Training and Test Plan

Andy Meyer is a native Oregonian and has been at the Bonneville Power Administration since fall of 2000 when he started as a student intern. He currently supervises the Power Services Preschedule group and is the WECC ISAS Chair.

PGE Solar Power

Scott Russell is an Originator for the Portland General Electric Power Operations and Resource Strategy group. Scott specializes in structured transactions, asset acquisitions, and long-term strategic planning for the wholesale power portfolio. Prior to joining PGE, Scott worked for TransCanada in the US Pipelines West division as a financial analyst in the pricing and regulatory affairs departments. He is a native Oregonian and Oregon State University alumnus.

Peak RC

Michelle Mizumori serves as the Director, Operations for Peak Reliability, the Western Interconnection's new Reliability Coordinator company. She oversees the the Real-Time Operations group. Michelle joined the Western Electricity Coordinating Council (WECC) in 2008 as Market Interface Manager.

Prior to joining WECC, Michelle spent three years at Madison Gas and Electric (MGE) Company. There she worked with MGE's Balancing Authority operations group and was responsible for MGE's participation in the Midwest ISO, the Midwest Contingency Reserve Sharing Group, purchased power agreements, and operator training. Michelle has a Doctorate from Johns Hopkins University, Baltimore, Maryland and a Bachelors of Science from Swarthmore College, Swarthmore, Penn

BPA's Improvement/upgrade project to DC Intertie

Karl A. Mitsch is the Program Manager for FACTS (Flexible AC Transmission Systems) and HVDC (High Voltage Direct Current) Systems at the Bonneville Power Administration in Vancouver, WA. Mr. Mitsch is also the lead Project Manager for the Pacific DC Intertie Upgrade Project which BPA is executing on its portion of the intertie. Mr Mitsch has been with the BPA for 13 years where he has worked mainly in the area of reactive compensation, HVDC and FACTS as an application engineer and project manager. An electrical power system engineer with over 25 years in the electric utility business, Mr. Mitsch has also worked for General Electric and Consolidated Edison. Mr Mitsch has an MSEE and BSEE from Clarkson University and a BS in Mathematics from SUNY Oneonta.

15 Minute Scheduling Panel

Lou Miranda has been with BPA for over 20 years and has worked in both Power and Transmission Scheduling for over a decade. A graduate of Portland State University, Lou is a native of the Pacific Northwest.

15 Minute Scheduling Panel

Demetrios Fotiou was born, raised and has always lived in Vancouver. Demetrios has a Bachelor Degree in Civil Engineering and a Masters Degree in Hydrology/Environmental Engineering from the University of British Columbia in Vancouver. Demetrios has been in the industry for almost 25 years, of which 17 years have been with Powerex, in Vancouver. Part of Demetrios' role at Powerex is management of the Realtime Trading desk, a role that he has held since the inception of the Realtime Trading group at Powerex. Demetrios has been heavily involved in the industry in the past 17 years, including being a member of many WECC workgroups and Committees historically and/or currently, including MIC, OC, ISAS, RTSWG, ISWG, EIWG and MIS. Demetrios spends much of his spare time coaching his children's sports, trying to remember to praise his wife, and working on old classic cars.

15 Minute Scheduling Panel

Matt Richard is the OASIS and Scheduling Systems Analyst for the Portland General Electric Transmission and Reliability Services group. Matt has been with PGE for nearly 34 years serving initially in Trojan Nuclear Power Plant operations for 12 years, Power Operations as a real-time scheduler for 6 years, before his current roles in PGE Transmission where he began as a transmission prescheduler and now specializes in scheduling and e-tagging systems support and policy. Matt is a 6 year US Navy veteran where he served in its nuclear power program.

NWPP Meeting MC

ChaRee DiFabio joined the joined the Northwest Power Pool in July 2000. She is currently the Reserve Sharing Group Committee Manager and oversees all related activities as well as the program. Also, she provides support to the NWPP Operating Committee (OC), NWPP Training, various subcommittees and work groups through coordination, meeting facilitation, and informational reporting on behalf of the membership to the internal companies and other organizations such as WECC and NERC.

Prior to working for the NWPP she worked for Idaho Power Company for 5 years at the Boise Bench Substation where she worked with the System Dispatch, After-the-Fact, and the System Scheduling groups.

WECC SCHEDULE CHANGE REQUEST FORM

Please send this completed and signed form to disputereports@wecc.biz

	Date D-M-Y	HE	Time Zone	Tag	Current MW Schedule	Requested MW Schedule	Reason
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							

Source BA:	
Responsible ATF Name:	
Signature:	
Date:	

Sink BA:	
Responsible ATF Name:	
Signature:	
Date:	

Intermediary BA	
Responsible ATF Name:	
Signature:	
Date:	

Intermediary BA:	
Responsible ATF Name:	
Signature:	
Date:	

Dispute Report Issues
May 01, 2014

On May 1, 2014, Operations Staff was in receipt of 29 Dispute Report Schedule Change Request forms, containing 156 Schedules that covered a 3 day period from April 28-30, 2014. The schedules were broken down as follows:

NWMT	46
BPAT	156
PGE	71
NEVP	1
AVA	4
TPWR	1
SCL	2
PSEI	9
IPCO	4
CHPD	1

The Dispute Reports were all signed and dated by each Source, Sink and Intermediary that was on each tag as required prior to entering the Dispute Reports into the WIT. 86 of the schedules reported that they contained the "Wrong Sink". 70 of the schedules reported that they contained the "Wrong Source". The Dispute Reports were split up between 2 staff members in order to complete the process in a reasonable timeframe without unnecessarily burdening one person. All of the schedule changes were completed by approximately 1300 MDT on May 1, 2014. BPAT reported back that the changes all "looked good". At 1659 MDT a WECCNet message was received from PGE reporting that they were not participating in Automatic Time Error correction until "OATI corrects PGE's primary inadvertent calculations." At 0819 MDT on Friday, May 2nd an attempt was made to contact PGE and determine what their problem was. After reviewing the WIT, starting on April 28th, through April 30th, PGE accumulated mass Inadvertent Interchange numbers OnPeak of several thousand MW's.

WECC started an investigation with PGE to determine why. Shortly thereafter a WECC Staff member received a telephone call from NWMT wanting to know why there were so many issues going on in WIT regarding Primary Inadvertent. Review of the WIT showed the same Inadvertent Interchange accumulations for NWMT during the same 3 day period. It occurred to staff that there might be a relationship between these two Registered Entities problems and the schedule changes that were entered on May 1. A short time later another staff member was notified that Shell Energy, the merchant on all of the tags, had notified PGE that the ATF tags would not be ready for implementation until later that day or even not until Monday, May 5th. NWMT was notified and requested that either the original schedules be put back into WIT or the ATF tags get implemented immediately because it was resulting in a massive amount of erroneous "payback" of accumulated primary inadvertent through ATEC. SHELL energy was contacted and they reported that some of the ATF tags were being implemented at the same time and others would need approval and may be as late as Monday. They were instructed to approve and implement ALL ATF tags immediately or all the schedules would be returned to the WIT until the ATF tags could be ready for processing. At 1047 MDT, WECC staff was notified that all ATF tags had been implemented. And both PGE and NWMT were notified. At 1339 notification was received from NWMT that everything was in the process of correction and it all looked good. Following is a report of what occurred to NWMT alone because of the issue. No reports were received from other Registered Entities as to the problems that were encountered.

> During this change NorthWestern Energy noticed Primary Inadvertent values go as high as 4,000 MW and after the proper corrections, the On-Peak Primary Inadvertent resulted to 287 MW. The problem with an improper Primary Inadvertent value is we pay it back each hour through ATEC. If the problem is not caught in a fast manner a Balancing Authority (BA) could payback

a large amount of Primary Inadvertent that could even be in the opposite direction of the correct Accumulated Primary Inadvertent. Please also note that per the BAL-004-WECC-2 standard, a BA is only allowed to operate with ATEC out of service for a total of 24 hours in a calendar quarter.

The lesson learned here should be that Registered Entities entering into "Dispute Reports" should verify that the ATF tags will be entered in a reasonable amount of time shortly after the agreed upon Dispute Reports have been implemented.

NORTHWEST POWER POOL

Reliability through Cooperation

2014 Update

Presentation Outline

- **History of Northwest Power Pool**
- **BAL-002-WECC-2**
    - What is out
    - Major impact to NWPP RSG
    - New Standard
    - Impact at cross-over (Pre CRO- 3,156 MW Post CRO- 2,948 MW)
    - Impact on System Operators
- **NERC BAL-003**
    - Timing
- **Questions**

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BAL-002-WECC-2

What is out

- Load responsibility term
- Interruptible
- The sum of 5% of the load responsibility served by hydro generation and 7% of the load responsibility served by thermal generation
- Additional reserve for interruptible imports
- Additional reserve for on-demand obligations

BAL-002-WECC-2

Major impact to NWPP RSG

Reallocation of the Contingency Reserve Obligation (CRO). Some Participating Balancing Authority's CRO increased while others decreased

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BAL-002-WECC-2

Requirements and Measures

R1. Each Balancing Authority and each Reserve Sharing Group shall maintain a minimum amount of Contingency Reserve, except within the first sixty minutes following an event requiring the activation of Contingency Reserve, that is: [*Violation Risk Factor: High] [Time Horizon: Real-time operations]*

R1.1 The greater of either:

- The amount of Contingency Reserve equal to the loss of the most severe single contingency;
- The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation.

BAL-002-WECC-2

R1.2 Comprised of any combination of the reserve types specified below:

- Operating Reserve – Spinning
- Operating Reserve - Supplemental
- Interchange Transactions designated by the Source Balancing Authority as Operating Reserve – Supplemental
- Reserve held by other entities by agreement that is deliverable on Firm Transmission Service
- A resource, other than generation or load, that can provide energy or reduce energy consumption
- Load, including demand response resources, Demand-Side Management resources, Direct Control Load Management, Interruptible Load or Interruptible Demand, or any other Load made available for curtailment by the Balancing Authority or the Reserve Sharing Group via contract or agreement.
- All other load, not identified above, once the Reliability Coordinator has declared an energy emergency alert signifying that firm load interruption is imminent or in progress..

BAL-002-WECC-2

R1.3 Based on real-time hourly load and generating energy values averaged over each Clock Hour (excluding Qualifying Facilities covered in 18 C.F.R. § 292.101, as addressed in FERC Order 464).

R1.4 An amount of capacity from a resource that is deployable within ten minutes.

M1. Each Balancing Authority and each Reserve Sharing Group will have documentation demonstrating its Contingency Reserve was maintained, except within the first sixty minutes following an event requiring the activation of Contingency Reserve.

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BAL-002-WECC-2

R2. Each Balancing Authority and each Reserve Sharing Group shall maintain at least half of its minimum amount of Contingency Reserve identified in Requirement R1, as Operating Reserve – Spinning that meets both of the following reserve characteristics. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

R2.1 Reserve that is immediately and automatically responsive to frequency deviations through the action of a governor or other control system;

R2.2 Reserve that is capable of fully responding within ten minutes.

M2. Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates it maintained at least half of the Contingency Reserve identified in Requirement R1 as Operating Reserve – Spinning, averaged over each Clock Hour, that met both of the reserve characteristics identified in Requirement R2, Part 2.1 and Requirement R2, Part 2.2.

BAL-002-WECC-2

R3. Each Sink Balancing Authority and each sink Reserve Sharing Group shall maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve in Requirement R1, equal to the amount of Operating Reserve–Supplemental for any Interchange Transaction designated as part of the Source Balancing Authority's Operating Reserve–Supplemental or source Reserve Sharing Group's Operating Reserve–Supplemental, except within the first sixty minutes following an event requiring the activation of Contingency Reserve. [Violation Risk Factor: High] [Time Horizon: Real-time operations]

M3. Each Sink Balancing Authority and each sink Reserve Sharing Group will have dated documentation demonstrating it maintained an amount of Operating Reserve, in addition to the Contingency Reserve identified in Requirement R1, equal to the amount of Operating Reserve–Supplemental for any Interchange Transaction designated as part of the Source Balancing Authority's Operating Reserve–Supplemental or source Reserve Sharing Group's Operating Reserve–Supplemental, for the entire period of the transaction, except within the first sixty minutes following an event requiring the activation of Contingency Reserves, in accordance with Requirement 3.

BAL-002-WECC-2

R4. Each Source Balancing Authority and each source Reserve Sharing Group shall maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve amounts identified in Requirement R1, equal to the amount and type of Operating Reserves for any Operating Reserve transactions for which it is the Source Balancing Authority or source Reserve Sharing Group. [Violation Risk Factor: High] [Time Horizon: Real-time operations]

M4. Each Source Balancing Authority and each source Reserve Sharing Group will have dated documentation that demonstrates it maintained an amount of additional Operating Reserves identified in Requirement R1, greater than or equal to the amount and type of that identified in Requirement 4, for the entire period of the transaction.

Participating Balancing Authority Impact at Cross-Over (MW)

- Avista Pre-74 Post-74
- Alberta Electric System Operator Pre-556 Post-450
- Balancing Authority of Northern California Pre-71 Post-109
- Bonneville Transmission Pre-677 Post-548
- British Columbia Hydro & Power Authority Pre-313 Post-391
- Chelan PUD Pre-17 Post-22
- Douglas PUD Pre-11 Post-8
- Grant PUD Pre-26 Post-26
- Gridforce Energy Management Pre-26 Post-26
- Idaho Power Pre-114 Post-109
- NaturEner Power Watch – GWA Pre-1 Post-2
- NaturEner Power Watch – WWA Pre-4 Post-5
- NorthWestern Energy Pre-91 Post-83
- PacifiCorp West Pre-174 Post-151
- PacifiCorp East Pre-386 Post-341
- Portland General Electric Pre-97 Post-115
- Puget Sound Energy Pre-121 Post-141
- Seattle City Light Pre-51 Post 51
- NV Energy Pre-300 Post-259
- Tacoma Power Pre-15 Post-25
- Turlock Irrigation DistrictPre-18 Post-18
- Western Area Power Administration Upper Great Plains Pre-4 Post-4

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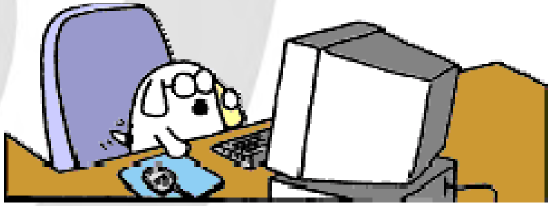
BAL-002-WECC-2
Impact On system Operators

The new WECC Standard has no impact on the implementation of requesting or delivery of Assistance Reserve; therefore, no impact on System Operators.



NERC BAL-003-1 Implementation

Compliance with BAL-003-1 shall be implemented over a two-year period, as follows:

- *In those jurisdictions where regulatory approval is required, Requirements R2, R3 and R4 of this standard shall become effective the first calendar day of the first calendar quarter 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R2, R3 and R4 of this standard shall become effective the first calendar day of the first calendar quarter 12 months after Board of Trustees adoption.*
- *In those jurisdictions where regulatory approval is required, Requirements R1 of this standard shall become effective the first calendar day of the first calendar quarter 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 of this standard shall become effective the first calendar day of the first calendar quarter 24 months after Board of Trustees adoption.*
- *Requirement R1 cannot be implemented prior to the addition of Frequency Response Sharing Group to the Compliance Registry.*

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NERC BAL-003-1 Requirements

R1 – BAs must achieve an annual Frequency Response Measure (FRM) that is more negative than its Frequency Response Obligation (FRO).

R2 – BAs using fixed Frequency Bias Settings (FBS) must use determination method described in Attachment A.

R3 – BAs using a variable FBS shall maintain setting that is:

3.1 Less than zero at all times and

3.2 Equal to or more negative than its FRO when frequency varies from 60 Hz by more than ± 0.036 Hz.

R4 – Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation, in order to represent the Frequency Bias Setting for the combined Balancing Authority Area, to be equivalent to either:

- The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRSForm 2 for the participating Balancing Authorities as validated by the ERO, or
- The Frequency Bias Setting shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.

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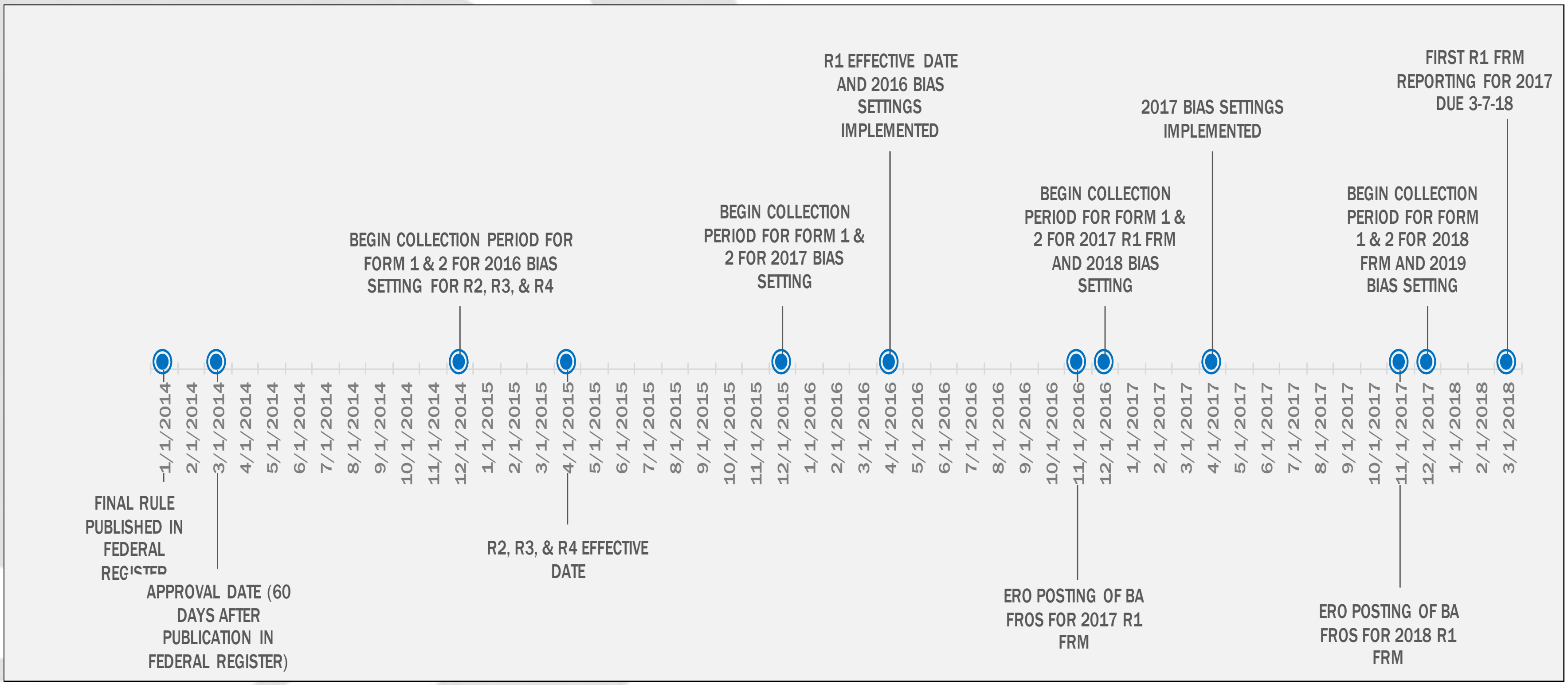
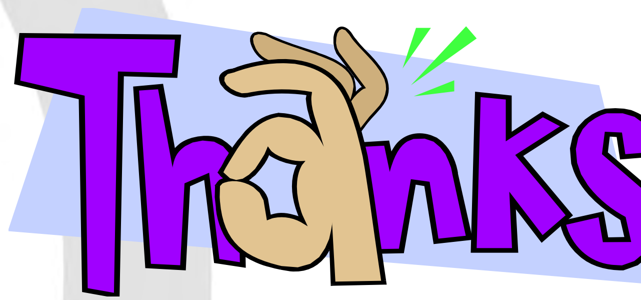
BAL-003-1 Implementation Plan

Revised August 20, 2014



QUESTIONS?



NORTHWEST PowerPool

CAISO-PacifiCorp EIM Update
NWPP ATF-System Schedulers Meeting

October 2014




PACIFICORP

Let's turn the answers on.

Agenda

- Why EIM and Why CAISO
  - Benefits
- Project implementation status
- How the EIM works
- CAISO Advanced Real-Time Market

EIM benefits for PacifiCorp

- Regulatory encouragement
- Improved network modeling
  - ISO, PAC, BPA, and others
- Upgrading system reliability
  - Replacing and enhancing outdated metering
  - Improved generation dispatch
  - Improved scheduling accuracy and accountability
    - Generation, interchange, and load
- Economics

EIM Benefits

- Leveraging the ISO's existing systems increases system redundancy and back-up capabilities
  - CAISO's 764 compliance beyond FERC requirements
- Modest start-up cost (capital and O&M)
- Manageable ongoing cost
- Incentive for constraint relief
- Diverse imbalance management

Current Status (Oct 20)

- Parallel operation commenced on schedule Oct 1
  - All critical data interfaces are in production
  - Refining data
- Full implementation on schedule for Nov 1
  - Will continue to replace manual processes with automation
  - Settlements will begin billing

Variable Generation Integration Solar/Wind

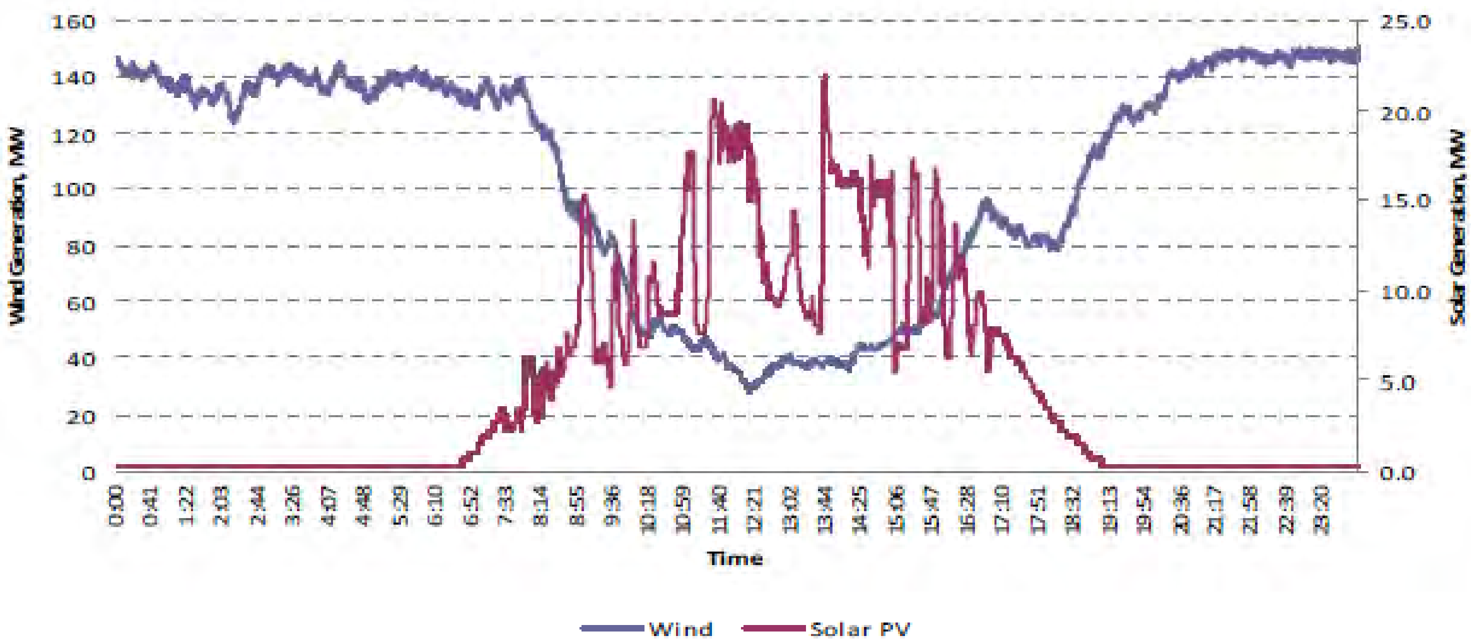
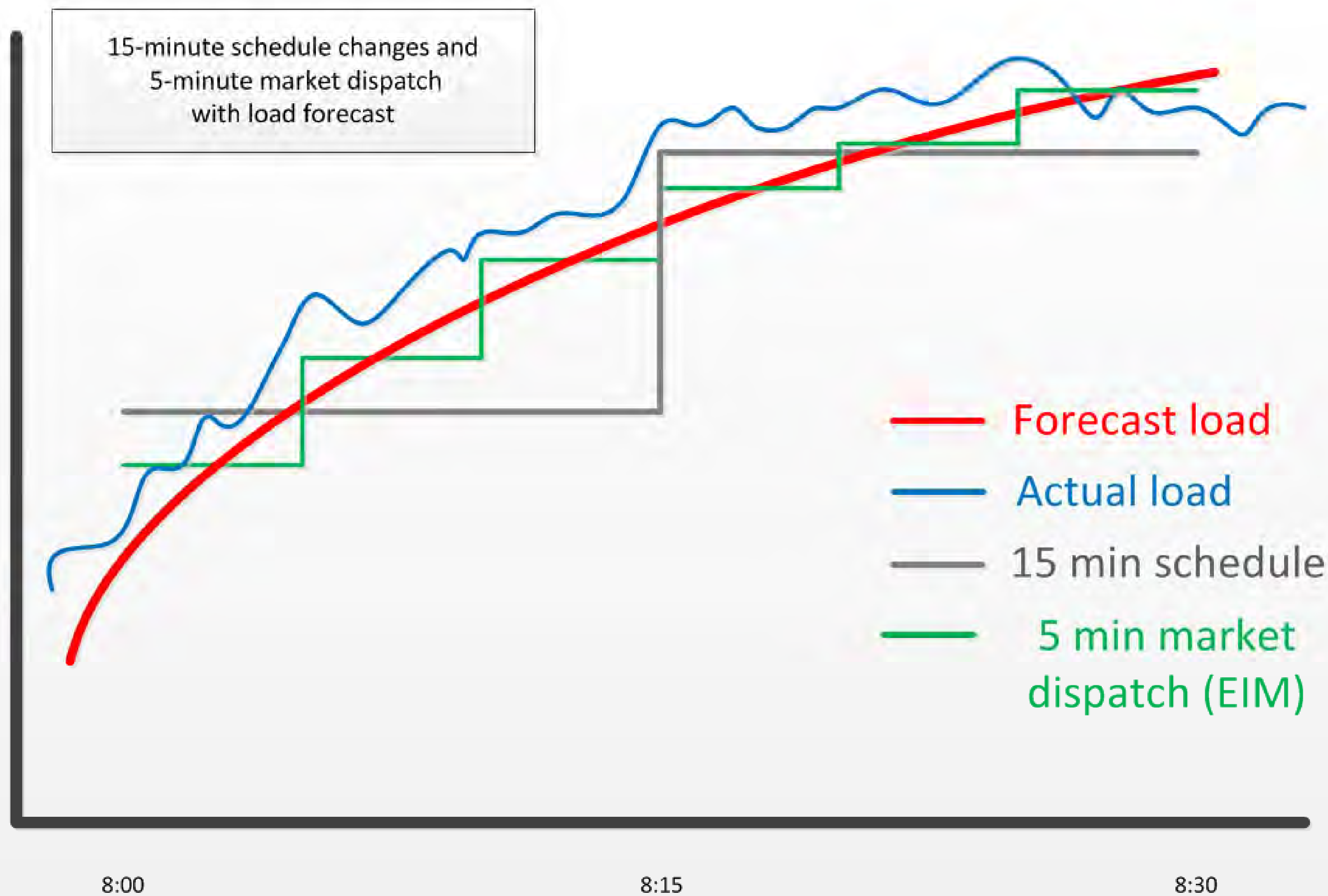


