SOUTHWEST POWER POOL
ECONOMIC STUDIES WORKING GROUP MEETING

December 7-8, 2022
Net Conference

SUMMARY OF MOTIONS AND ACTION ITEMS

General Items:

- Approved 2023 ESWG meeting schedule
- Approved November ESWG minutes
- Approved MDAG recommendations for the CPPTF SCRIPT C3 Common Model Set

2024 ITP:

- Approved Resource Plan methodologies for 2024 ITP Scope
- Approved Sunflower's resource addition request for Russell Solar

Action Items:

- An action item was added for staff to review process of accrediting existing resources in the ITP

SOUTHWEST POWER POOL
ECONOMIC STUDIES WORKING GROUP MEETING
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MINUTES

AGENDA ITEM 1 – ADMINISTRATIVE ITEMS

Economic Studies Working Group (ESWG) Chair Alan Myers called the meeting to order at 8:00 a.m. The following members were in attendance or represented by proxy:

Al Tamimi, SUNC
Alan Myers, ITC
Anita Sharma, AEP
Calvin Daniels, WFEC
Derek Brown, Evergy
Gayle Nansel, WAPA
Jeremy Severson, BEPC
Jody Holland, GHP
Jordan Schmick, SPS
Kurt Stradley, LES
Kyle McKinney, GSEC
Michael Watt, OMPA
Randy Collier, CUS
Steve Gaw, APA
Steve Hohman, OPPD
Tim Owens, NPPD
Zac Hager, OGE

(Attachment 1) (Attachment 2)

Joshua Norton confirmed there was a quorum and provided the antitrust statement. Alan Myers reviewed the agenda for any changes. (Attachment 3)

> **Jeremy Severson made a motion, seconded by Steve Gaw to approve the agenda. The motion was approved unanimously.**

AGENDA ITEM 2 – CONSENT AGENDA

The consent agenda included the following items:

- 2023 ESWG Meeting Schedule (Attachment 4)
- Meeting Minutes – November 2-3, 2022 (Attachment 5)

The consent agenda was approved unanimously.

AGENDA ITEM 3 – CPPTF SCRIPT C3 COMMON MODEL SET

Brandon Hentschel presented the SCRIPT C3 common model set guidance and presented to the group the MDAG recommendation for defining the CPP Common Model Topology (Slide 11) and a recommendation that "At a minimum, the Common Model Topology set in MOD should include the year/seasons necessary for the next MMWG and also include any additional year/seasons desired for the CPP process." Al Tamimi noted that it is not clear where the efficiencies will be realized and would like more frequent updates from the CPPTF. (Attachment 6)

Al Tamimi made the motion, seconded by Gayle Nansel, to approve both MDAG Recommendations. The motion was approved unanimously.

AGENDA ITEM 4 – HITT M1 STAFF RECOMMENDATIONS TO SPP BOARD

Micha Bailey reviewed the TSR process at a high level, provided education on the congestion hedging process, and detailed next steps. (Attachment 7) (Attachment 8)

AGENDA ITEM 5 – RR 528 BP7060 CONSISTENCY IN TERM RE-EVALUATION AND UPDATES TO SECTION 11 & 13

This item was struck from the agenda to be placed on the January 2023 agenda.

AGENDA ITEM 6AI – 2024 ITP SCOPE DEVELOPMENT: RESOURCE PLAN

Krishada Watson presented several remaining items for the resource plan section of the 2024 ITP scope. She presented a methodology and recommendation for conventional generator prototypes. Zac Hager gave specific feedback and the recommendation was updated to be the following: "SPP Staff recommends that ESWG approve the methodology for conventional generator prototypes for 2024 ITP scope, but drop SMR option and staff review VOM assumptions for units relative to existing PROMOD model data for similar resources" (Attachment 9)

Tim Owens made the motion, seconded by Zac Hager, to approve the methodology for conventional generator prototypes for 2024 ITP scope, but drop SMR option and staff review VOM assumptions for units relative to existing PROMOD model data for similar resources. The motion was approved unanimously.

Krishada then reviewed the resource accreditation process for existing resources. (Attachment 9)

Steve Hohman made the motion, seconded by Anita Sharma, to approve the methodology for accreditation of existing resources for 2024 ITP scope. The motion was approved unanimously.

Steve Gaw requested an action item based on the discussion of accrediting existing resources.

Action Item: Staff to review process of accrediting existing resources in the ITP

Krishada presented the new resource allocation process and reviewed two scenarios that could occur depending on whether scoped resource amounts were in excess of submitted resource plans or whether there is a deficiency in scoped resources when compared to submitted resource plans. She presented staff's recommendation. (Attachment 9)

Anita Sharma made the motion, seconded by Steve Gaw, to approve the methodology for allocation of new resources for accreditation:

- **Excess Scenario: Allocate pro rata (all fuel types) based upon shortfall to non-respondents, capped at PRM**
- **Deficit Scenario: Responding utilities awarded 80% of requested MW based upon pro rata share**
    - **For non-respondents, follow same approach defined previously in Excess Scenario**

The motion was approved with one vote against (Jordan Schmick).

Voting Rational:

Jordan Schmick: Against
"Xcel Energy voted against the resource accreditation and the resource siting portions of the ITP 2024 scope. We have spoken out against over-reliance on resource plans in the ITP in other forums for a number of reasons: largely we are concerned about the inability to hold stakeholders accountable to their projections

(since the submitted resource templates are not binding) and the potential for 'gaming' of submissions to seek more resources and projects than would be expected otherwise. Stakeholders could submit inflated resource projections and nothing holds them to those numbers, so the projected resource plans could be more inaccurate than otherwise used, especially with the fast-moving nature of resource planning in the current environment, and the advance notice (up to a year and half before model building) SPP requests for the resource projections in the process."

Krishada reviewed ownership assignment of resources in the ITP and presented staff's recommendation. (Attachment 9)

Steve Gaw made the motion, seconded by Steve Hohman, to approve the methodology for new resource ownership assignment to be that 100% of requested non-policy wind, solar, and storage resources should be assigned to requesting utilities. And the specific resource assignments should be made in parallel with the siting milestone for the 2024 ITP. The motion was approved with one vote against (Jordan Schmick).

Rationale:

Jordan Schmick: Against

see response to previous motion

AGENDA ITEM 6AII – 2024 ITP SCOPE DEVELOPMENT: PERSISTENT OPERATIONAL SOLUTION EVALUATIONS

Joshua Norton reviewed feedback received since last meeting and presented updated scope language. Some edits were made in the meeting and it was determined to give the group time to consider those edits and perform an email vote on the final language. (Attachment 10)

AGENDA ITEM 6AIII – 2024 ITP SCOPE DEVELOPMENT: SCOPE DOCUMENT

Joshua Norton reviewed a draft of the scope document and received feedback from the group. (Attachment 11)

AGENDA ITEM 6B – 2024 ITP: RESOURCE ADDITION REQUEST: SUNFLOWER RUSSELL SOLAR

Ryan Yokley presented a request to include Russell Solar in the 2024 ITP Market Economic Models. (Attachment 12)

> **Tim Owens made the motion, seconded by Calvin Daniels, to approve Sunflower's resource addition request for Russell Solar. The motion was approved unanimously.**

AGENDA ITEM 7A – 2023 ITP: NTC RE-EVALUATION MODEL CORRECTION

Eddie Watson provided an update on 2023 ITP model corrections and updates. (Attachment 13)

AGENDA ITEM 7B – 2023 ITP: CONSTRAINT ASSESSMENT

Maurisa Hughes provided updates on the 2023 ITP constraint assessment milestone. (Attachment 14)

AGENDA ITEM 8 – ITP SCHEDULES

Dara Solomon reviewed an updated monthly report of the ITP schedules. (Attachment 15)

AGENDA ITEM 9A – 20-YEAR ASSESSMENT: SOLUTION SUBMITTAL FORM REVIEW

Kirk Hall covered the item in place of Chris Davis. He reviewed the solution submittal window and a template to be used for submitting solutions. (Attachment 16)

AGENDA ITEM 10 – REVIEW OF ACTION ITEMS

Joshua Norton reviewed action items. Action items 210, 211, 212, and 213 were all marked as complete. (Attachment 17)

ECONOMIC STUDIES WORKING GROUP MINUTES

December 7-8, 2022

AGENDA ITEM 15 – CLOSING ITEMS

An action item was taken for staff to review process of accrediting existing resources in the ITP.

EMAIL ITEMS

There were no email items since the prior meeting.

Respectfully Submitted,

Joshua Norton

Secretary

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Proxy Statements

Proxy	Member	Note
Aravind Chellappa	Jody Holland	
Cliff Franklin	Al Tamimi	12/7; as needed
Josh Verzal	Steve Hohman	12/8
Robert Bouda	Derek Brown	

Joshua,

I'm providing my proxy to Aravind for this meeting (both days). Thx!

Jody Holland

I have several conflicts throughout the day today, Cliff will have my proxy if I am not on.

Al Tamimi

Alan, Josh N.,

Josh Verzal will have my proxy for the ESWG meeting tomorrow, 12/8.

Thanks,

Steve

Josh,

@Robert Bouda will have my proxy on our 12/7-12/8 ESWG meeting while I'm out on paternity leave.

Thanks!

Derek Brown, MSEE, PE
Regulatory Affairs Manager
Evergy

ECONOMIC STUDIES WORKING GROUP MEETING

December 7-8, 2022

Net Conference

AGENDA

DAY 1

Wednesday, 12/07, 8:00 a.m.-12:00 p.m. CST

Estimated material time: 4 hrs. 25 mins.

1. Administrative Items ..... Alan Myers 15
   - A. Call to Order, Introductions ..... Alan Myers
   - B. Receipt of Proxies ..... Joshua Norton
   - C. Review of Agenda ..... Alan Myers
   - D. Antitrust Reminder ..... Joshua Norton
2. Consent Agenda
   - A. 2023 ESWG Meeting Schedule
   - B. ESWG Minutes – 11/02-03/2022
3. CPPTF SCRIPT C3 Common Model Set (Approval) ..... Brandon Hentschel 20
4. HITT M1 Staff Recommendations to SPP Board ..... Micha Bailey 60

   This is not for approval, and will be moved to after item 10 on the agenda.

5. ~~**RR 528** BP7060 Consistency in term reevaluation and updates to Section 11&13 (Approval) ..... Tammy Bright 20~~

   This has been removed from the agenda and will be placed on the January agenda.

6. 2024 ITP
   - A. Scope Development
     - i) Resource Plan (Approval) ..... Krishada Watson 60
       - (1) Conventional Gen Prototypes

(2) Resource Allocation, Assignment & Accreditation

ii) Persistent Operational Solution Evaluations (Approval) ..... Joshua Norton 20

iii) Scope Document ..... Joshua Norton 10

B. Resource Addition Request: Sunflower Russell Solar (Approval) ..... Ryan Yokley 15

7. 2023 ITP

A. NTC Re-evaluation Model Correction ..... Eddie Watson 15

B. Constraint Assessment ..... Maurisa Hughes 20

8. ITP Schedules ..... Dara Solomon 15

9. 20-Year Assessment (20YA)

A. Solution Submittal Form Review ..... Chris Davis 20

10. Review of Action Items ..... Joshua Norton 10

11. Closing Items ..... All 10

A. Summary of Action Items

B. Upcoming Meeting Agenda Items

C. Future Meetings

i) January 4-5, 2023 – Net Conference

ii) February 1-2, 2023 – Net Conference

iii) March 1-2, 2023 – Little Rock, AR

12. No informational Items

DAY 2

Thursday, 12/08, 8:00 a.m.-12:00 p.m. CST

Estimated material time: as needed

				202
Group	MONTH	DATE	Day 1 Time (CT)	Day 2 Time (CT)
TWG	Meeting 1	Jan 3-4	1-5	9-3
ESWG	Meeting 1	Jan 4-5	9-3	8-12
TWG	Meeting 2	Jan 31-Feb 1	9-3	8-12
ESWG	Meeting 2	Feb 1-2	1-5	8-12
TWG	Meeting 3	Feb 28-Mar 1	9-3	8-12
ESWG	Meeting 3	Mar 1-2	1-5	8-12
TWG	Meeting 4	Mar 28-29	9-3	9-3
ESWG	Meeting 4	Mar 29-30	9-3	8-12
TWG	Meeting 5	May 2-3	9-3	8-12
ESWG	Meeting 5	May 3-4	1-5	8-12
TWG	Meeting 6	May 30-31	1-5	8-12
ESWG	Meeting 6	May 31-Jun 1	1-5	8-12
TWG	Meeting 7	Jun 27-28	9-3	9-3
ESWG	Meeting 7	Jun 28-29	9-3	8-12
TWG	Meeting 8	Aug 1-2	9-3	8-12
ESWG	Meeting 8	Aug 2-3	1-5	8-12
TWG	Meeting 9	Aug 29-30	9-3	8-12
ESWG	Meeting 9	Aug 30-31	1-5	8-12
TWG	Meeting 10	Sep 26-27	9-3	9-3
ESWG	Meeting 10	Sep 27-28	9-3	8-12
TWG	Meeting 11	Oct 31-Nov 1	9-3	8-12
ESWG	Meeting 11	Nov 1-2	1-5	8-12
TWG	Meeting 12	Nov 28-29	9-3	8-12
ESWG	Meeting 12	Nov 29-30	1-5	8-12
				- Joint ESW
				- Day after H