Figure 1-2: Sub-hourly wind and solar generation for a day for a 150 MW wind generator and a 24 MW Solar PV plant

Operational Concept Overview

- Expansion of CAISO’s advanced real-time market
- Security Constrained Economic Dispatch
- Congestion management
- Network model visibility and accuracy
- Market Operator, EIM Entity, Participating Resources, Manual Dispatch, Instructed/Uninstructed Imbalance charges, …..
- Detailed outage reporting and situational awareness

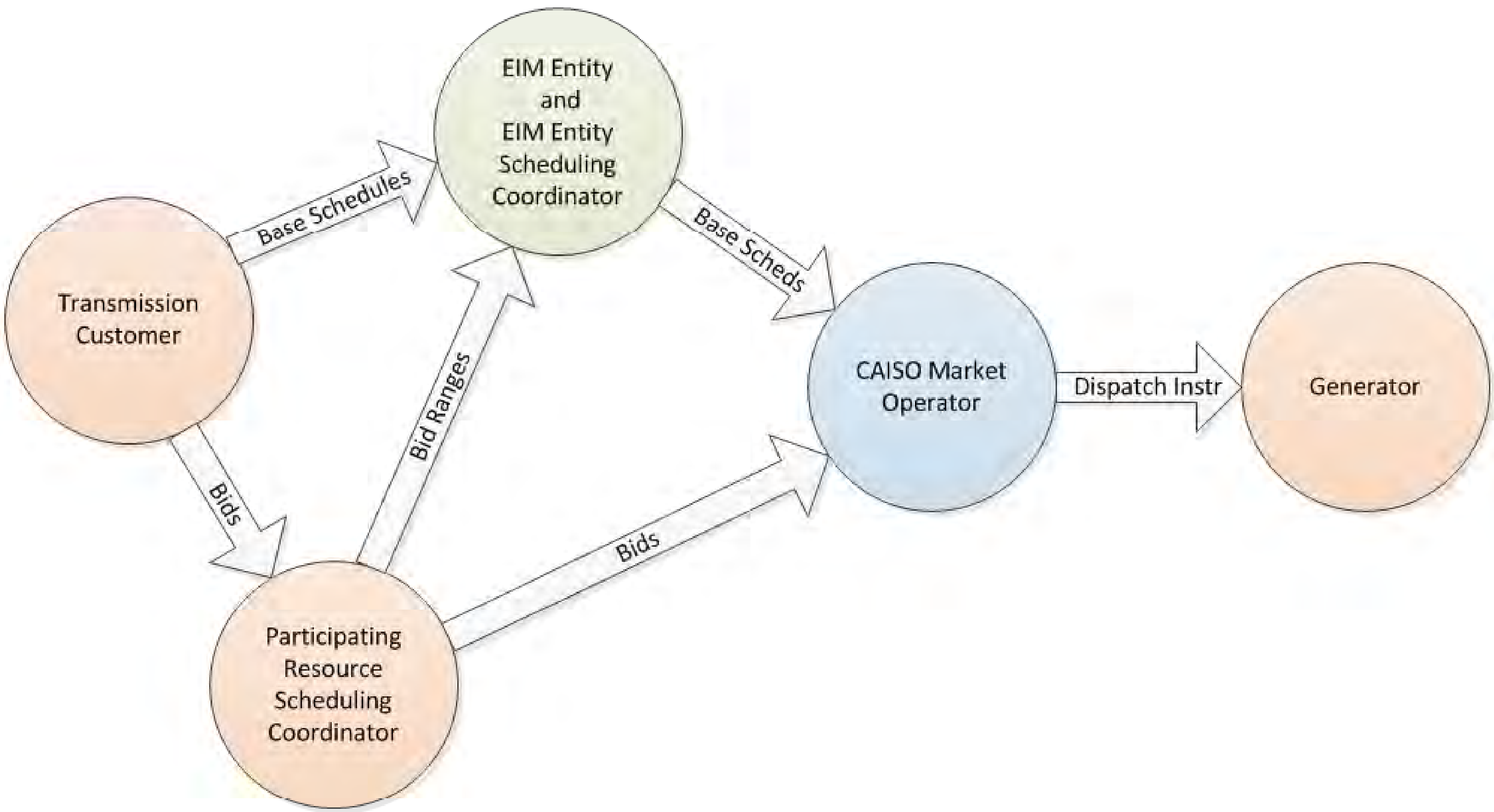
Redispatch


15-minute schedule changes and
5-minute market dispatch
with load forecast
Forecast load
Actual load
15 min schedule
5 min market
dispatch (EIM)
8:00
8:15
8:30

Base Schedules

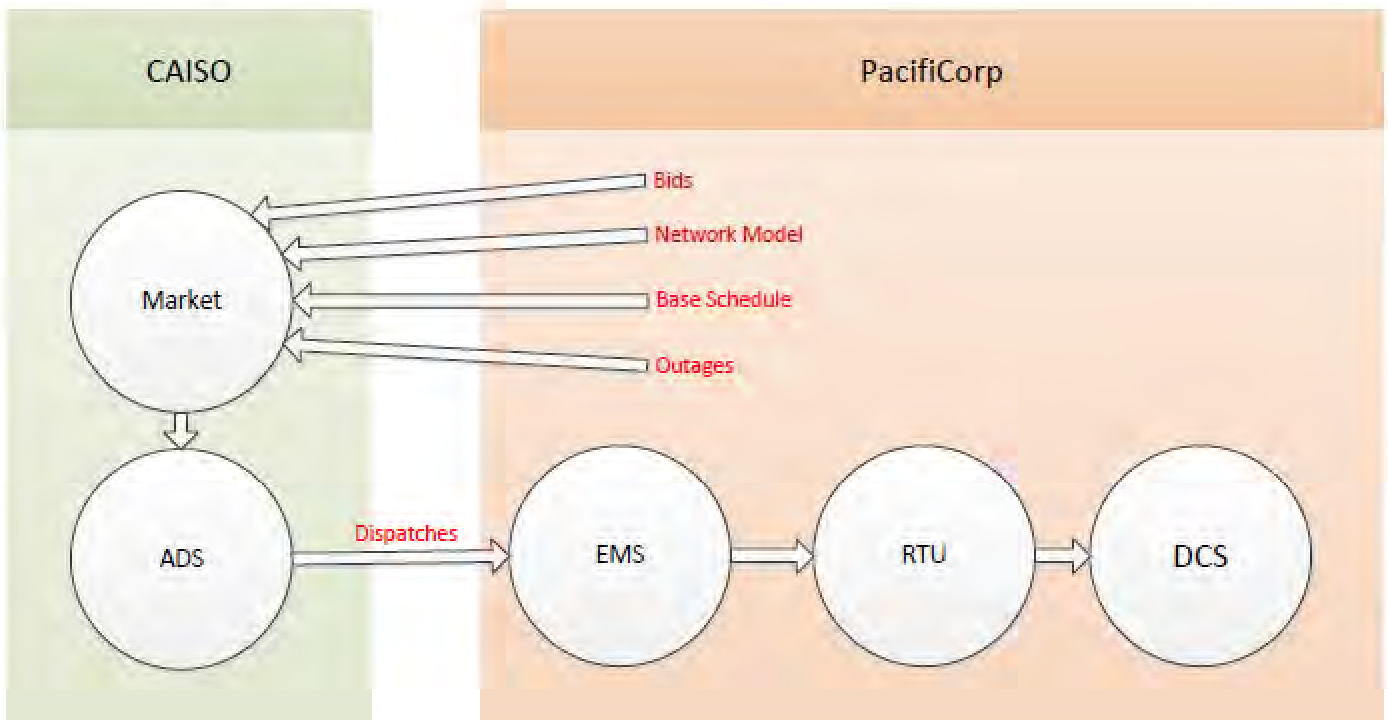
- Entity must come to the market **balanced**
- Base Schedule (G + I = L) (feasibility check)
  - Forecast of load
  - Forecast of generation
  - Forecast of interchange
- Submitted by all customers to EIM Entity
- Data aggregated and validated by PacifiCorp Grid
- Entity retains all BAA responsibilities

Base Schedule data flow



Dispatch

- Automated Dispatch System to PacifiCorp's EMS, to RTU, and to DCS at the plant



PAC and CAISO responsibilities

- PAC retains all reliability function responsibility
- PAC will balance their ACE, manage reserves (no impact to NWPP RSG) and manage their voltage
- Under EIM, CAISO operates the market and publishes market results for both PAC and CAISO (the EIM footprint)
- Under EIM, PAC will operate transmission, monitor generation, process outages, and balance PACW and PACE

Responsibilities within PAC

- PAC Tx retains all reliability function responsibility
- PAC Tx retains all reserve sharing responsibility
- PAC Merchant continues as "balancing agent" for the BAAs
- PAC Merchant continues to utilize its transmission rights to balance load and resources, and instructs CAISO to dispatch resources within specified transmission capacities
- PAC Merchant bids dispatchable resources to CAISO

Unscheduled Flow Mitigation Procedures

- EIM enhances load/resource forecasts and state estimator modeling integration
- EIM improves transmission/generation outage management
- EIM is forward-looking, proactive generation dispatching to forecasted load within remaining transmission capacity and system operating limits
- EIM can dispatch multiple generators simultaneously to have a positive impact on transmission constraints

Unscheduled Flow Mitigation Procedures

- EIM provides reduced area control error deviations (ACE)
- EIM broadens generation ramping and regulating capacity in conjunction with smaller ramps
- WebSAS curtails e-Tags for next hour based on current hour actual flows
- EIM real-time & forward-looking
- Energy profile on dynamic e-tags for USF mitigation
  - In hour dispatches will honor USF curtailments

EIM Design (CAISO)

- Allows voluntary participation
- Increased reliability: Provides information that improves operational awareness and responsiveness to grid conditions across its large footprint
- Improved renewable integration: Helps integrate renewable resources by capturing the benefits of geographic diversity
- Cost savings: Benefits all by serving energy imbalance needs from the most economic resources in a larger pool

EIM Annual Benefits

	Transfer capability					
	Low (100 MW)		Medium (400 MW)		High (800 MW)	
	Low	High	Low	High	Low	High
Interregional dispatch	$14.1	$11.0	$22.3	$17.7	$22.4	$17.8
Intraregional dispatch	$2.3	$23.0	$2.3	$23.0	$2.3	$23.0
Flexibility reserves	$4.0	$20.8	$11.0	$51.3	$13.4	$77.1
Renewable curtailment	$1.1	$10.8	$1.1	$10.8	$1.1	$10.8
Total benefits	**$21.4**	**$65.6**	**$36.7**	**$102.8**	**$39.2**	**$128.7**

$10.5 million to PacifiCorp customers
$10.9 million to ISO customers

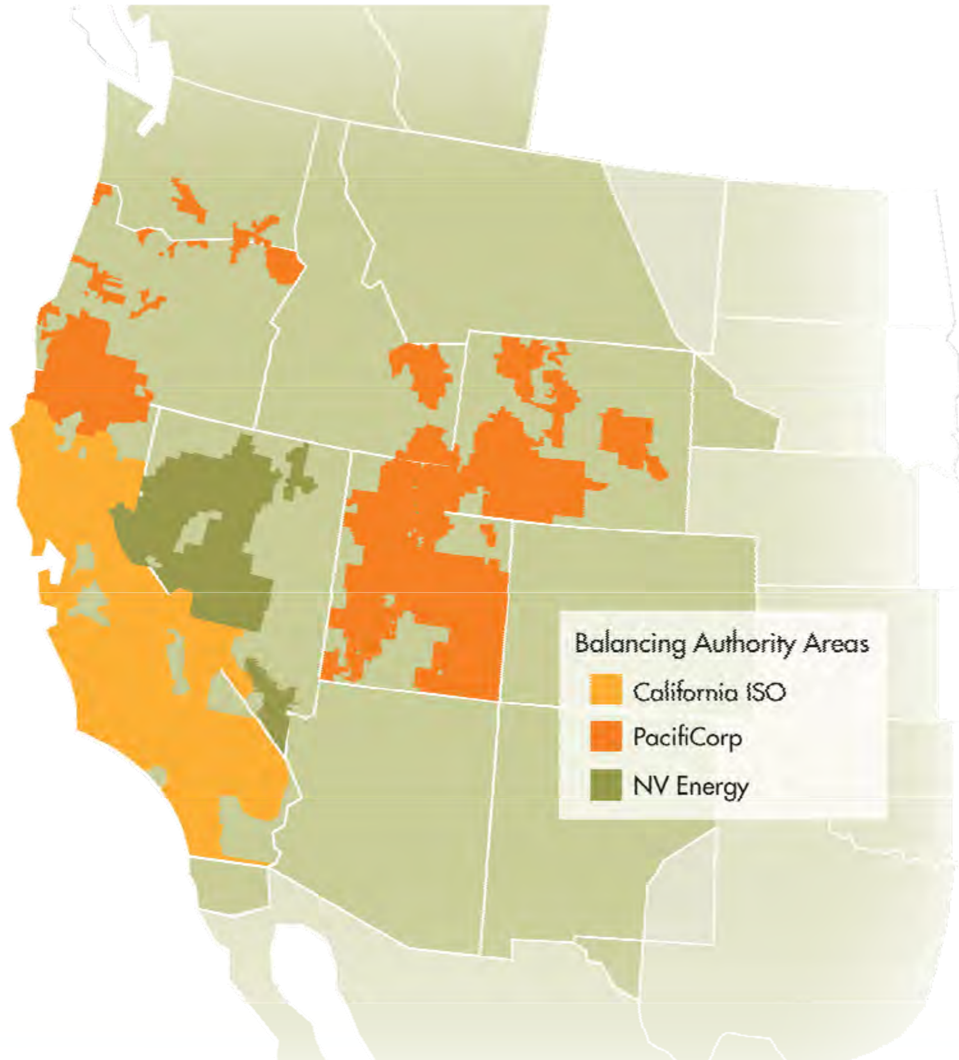
Scale of EIM in the West

PacifiCorp
1.7 million customers
9,500 MW peak demand
10,600 MW generating capacity

NV Energy
1.2 million customers
8,148 MW peak demand
5,815 MW generating capacity

CAISO
11.4 million customers
50,280 MW peak demand
58,246 MW generating capacity

CAISO is working with other interested parties



EIM Leverages CAISO's Advanced Real-Time Market

CAISO

Day Ahead Schedule

↓ △

15-Minute Unit Commitment & Energy Schedule, and Incremental AS Awards

↓ △

Real-Time Dispatch

EIM

Hourly Base Schedule (basis of financial settlement)

↓ △

15-Minute Unit Commitment & Energy Schedule

↓ △

Real-Time Dispatch

Resource Sufficiency Test

- Addresses real-time leaning prior to each hour
- Under-scheduling incentivizes balanced base schedules and compensates other LAPs for leaning
- BAA real-time congestion balancing account isolates the cost of infeasible base schedules to the BAA
- Ensures EIM Entity can meet their requirements, based on diversity benefit, independently before start of market optimization across EIM footprint
- Benefits of reduced flexibility requirements realized
- Information provided to facilitate opportunity for EIM entity to resolve infeasible base schedules

California Greenhouse Gas Regulations

- Optimization process efficiently schedules resources at least cost, recognizing Calif. Air Resources Board obligations for energy transferred to California.
- Market dispatch enables compliance, compensates resources, and does not assign costs to non-CA load.
- EIM Participating Resources may submit a separate bid for the GHG compliance obligation costs.
- Energy generated outside California that is not imported is not subject to GHG obligation.
- GHG costs for transfers into California incorporated into price paid by CA demand.

Energy Imbalance Market Summary

- EIM provides reliability and financial benefits to California, EIM participants, and the West
- CAISO implementation is based on its existing platform to provide a flexible and scalable approach, at low cost, to other balancing authorities
- EIM implementation helps facilitate renewable integration across the West

Completed ISO stakeholder initiatives that impact EIM

- EIM Go-Live Enhancements
  - Apply MPM to EIM transfer constraints into an EIM BAA
  - Allow MSG transition costs to be negotiated for non-gas units
  - http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=B0B9231D-3C0A-4436-AA2E-A80ED0313E26
- Contingency reserve cost allocation
  - Same settlement for static import/exports and EIM transfers
  - Not an EIM charge per se
  - http://www.caiso.com/informed/Pages/StakeholderProcesses/ContingencyReserveCostAllocation.aspx
- Grid Management Charge
  - Establishes EIM administrative rate at $0.19 MWh 2015-2017
  - http://www.caiso.com/informed/Pages/StakeholderProcesses/Budget-GridManagementCharge.aspx

Flexible ramping product will replace existing constraint in Fall 2015

- Add downward flexible ramping test in hourly resource sufficiency evaluation
- Allocates costs in same manner for participating and non-participating resources
- Initiative is ongoing. BOG approval in February 2015
- http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleRampingProduct.aspx

EIM Year 1 Enhancements stakeholder initiative to commence in November 2014

- March 2015
  - Add GHG flag for participating resource to opt out
  - Intertie bidding rules on external EIM interties
  - Timeline for submission of EIM transfer capability
  - Other clarifications

- Later in 2015
  - Base schedule flow entitlement on other EIM BAAs
  - Dynamic market power mitigation trigger on EIM transfers
  - Potential EIM wide transmission rate
  - Other clarifications

Questions

NWPP Members' Market Assessment and Coordination Initiative

NWPP ATF – System Schedulers Meeting
October 21st, 2014

Dan Williams
NWPP MC Leadership Committee Chair
Portland General Electric

Agenda

- Introductions and Opening Remarks
- Schedule Overview
- Technology Update
- SCED RFP Approach
- SCED Summary
- Next Steps for the NWPP MC Initiative

Key Takeaways Today

- Significant progress being made toward decision on whether to install a within-hour energy market in the NWPP footprint
  - Members' knowledge of core issues and opportunities has advanced significantly through Phase 3 activity
  - RFP for Market Operator being issued in October 2014
  - Critical regulatory (local and Federal) engagement underway
  - High level of Executive and Stakeholder buy-in to project
- Near-term market and reliability benefits coming through Phase 3 technical tools development and advanced data-sharing

NWPP MC MEMBERS' INITIATIVE

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- Introductions and Opening Remarks
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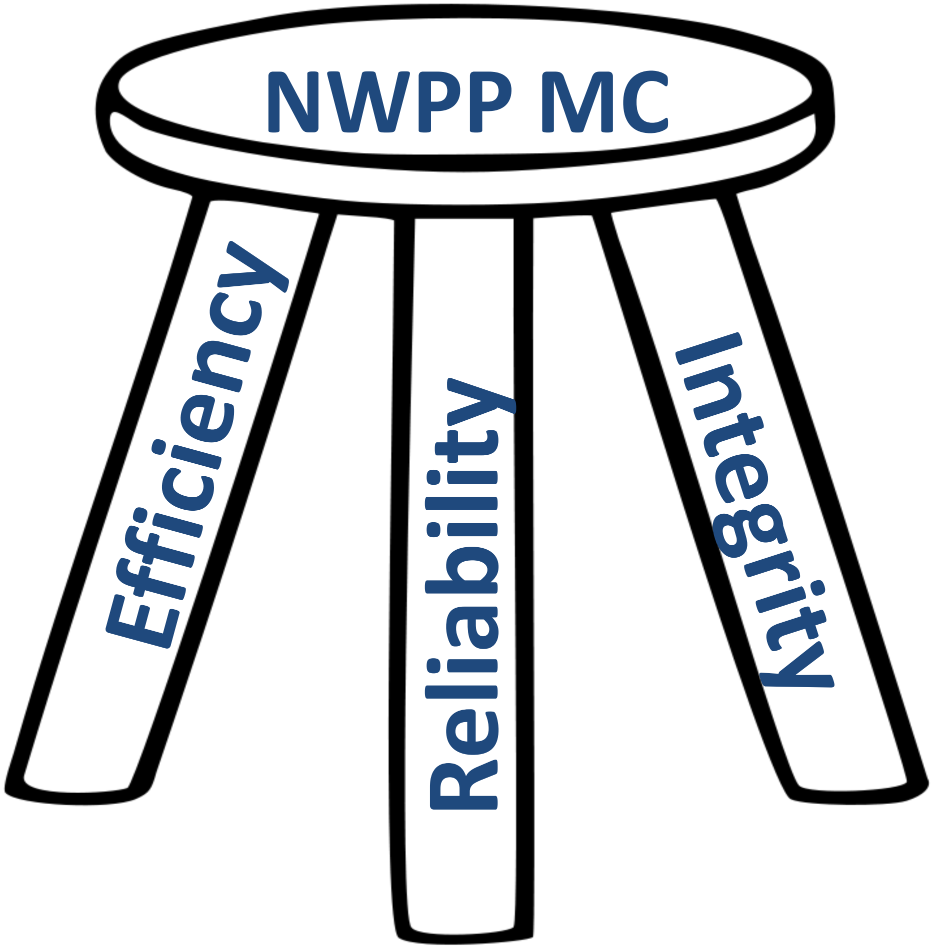
NWPP MC MEMBERS' INITIATIVE

NWPP MC Initiative Background

See Appendix for:

- Phase 1 Objectives
- Phase 1 Key Outcomes
- Phase 1 Value Proposition
- Phase 2 Key Outcomes
- Phase 3 Deliverables Scope

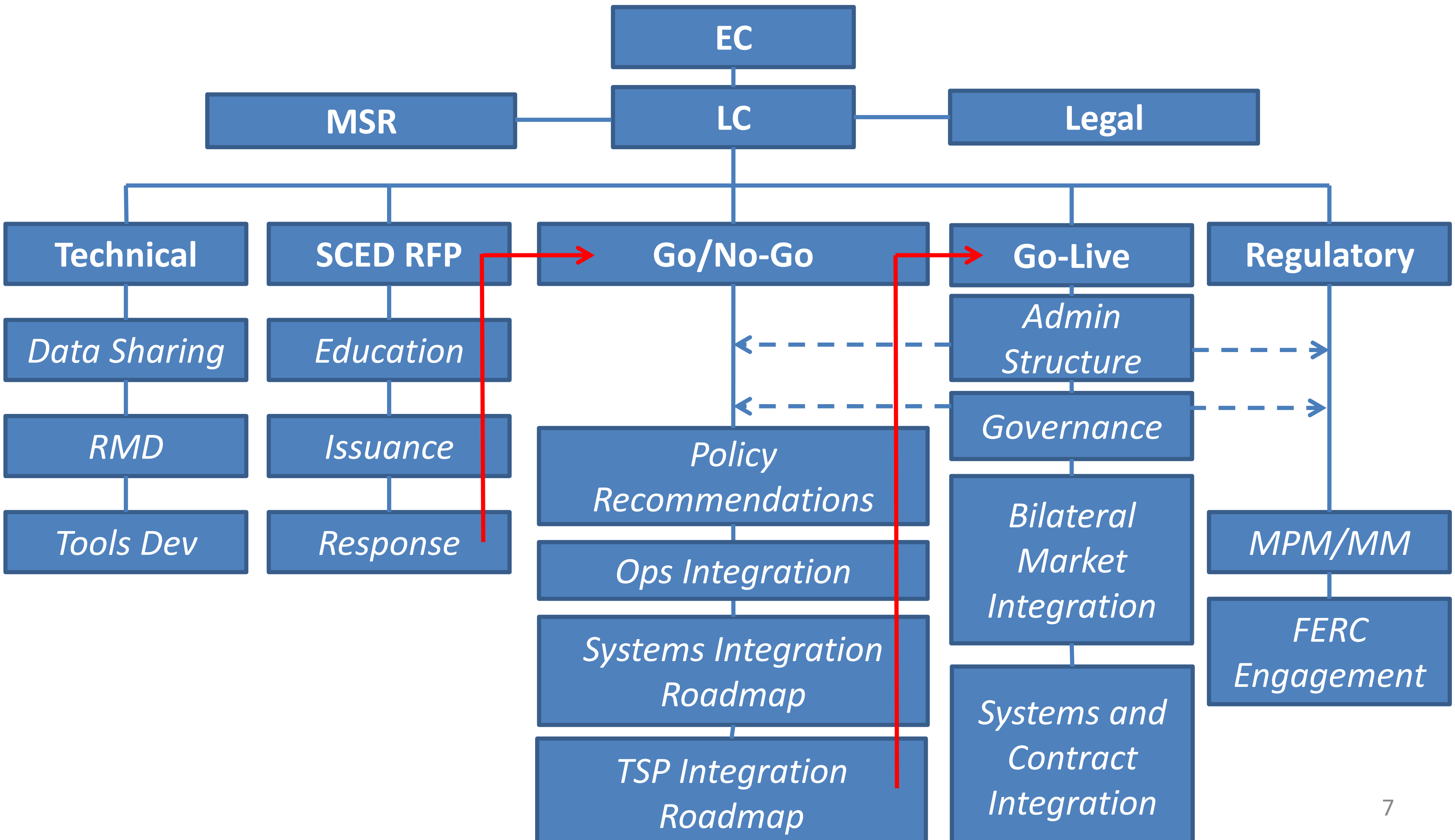


Phase 3 Expectations – set Jan 2014

- January 10, 2014 – 19 members of NWPP MC Executive Committee approved $4.325 million in regional funding:
  - Technical Infrastructure
  - SCED Design and RFP Issuance
- Approved Phase 3 Summary scope
- Approved staffing and internal implementation resources
- We are in the implementation phase: “How” not “If”
- 12 month deliverable with key milestones
- Monthly EC check-ins – expecting results

NWPP MC MEMBERS' INITIATIVE

Phase 3 Organizational Flow



Phase 3 Mid-Year Assessment

On-track / Completed

Market Design and Policy Deliverables:

- SCED Design v0 completed (v1 draft in circulation)
- Resource Sufficiency Metric v0 completed
- 15-min market opportunities and tools tested
- SCED RFP on track for October issuance
- Regulatory engagement in progress

Technical Team Deliverables:

- Data-sharing agreements completed
- Vendor selection and scope of work completed
- Initial Regional Flow Forecast and Resource Monitoring and Deliverability paper deliverables completed

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Technology Implementation Status