3 ESWG-TWG SCHEDULE

LOCATION	ALT. LOCATION	Type Mtg
Net Conference Only		WebEx
Net Conference Only		WebEx
Net Conference Only		WebEx
Net Conference Only		WebEx
SPP Corporate Offices – Aud. B		In Person
SPP Corporate Offices – Aud. B		In Person
Net Conference Only		WebEx
Net Conference Only		WebEx
Evergy (Kansas City, MO)	SPP - Aud. B	In Person
Evergy (Kansas City, MO)	SPP - Aud. B	In Person
Net Conference Only		WebEx
Net Conference Only		WebEx
Net Conference Only		WebEx
Net Conference Only		WebEx
Evergy (Kansas City, MO)		In Person
Evergy (Kansas City, MO)		In Person
Net Conference Only		WebEx
Net Conference Only		WebEx
Tri-State (Denver, CO)	SPP - Aud. B	In Person
Tri-State (Denver, CO)	SPP - Aud. B	In Person
Net Conference Only		WebEx
Net Conference Only		WebEx
Net Conference Only		WebEx
Net Conference Only		WebEx

G/TWG meeting

holiday

Notes
Pre-MOPC - JOINT
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ECONOMIC STUDIES WORKING GROUP MEETING

November 2-3, 2022

Net Conference

AGENDA

DAY 1

Wednesday, 11/02, 8:00 a.m.-12:00 p.m. CDT

Estimated material time: 3 hrs. 40 mins.

1. Administrative Items ..... Alan Myers 15
   - A. Call to Order, Introductions ..... Alan Myers
   - B. Receipt of Proxies ..... Joshua Norton
   - C. Review of Agenda ..... Alan Myers
   - D. Antitrust Reminder ..... Joshua Norton
2. Consent Agenda
   - A. No items
3. October 2022 MOPC & Board Debrief ..... Joshua Norton / Alan Myers 15
4. Chair nominations for 2023-2024 term (Approval) ..... Joshua Norton / Alan Myers 15

   Email vote will be taken and results shared on next day
5. 2023 ITP
   - A. Needs Assessment ..... Greg Lampley / Spencer Magby 30
   - B. SASKPower – SPP Point-to-Point changes+ ..... Eddie Watson 10
6. 2024 ITP
   - A. Scope Development
     - i) Hurdle Rates & Interchange (Approval) ..... Joshua Norton 10
     - ii) Curtailment Price (Approval) ..... Joshua Norton / Colton Stanton 15

iii) State Renewable Policy Standards (Approval) ..... Krishada Watson 10

iv) Resource Plan (ESWG AIs 211 & 212) ..... Krishada Watson 30

(1) Conventional Gen Prototypes

(2) Resource Allocation, Assignment & Accreditation

v) Persistent Operational Solution Evaluations (Approval) ..... Ahmed Alazzawi 10

vi) Portfolio Consolidation (Approval) ..... Ahmed Alazzawi 15

vii) Sensitivity Analysis (Approval) ..... Spencer Magby 20

viii) Draft Scope Document ..... Joshua Norton 20

B. Load & Generation review update+ ..... David Duhart 15

DAY 2

Thursday, 11/03, 8:00 a.m.-12:00 p.m. CDT

Estimated material time: 2 hrs..

7. 2022-2023 Comprehensive Roadmap cycle ..... Erin Cathey 10
8. Market Powerflow Models (MPMs) in the ITP ..... Joshua Pilgrim 30
9. ESWG Action Item 190 - Transmission outage metric review ..... Antonio Barber 20
10. ITP Schedules ..... Dara Solomon 15
    A. 2022 20-Year Assessment
    B. 2023 ITP Schedule
    C. 2024 ITP Schedule+
11. 20-Year Assessment (20YA)
    A. Scope & Study Action Items Update ..... Sherri Maxey 10
12. 2023 ESWG Meeting Schedule ..... Joshua Norton 15
13. Review of Action Items ..... Joshua Norton 10
14. Closing Items ..... All 10
    A. Summary of Action Items
    B. Upcoming Meeting Agenda Items

C. Future Meetings

i) December 7 & December 8 – Net conference

15. No informational Items

+ denotes verbal update

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Joshua Norton	jnorton@spp.org	Webex
Joshua Pilgrim	jpilgrim@spp.org	Webex
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Kelsey Allen	kallen@spp.org	Webex
Kirk Hall	khall@spp.org	Webex
Krishada Watson	kwatson@spp.org	Webex
Kristen Darden	kdarden@spp.org	Webex
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Kyle Combes	kyle.combes@1898andco.com	Webex
Kyle McKinney	kmckinney@gsec.coop	Webex
Kyle Vaughan	kvaughan@spp.org	Webex
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Ryan Benton	bentonre@oge.com	Webex

Ryne Garrison	ryne.garrison@1898andco.com	Webex
Sherri Maxey	smaxey@spp.org	Webex
Spencer Magby	smagby@spp.org	Webex
Steve Gaw	rsgaw1@gmail.com	Webex
Steve Hohman	shohman@oppd.com	Webex
Steve Malousek	srmalousek@oppd.com	Webex
Sunny Raheem	sraheem@spp.org	Webex
Susanna Padilla	spadilla@spp.org	Webex
Tim Owens	tjowens@nppd.com	Webex
Travis Hancock	travis.hancock@sunflower.net	Webex
Tyler Baxter	tyler.baxter@cbpower.coop	Webex
William Eckert	weckert@spp.org	Webex

SOUTHWEST POWER POOL

ECONOMIC STUDIES WORKING GROUP MEETING

November 2-3, 2022

Net Conference

SUMMARY OF MOTIONS AND ACTION ITEMS

2024 ITP Scope:

- Approved **hurdle rates & interchange** scope language
- Approved **curtailment price** scope language
- Approved **state renewable policy standards** scope language
- Approved the **portfolio consolidation** scope language
- Approved the **sensitivity analysis** scope language

2023 ITP

- Approved the **2023 ITP MEM for use in the 2023 ITP constraint assessment**

SOUTHWEST POWER POOL

ECONOMIC STUDIES WORKING GROUP MEETING

November 2-3, 2022

Net Conference

MINUTES

AGENDA ITEM 1 – ADMINISTRATIVE ITEMS

Economic Studies Working Group (ESWG) Chair Alan Myers called the meeting to order at 8:00 a.m. The following members were in attendance or represented by proxy:

Al Tamimi, SUNC
Alan Myers, ITC
Anita Sharma, AEP
Calvin Daniels, WFEC
Derek Brown, Evergy
Gayle Nansel, WAPA
Jeremy Severson, BEPC
Jody Holland, GHP
Jordan Schmick, SPS
Kurt Stradley, LES
Kyle McKinney, GSEC
Michael Watt, OMPA
Randy Collier, CUS
Steve Gaw, APA
Steve Hohman, OPPD
Tim Owens, NPPD
Zac Hager, OGE

(Attachment 1) (Attachment 2)

Joshua Norton confirmed there was a quorum and provided the antitrust statement. Alan Myers reviewed the agenda for any changes. (Attachment 3)

> **Tim Owens made a motion, seconded by Kurt Stradley to approve the agenda. The motion was approved unanimously.**

AGENDA ITEM 2 – CONSENT AGENDA

There were no consent agenda items.

AGENDA ITEM 3 – OCTOBER 2022 MOPC & BOARD DEBRIEF

Joshua Norton and Alan Myers reviewed ESWG-related items from MOPC. (Attachment 4)

AGENDA ITEM 4 – CHAIR NOMINATIONS FOR 2023-2024 TERM

Joshua Norton reviewed nominations. Jordan Schmick and Calvin Daniels were the nominees and gave a brief statement. An email vote was taken resulting in Calvin Daniels receiving the ESWG recommendation for chair. The Corporate Governance Committee will take this up in their next meeting. (Attachment 5)

AGENDA ITEM 5A – 2023 ITP: NEEDS ASSESSMENT

Greg Lampley and Spencer Magby reviewed a presentation on the reliability, policy, and economic needs assessment milestone. (Attachment 6)

AGENDA ITEM 5B – 2023 ITP: SASKPOWER – SPP POINT-TO-POINT CHANGES

Eddie Watson and David Duhart discussed updates made to the model for SASK power.

AGENDA ITEM 6AI – 2024 ITP SCOPE DEVELOPMENT: HURDLE RATES & INTERCHANGE

Joshua Norton presented recommended scope language for handling hurdle rates and interchange in the MEM. (Attachment 7)

> **Anita Sharma made a motion, seconded by Jeremy Severson to approve the hurdle rates & interchange scope language. The motion was approved unanimously.**

AGENDA ITEM 6AII – 2024 ITP SCOPE DEVELOPMENT: CURTAILMENT PRICE

Joshua Norton presented recommended scope language for curtailment pricing and provided details on some tests staff is performing to further determine curtailment pricing methodology. (Attachment 8) (Attachment 9)

> **Steve Gaw made a motion, seconded by Calvin Daniels to approve the curtailment price scope language. The motion was approved unanimously.**

AGENDA ITEM 6AIII – 2024 ITP SCOPE DEVELOPMENT: STATE RENEWABLE POLICY STANDARDS

Krishada Watson presented the state RPS table for inclusion in the scope. (Attachment 10)

> **Tim Owens made a motion, seconded by Kyle McKinney to approve the state renewable policy standards scope language. The motion was approved unanimously.**

AGENDA ITEM 6AIV – 2024 ITP SCOPE DEVELOPMENT: RESOURCE PLAN

Krishada Watson reviewed previous ITP scope's process for resource planning, ELCC method, and options for resource planning in the 2024 ITP. (Attachment 11)

After discussion, the following straw polls were taken:

Allocation methodology:

Option 1 (Status quo using LRS) received 1 vote

Option 2 (Allocate renewables first based upon resource planning template responses to those utilities forecasting additions) received 16 votes

Conventional prototype methodology:

Option 1 (Use current methodology of assigning CCs & CTs) received 12 votes

Option 2 (Use resource planning software to choose the best conventional generator prototypes for SPP as a whole) received 2 votes

Regional or zonal reserve margin:

Regional received 1 vote

Zonal received 7 votes

This item will be on the December agenda for further review and approval.

AGENDA ITEM 6AV – 2024 ITP SCOPE DEVELOPMENT: PERSISTENT OPERATIONAL SOLUTION EVALUATIONS

Ahmed Alazzawi presented language for persistent operational solution evaluation. It was determined follow up was needed with several members before bringing language to approve in December. (Attachment 12)

AGENDA ITEM 6AVI – 2024 ITP SCOPE DEVELOPMENT: PORTFOLIO CONSOLIDATION

Ahmed Alazzawi presented recommended portfolio consolidation process for the scope. (Attachment 13)

> **Tim Owens made a motion, seconded by Kurt Stradley to approve the portfolio consolidation scope language for the 2024 ITP. The motion was approved unanimously.**

AGENDA ITEM 6AVII – 2024 ITP SCOPE DEVELOPMENT: SENSITIVITY ANALYSIS

Spencer Magby presented recommended scope language for sensitivity analysis. (Attachment 14)

> **Steve Gaw made a motion, seconded by Jeremy Severson to approve the sensitivity analysis scope language for the 2024 ITP. The motion was approved unanimously.**

AGENDA ITEM 6AVIII – 2024 ITP SCOPE DEVELOPMENT: DRAFT SCOPE DOCUMENT

Joshua Norton spoke about the next steps for the 2024 ITP scope. A draft scope document will be circulated after the meeting for feedback ahead of the December meeting.

AGENDA ITEM 6B – 2024 ITP: LOAD AND GENERATION REVIEW UPDATE

David Duhart gave an update on the ongoing load and generation review milestones for the 2024 ITP.

AGENDA ITEM 7 – 2022-2023 COMPREHENSIVE ROADMAP CYCLE

Erin Cathey reviewed the comprehensive roadmap process and informed the group of upcoming trainings. (Attachment 15)

AGENDA ITEM 8 – MARKET POWERFLOW MODELS (MPMS) IN THE ITP

Joshua Pilgrim presented potential ITP manual language for MPMs. (Attachment 16) (Attachment 17)

AGENDA ITEM 9 – ESWG ACTION ITEM 190 - TRANSMISSION OUTAGE METRIC REVIEW

Antonio Barber presented the methodology for the upcoming work to update the transmission outage metric value. (Attachment 18)

Tim Owens began to chair the meeting.

AGENDA ITEM 10 – ITP SCHEDULES

Dara Solomon reviewed the ITP schedules. (Attachment 19) (Attachment 20)

AGENDA ITEM 11 – 20-YEAR ASSESSMENT: SCOPE & STUDY ACTION ITEMS UPDATE

Sherri Maxey reviewed the action items for the 20-year assessment and noted that the remaining three items will be coming to the group soon for discussion. (Attachment 21)

AGENDA ITEM 12 – 2023 ESWG MEETING SCHEDULE

Joshua Norton reviewed the draft 2023 ESWG meeting schedule and received feedback for a few changes. (Attachment 22)

AGENDA ITEM 13 – REVIEW OF ACTION ITEMS

Joshua Norton gave a summary of progress on the action items. (Attachment 23)

ECONOMIC STUDIES WORKING GROUP MINUTES
November 2-3, 2022

AGENDA ITEM 14 – CLOSING ITEMS

There were no action items taken.

EMAIL ITEMS

October 24, 2022

A motion was solicited to approve the 2023 ITP Market Economic Model (MEM) for use in the 2023 ITP Constraint Assessment, as posted to GlobalScape on 10/21/2022.

> **Al Tamimi made a motion, seconded by Jeremy Severson, to approve 2023 ITP Market Economic Model (MEM) for use in the 2023 ITP Constraint Assessment, as posted to GlobalScape on 10/21/2022. The motion was approved unanimously.**

Respectfully Submitted,

Joshua Norton

Secretary

SOUTHWEST POWER POOL, INC.
ECONOMIC STUDIES WORKING GROUP

Action Items Status Report
November 2-3, 2022

	Action Item	Date Originated	Status	Comments
190	Utilize the results from RCAR III to determine the ratio of APC benefit to Transmission Outages benefit to be applied in the ITP assessments.	10/12/17	In progress	Working with SPP operations on additional APC benefit with outages included. Mar: Ops is planning to perform after RCAR III and Value of Transmission study. Sept 29: Estimated start date is 2022 Q2 Aug: Estimated to complete by 2022 EOY **Nov '22: Methodology on agenda**
210	Create list of 20YA items to review	01/07/21	In Progress	June: Continue review of list and discussion of items Jan: Several items on the agenda for discussion Feb: Several items on the agenda for discussion Mar: Emissions target analysis being discussed Aug 4: Update presented Aug 31-Sep 1: Constraint Assessment on agenda
211	Revisit the SPP Other bucket and how we use those resources in Resource Plan Phase II Accreditation	05/19/21	In progress	July: Review process in upcoming meeting Sept 29: Resource Accreditation is being discussed as part of 2023 ITP Scope. Feb: To be discussed as part of 2024 ITP Scope development ~June 2022 **Nov '22: Accreditation methodology on agenda**
212	Review ELCC Accreditation	11/03/21	In progress	Feb: To be discussed as part of 2024 ITP Scope development ~June 2022 May: Begin discussions **Nov '22: ELCC accreditation on agenda**
213	Discuss incorporation of Utility Integrated Resource Plans in the ITP	11/03/21	In progress	Feb: To be discussed as part of 2024 ITP Scope development ~June 2022 May: Begin discussions Aug: Will be discussed at ESWG meeting.

	Action Item	Date Originated	Status	Comments
				Nov '22: final piece for 2024 ITP scope on agenda as part of accreditation process
216	Address PROMOD battery modeling issues	03/30/22	In Progress	Mar 30: Action Item added.
217	Review modeling issues surrounding hybrid and co-located resources in economic models	05/05/22	In Progress	May 5: Action Item added

Proxy	Member	Note
Chris Mathes	Anita Sharma	2nd day
Curtis Miller	Calvin Daniels	2nd day 10:00am
Robert Bouda	Derek Brown	2nd day
Ryan Benton	Zac Hager	

Hello Josh,

I give my proxy to Chris Matthes for Day 2 of the ESWG meeting this week (on Nov 3).

Thanks,

AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY™

ANITA A SHARMA | **ENGINEER STAFF**
ASHARMA@AEP.COM | C:614.753.5908

I must jump off at 10 for a little while. Please accept Curtis Miller as my proxy for that time.

Calvin Daniels

Principal Resource Planning Engineer

Josh,

I don't think we have any voting items on 11/3, but Robert Bouda will have my proxy that day.

Thanks,

Derek Brown, MSEE, PE

I won't be able to attend the ESWG this month so I am going to have Ryan Benton be my proxy.

Thanks,

Zac Hager

OG&E Resource Planning

OCTOBER 2022 MOPC & BOARD DEBRIEF

JOSHUA NORTON / ALAN MYERS

ESWG NOVEMBER 2022

MOPC

MEETING MATERIALS

MEETING MINUTES

MOPC – CONSENT AGENDA

Passed 100%

a. **July 2022 meeting minutes**

b. **Economic Studies Working Group (ESWG)**
   RR498 – Resource addition requests

c. **Market Working Group**
   i. RR514 – Violation relaxation limits annual analysis 2022 recommendations
   ii. RR504 – Improved economic incentive of regulation mileage
   iii. RR503 – Clarification of fast-start pricing mitigation
   iv. RR518 – Regulation limit deviation correction

d. **Project Cost Working Group**
   RR497 – BP7060 Section 2.2

e. **Regional Tariff Working Group**
   RR507 – Annual revisions to Attachment W index of grandfathered agreements

f. **Transmission Owner Selection Task Force (TOSPTF)**
   RR510 – Transmission owner selection process Business Practice 7700 updates
   RR511 – Independent Expert Panel public report posting deadline

g. **Transmission Working Group (TWG)**
   RR492 – Clarifications to financial security refund eligibility per Section 8.14 of Attachment V

h. **TWG & ESWG**
   RR500 – ITP Manual, section 10.3 updates

i. **Supply Adequacy Working Group (SAWG)**
   RR499 – SPP Planning Criteria testing requirement change

OCTOBER BALLOT RECAP

96% average consensus

Approved the consent agenda as presented **(13 items) – on previous slide**	PASS	100%
Approved RR508–Deliverable capacity for winter season, as presented	PASS	100%
Approved RR513–Removing barriers to surplus service, as presented	PASS	100%
Approved RR517–Interim and Limited Service, as presented	PASS	93%
Approved RR516–Planning Reserve Margin increase, as presented	PASS	66%
Approved RR515 as approved by SAWG, modified by staff with edits to 5(a), 6(a) and 6(c)	PASS	72%
Approved completion of MOPC action item 314, as presented	PASS	100%
Approved RR520–Reporting non-registered accredited demand response, as presented	PASS	83%
Approved RR512–Reporting accredited behind-the-meter generation, as presented	PASS	100%
Endorsed the 2022 ITP Recommended Plan as presented and endorse the 2022 ITP Assessment Report as documentation of completion of the ITP planning process	PASS	96%