- Implementation Schedule **On Track**
  - Development occurs in 3 week Sprints, 3 per Stages 1 thru 3
  - Current focus on Design
  - Current Status: completed 2nd Sprint of 3 for Stage 1
- Project Coordination with Peak RC – Collaborative and Productive
  - Twice weekly Touch Point Progress Status meetings with Peak RC
  - Sprint Planning meetings/post mortem ongoing
  - Weekly in-person meetings at Peak and frequent web/conference calls
- Coordination activities with MC participants – Engaging and Interactive
  - Launched Kick off of data exchange process – October 2nd
  - Engaged Legal Workgroup on Output Results sharing- data access policy
  - Presented update on Phase 3 Technology development – October 9th
  - Developing Operational Guides for Phase 3 Tools – working with OIWG

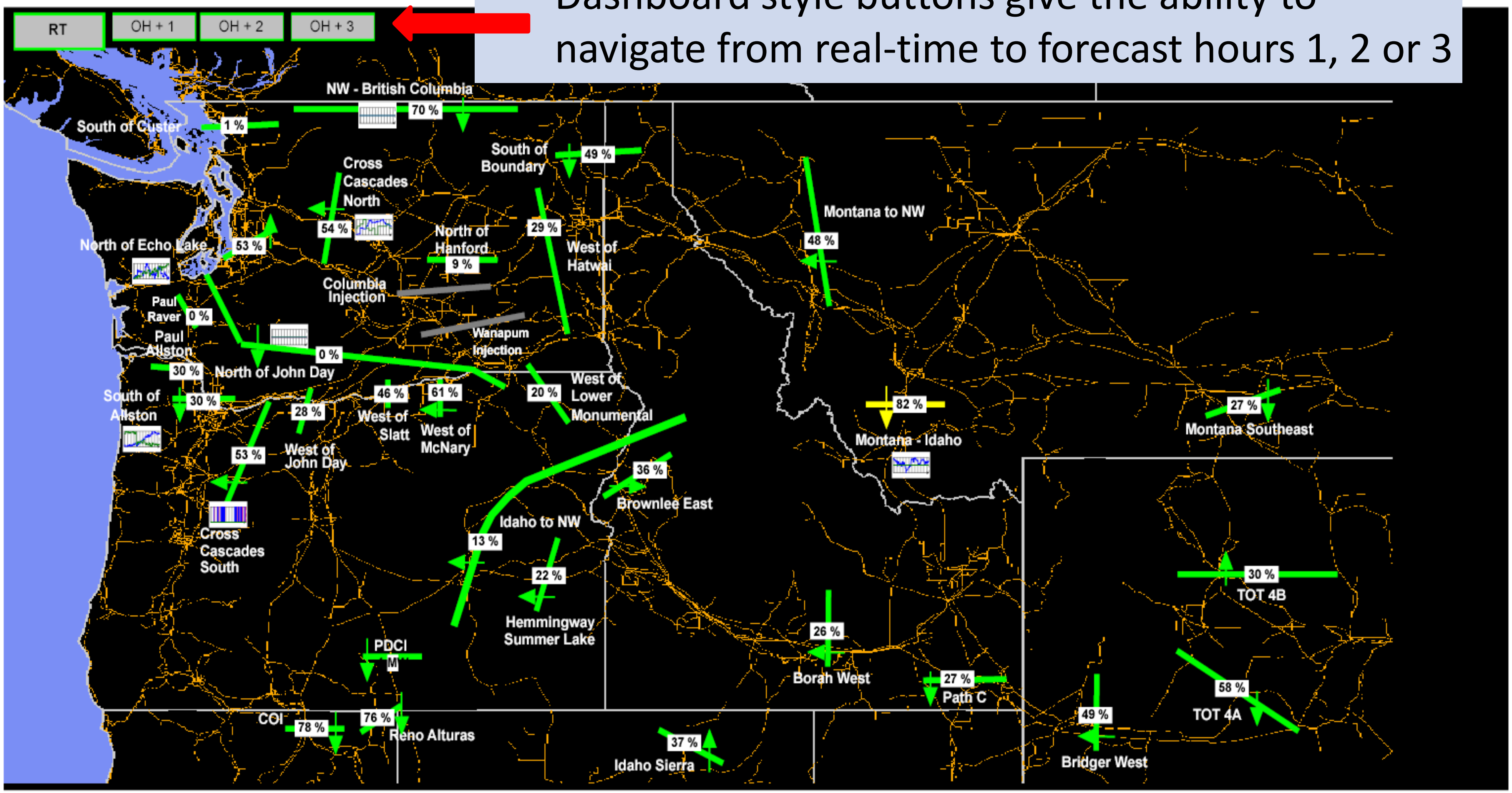
Key Implementation Milestones

Deliverable	Finish	%Complete (25-50-75-100)	Status Update (Text)
SOW Design / Vendor Planning	7/25/14	100	Milestone Complete – Implementation underway
NWPP MC Regional Flow Forecast Tool Paper	10/15/14	75	Final review of drafts papers for RMD and RFF in progress with the notion that theses papers will drive Operational guides for the tools use
NWPP MC Resource Monitoring & Deliverability Tool Paper	10/8/14	75	
Display Mockup Development	10/1/14	75	Display designs and mockup in final stage of completion
EIDE System Upgrade	10/7/14	25	Task underway (design stage) – Participant Dept. Data Specification webinar Oct 2
RS Calculation Engine	11/11/14	50	Task underway with design stage < 25%
RFF DC Model Implementation	12/9/14	25	
Tool Integration RFF DC Model/RMD RS	2/3/15	0	

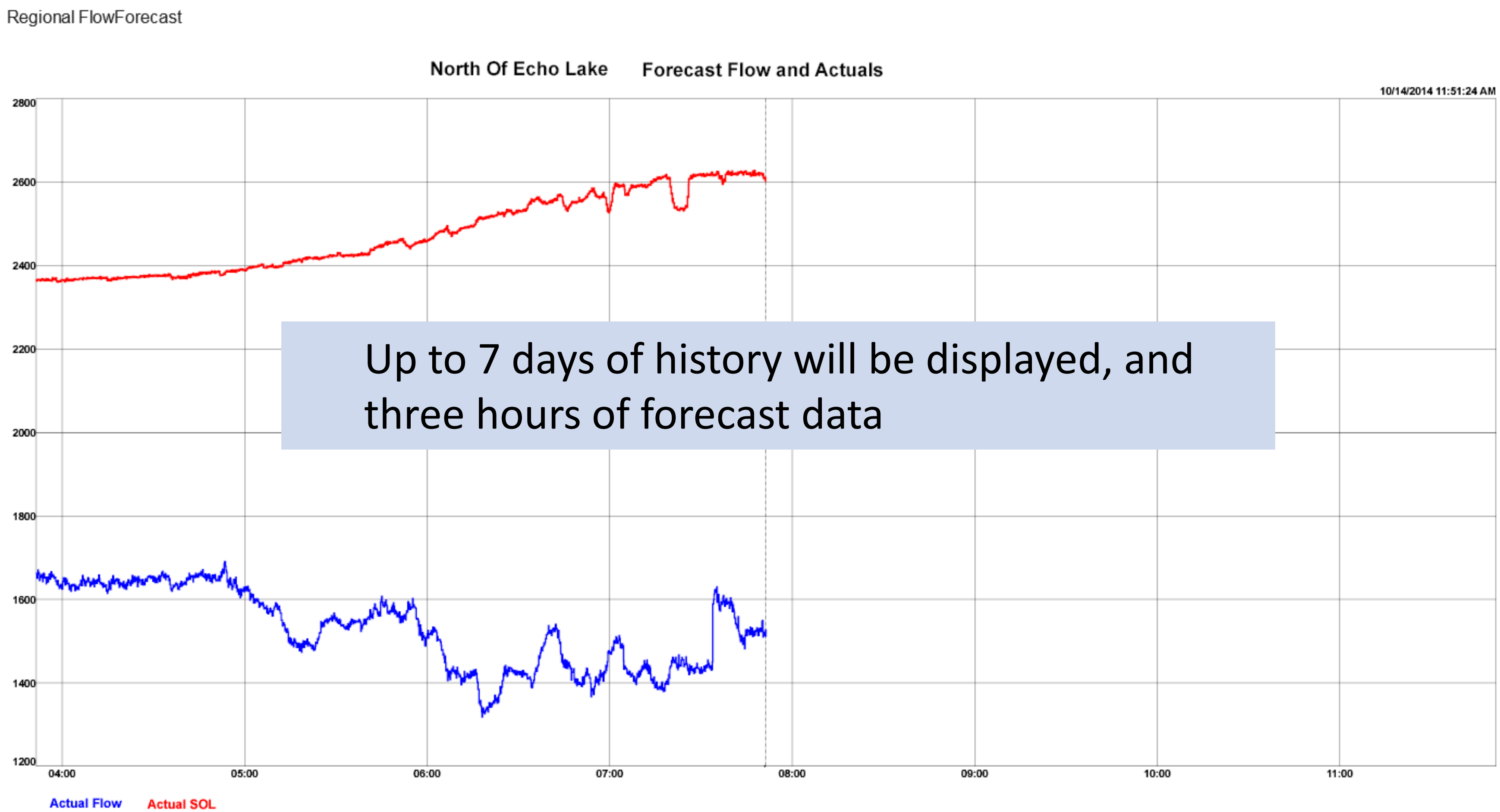
Regional Flow Forecast – Geographic View

Dashboard style buttons give the ability to navigate from real-time to forecast hours 1, 2 or 3

Regional FlowForecast



Regional Flow Forecast – Trend View



Up to 7 days of history will be displayed, and three hours of forecast data

Regional Flow Forecast – Tabular View

Regional Flow Forecast

		14:45	15:00	15:15	15:30	15:35	15:45	16:00	16:15	16:30	16:30	17:30	18:30
Forecast SOL		2751	2752	2754	2751	2769	2748	2755	2754	2740	2738	2751	2736
Forecast Flowgate		272	264	263	237	7	113	73	51	71	91	185	181
MARGIN		2480	2488	2491	2514	2762	2635	2681	2704	2669	2647	2567	2556
%	South Of Custer	10%	10%	10%	9%	0%	4%	3%	2%	3%	3%	7%	7%
Forecast SOL		2607	2600	2592	2563	2574	2571	2560	2555	2580	2569	2588	2541
Forecast Flowgate		818	801	798	854	875	901	890	909	911	899	755	794
MARGIN		1789	1798	1794	1709	1698	1671	1670	1646	1668	1669	1832	1747
%	North of Echo Lake	31%	31%	31%	33%	34%	35%	35%	36%	35%	35%	29%	31%
Forecast SOL		2,607	2,600	2,592	2,563	2,574	(2,000)	(2,000)	(2,000)	(2,000)	(2,000)	(2,000)	(2,000)
Forecast Flowgate		818	801	798	854	875	(1,602)	(1,602)	(1,600)	(1,596)	(1,596)	(1,700)	(1,794)
MARGIN		1,789	1,798	1,794	1,709	1,698	(398)	(398)	(400)	(404)	(404)	(300)	(206)
%	North of John Day											85%	90%
Forecast SOL												2370	2370
Forecast Flowgate												1490	1482
MARGIN												880	888
%	South of Allston											63%	63%
Forecast SOL		2607	2600	2592	2563	2574	8834	8830	8807	8790	8783	8713	8673
Forecast Flowgate		818	801	798	854	875	3549	3503	3524	3587	3615	3355	3327
MARGIN		1789	1798	1794	1709	1698	5285	5327	5283	5203	5169	5358	5346
%	Cross Cascades North	31%	31%	31%	33%	34%	40%	40%	40%	41%	41%	39%	38%
Forecast SOL		-560	-560	-560	-560	-560	-560	-560	-498	-250	-150	-50	-50
Forecast Flowgate		-167	-154	-147	-209	-290	-248	-250	-226	-180	-101	33	3
MARGIN		-393	-406	-413	-351	-270	-312	-310	-272	-70	-49	-83	-53
%	Cross Cascades South	30%	28%	26%	37%	52%	44%	45%	45%	72%	67%	-67%	-5%
Forecast SOL		3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000
Forecast Flowgate		2062	2053	2057	2018	2029	2048	2058	2019	1966	1944	1838	1749
MARGIN		938	947	943	982	971	952	942	981	1034	1056	1162	1251
%	West Of McNary	69%	68%	69%	67%	68%	68%	69%	67%	66%	65%	61%	58%

Up to 1 hour of history will be displayed, and three hours of forecast data

Data Access Summary

Data Category	Originating MC Balancing Authority (BA) + Vendor Category 1	MC BAs Category 2	All Merchant Category 3	General Public Category 4
Raw Data or individual Output Data	Yes	No, unless authorized by Exchanging Party (from which data originated or data applies)	No	No
Aggregated Output Data Level 1 • May include CEII, commercially sensitive data, and non public transmission function information • Does not include Raw or individual Output Data	Yes	Yes	No	No
Aggregated Output Data Level 2 • May include CEII • Does not include Raw or individual Output Data, commercially sensitive information, and non public transmission function information	Yes	Yes	EC Review and Approval Required	No
Aggregated Output Data Level 3 • Does not include Raw or individual Output Data, CEII, commercially sensitive information, and non public transmission function information	Yes	Yes	EC Review and Approval Required	EC Review and Approval Required

Policy Topics (Phase 3)

Regional Flow Forecast displays

The current thinking is that RFF displays:

- Need to be treated as non-public transmission function information and, if shared outside of MC Participants' reliability functions, must be shared on a non-discriminatory/equal access basis with **all** marketers (including marketers affiliated with non Participating BAs)
- May require FERC clarification to ensure posting on OASIS is not required
- Will be shared with Participating BAs
- Will consider sharing with non-participating BAs if they provide data
- Do not need to be posted publicly

Resource Monitoring and Deliverability displays

The current thinking is that RMD displays:

- Will only be shared with Participating BAs
- BAs can view only their own BA information plus a regional data roll-up

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What is the NWPP MC SCED Proposal?

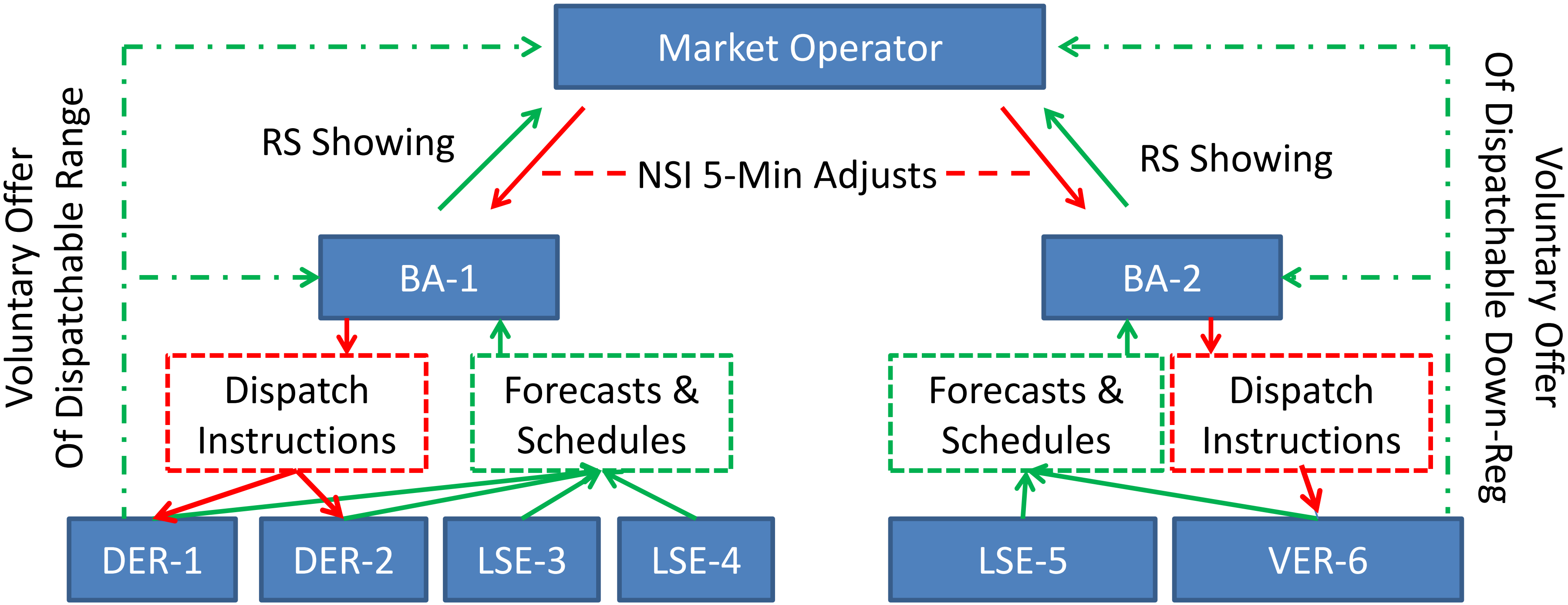
NWPP MC SCED is…

- A within hour energy only market
- Security-constrained via state estimator model
- Market to optimize energy dispatch
- Centralized Unit Dispatch for Offered Resources
- Uses "as-available" transmission system capability

NWPP MC SCED is <u>not</u>…

- An RTO (with planning, day-ahead markets, etc.)
- Capacity market
- A replacement for current bi-lateral contractual business structure
- A provider of transmission services

NWPP MC SCED Simplified Process Flow*



- LSE and Generator Relationship to BA/TSP carries over from existing pre-SCED landscape
- BA aggregates their load/gen balancing requirements
- TSP provides GI/EI under its OATT (or comparable)
  - Determines capacity charges (if any) for balancing
  - Offers discounted service for performance and sets service requirements (scheduling, forecasting)
- Generator has option to provide dispatchable range to MO

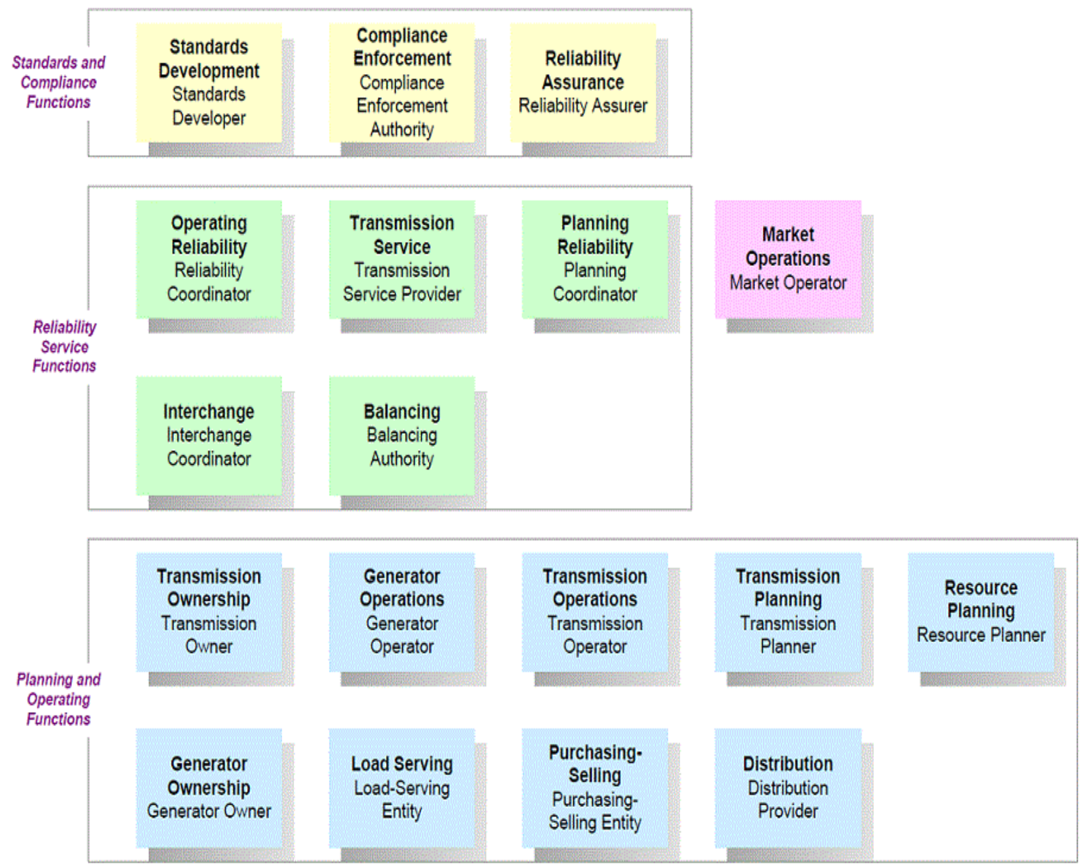
- Same as to the left – plus…
- VER balancing policies are determined through tariffs, business practices, and/or contracts between the BA/TSP and the VER (incl. DSO-216)
- BA sets their pooled VERs capacity allocation for RS
- MO reports any BA capacity shortfalls for remediation (method tbd.)

* Draft pending further input from Market Design workgroups and outcome of SCED RFP

SCED Design Considerations

FUNCTIONAL ROLES:

- SCED design maintains current NERC Functional Roles and associated responsibilities.
- Participants may collectively choose to make a decision to change the collective ownership of Function Roles in the future, or may aggregate their individual performance of Function Roles through Member-to-Member agreements; but for the initial phase of the SCED design the Roles and responsibilities will stay as current.



* Draft pending further input from Market Design workgroups and outcome of SCED RFP

SCED Design Considerations

- A Resource Sufficiency (RS) test is a critical pre-condition in a SCED in order to ensure reliable and equitable market outcomes for all participating entities (no leaning - economics/reliability)
- In the NWPP MC's draft Market Design, the Balancing Authority (BA) is responsible for assuring RS.
  - Check for resource sufficiency is done at the BA level
  - Any insufficiency is addressed at the BA level
  - Assurance to maintain system balance is a BA responsibility
- The BA will determine how best to gather the necessary data from LSEs and GOPs within their Balancing Authority Area.
- Market Participants, LSEs and GOPs are not required to demonstrate RS to the Market Operator. They will have an obligation to meet the requirements established by their BA, which may include meeting the rates, terms, and conditions of their Transmission Service Provider.

* Draft pending further input from Market Design workgroups and outcome of SCED RFP

NWPP MC MEMBERS' INITIATIVE

Agenda

- Introductions and Opening Remarks
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Proposed RFP Timeline

Milestone	Target Completion Date
Pre-Offer Conference	10/9
Confirm Intent to Offer	Before the end of October
RFP Issued	10/31
Respondent Questions Due	11/10
MC Initiative Response to Questions Released	11/17
Conference with Respondents	TBD
Proposal Submission Deadline	12/19
Proposal Evaluation (including interviews, as necessary)	January 2015
Offer Selection and Notification	February 2015

Pre-Issuance Bidders' Conference held 10/9/2014

See slides at: http://www.nwpp.org/our-resources/MC-Initiative

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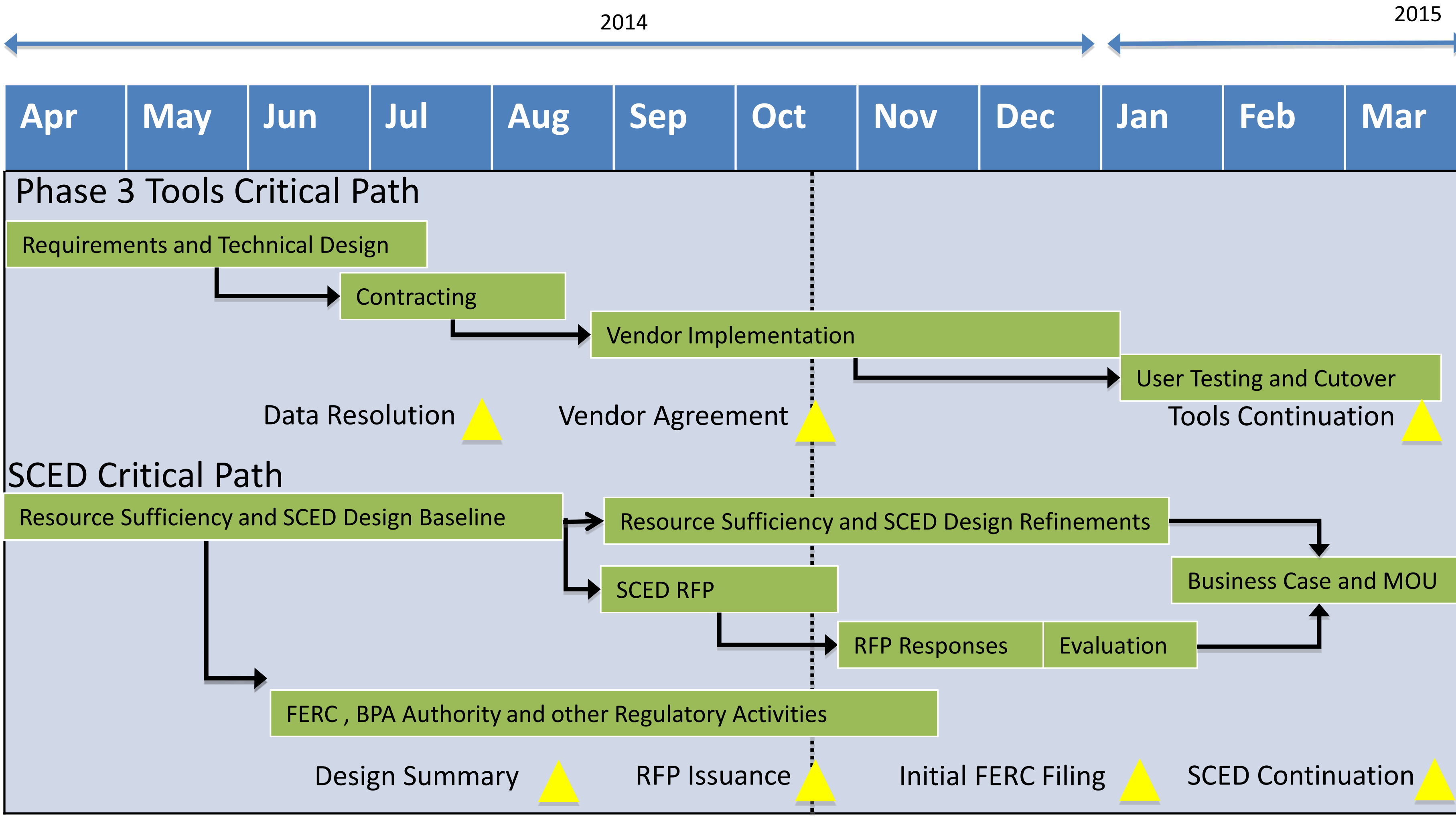
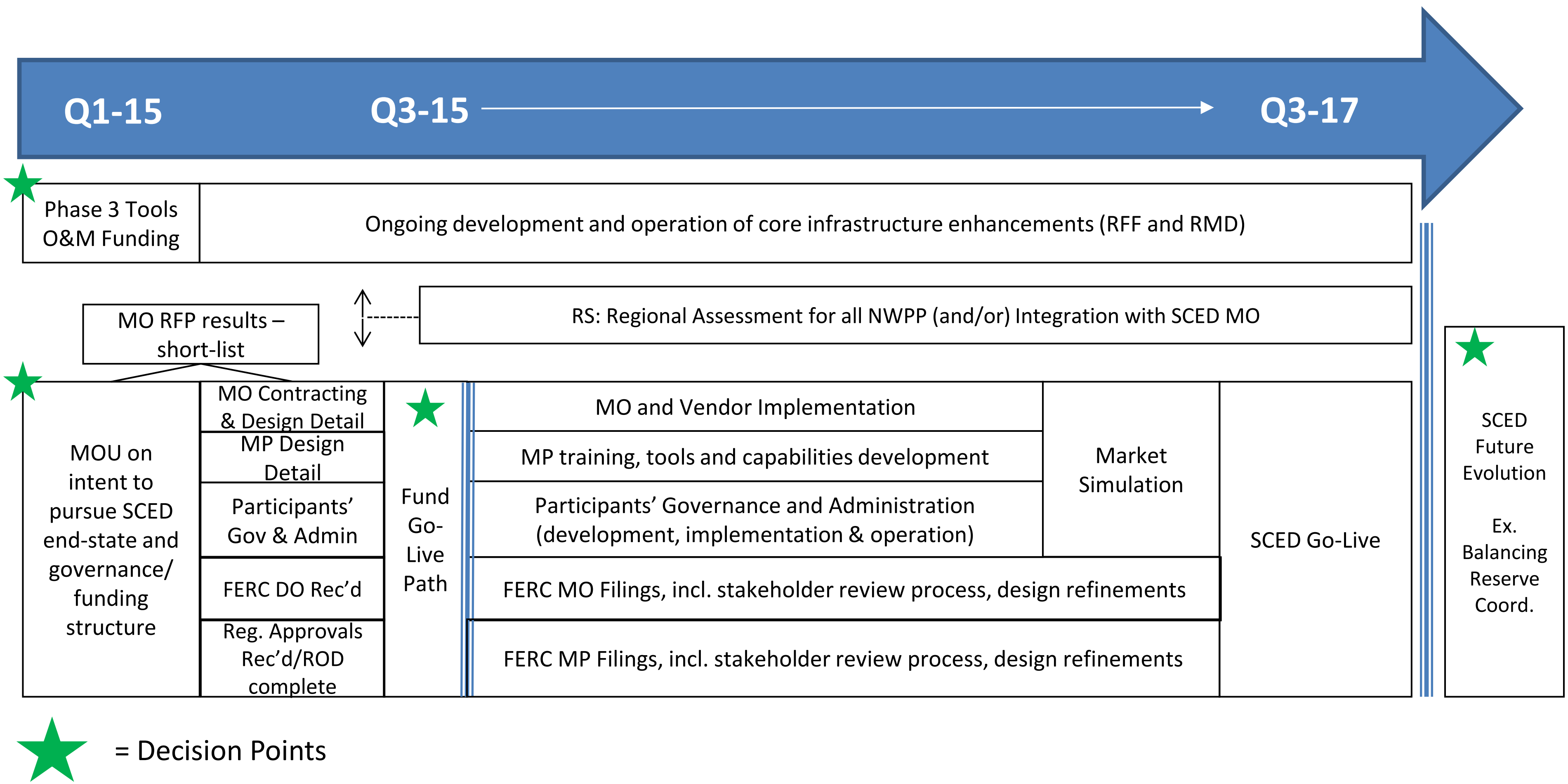
Program Management Update