RR SUMMARY TO MOPC – OCTOBER 2022

Revision Requests Submitted for MOPC Approval

Primary Working Group	Title	Impacted Document						Estimated Cost	
		Tariff	ITP Manual	Business Practice	Planning Criteria	Operating Criteria	Market Protocols	Vendor Cost	Staff Hours
ESWG	RR 498 – Resource addition requests		X					None	None
MWG	RR 503 – Clarification of fast-start pricing mitigation	X					X	None	None
MWG	RR 504 – Improved economic incentive of regulation mileage	X					X	$20-60k	2,258
MWG	RR 514 – Violation relaxation limits annual analysis 2022 recommendations	X					X	None	None
MWG	RR 518 – Regulation limit deviation correction	X					X	None	None
ORWG	RR 512 – Reporting accredited behind-the-meter generation (WWE RPA2.13)					X		None	None
ORWG	RR 520 - Reporting non-registered accredited demand response					X		None	None
PCWG	RR 497 – BP7060 Section 2.2			X				None	None
RTWG	RR 507 – Annual revisions to Attachment W index of grandfathered agreements	X						None	None
TOSPTF	RR 510 – Transmission Owner Selection Process Business Practice 7700 updates			X				None	None

Approval Implications

- Estimated Vendor Cost for submitted RRs $20-60k
- Estimated Staff Hours for submitted RRs is 2,258

RR SUMMARY TO MOPC – OCTOBER 2022 – CONT.

Revision Requests Submitted for MOPC Approval – cont.

Primary Working Group	Title	Impacted Document						Estimated Cost	
		Tariff	ITP Manual	Business Practice	Planning Criteria	Operating Criteria	Market Protocols	Vendor Cost	Staff Hours
TOSPTF	RR 511 – IEP public report posting deadline	X						None	None
TWG	RR 492 – Clarifications to financial security refund eligibility per Section 8.14 of Attachment V	X						None	None
TWG	RR 498 – Generator Interconnection Manual			X				None	None
TWG	RR 513 – Removing barriers to surplus service	X						None	None
TWG	RR 517 – Long-term service implications to interim interconnection service and interconnection service subject to limited operations			X				None	None
TWG/ESWG	RR 500 - ITP Manual, section 10.3 updates		X					None	None
SAWG	RR 499 – SPP Planning Criteria testing requirement changes				X			None	None
SAWG	RR 508 – Deliverable capacity for winter season	X						None	None
SAWG	RR 515 – PRM waiver process	X						None	None
SAWG	RR 516 – Planning reserve margin (PRM) increase				X			None	None

SPP BOARD

MEETING MATERIALS

ADDITIONAL MATERIALS

BOARD – CONSENT AGENDA

All Passed

Recommendations: Consent Agenda

a. Approve 07/26/2022 Minutes

b. CGC-Committee Nominations

i. Finance Committee
- TU-Mike Wise, Golden Spread Electric Coop.

ii. Human Resources Committee
- TU-Noman Williams, GridLiance High Plains

iii. Strategic Planning Committee
- TO-Tom Christensen, Basin Electric Power
- TO-Richard Ross, American Electric Power
- TU-Matt Pawlowski, NextEra Energy Resources
- TU-Natasha Henderson, Golden Spread Electric Co.

iv. Organizational Chair Expiring Terms
- Credit Practices Working Group, Caleb Head, NTEC
- System Protection & Control Advisory Group, Chris Angland, OPPD
- Project Cost Working Group, Brian Johnson, AEP
- Market Working Group, Richard Ross, AEP

c. Staff: Southwestern Public Service Co. NTC 210574 upgrade withdrawals
- i. Newhart-Potter 230 kV Terminal Upgrades
- ii. Cargill – Deaf Smith #24 115 kV Ckt 1 Rebuild
- iii. Parmer - Deaf Smith #24 115 kV Ckt 1 Rebuild
- iv. Parmer – Deaf Smith #20 115 kV Ckt 1 Rebuild

d. Staff:
- i. Southwestern Public Service Co. – Twist – Wilco 115 kV Modification
- ii. Basin Electric Power Coop. –Whitlock 230 kV Terminal Upgrades Withdrawal
- iii. OPPD S3454 –S3740 345 kV New Line Cost Increase
- iv. Sheldon-Monolith Cost Estimate Increase
- v. Anadarko-Gracemont 138 kV Rebuild Out of Cycle Re-Evaluation Request
- vi. Line - Kummer Ridge - Round Up 345 kV Suspension
- vii. Western Joint Dispatch Agreement

e. MOPC:
- i. RR514 Violation Relaxation Limits (VRL) Annual Analysis 2022 Recommendation
- ii. RR508 Deliverable Capacity for the Winter Season
- iii. RR516 PRM Increase
- iv. RR499 SPP Planning Criteria Testing Requirement Changes
- v. RR512 Reporting Accredited BTM Generation (WWE RPA2.13)
- vi. RR520 Reporting on Non-Registered Accredited Demand Response

OCTOBER BALLOT RECAP

Approved the consent agenda as presented – **on previous slide**	**PASS**
Approved the 2023 SPP Operating and Capital Budget as recommended by the Finance Committee	PASS
Approved the 2022 ITP recommended plan and the 2022 ITP Assessment Report as documentation of completion of the ITP planning process	PASS
Authorized the filing of RR515 as modified and approved by the SPP RSC consistent with the RSC's authority under Section 7.2 of the SPP Bylaws	PASS

Name of Nominee:	Calvin Daniels
Company:	Western Farmers Electric Cooperative
Email:	Calvin.Daniels@wfec.com
Phone:	405.402.0149
Brief description of relevant experience or involvement with the ESWG:	Involved with ESWG since 2017 and currently a voting member. Worked with all utility structures, including RTOs, large IOUs, generation developers, Joint Action Agencies, G&T Coops, and consultants. Understanding the points of view of the participants will help with facilitating discussions and keeping the focus on the larger picture. Work experience over 40 years in the industry includes Transmission Planning, Generation Planning, NERC compliance, consulting for the industry, load forecasting, operations, and planning software development. More details on my work experience are included in my LinkedIn profile.