Schedule Overview



NWPP MC MEMBERS' INITIATIVE

NWPP MC Future Phase Roadmap



NWPP MC Roadmap Assumptions

- Individual entities would make next-steps decision in Q1-2015
- Commitment from critical mass of entities is required to move forward
- Delay in Go/No-Go timing risks MC Initiative losing critical mass
- Successful implementation requires MPs to find least-invasive way to update critical associated business practices, tariffs, and agreements
- Expecting 24-month IT implementation horizon for MO, Data-Facilitation Vendors, and MPs (starting Q3 2015)
- RS Metric can be implemented within SCED or stand-alone
- October 2017 start-date maximizes participation opportunities by aligning with BPA BP-18/19 rate periods
- A sustainable administrative structure is needed for future activities

Questions

Please send any questions or information requests to the NWPP MC at:

questions@nwppmc.org

Public Meeting

Nov 19th – 1-3p at Sea-Tac

(webinar available)

Appendix

Phase 1 Objectives

In Phase 1 the group defined a "problem statement" aimed at delivering a comprehensive Northwest solution to:

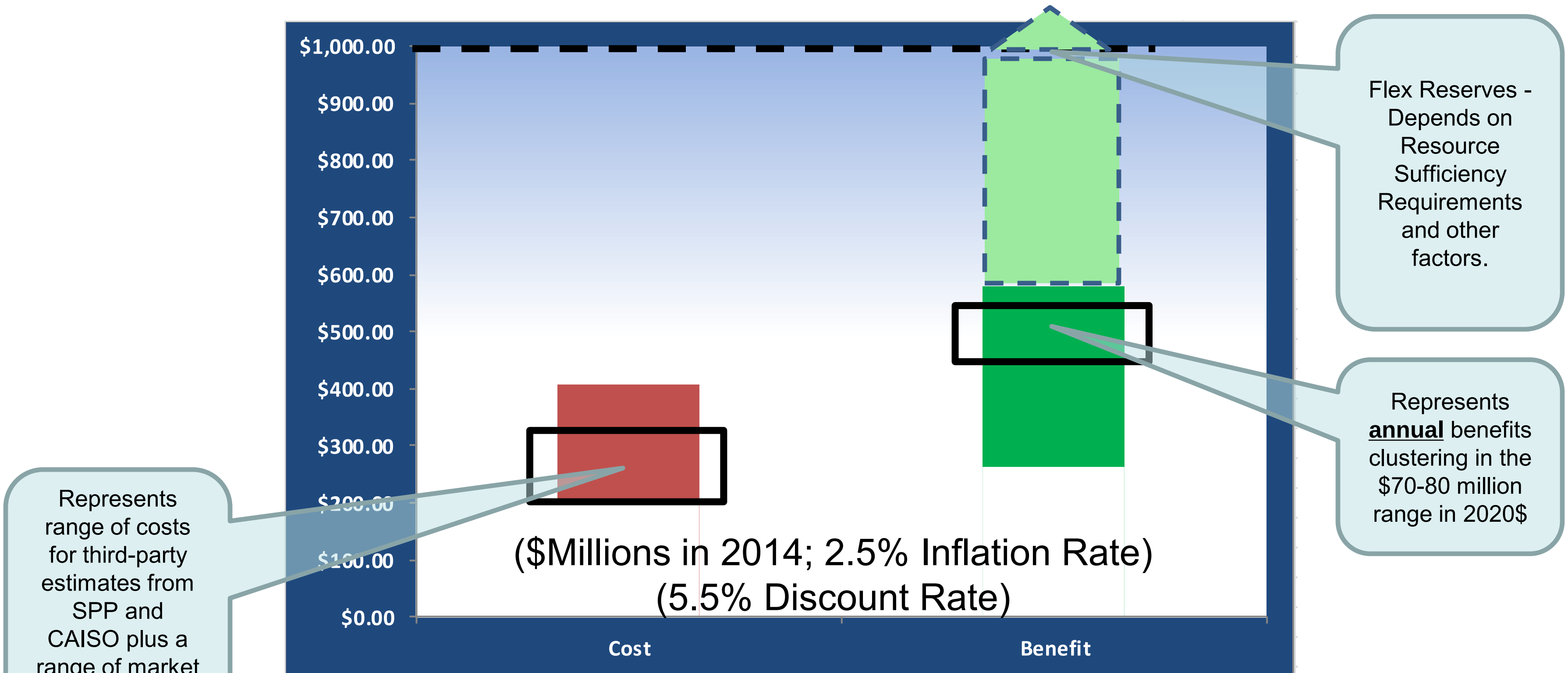
- Manage Variable Energy Resource Operational Impacts
- Share Regional Balancing Diversity and Capabilities
- Enhance Reliability of Transmission Constraint Management
- Mitigate Compliance Exposure and Costs
- Leverage Existing Tools Where Expedient
- Preserve Existing Reserve Sharing Group Benefits
- Respect Local Control and Self-Determination Priorities

Phase 1 Key Outcomes

- No single solution addresses entire problem statement
  - 15-min intra-hour energy-only transactions are not sufficient
  - FRAP has promise, but likely more complicated than EIM solution
  - Diversity benefits are real, but ability to access is constrained by existing transmission, coordination, and economic environment
- Region needs a comprehensive operations and commercial framework
  - Built on foundation of reliability and local control
  - Addresses capacity sufficiency
  - Captures cost savings through diversity and economic dispatch of resources

NWPP MC MEMBERS' INITIATIVE

Phase 1 Regional Value Proposition



Costs (Operator+Participants): 14 years, 2014-2017 Start-up, 2018-2027 Operations,
Entities borrow start-up capital at 4.5% interest rate and fully repay it in first 10 years of operation
Low Range Costs are based on CAISO estimates
High Costs assume Stand-Alone Market Operator with high costs to develop software
Benefits: 10 years, 2018 EIM launch date through 2027
Inflation Rate = 2.5% ; Discount Rate = 5.5% based on Participant feedback for capitalization example purpo

Phase 2 Key Outcomes

- Developed Northwest regional implementation plan that maximizes benefits and options (with or without an EIM)
  - Based on Policy and Technical refinements
  - Integrates with Peak Reliability and NWPP RSG initiatives
  - Leverages existing infrastructure and near-term projects
- Refined SCED/EIM cost estimates at the Member Participant level
  - Made minor costing updates; ultimate SCED design will shift costs
- Drafted bylaws for EIM Admin Corp that address concerns about FERC jurisdiction and scope creep

Phase 3 Scope

- Regional Flow Forecast: Provide MC participants with a regional flow forecast on targeted flowgates
- Reserve Monitoring and Deliverability: Improve deliverability assessment of contingency and balancing reserves/energy
- Regional Data Sharing Tools: Provide Balancing Authorities and merchants with access to selected operational data
- Flow-based Operations Integration: Identify, specify and enable the integration points between RSG, BA, TSP and RC
- 15-Minute Flexible Capacity: Define Flexible Capacity products, facilitate WSPP approval, and trading on established platform if feasible
- Resource Sufficiency: Develop BA-level data collection and reporting process, protocols, and agreements w/ and w/o a SCED Platform end-state
- SCED Tasks: Complete Market Operator RFP based on finalized SCED design, including operational protocols and agreements

NORTHWEST POWER POOL

Interactive Memory Quiz

Quick picture flash…
… then you have 5 minutes


THE UNITED STATES OF AMERICA
ONE DOLLAR
cruzer
micro 4GB
NORTHWEST
PowerPool
Associated Press / Kristin Murphy
NERC
ORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION
MWh

What did you see?

1. *Transformer*
2. *Solar Panel*
3. *Laptop*
4. *Sine wave*
5. *iPad*
6. *NWPP Logo*
7. *Coffee Mug*
8. *Hydro Power Plant*
9. *Transmission Line*
10. *Cell Phone*
11. *Flashdrive*
12. *Mouse*
13. *Wind Turbine*
14. *MW*
15. *Coal Power Plant*
16. *Light Bulb*
17. *Nuclear Symbol*
18. *Substation/Power Circuit Breaker*
19. *NERC Logo*
20. *$*

ISAS Update

Andy Meyers

Interchange Scheduling & Accounting Subcommittee Chair

NWPP After-the-Fact Scheduler's Meeting
22 October 2014

Portland, OR

Agenda

- Interchange Work Group (IWG)
- Electronic Scheduling Work Group (ESWG)
- After-the-Fact Work Group (ATFWG)
- Recent WECC happenings
  - UFAS Dues Methodology
  - Dynamic/Psuedo Tie Work Shop
  - WIT ownership
  - Updated WECC Website
- 2015 ISAS Meetings

WECC

Interchange Work Group (IWG)

- IWG Chaired by Danielle Johnson
- IWG recently completed consolidation of the Real Time Scheduling Work Group (RTSWG) & eTag Issues Work Group (EIWG)
  - Two work groups had been inactive
  - Charter has been updated
  - Work group members have been absorbed into IWG

Interchange Work Group (IWG)

- WIT Authority Back Up (WIAB) Test
  - INT-020-WECC-CRT-1.1
    - WIT Back up procedure
  - Only 1 WECC member has volunteered to participate in 2014 WIAB test (WAPA Rocky Mountain Power)
  - IWG chair concerned that there will be insufficient participation to have the table top test
  - Looking at delaying WIAB test until early 2015

Interchange Work Group (IWG)

- IWG had submitted a SAR request regarding WECC Regional Criteria INT-011 (Ten Minute Recallable)
  - IWG has asked for WR 1.3 & WR 1.4 to be removed as a result of BAL-002 implementation
    - WR 1.3 -- Reserve obligation multiplier option set to “100%”; and
    - WR 1.4 -- Reserve responsible entity set to either of the following options in order to identify the entity accepting the energy
      - Sink Balancing Authority (or)
      - Reserve Sharing Group member that is located inside the Sink Balancing Authority

Interchange Work Group (IWG)

- Drafting team (WECC-0110) has been convened but it will take some time to clean up the regional criteria.
- IWG has contacted Shannon Black regarding language in WECC Regional Criteria INT-009 (Capacity Tag Functionality)
  - INT-009 utilizes terms of “On Demand Spinning” & “On Demand Non-Spinning”
  - Would need to be replace with BAL-002 terminology of “Operating Reserves – Spinning” & “Operating Reserves – Supplemental”

Electronic Scheduling Work Group (ESWG)

- Chaired by Raymond Vojdani (WAPA)
- ESWG held a webinar on 7/20 and an in person meeting on 8/20
  - Have continued to discuss checkout using WIT
- ESWG submitted a SAR on July 25th to modify WECC Regional Criteria INT-021 (WIT Checkout Confirmation)
  - ESWG requested modification of WR 3
    - Each Balancing Authority shall use the electronic confirmation process provided by the Reliability Assurer (WECC) as the primary means to acknowledge agreement of NAI for past hour checkout in the current day and past day checkout.

Electronic Scheduling Work Group (ESWG)

- Drafting team has been convened (WECC-0108)
  - DT still seeking additional members
- DT looking at striking WR3, revising WR 2, adding additional requirements
- Clean & Redline versions of the Criteria are posted on DT website
- Next meeting is Monday 10/20 (10-12 Mountain

After-the-Fact Work Group (ATFWG)

- ATFWG met prior to August ISAS meeting
  - April/May eTagging issue provides a good opportunity for member education
    - Annual Webinar training on use of ATF etags?
  - ATFWG is examining the After-the-fact tagging guideline in order to recommend changes
    - Any changes will be posted for 30 day comment period

Other WECC Happenings

- At October OC meeting UFAS proposed the removal of the 1995 Dues Cap
  - Provides full compensation for qualified device owners
  - Members should review the posted spreadsheet to get a sense how their companies dues will change
- Dynamic & Pseudo Tie Schedules
  - WECC hosting a 1 day workshop & webinar to discuss use of Dynamic & Pseudo Tie schedules in the interconnection
  - Work shop scheduled for Thursday November 6th at WECC office in Salt Lake City from 8-5
- WIT Ownership Discussion
  - Webinar meeting on 11/12 from 9:30-12:30 (Mountain)
- 2015 Meeting Dates
  - January 27-29, 2015, Salt Lake City UT
  - April 21-23, 2015, Salt Lake City UT
  - August 18-20, 2015 Salt Lake City UT

Questions

Andy Meyers – Bonneville Power Administration

(apmeyers@bpa.gov)

PGE Solar Power

Scott Russell
Structuring & Origination
Power Operations & Resource Strategy
Portland General Electric

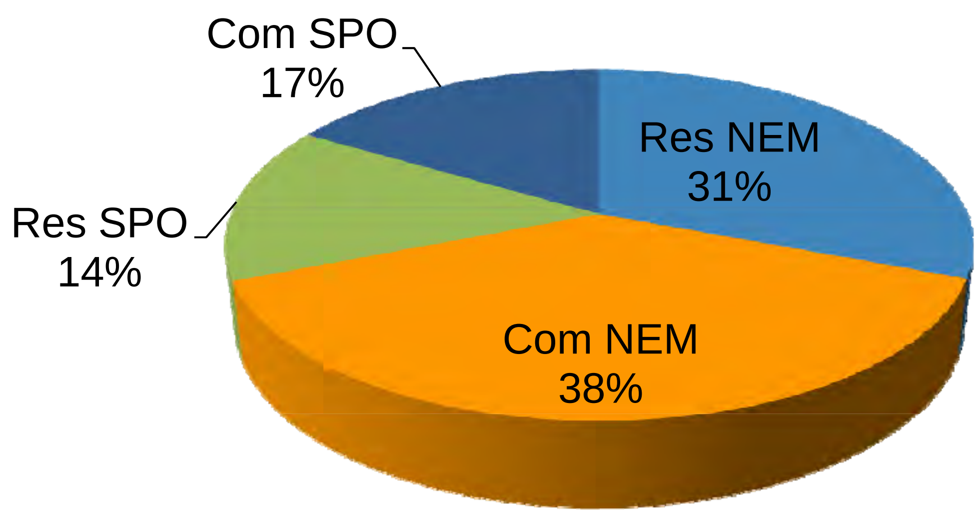
PGE Service Territory

- 4,000-square-mile operating area with population of 1.7 M
- 842,000 customers
- 43% of statewide customers, 38% of load
- Area is state's economic engine – 70% of the state's GDP
- 52 cities served
- Summer peak load of 3,949 MW (2009)
- Winter peak load of 4,073 MW (1998)

Where are we now in solar PV? (under 500 kW)

	Customers	Capacity DC	Capacity AC
Net Metered	3,237	27 MW	23 MW
Solar Payment Option	1,070	12MW	10MW
Total	4,307	40MW	34 MW

As of 12/2013



Residential solar customer profile

- Affluent and highly educated
  - Graduate degree
  - Professional occupation
  - High dual-income
  - Married
- Value comfort and “green” products
- High consumers of information
- Long established customers
  - PGE account older than 6 years
  - Registered on PGE website
  - Pay electronically
  - Buy renewable power
- Single family homes that they own
  - Value over $300,000

Commercial Solar Projects

▪ Prologis Rooftop	3	MW (AC)
▪ Baldock Rest Area	1.5	MW (AC)
▪ Yamhill and Bellevue	2.5	MW (AC)
▪ Outback	5	MW (AC)
Total	**12**	**MW (AC)**

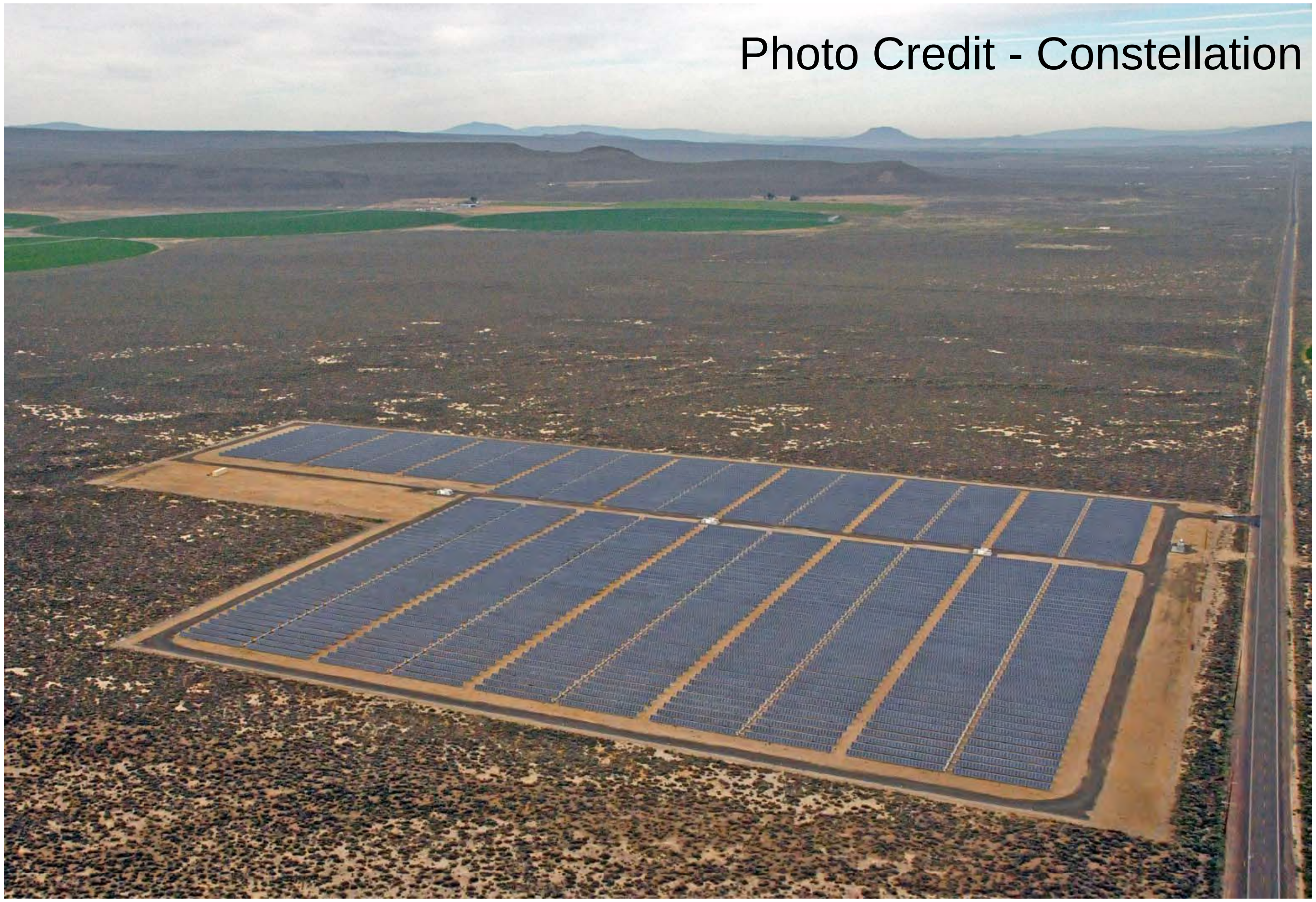
Baldock Rest Area

Portland General Electric

Yamhill & Bellevue

Prologis Rooftop Projects

Outback Solar



Utility role in solar development

More than convener or facilitator

- Policy development role – FIT, PV Capacity Standard, OPUC dockets
- System Development role – Utility scale solar facilities
- Customer facing role – Powering our customers' potential as the region's trusted energy partner
- Planning role – Within the Integrated Resource Planning process
- Safety role – Our 125 year history gives us a unique appreciation for the nuts and bolts challenges of meeting the needs of our 836,000 customers all day, every day, no matter what

Solar Opportunities in Oregon

Opportunities

- PGE has the #1 ranked voluntary renewable program in the US
- PGE Customers value solar beyond the $/kWh
- Solar is becoming more cost competitive every year

Challenges

- Variable Energy Resources (VERs) provide energy when the “sun shines” or when the “winds blows”
- Wind is currently the least-cost option for RPS compliance
- Abundance of natural gas reserves
- Uncertainty around tax credits creates uncertainty in the marketplace

Thank-you!

Peak Update
Michelle Mizumori
Director of Operations

Schedulers' Meeting
October 22, 2014
Portland, Oregon

PEAKRELIABILITY
assuring the wide area view

Discussion Topics

- Five-year Strategic Plan
- Performance Dashboard
- 2014 Customer Survey
- US DOE Grant
- BC Hydro
- RMT
- webSAS
- Enhanced Curtailment Calculator (ECC)
- Hosted Advance Applications

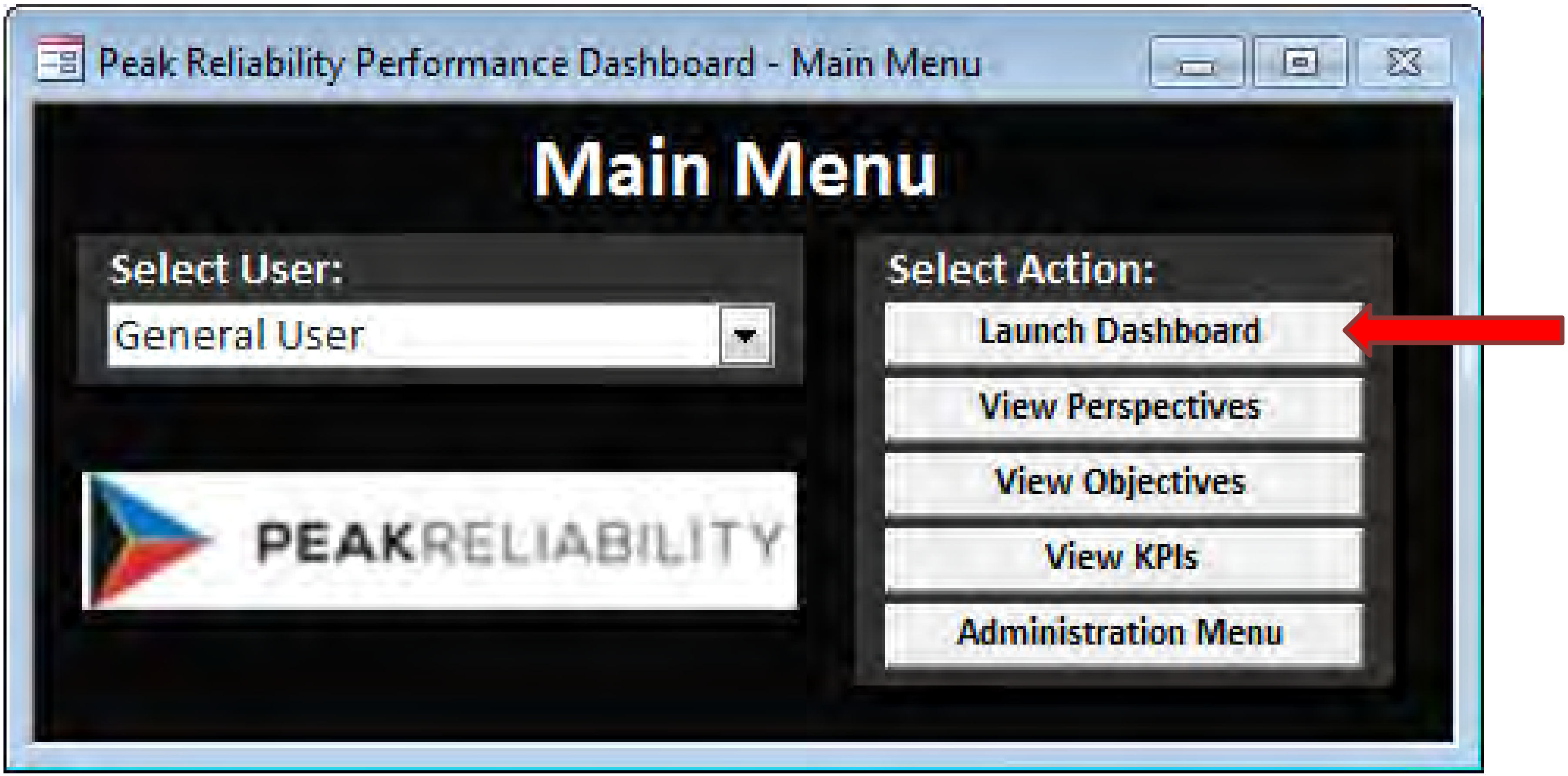
PEAKRELIABILITY

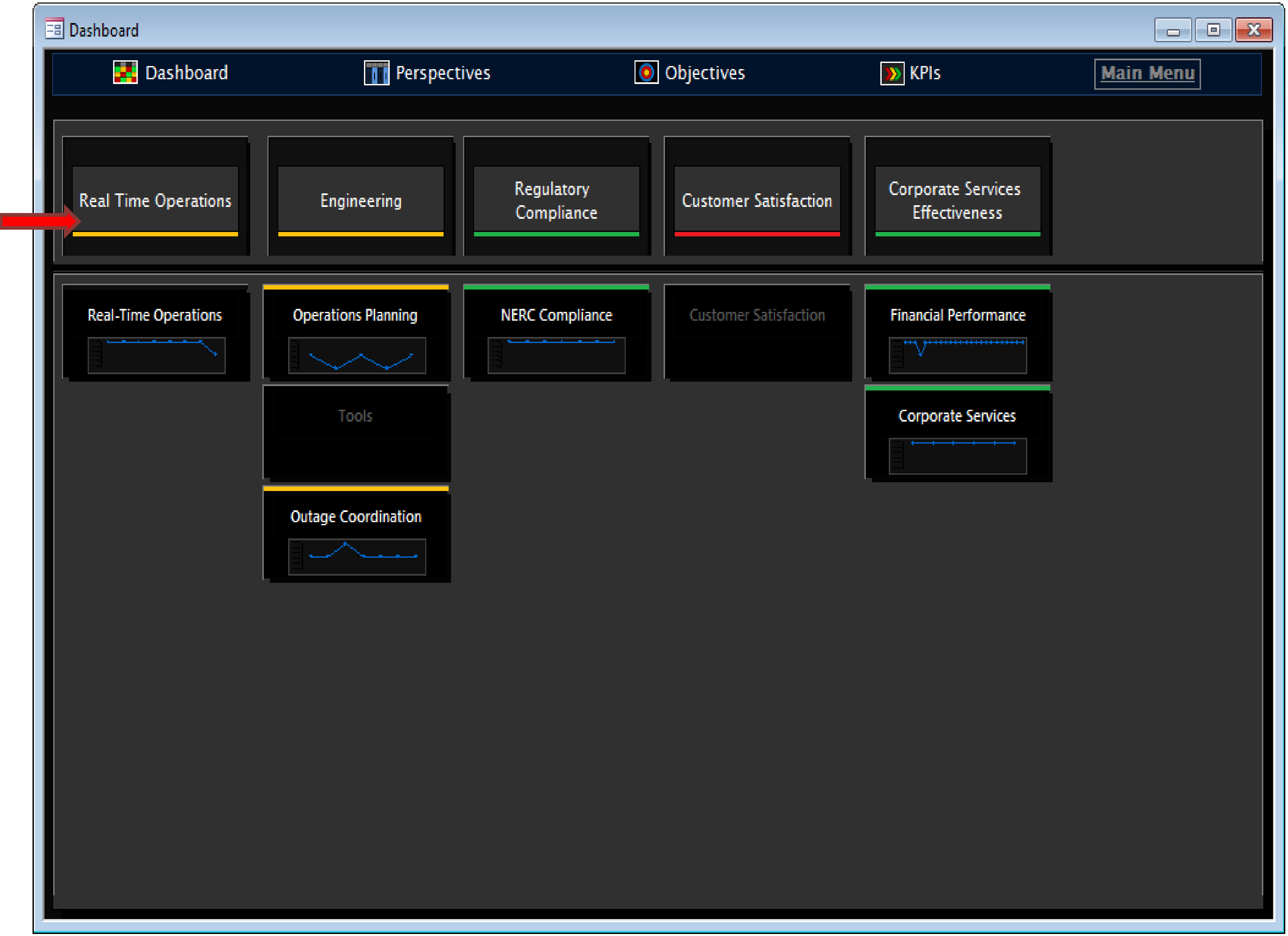
Five-year Strategic Plan

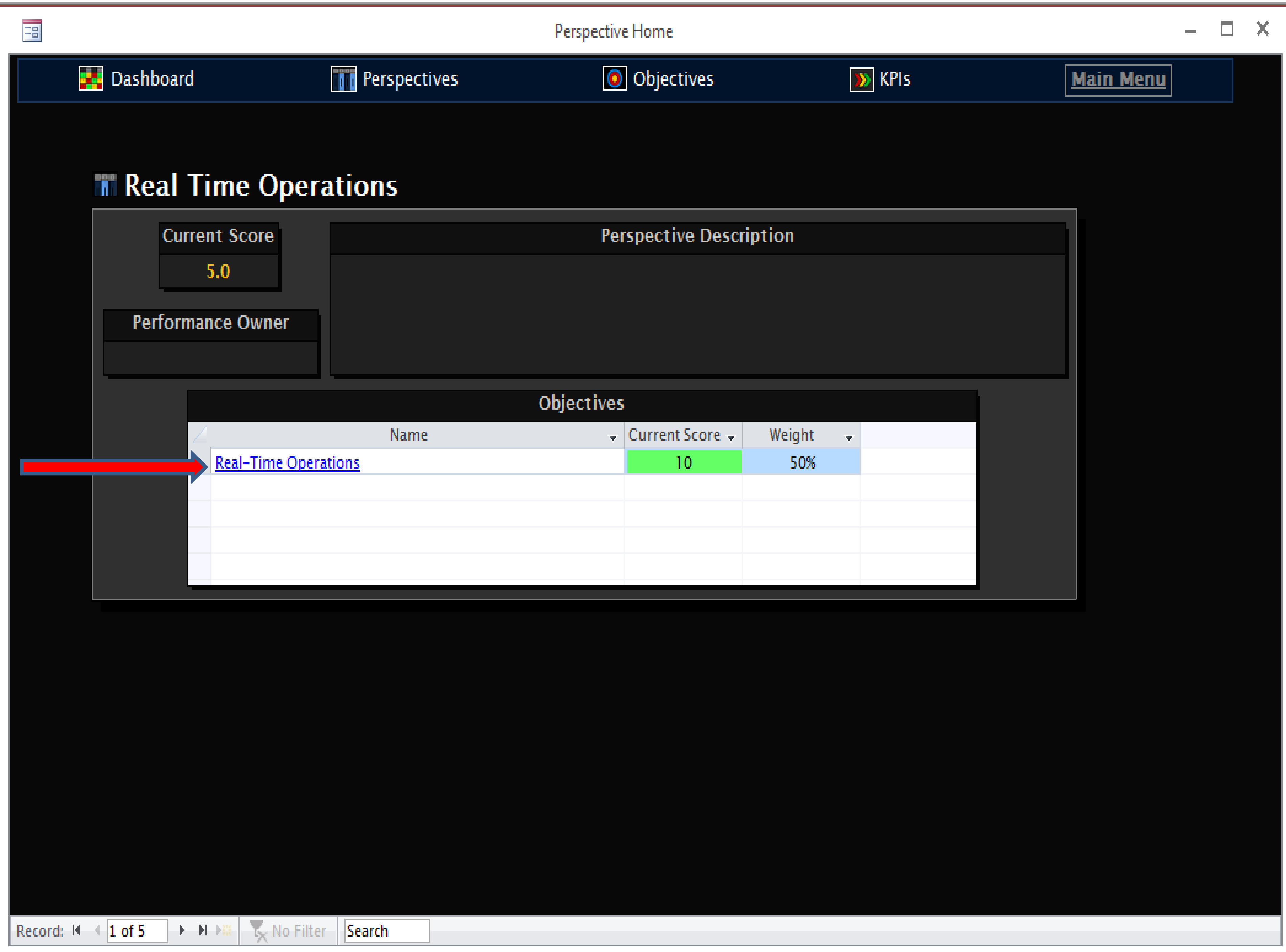
- Performance monitored through key metrics
- Underpinned by Four Pillars:
    1. Interconnection-wide operational excellence
    2. Stakeholder value
    3. Employee engagement
    4. Financial stability
- Transparent and public process

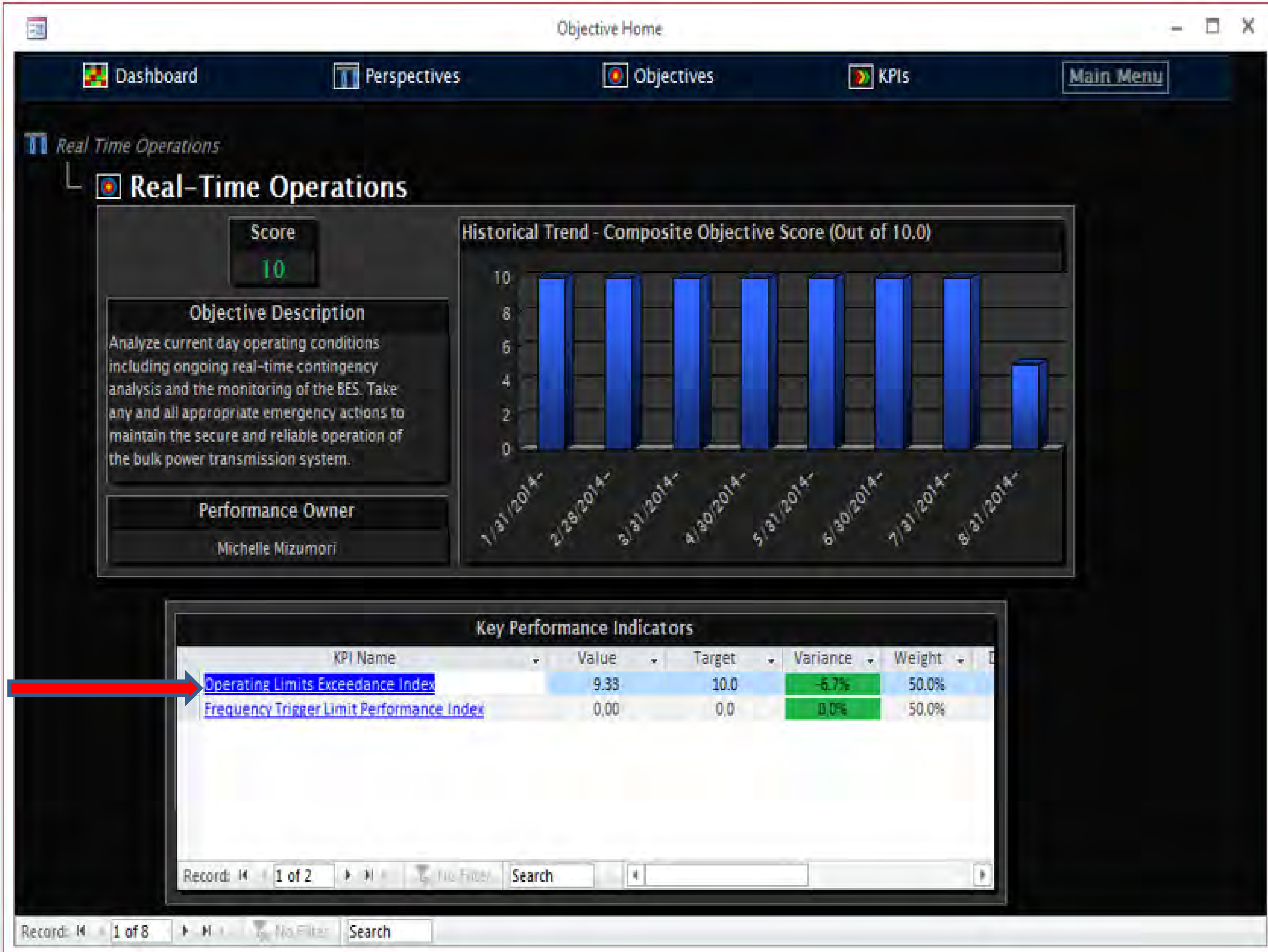
PEAKRELIABILITY

Performance Dashboard




Dashboard
Dashboard
Perspectives
Objectives
KPIs
Main Menu
Real Time Operations
Engineering
Regulatory Compliance
Customer Satisfaction
Corporate Services Effectiveness
Real-Time Operations
Operations Planning
NERC Compliance
Customer Satisfaction
Financial Performance
Tools
Corporate Services
Outage Coordination


Perspective Home
Dashboard
Perspectives
Objectives
KPIs
Main Menu
Real Time Operations
Current Score
5.0
Perspective Description
Performance Owner
Objectives
Name
Current Score
Weight
Real-Time Operations
10
50%
Record: 1 of 5
No Filter
Search


Objective Home
Dashboard
Perspectives
Objectives
KPIs
Main Menu
Real Time Operations
Real-Time Operations
Score
10
Objective Description
Analyze current day operating conditions including ongoing real-time contingency analysis and the monitoring of the BES. Take any and all appropriate emergency actions to maintain the secure and reliable operation of the bulk power transmission system.
Performance Owner
Michelle Mizumori
Historical Trend - Composite Objective Score (Out of 10.0)
10
8
6
4
2
0
1/31/2014-
2/28/2014-
3/31/2014-
4/30/2014-
5/31/2014-
6/30/2014-
7/31/2014-
8/31/2014-
Key Performance Indicators
KPI Name
Value
Target
Variance
Weight
Operating Limits Exceedance Index
9.33
10.0
-6.7%
50.0%
Frequency Trigger Limit Performance Index
0.00
0.0
0.0%
50.0%
Record: 1 of 2
Search
Record: 1 of 8
Search


KPI Home
Dashboard
Perspectives
Objectives
KPIs
Main Menu
Real Time Operations
Real-Time Operations
Operating Limits Exceedance Index
Overall Performance
SOL's
IROL's
Current Value
9.33
Target Value
10.00
Variance
-6.7%
KPI Description
Weighted Avg. Score (0 – 10) corresponding to the no. of times System Operating Limits (SOLs) have been exceeded and returned to normal within 10, 20, and 30+ minutes.
Performance Owner
Michelle Mizumori
Data Owner
Jill Hoyt
Target Value
12
10
8
6
4
2
0
01/2014 -
02/2014 -
03/2014 -
04/2014 -
05/2014 -
06/2014 -
07/2014 -
Related Key Performance Indicators
KPI Name
Value
Target
Variance
Weight
Data Date
Operating Limits Exceedance Index 9.33 10.0 -6.7% 50.0% 2014/07/31
Frequency Trigger Limit Performance Index 0.00 0.0 0.0% 50.0% 2014/08/31
Record: 1 of 2
No Filter
Search
Record: 1 of 12
No Filter
Search

2014 Customer Satisfaction Survey

- 2014 Baseline Customer Satisfaction Interviews – October 2014
  - Twenty in-depth interviews with senior executives from a selection of BAs and TOPs
  - Online survey to all Peak members and non-member BAs and TOPs

PEAKRELIABILITY

US DOE Grant

- Peak awarded $6.2 million DOE match for a total program of $12.4 million
- Facilitates the operationalization of the infrastructure created under WISP
- Reliability benefits include:
  1. Avoiding of cascading electrical failure
  2. Making full utilization of available transmission capacity
  3. Improving data delivery system efficiency

British Columbia (BC) Hydro

- BC Hydro's Balancing Authority Area will remain part of the Peak RC Area
- Positive outcome for reliability and financially
- BC Hydro will pay full assessment from 2015 onwards

Reliability Messaging Tool

- Development through end of 2014
- 2015 Q1 internal testing
- March 2015 beta test
- Mid-May 2015 begin parallel operations

PEAKRELIABILITY

webSAS

- Changing curtailment calculation
  - o 16 buckets
  - o Transmission priority and On-/Off-Path
- November 3-7, 2014 - Testing

Enhanced Curtailment Calculator

- ECC Functional Spec for phase I (RC situational awareness) complete
- Working on contract language with vendor
- Roadmap
  - Phase I delivery to Peak Q2 2015
  - Curtailment methodology discussions to start soon with ECCTF and industry support
  - Phase II functional spec complete end of Q2 2015

PEAKRELIABILITY

Hosted Advance Apps

- Critical new tool set
- Leverages Peak's West-wide System Model, state estimator, contingency analysis and study network applications
- Value to transmission operators
  - o Financial
  - o Operational
- 10 contracts signed

PEAKRELIABILITY

Michelle Mizumori

Director of Operations

mmizumori@peakrc.com

360-713-9599

Pacific DC Intertie Upgrade

Project Update

BY KARL MITSCH
BPA TRANSMISSION SERVICES

NWPP SCHEDULERS MEETING
OCT 21-22, 2014

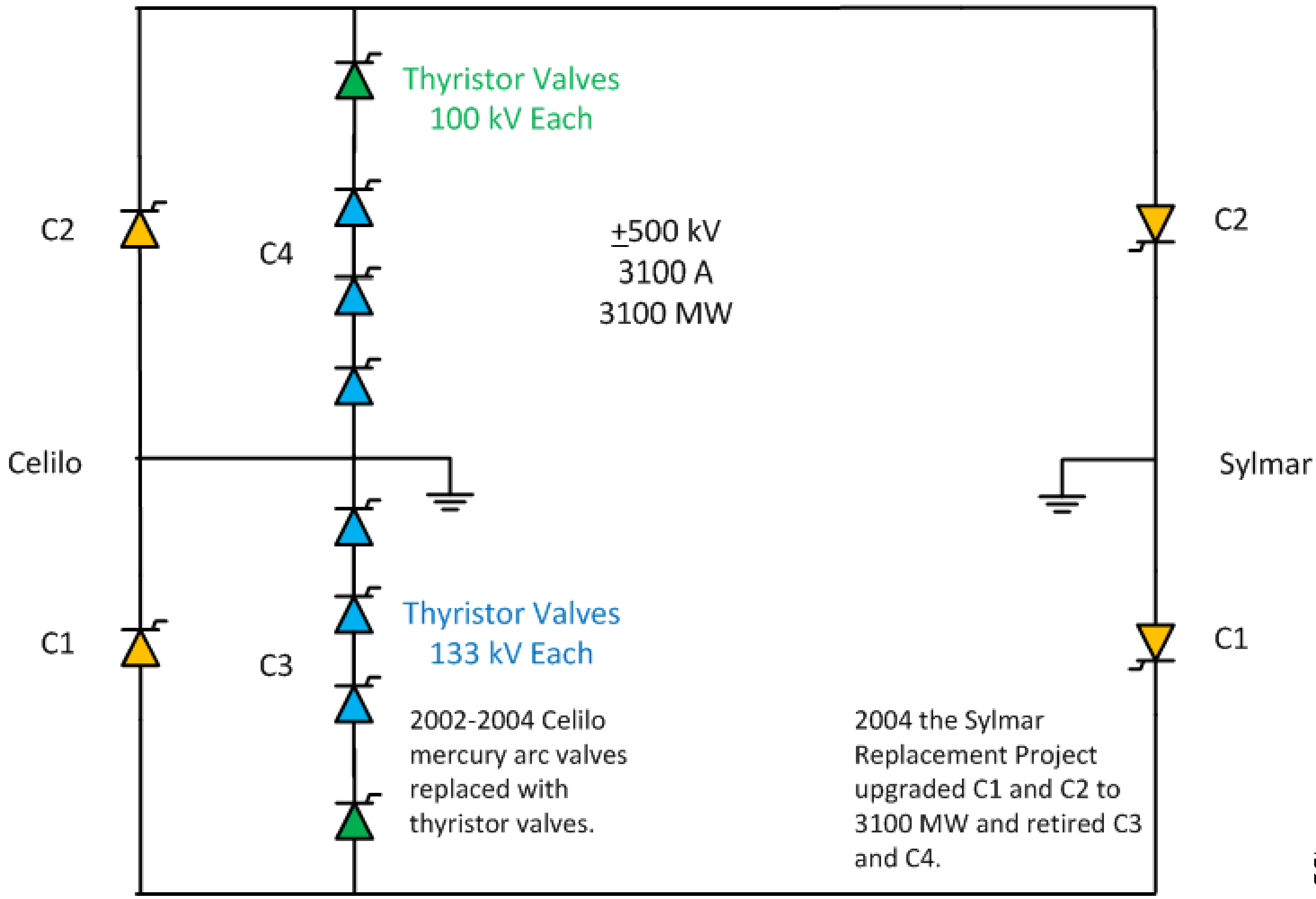
DOUBLETREE BY HILTON – LLOYD DISTRICT
1000 NE MULTNOMAH, PORTLAND, OR 97232

Celilo Converter Station

Present Condition

- Aging control systems becoming unmaintainable and degrading reliability.
- Original GE transformers over 40 years old and gassing.
- Expansion transformer and smoothing reactor design defect.
- Siemens valve grading electrode problem.
- Celilo-NOB dc transmission line vibration dampers and compression fittings nearing end of life.
- Multi – converter complexity

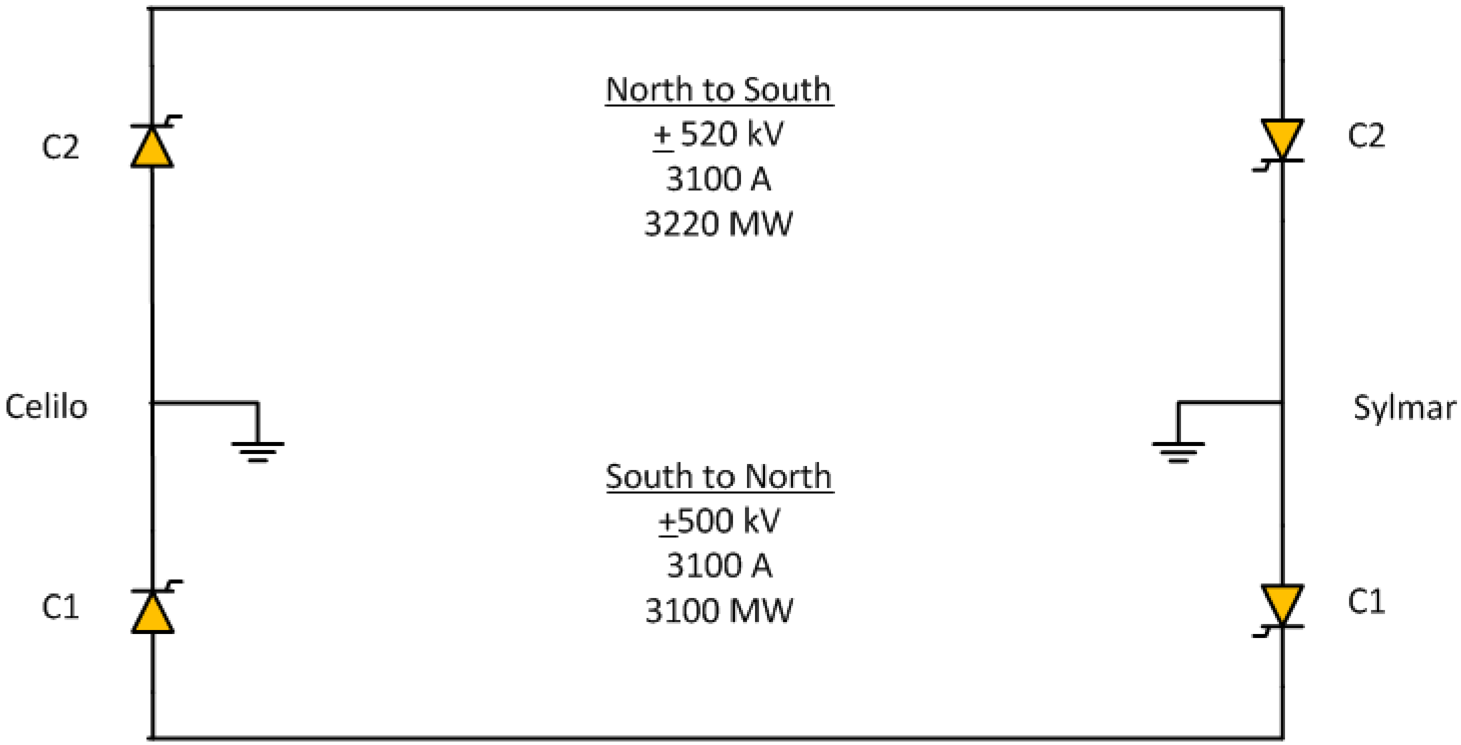
PDCI 2004


Thyristor Valves
100 kV Each
C2
C4
+500 kV
3100 A
3100 MW
C2
Celilo
Sylmar
C1
C3
Thyristor Valves
133 kV Each
C1
2002-2004 Celilo mercury arc valves replaced with thyristor valves.
2004 the Sylmar Replacement Project upgraded C1 and C2 to 3100 MW and retired C3 and C4.

PDCI Upgrade Project

- Replace aging Celilo 4 converter terminal with a new 2 converter terminal rated ±560kV and 3410A and upgrade Celilo-NOB transmission line insulators.
- Reliability driven project – must replace older unsupported technologies to maintain reliability.
- Initial upgrade to 3220MW with future opportunity to increase PDCI to 3800MW N-S.