Name of Nominee:	Jordan Schmick
Company:	Xcel Energy/Southwestern Public Service Co
Email:	Jordan.h.schmick@xcelenergy.com
Phone:	719-238-4935
Brief description of relevant experience or involvement with the ESWG:	I have been the Regional Transmission Planner for Xcel Energy southwest region for 8 years, primarily focusing on economic modeling and large-scale transmission projects. During that time, I've been the primary technical representative for Xcel Energy Transmission in SPP efforts focused on economic and regional planning, including the ESWG. This includes developing and providing feedback on transmission models, participating in the SPP stakeholder processes, policy development and coordinating our company's project submissions and feedback on futures and modeling. I am the current Xcel Energy representative on ESWG. Additionally, I serve as the company representative in the Seams Steering Committee, now the Seams Advisory Group, since 2016 and coordinate positions of Xcel Energy for both internal planning and SPP stakeholder process efforts. I have a Bachelor of Science in Electrical Engineering from the Colorado School of Mines and a Master in Business Administration from Colorado State University. I am a licensed Professional Engineer in the state of Colorado since 2015.

SPP Southwest Power Pool

2023 ITP

ESWG

Working together to responsibly and economically keep the lights on today and in the future.

SouthwestPowerPool SPPorg southwest-power-pool

SPP Southwest Power Pool

2023 ITP

NEEDS ASSESSMENT

ESWG: NOVEMBER 2-3, 2022

OVERVIEW

- Needs Assessment Purpose
- Needs Assessment Process
  - Reliability
    - Upcoming Postings
  - Economic & Policy

NEEDS ASSESSMENT PURPOSE

- Produce a robust list of needs to be addressed in the annual ITP Study
  - Reliability
  - Short Circuit
  - Operational
  - Economic
  - Policy
- System intact and contingency conditions
- Post a Final Needs List and open the DPP window

2023 ITP

RELIABILITY NEEDS ASSESSMENT

RELIABILITY NEEDS ASSESSMENT PROCESS

- Perform ACCC on nine base reliability (BR) models
  - Contingencies (NERC Standard TPL-001)
    - Auto-generated and member submitted
    - Taken against all models, not just TPL sensitivity models
  - Verifying Needs
    - SPP Planning Criteria and local planning criteria are taken into account
    - Initial violations list is examined by staff to remove specific invalid violations (Non-SPP, Out of Scope, etc.)
    - Preliminary violations are posted for TOs to provide existing mitigation information to help identify true needs

RELIABILITY NEEDS ASSESSMENT PROCESS

Invalidation Criteria Template – Preliminary Violations Posting

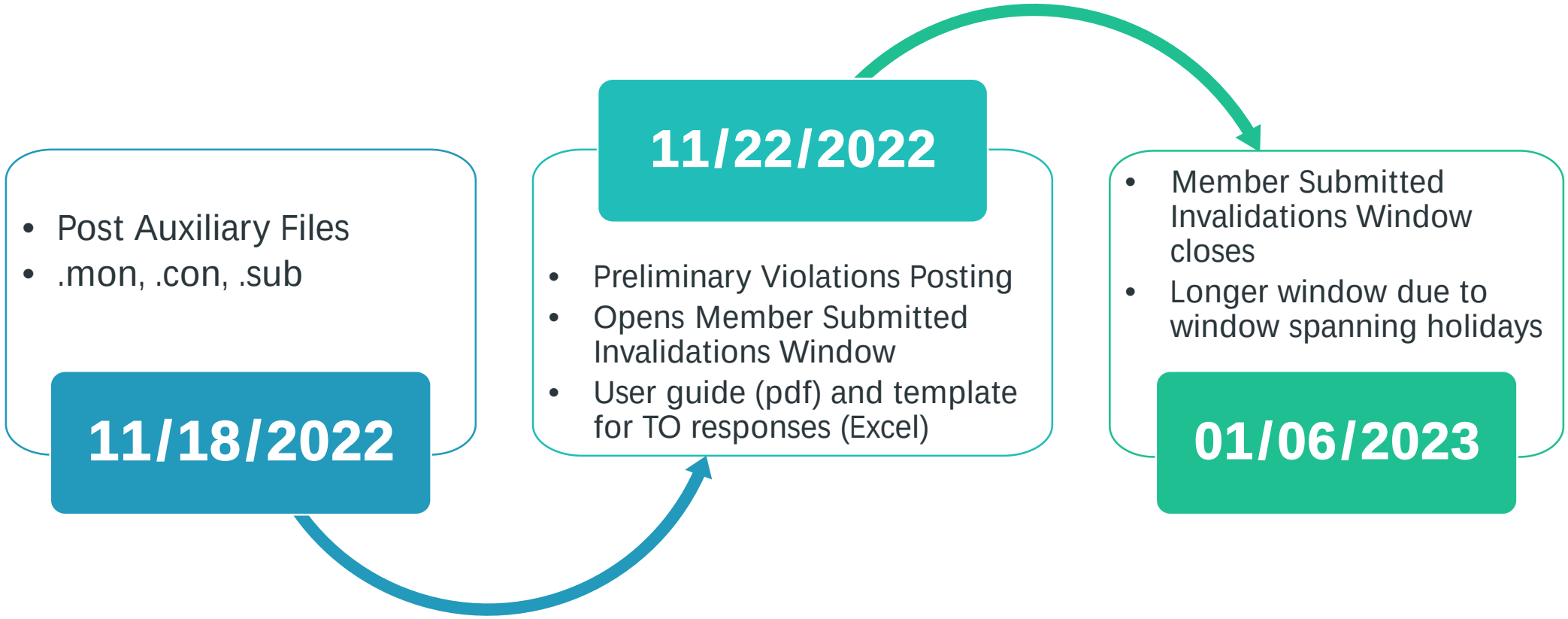
	A	B	C
1	**Type Name**	**Idev Required**	**Type Description**
2	Model Correction	Y	Correction to model assumptions to be applied in the basecase. Examples: mileage/impedance correction, load power factor changes, TO planned projects
3	Reactive Adjustment	Y	Changes in reactive settings to resolve voltage violations for specific events. Examples: transformer tap changes, switched shunt mode/init output changes
4	Existing Operating Guide	Y	Operating guide on file with SPP to resolve transmission violations in lieu of transmission upgrades
5	Internal Redispatch	Y	Firm-to-Firm generation redispatch option to resolve transmission violations in lieu of transmission upgrades
6	Existing NTC or Planned Project	Y	There is an existing SPP NTC or TO planned project to resolve transmission violations. Please indicate the planned project's expected in-service date in the Submitter Comments field and follow the TO planned project process as applicable.
7	Non-Tariff Facility	N	Monitored facility is not under the SPP tariff
8	Non Load-Serving Bus	N	Load is not being served from the voltage violated bus, either at the bus itself or at the distribution level through the violated bus. This invalidation applies to contingency conditions only.
9	Invalid Contingency	N	Elements are not able to be outaged as a result of a single event as defined in the contingency file or otherwise incorrectly defined
10	Other	N	Other invalidation type, with description entered by submitter on "Submission" tab
11			
12			
13			