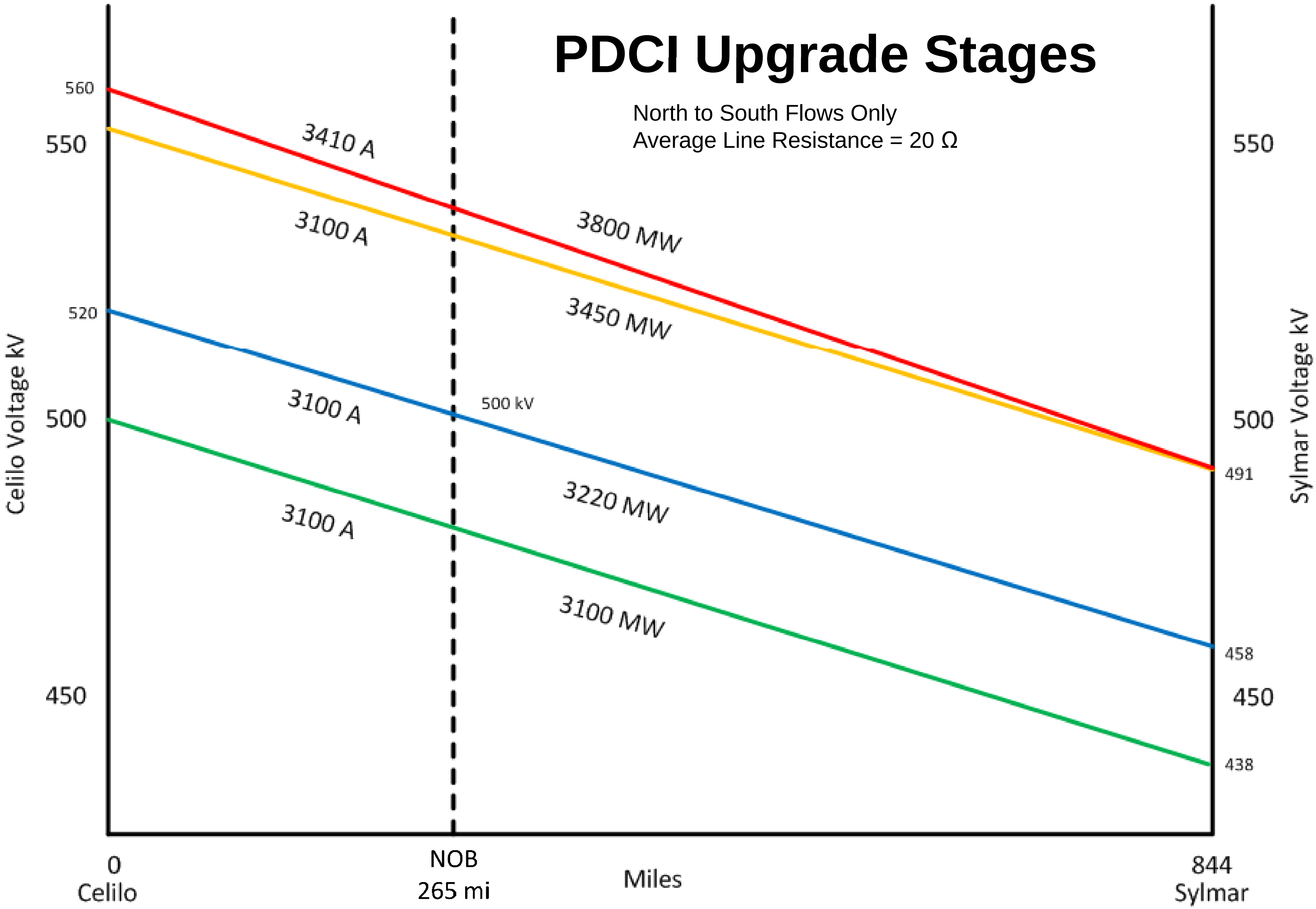
PDCI 2016



Celilo Upgrade Project upgrades C1 and C2 to 3800 MW and retires C3 and C4. Upgrade of Celilo-NOB line will allow operating at 3220 MW. Further upgrades will depend on NW system upgrades, upgrading the NOB-Sylmar line and system upgrades in the LA area.

Upgrade Benefits

- Less frequent forced and maintenance outages
- One manufacturer technology and less equipment improves reliability, availability and maintainability.
- Simpler configuration could facilitate remote operation and dynamic scheduling.
- Substantial reduction in spare parts inventory
- Power order via SCADA signal
- Lower transmission losses / Increase capacity N-to-S
- Reduce future O&M costs
- Round power / back to back modes


PDCI Upgrade Stages
North to South Flows Only
Average Line Resistance = 20 Ω
560
550
520
500
450
Celilo Voltage kV
550
500
491
458
450
438
Sylmar Voltage kV
3410 A
3800 MW
3100 A
3450 MW
3100 A
500 kV
3220 MW
3100 A
3100 MW
0
Celilo
NOB
265 mi
Miles
844
Sylmar

General Project Schedule

- Contract awarded to ABB – Dec 2012
- Celilo building mods - Mar 2014 – Aug 2014
- BPA Site/Civil construction – Mar 2014 – Aug 2014
- Converter 1&2 released to ABB – Oct 13, 2014
- 2000 MW rating from Nov 9, 2014 – Oct 2015
- Final Celilo test complete – Dec 21, 2015 [3100 MW rating]
- Trial Operation period – Jan 16, 2016 – April 16, 2016
- 3 year Performance Guarantees start April 2016
- Line work completed Nov 2016 and [3220 MW rating]

Celilo Project Status – 10/14

Last 30 days

- ABB completed detailed design and engineering studies
- ABB awarded contracts for demolition and civil works
- Remodel and seismic upgrade of building space for new controls 95% complete
- BPA Civil and Site Development completed
- Established a Construction Inspection contract for BPA to ensure QA/QC for ABB construction activities
- Converters 1 & 2 released for construction to ABB

Next 30 days

- Hold BPA/ABB DRM for HVDC Control and Protection system
- Complete Building remodel and seismic upgrade – occupy new engineering office space.
- Commission Converters 3 & 4 for Stand-Alone Operation
- Continue with Big Eddy – Celilo line protection upgrade and Celilo SCADA replacement
- Coordinate with LADWP on telecomm upgrades and data systems work

Questions?

NWPP Schedulers Conference
Portland Oregon
October 21/22, 2014

Marketing Perspective 15 Minute Scheduling

Demetrios
Fotiou

powerex.
Supply. Flexibility. Commitment.
25 YEARS

DISCLAIMER

- The views expressed in this presentation are those of the presenter and do not necessarily reflect the views of Powerex Corp., its employees or directors. It is a presentation for the purpose of discussion, to express observations and to provoke discussion. Some of the information was submitted to me, I did not check its accuracy. Take this presentation for what it is worth, a bunch of slides, a bunch of information, and some interpretations of that information.

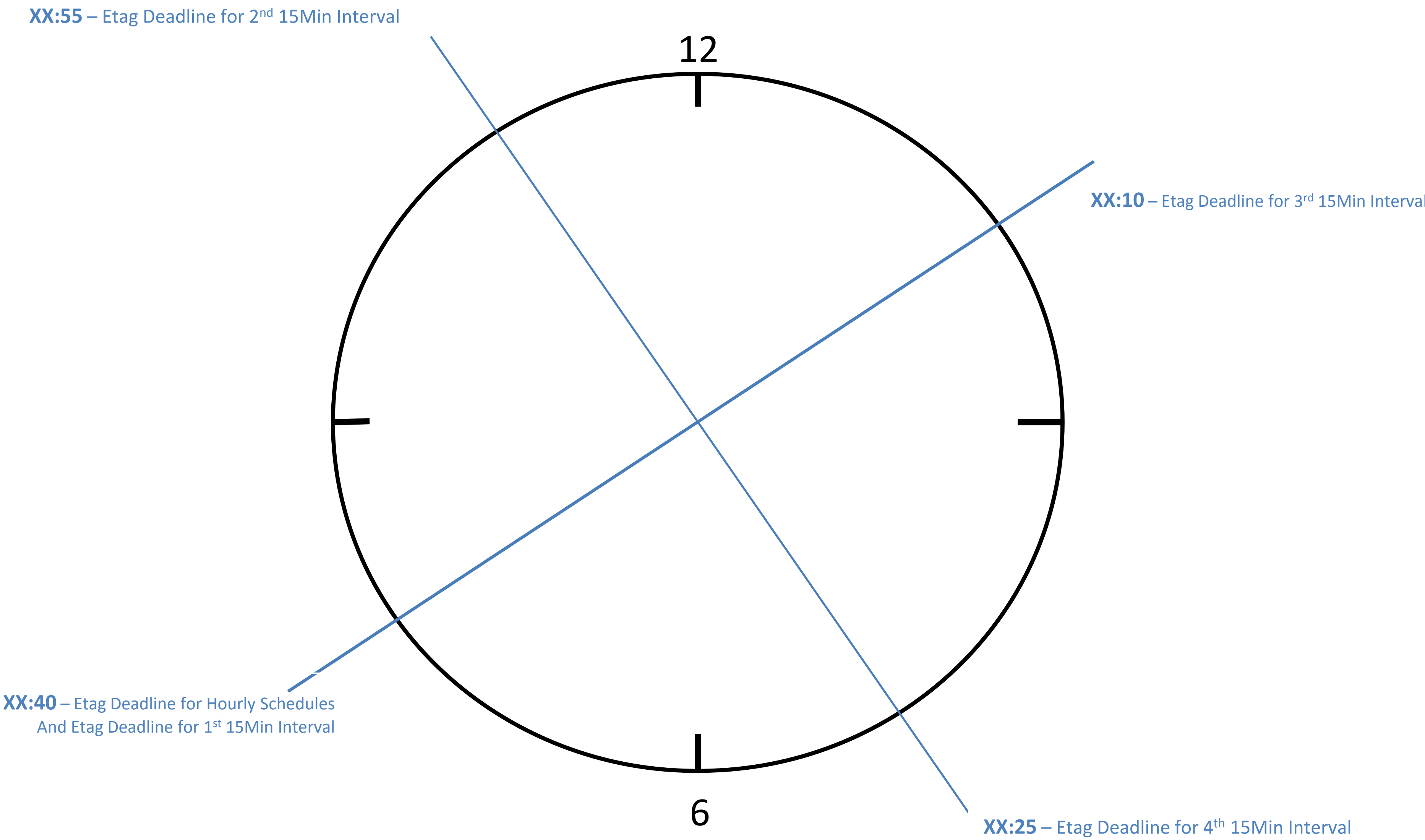
powerex. Supply. Flexibility. Commitment. 25 YEARS

Realtime History (NW Focus)

- Prior to 17 years ago
  - Dispatcher to Dispatcher, Neighbor to Neighbor
  - High quantity, low volume, usually multiple hour deals
  - Some system Parking with return at later date
  - Most entities planned to meet their own peak load with no help (systems were over-built)
- Approximately 17 years ago
  - organized Realtime Markets with separate Realtime Traders became the standard
- December 1, 2009
  - BPA began allowing "limited" intra-hour schedules with restrictions (export only, treated as NF, new etags only, existing tx)
- July 1, 2011
  - BPA allows full 30 minute access, restrictions lifted
  - Full intra-hour (30 min) access since

- October 21, 2014 (hopefully??)
  - BPA allows full 15 minute access, NW can transact at 15 Minute intervals

Realtime Trading Clock



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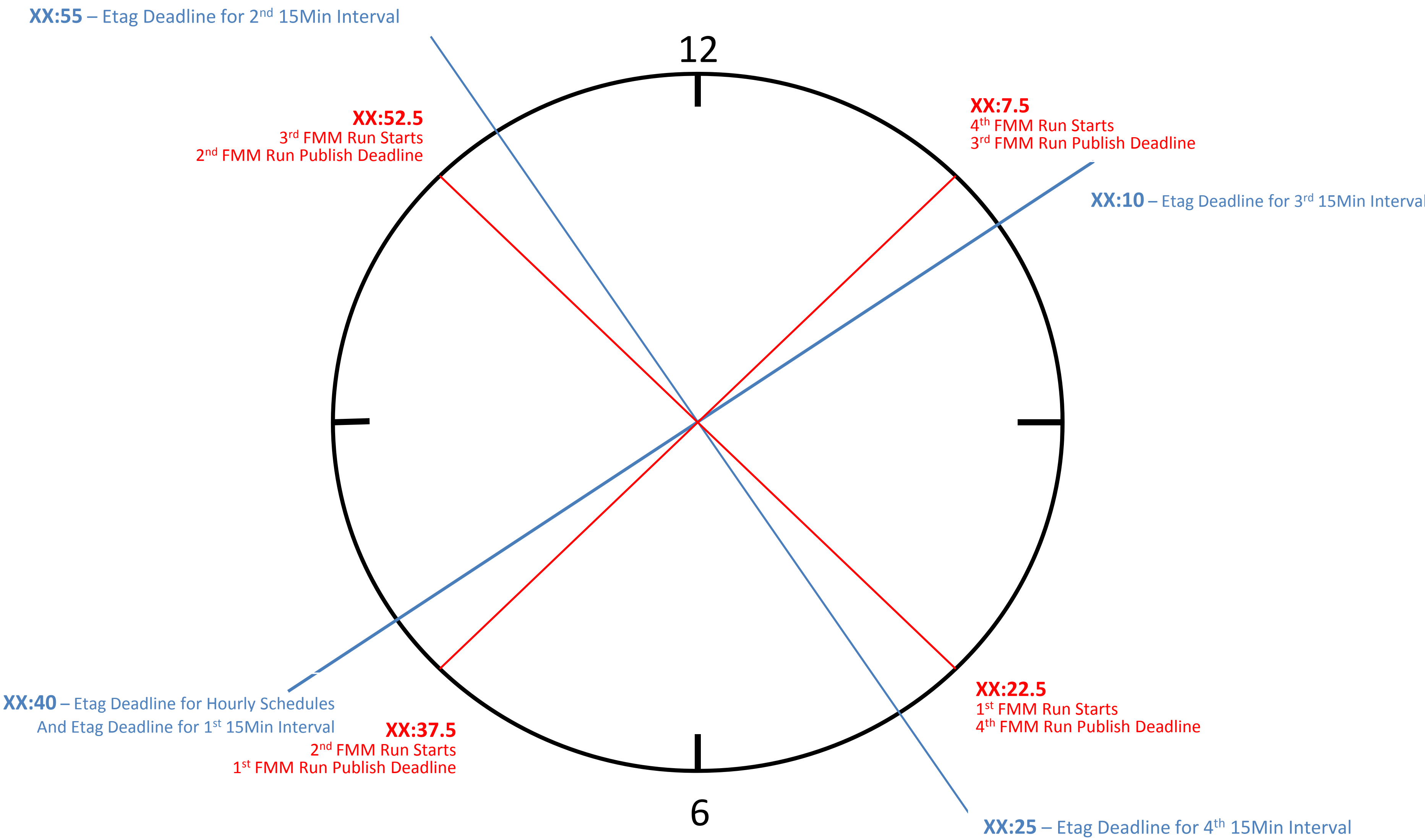
Realtime Trading Clock



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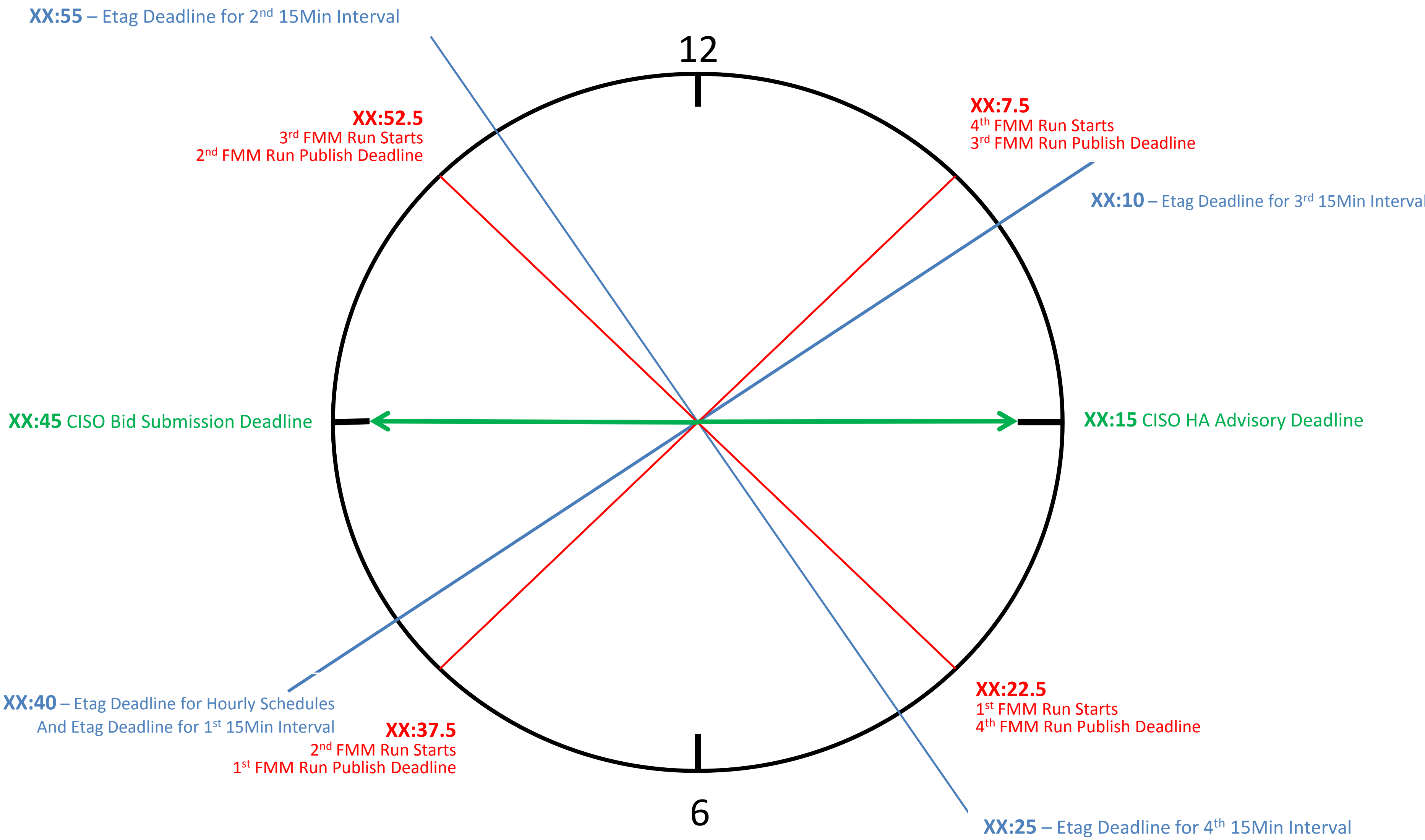
Realtime Trading Clock



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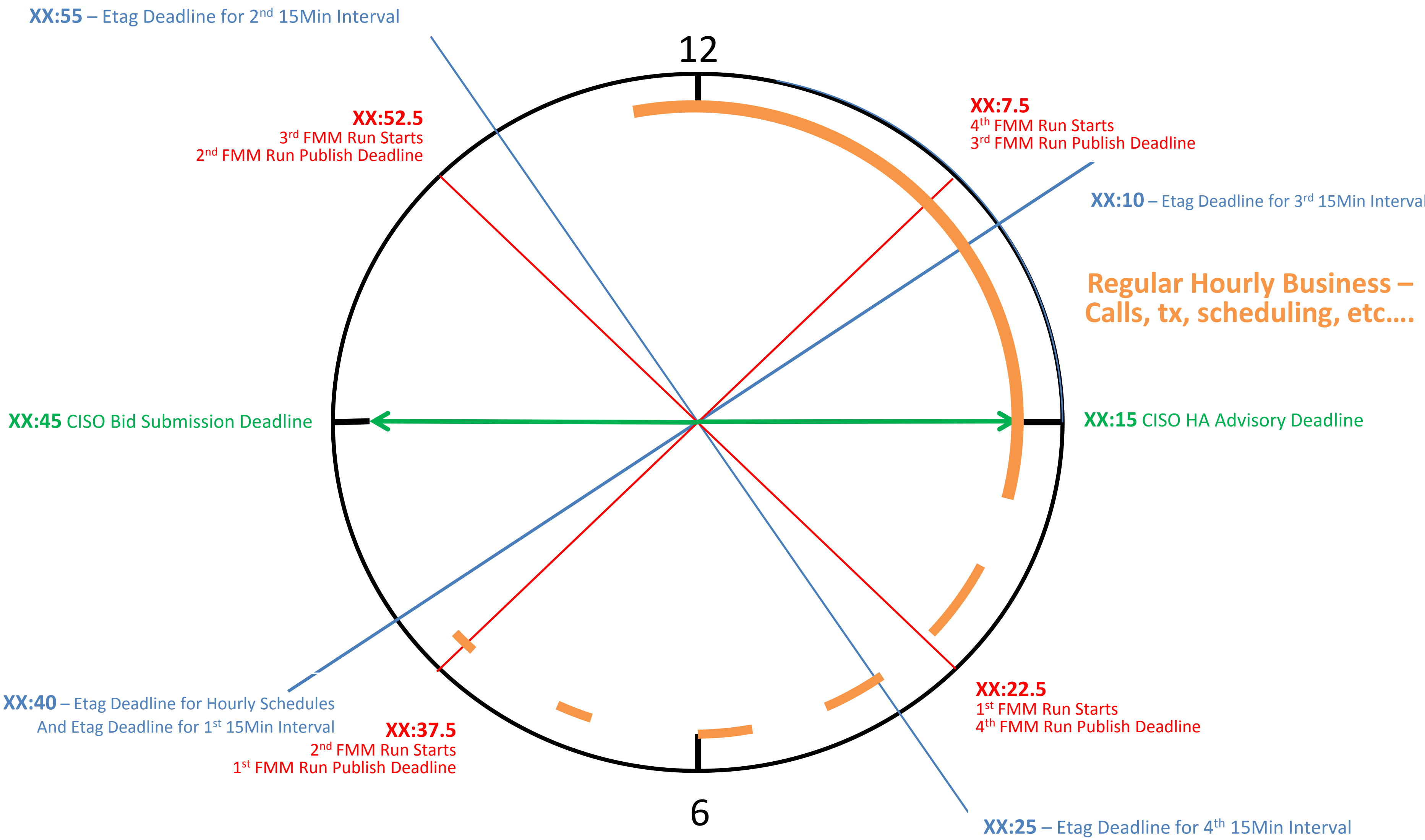
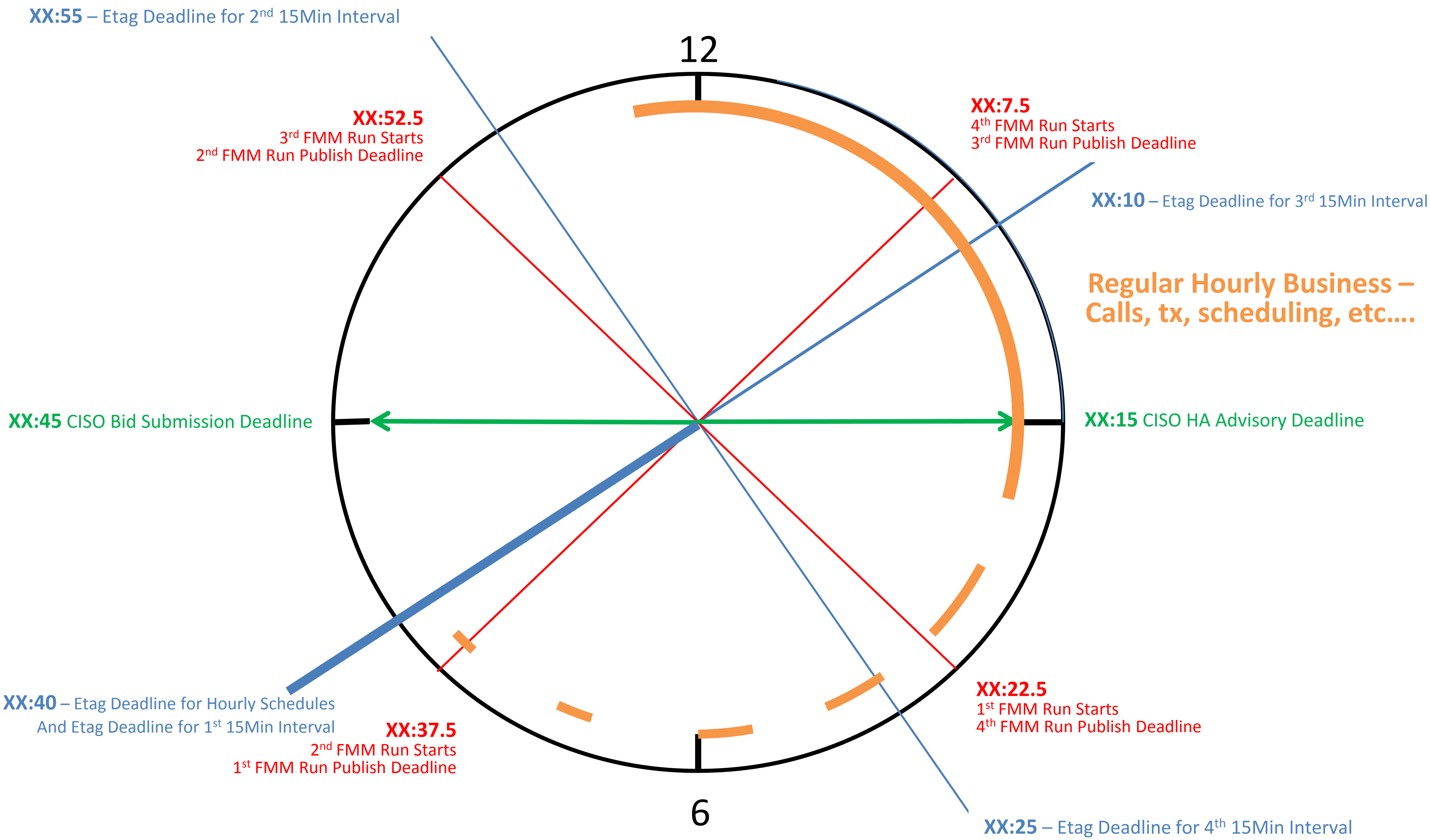
Supply. Flexibility. Commitment.

Realtime Trading Clock



Realtime Trading Clock



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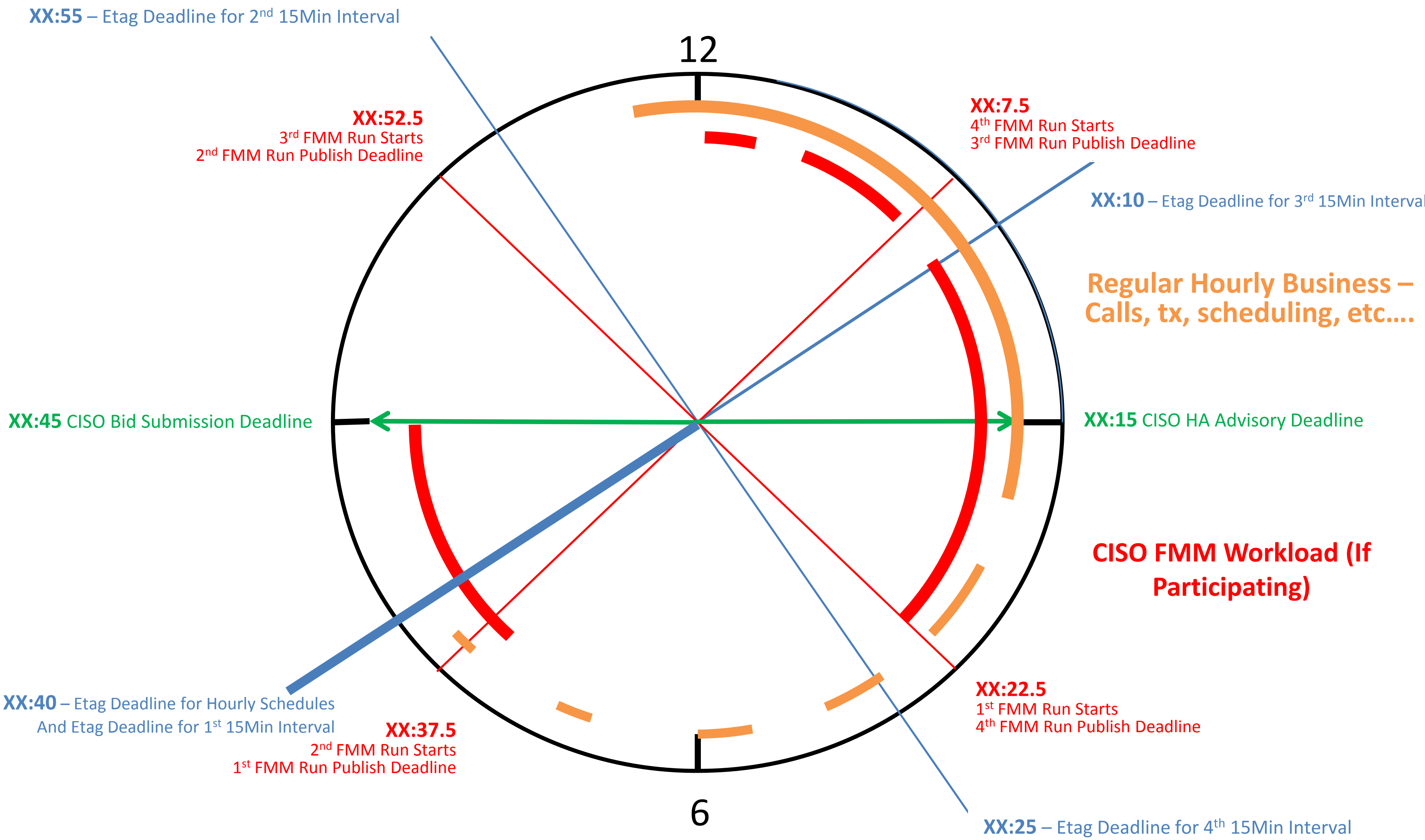
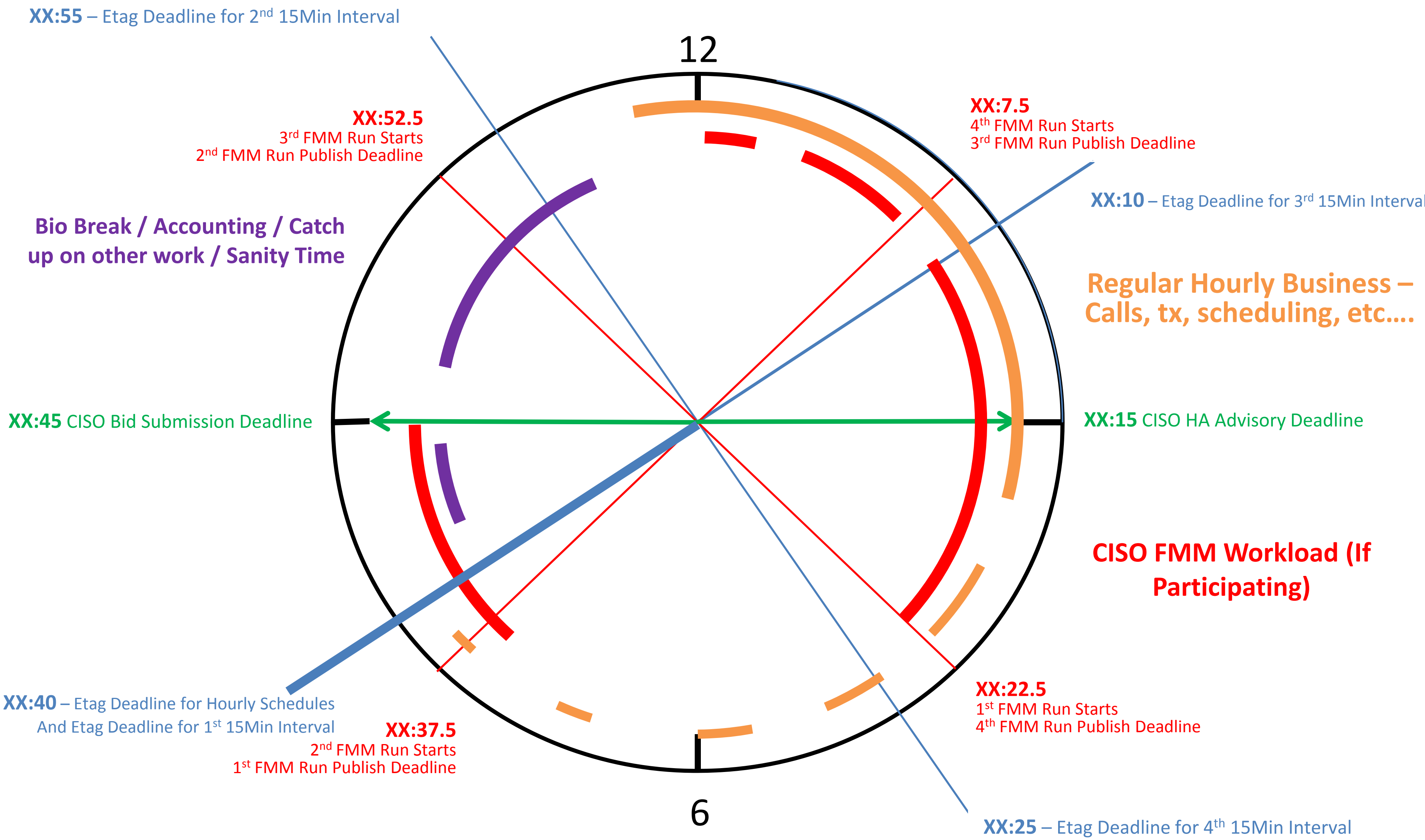
Realtime Trading Clock



Realtime Trading Clock



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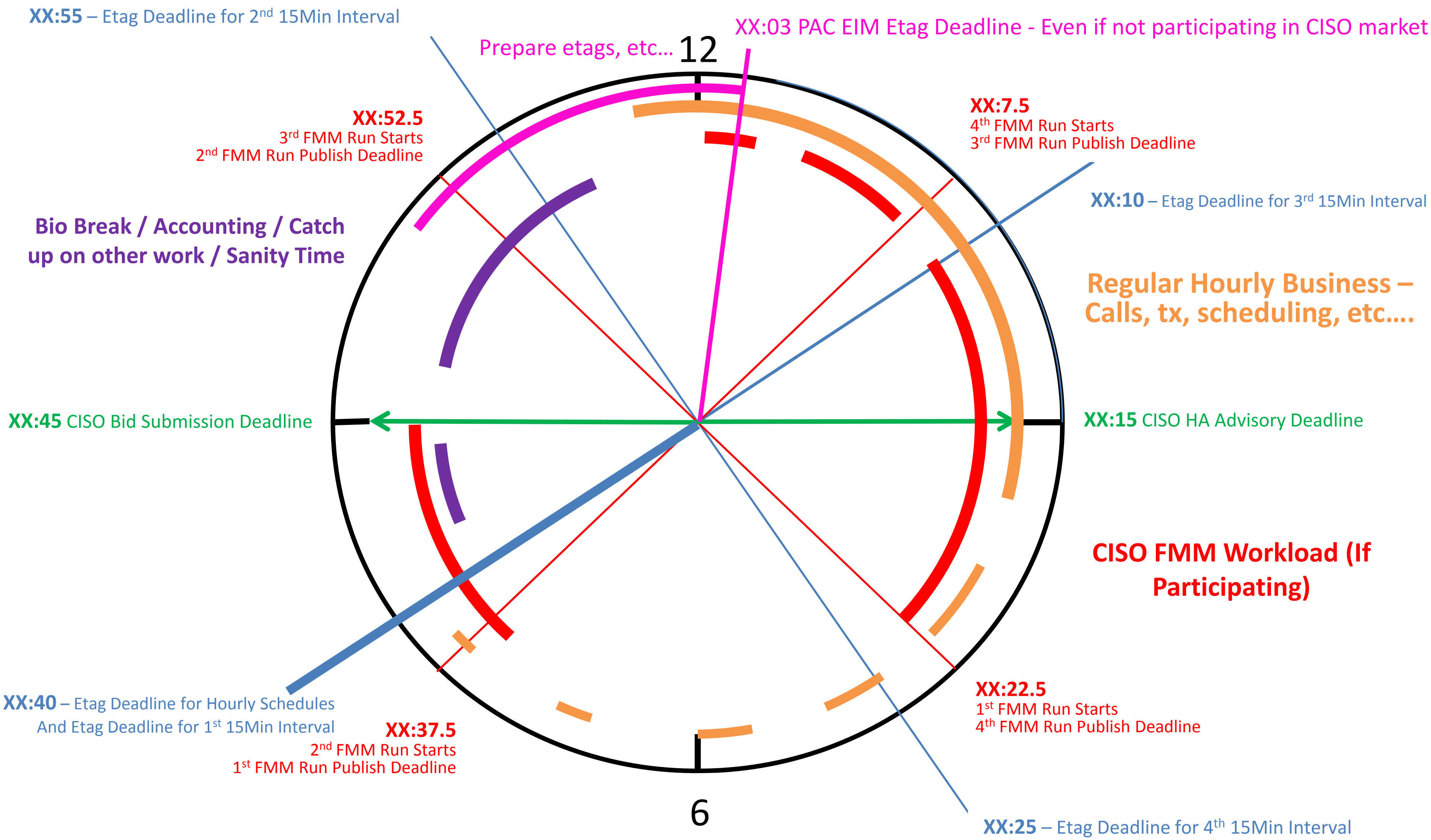
Realtime Trading Clock



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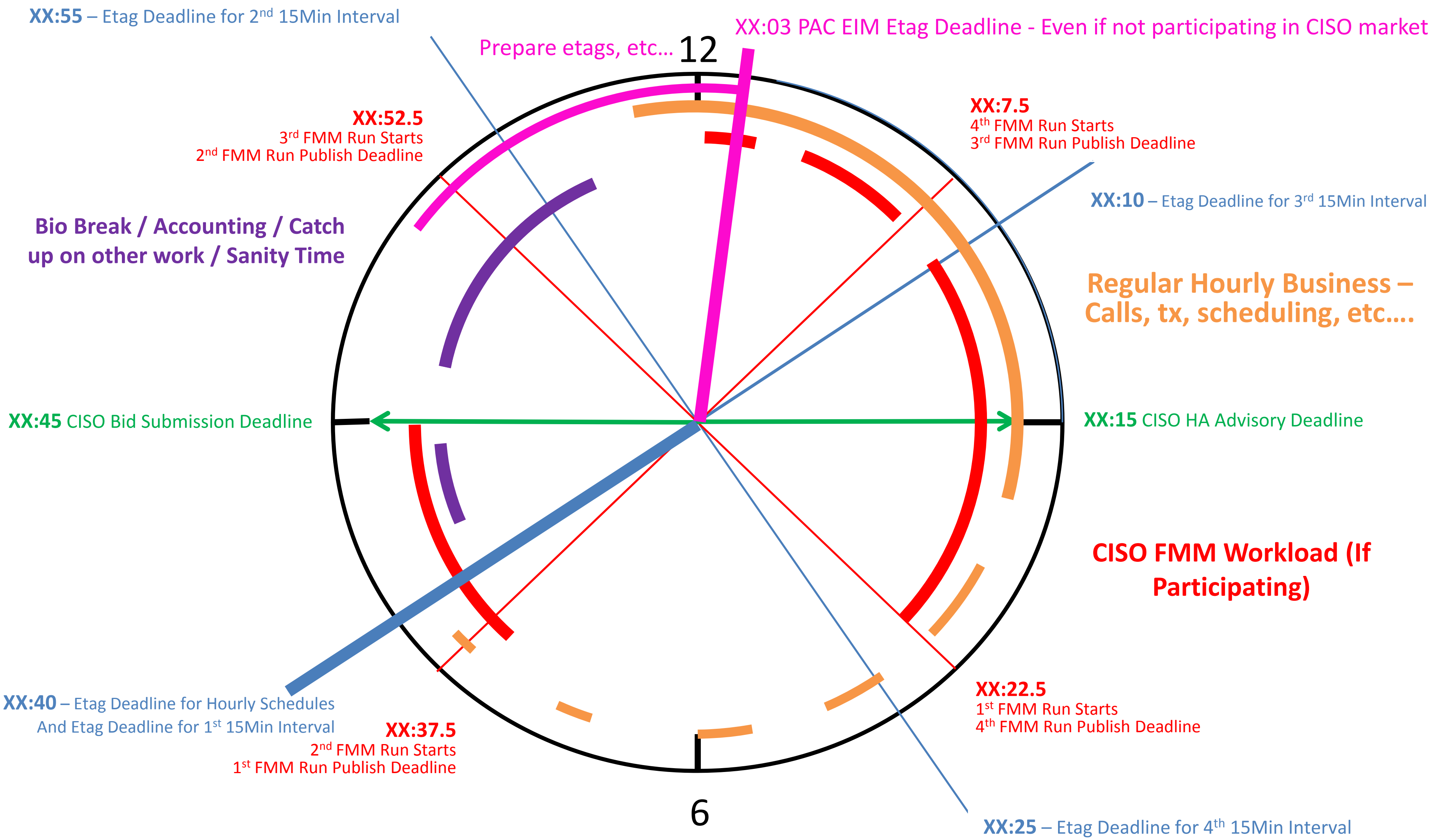
Realtime Trading Clock



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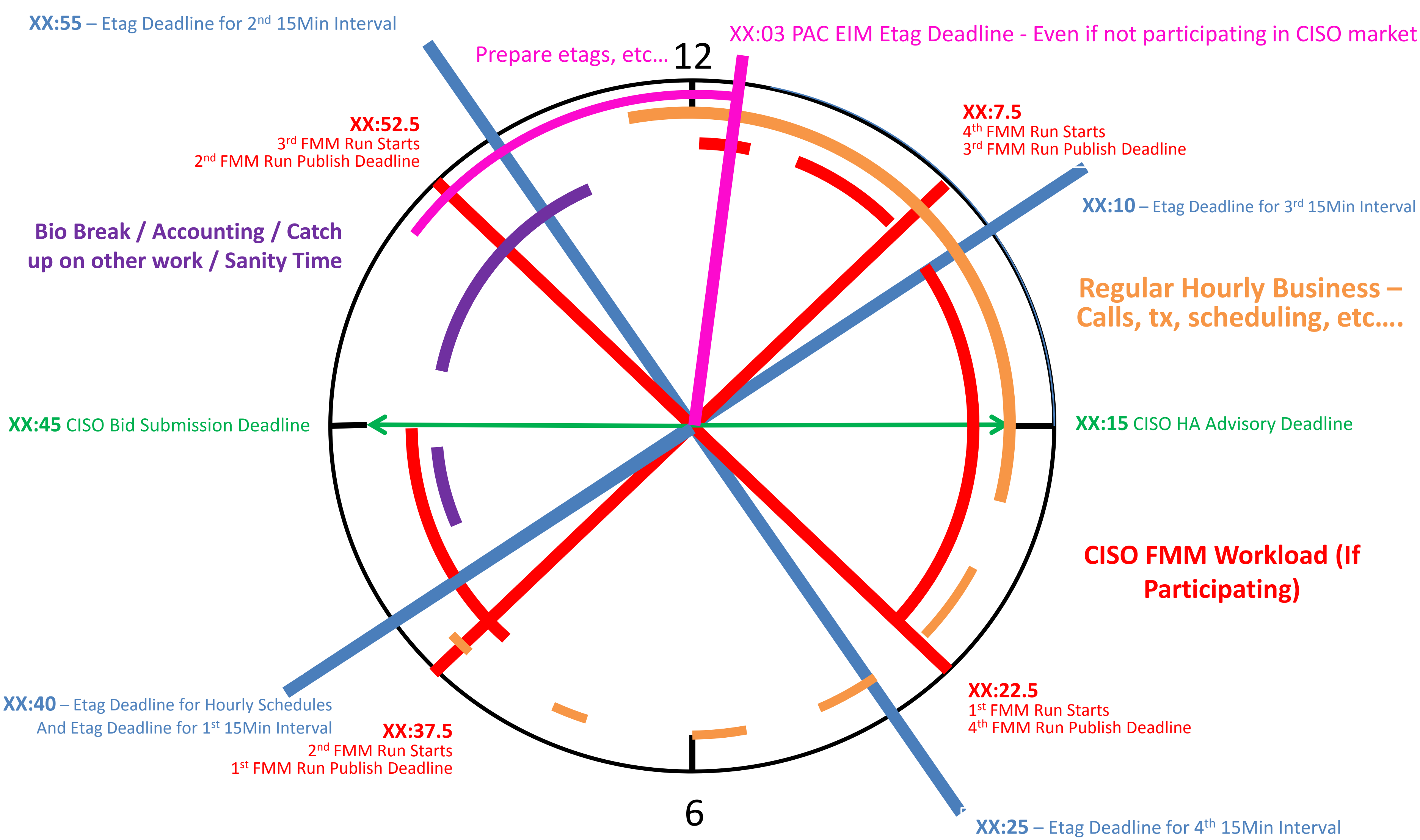
Realtime Trading Clock – Parcitipating in 15 Minute



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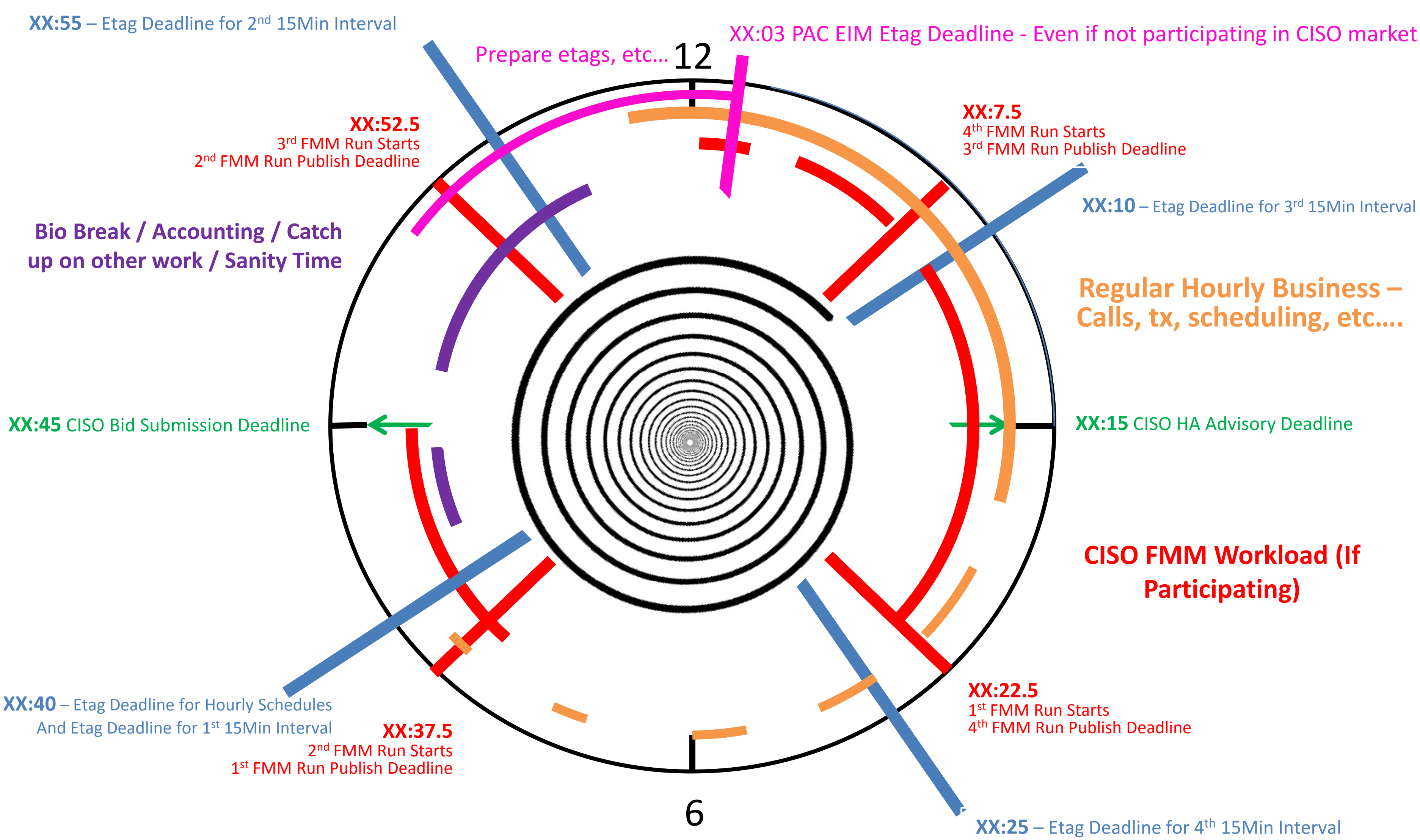
Realtime Trading Clock – Participating in 15 Minute



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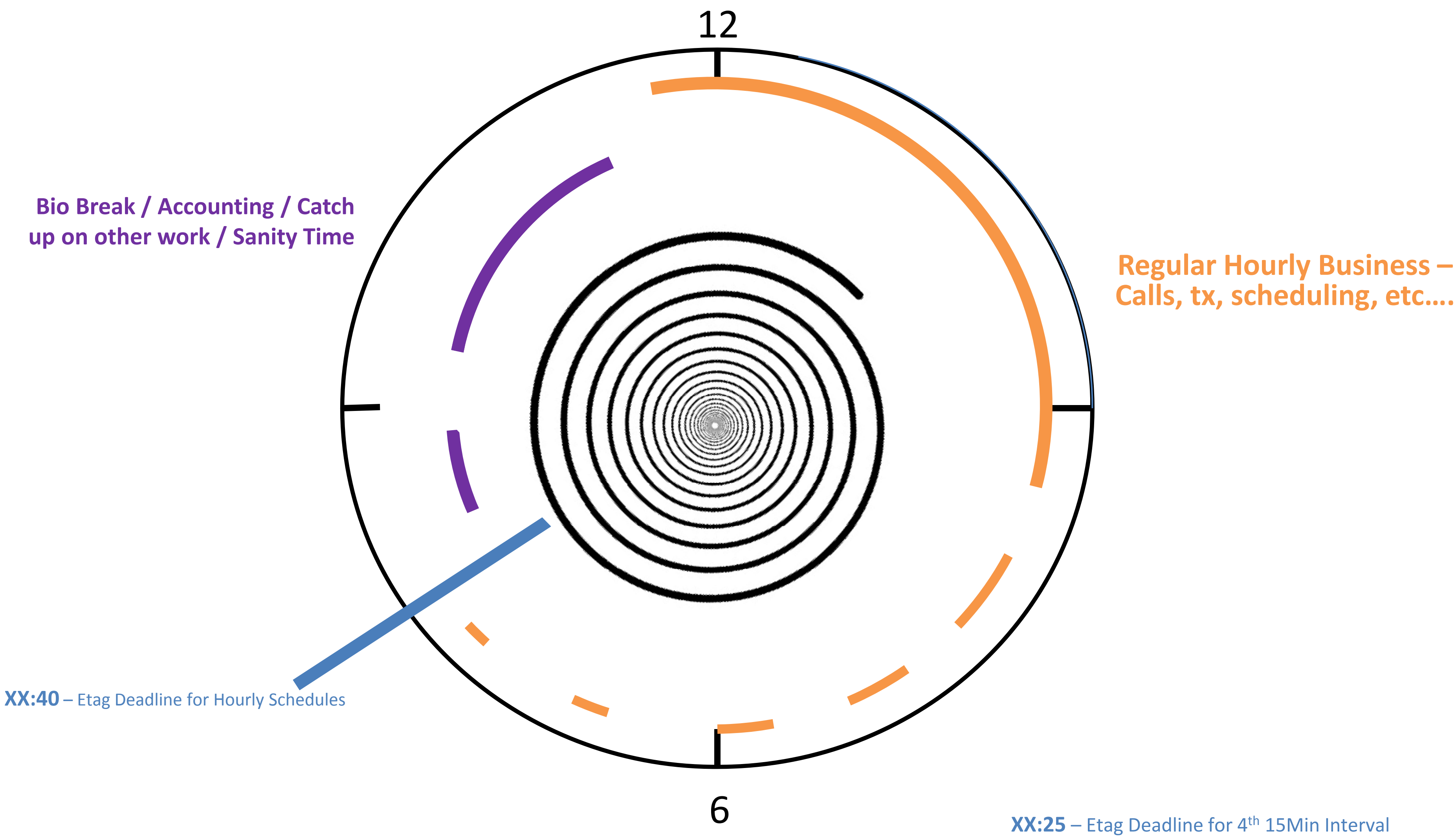
Realtime Trading Clock – Hourly Only



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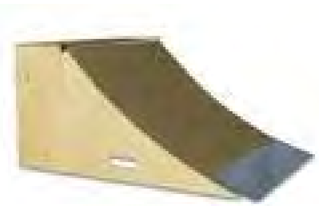
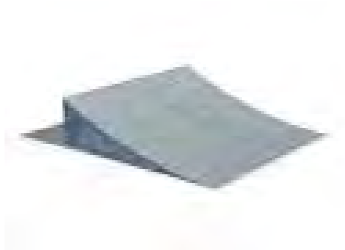
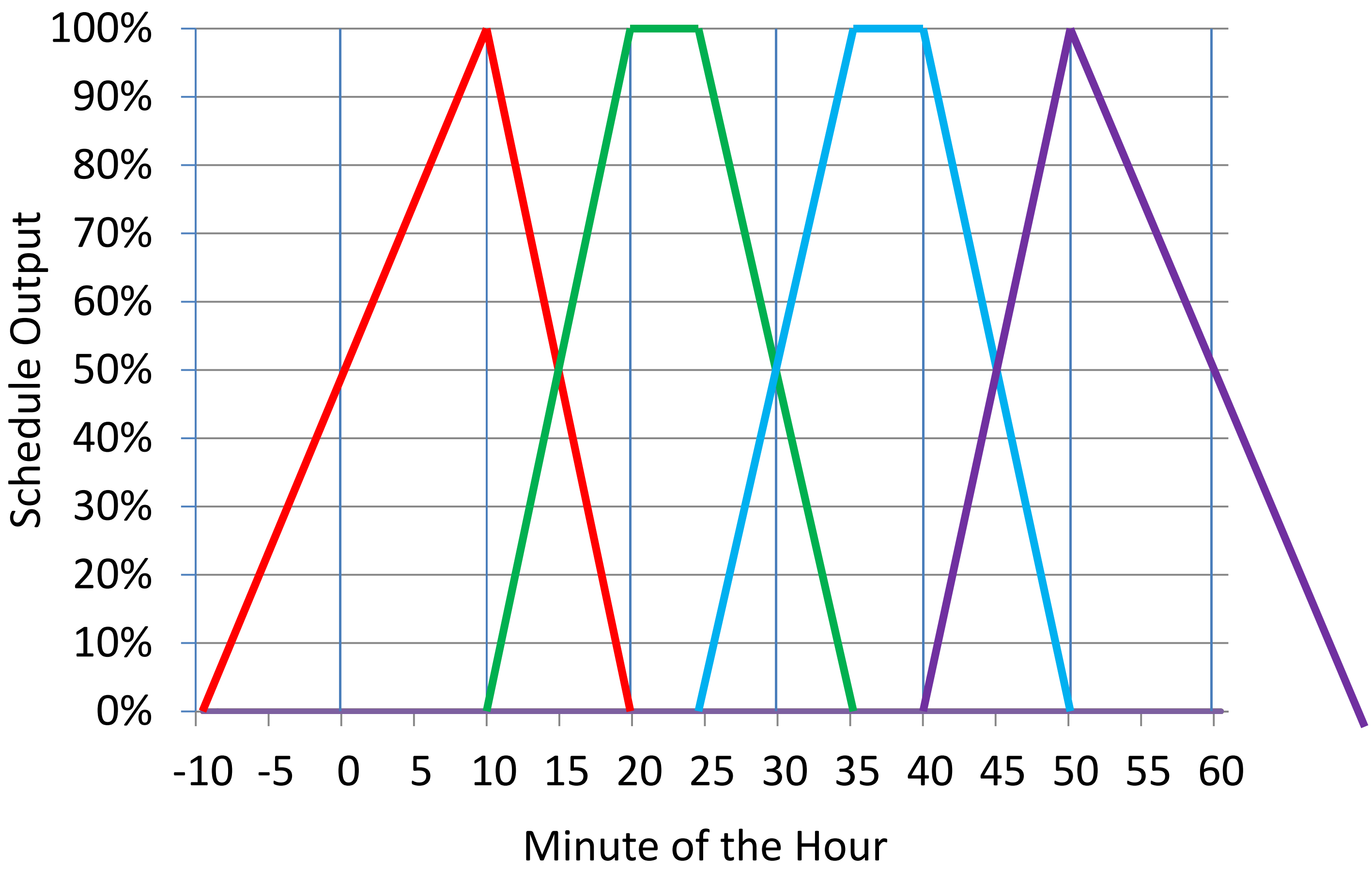
Lets Talk About Ramps





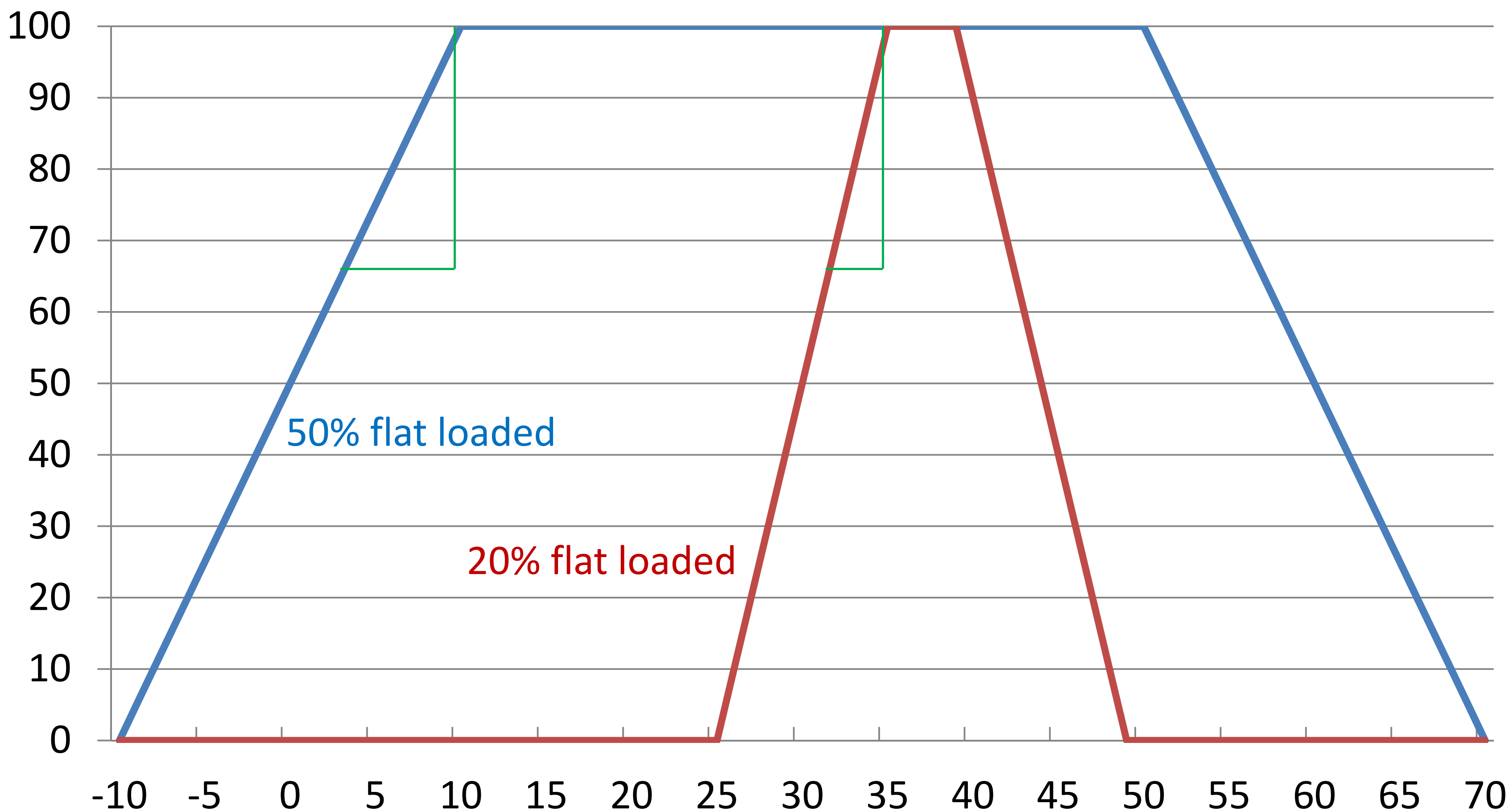
15 Minute Schedules with Ramps



Comparing 100MW schedules (Equal Peak)

Hourly – 100MWHrs, ramp 5MW/Min, Unit Stable for 40 minutes

15Minute – 25MWHrs, ramp 10MW/Min, Unit Stable for 5 minutes



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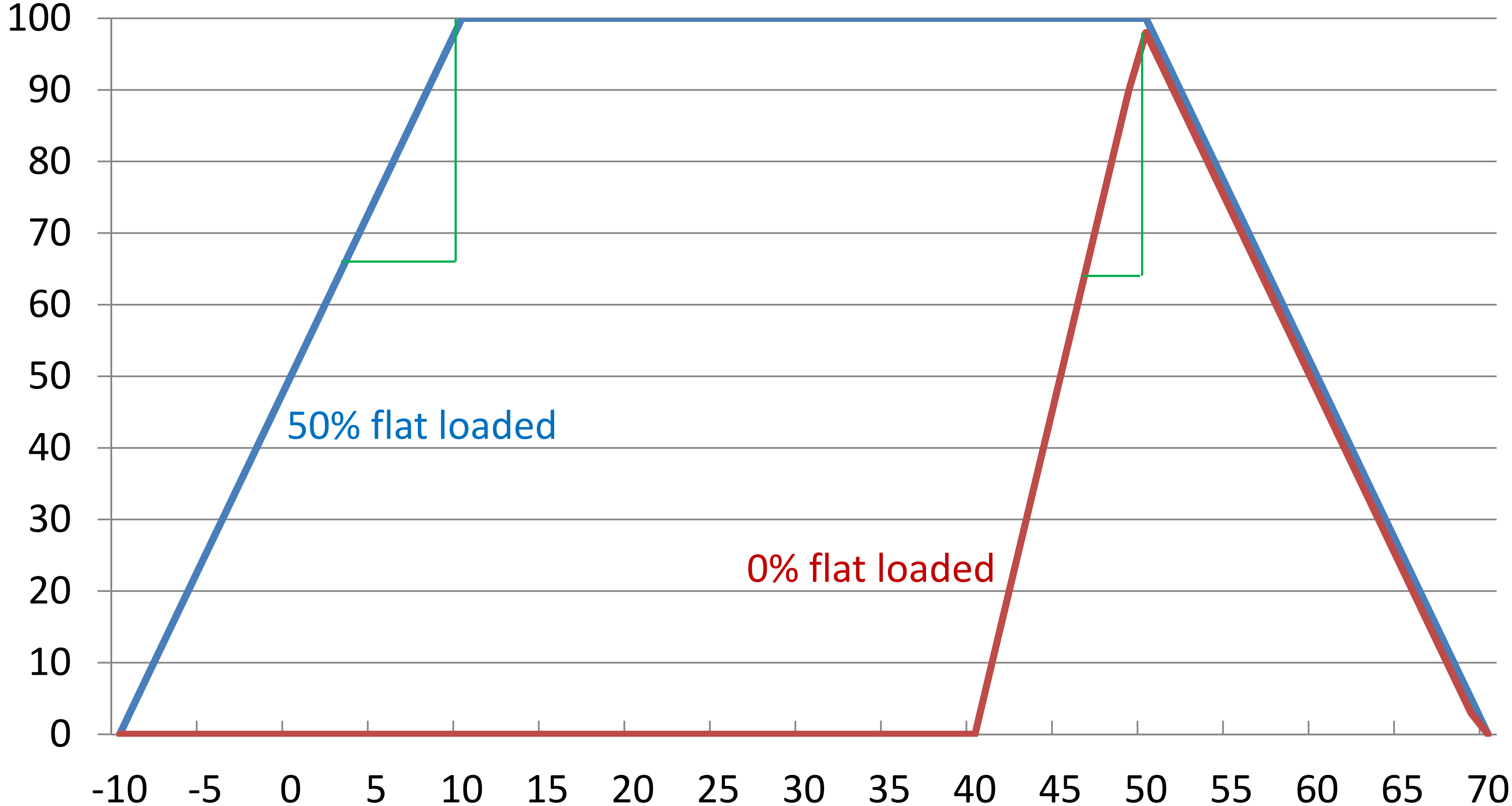
Comparing 100MW schedules (Equal Peak)

Hourly – 100MWHrs, ramp 5MW/Min, Unit Stable for 40 minutes

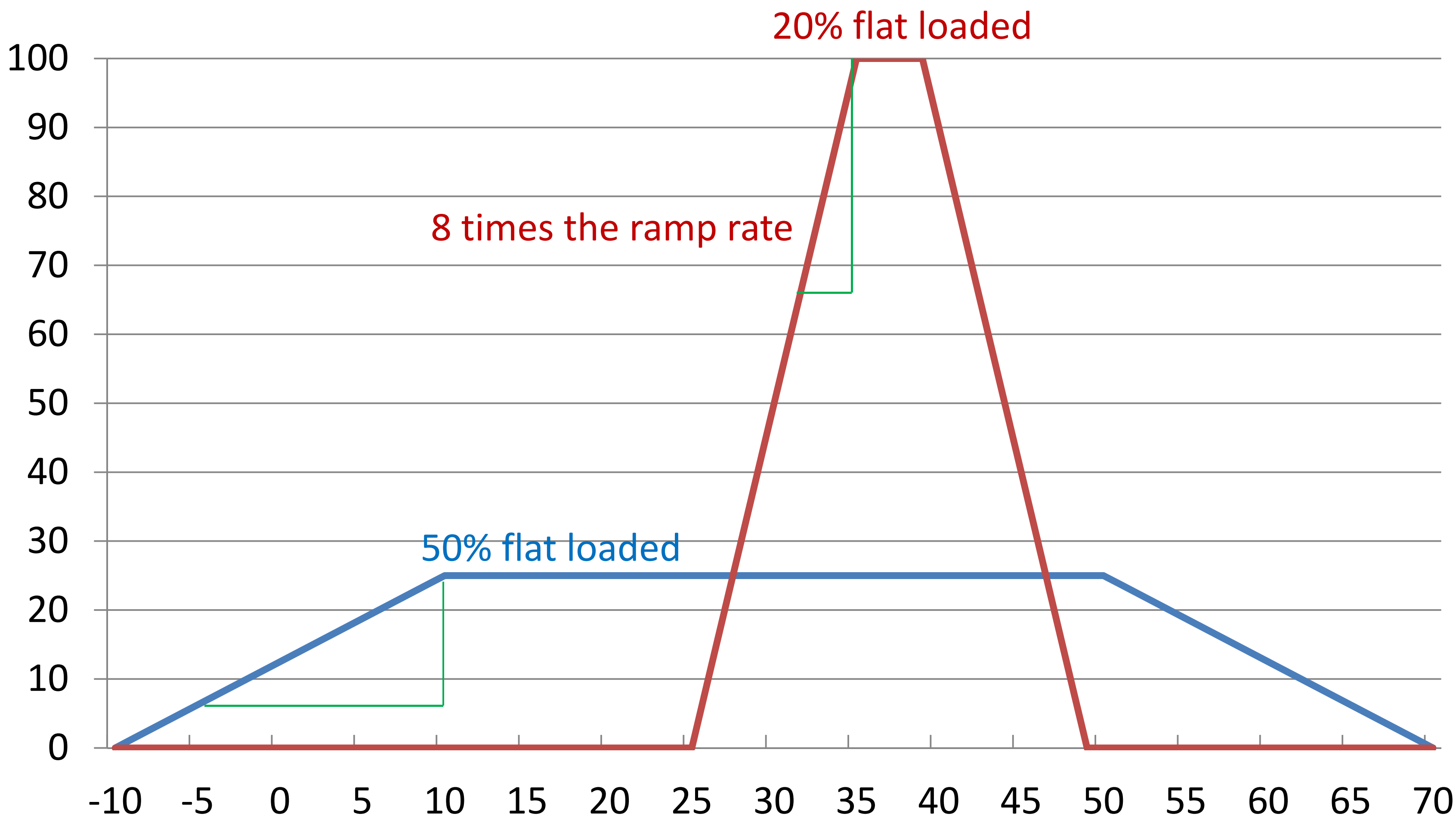
15Minute – 25MWHrs, ramp 5&10MW/Min, Unit Stable for 0 minutes



Comparing 25MWHr schedules (Equal Volume)

Hourly – **25MWHrs**, ramp 1.25MW/Min, Unit Stable for 40 minutes

15Minute – **25MWHrs**, ramp 10MW/Min, Unit Stable for 5 minutes



Costs and Impacts

Transmission

Hourly	15 Minute
Buy what you need	Need to purchase for full hour even if only using for single 15 minute interval
Easy to purchase and manage	More Cumbersome to purchase and manage
Fairly simple – becomes a routine	The hourly routine is compromised as you add in transmission purchasing at odd times of the hour
$	**$$$$**

Supply. Flexibility. Commitment. 25 YEARS

Ramping of Schedules

Hourly	15 Minute
Ramp is 50% of schedule duration	Ramp is 80-100% of schedule duration
Ramp is 20 minutes	Most Ramps 10, some 20 minutes
0.05MW/min ramp per MWHr of hourly schedule	0.20-0.40MW/min ramp per MWHr of 15min schedule (4-8 times the impact of hourly)
Baseline Unit Impact	Significant Unit Impact, increased wear and tear compared to hourly
$	**$$$$$$**

Planning Your System

Hourly	15 Minute
Planning is in hourly flat step targets	Planning around an upper and lower generation requirement each hour with no stable target – units basically continuously moving
Can accomplish with most generating units and limited operating ranges	Need very flexible units with wide operating ranges
Fairly simple to plan fuel (reservoirs)	More complicated to plan fuel (reservoirs)
Normal Wear and Tear on Units	Extreme Wear and Tear on Units (more than Dynamic Schedules) – the units are basically always moving to the next schedule interval target
$	**$$$$$$$$**

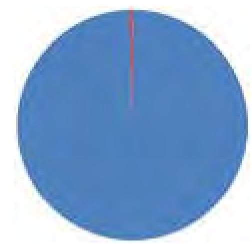
powerex. Supply. Flexibility. Commitment. 25 YEARS

System Maintenance Impacts

Hourly	15 Minute
Baseline Wear and Tear	Units will have significantly more Wear and Tear requiring more costly repairs
Baseline Downtime	Increase in Downtime due to longer and more frequent maintenance requirements – leads to loss of unit generating capability during the additional maintenance period (i.e. additional 2 weeks of maintenance each year, loss of use of the unit for these 2 additional weeks)
$	**$$$$$$$$$$$$**

30 Minute (Intra Hour) Scheduling

(Numbers based on YTD 2014 at midpoint - at the 3 year mark)



- Approximately 0.4% of etags were intra-hour etags (NW)
- Approximately 0.01% of etagged MWHr volume was intra-hour (NW)
- The vast majority of energy trading in the NW has been single or multiple hour blocks of energy
- The availability of Intra Hour Scheduling has not resulted in a shift away from hourly trading

So What Does This All Mean?

- The systems that will be tanking the swing for 15 minute schedules will mostly be requiring a premium to recover the above mentioned increased costs and impacts

- If the hourly market is at $35, it is very unlikely you will find a buyer and seller transacting for 15 minutes at $35

It Never Hurts To Call And Ask

- Depending on other business, how busy you are, how your system is set up, you still may be able to accommodate 15 minute scheduling at more moderate prices, so……..

- IT NEVER HURTS TO CALL AND ASK!

15 MINUTE SCHEDULING – BPA REAL TIME TRANSMISSION PERSPECTIVE

BY LOU MIRANDA
BONNEVILLE POWER ADMINISTRATION
TRANSMISSION SERVICES

NWPP SCHEDULERS MEETING
OCT 21-22, 2014

DOUBLETREE BY HILTON – LLOYD DISTRICT
1000 NE MULTNOMAH, PORTLAND, OR 97232

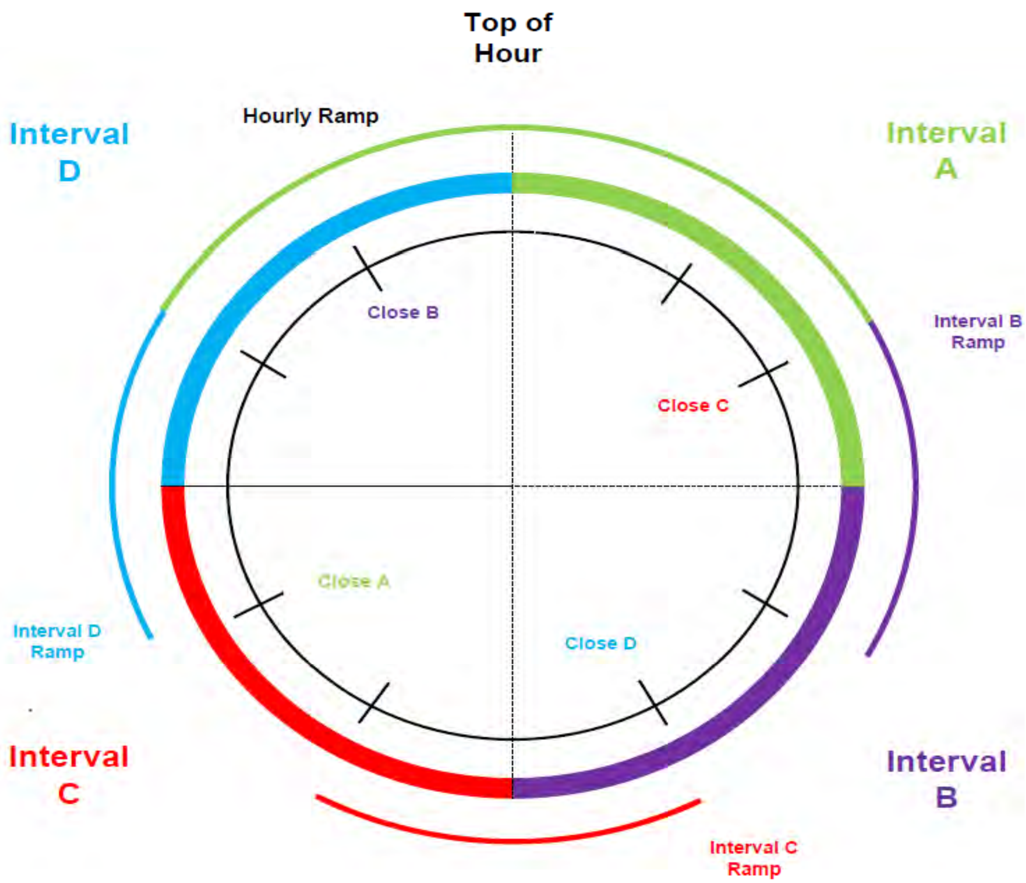
SCHEDULING INTERVALS

- The 15 Minute Scheduling Intervals are as follows:
  - 1st Interval XX:00 – XX:15 (Interval A)
  - 2nd Interval XX:15 – XX:30 (Interval B)
  - 3rd Interval XX:30 – XX:45 (Interval C)
  - 4th Interval XX:45 – XX:00 (Interval D)
- Schedules will be allowed in 15 min, 30 min, 45 min and 1 hour intervals.
  - Example: Customer can have a 45 min schedule from XX:15 to XX:00.
- Start and stop time must be aligned with the scheduling intervals.

TRANSSMISSION RESERVATION REQUESTS

- Transmission Service Request reservations will be sold in full hour increments.
- Confirmed reservation(s) – Firm or non-firm transmission can be utilized.
- Hourly Non-firm transmission can be purchased up to the end of the operating hour. This includes:
  - 1 – NS – Secondary Hourly PTP
  - 2 – NH – Hourly PTP
  - 6 – NN – Hourly NT

15 MINUTE SCHEDULING



E-Tag Submittal Times and Ramp Rates

E-Tags

- Request for Interchange (e-Tags) must be submitted 20 minutes prior to the start of the interval to be considered 'ON Time' by the Interchange Authority.

- Request for Interchange (e-Tags) submitted less than 20 minutes prior to the start of the interval will be considered 'Late' by the Interchange Authority. A late e-Tag will fail tag timing and may be denied.

Ramp Rates

- Top of the hour ramp rate for interval A is 20 min.

- Ramp rate for intervals B, C, and D will have 10 min straddle ramps.

WIT CHECKOUT – UNSCHEDULED FLOW

WIT CHECKOUT

- WIT checkout for the next hour will be completed at XX:40.
- WIT checkout will be completed for each 15 minute interval if there are any changes.

UNSCHEDULED FLOW (USF)

- The current WECC Unscheduled Flow (USF) curtailment procedure will <u>remain</u> an hourly process.
- There are no plans at this time to perform USF curtailments in 15 minute intervals.

CONGESTION MANAGEMENT

- BPAT will only curtail by specific 15-minute Intervals for congestion management.

- This differs from the WECC 15 Minute Task Force Recommendation of curtailing to the end of the hour.

- Reasons for adopting this change:

  - Less likely to cut intervals unnecessarily or deeper than necessary.
  - Lessens possibility of multiple curtailments and reloads.
  - Ensures curtailments are done pro-rata for all schedules in the closed interval.
  - Ensures that curtailments are done in curtailment priority order.

CONGESTION MANAGEMENT (External Path Curtailments – i.e. AC intertie, etc.)

- Curtailments will be made on a pro-rata basis within curtailment priority for the next Interval.

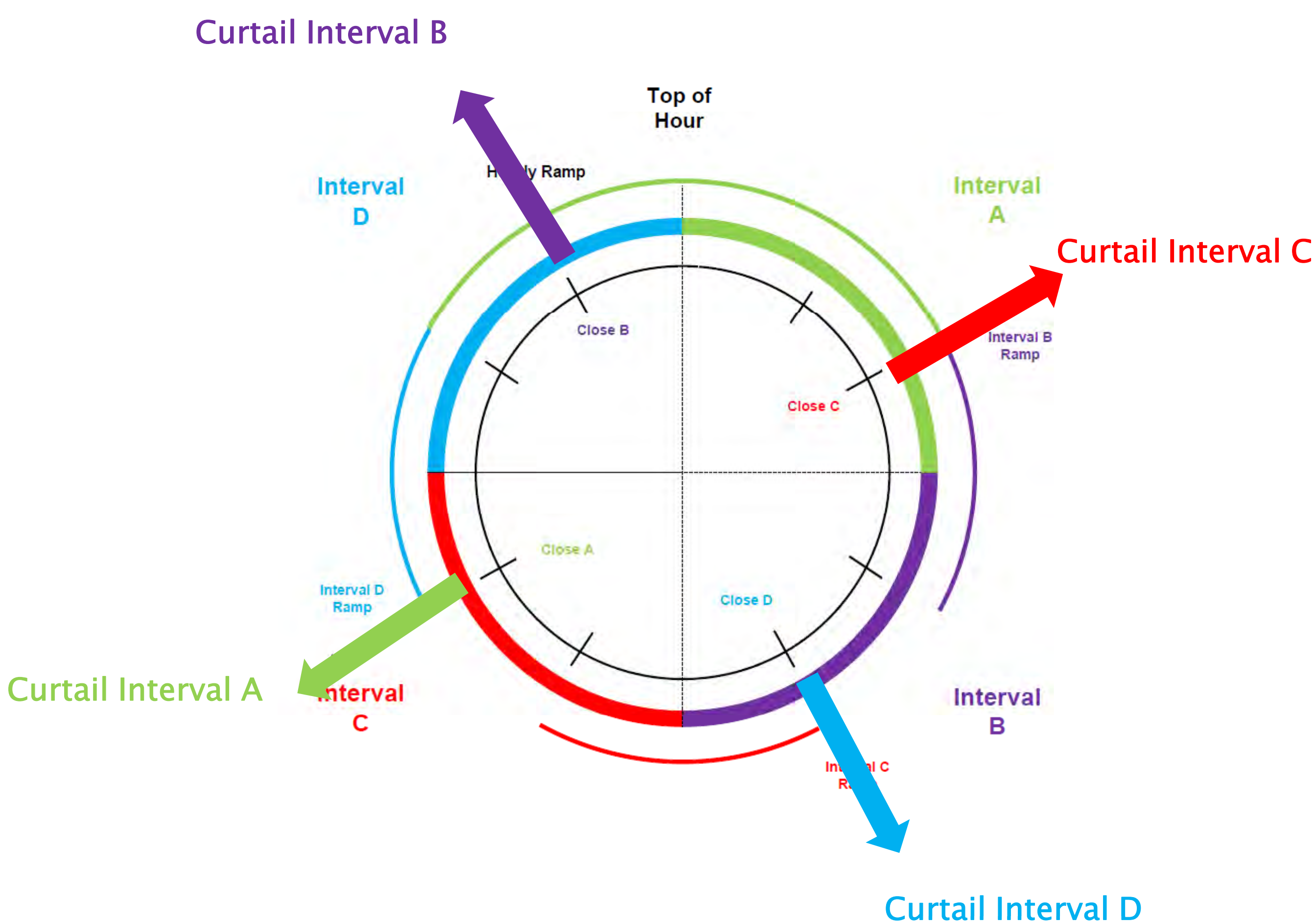
- Next Interval Curtailments.
  - Pro-rata within curtailment priority since January 2014.
  - Scheduled-based.
  - Curtailment trigger is when schedules exceed the next interval System Operating Limit (SOL).
  - Curtailments will be initiated approximately 20 minutes prior to the start of the next Interval.

- Within-Interval Curtailments
  - Pro-rata within curtailment priority.
  - Schedule Based.
  - Curtailment trigger is when actual flows exceed the SOL

Congestion Management For Network Flowgates

- Next Interval Curtailments
  - Curtailment procedure to be expanded to all flowgates (Currently next hour curtailments are initiated only on North of Echo Lake flowgate).
  - Pro-rata within curtailment priority
  - Schedule-based.
  - Trigger is when next interval forecasted flows exceed the next interval System Operating Limit (SOL).
- Within-Interval Curtailments
  - Pro-rata within curtailment priority.
  - Curtailment Trigger is when actual flows exceed the SOL.

CONGESTION MANAGEMENT



QUESTIONS

NORTHWEST
PowerPool