RELIABILITY NEEDS ASSESSMENT PROCESS

TPL-001 P3 Events

- P3 contingencies are a NERC defined contingency that entails the removal of a generator, a system adjustment, then a second contingency after that
- P3 process will be carried out on the TPL sensitivity models to determine if there are any potential P3 needs
- Potential P3 needs will be communicated to the affected TO to provide mitigations
- If there is no acceptable mitigation, then the need is valid and will be added to the needs assessment

RELIABILITY NEEDS ASSESSMENT POSTING DATES



2023 ITP

ECONOMIC NEEDS ASSESSMENT

ECONOMIC NEEDS ASSESSMENT PROCESS

- Identify congested flowgates per filtering requirements
  - Filter and rank congested constraints of each future and year to target a list of economic needs
- Identify top areas of congestion per future/year
  - Congestion is reflected as Locational Marginal Price (LMP) cost due to binding or breaching constraints
- Review underlying drivers of needs to facilitate invalidation of needs and determining related needs

ECONOMIC NEEDS ASSESSMENT PROCESS

- Congestion occurs when a transmission constraint results in sub-optimal dispatch of generation to avoid violating the constraint during SCUC/SCED simulation
- Constraints meeting criteria defined in the ITP Manual are classified as economic needs

ECONOMIC NEEDS ASSESSMENT PROCESS

- Binding constraints are ranked by highest congestion score

- Binding constraints with less than $50,000/MW annual congestion score are removed from consideration
  - Exception: Constraints related to others meeting criteria
- External constraints with less than $1M in potential benefit to SPP removed from consideration

ECONOMIC NEEDS ASSESSMENT PROCESS

- A list of binding constraints will be developed for each scenario and ranked based upon the congestion score associated with each constraint.
  - > $50,000/MW in annual congestion
- SPP may also use engineering judgement to include additional information such as need relationships (Economic/Reliability/Policy/Operational)

2023 ITP

POLICY NEEDS ASSESSMENT

POLICY NEEDS ASSESSMENT PURPOSE

- “Needs driven by public policy arise if the economic simulations identify conditions on the system that keep a utility from meeting its regulatory or statutory mandates and goals as defined by the **renewable policy review** and/or **future specific public policy assumptions** identified in the study scope.” – ITP Manual

POLICY NEEDS ASSESSMENT PROCESS

1) Determine which Utility by State requires a renewable mandate/goal per the Policy Survey.
2) Determine which renewable units can be applied to each Utility by State based on ownership percentage and state.
3) Determine how much renewable energy can be applied to the Utility by State renewable mandate/goal as determined by the Curtailment Report.
4) Ensure each Utility by State is meeting renewable energy requirement by renewable type as defined in the renewable policy review.

2023 ITP

QUESTIONS?

GOVERNING DOCUMENTS

- OATT, Attachment O Section III

6) Identification of Needs and Detailed Project Proposals

After the study scope has been finalized, the Transmission Provider shall **identify potential transmission needs**, including any needs driven by Public Policy Requirements, **in accordance with the Integrated Transmission Planning Assessment scope and the Integrated Transmission Planning Manual**. The Transmission Provider shall **notify stakeholders of identified transmission needs** and provide a transmission planning response window of thirty (30) days during which any stakeholder may propose a detailed project proposal (DPP)...

GOVERNING DOCUMENTS

- NERC TPL-001-4
  - Table 1 – Basis for contingencies to be assessed during the study
- ITP Manual
  - Section 4 Needs Assessment
    - 4.2 Reliability Needs Assessment
      - 4.2.7 Short-Circuit Needs Assessment
    - 4.4 Persistent Operational Needs Assessment

2.2.1.10 Renewable Pricing

The economic modeling of wind and solar resources include two primary parameters that impact pricing: curtailment price and VOM.

Wind and solar resources include an hourly profile. The curtailment price for wind and solar is the price at which the resource will curtail. If the locational marginal price (LMP) at the generation bus is greater than or equal to the curtailment price, the unit will generate energy in accordance with the hourly profile. If the LMP at the generation bus is less than the curtailment price, the unit generation will be curtailed. As a result, the curtailment prices impact the dispatch of wind and solar units in the economic models but do not impact the operating cost of the units.

To model a curtailment price reflective of market operation for wind and solar units, current IRS legislation will be utilized to account for projected production tax credit (PTC) impacts.

Both existing and projected wind and solar units will have a negative curtailment price[1] that reflects the "grossed-up" value of a PTC[2] in accordance with applicable laws and regulations. Investment tax credits (ITC) will not be considered in the adjustment of curtailment prices unless defined in the ITP Scope. If no PTC nor ITC is applicable, existing and projected units will have a $0/MWh curtailment price.

For the purposes of applying the above curtailment price modeling criteria to additional wind and solar amounts determined by the Renewable Resource Expansion Plan, SPP and the ESWG will estimate the additional wind and solar amounts per year and use information from the Resource Siting Plan to determine appropriate curtailment price methodology for additional units.[3]

If any significant changes to the PTC rules occur during an ITP assessment, SPP staff or stakeholders can bring information to the ESWG for review and potential approval for use in the ITP assessment. Any resulting deviations from this standard curtailment pricing will be noted in the study report.

The VOM for wind and solar resources defines the unit operating cost per MWh of energy generated. This operating cost is included in production cost calculations. The VOM parameter does not impact dispatch, curtailment, or LMPs in the economic model simulations.

For all wind and solar units, the VOM shall be $0/MWh to reflect the low operating cost of renewable resources.

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[1] The negative curtailment price will be adjusted for inflation to the study year using a typically assumed inflation rate for the study.
[2] Reflecting a IRS published PTC value and federal corporate income tax rate at the commencement of the study where the "grossed-up" PTC value = PTC/(1-corporate tax rate)
[3] For example, approximate projected wind amounts per year can be determined from existing wind amounts and projected wind amounts by linear interpolation or other means and wind site rankings from the Resource Siting Plan can be used by assuming highest rank sites receive earlier in-service dates.

SPP Southwest Power Pool

2024 ITP

SCOPE DEVELOPMENT – CURTAILMENT PRICING

NOVEMBER 2022

JOSHUA NORTON

OBJECTIVES

- Review ITP Manual and previous ITP scope language on renewable curtailment pricing
- Determine best approach for 2024 ITP scope

ITP MANUAL LANGUAGE
RENEWABLE PRICING

- To model a curtailment price reflective of market operation for wind and solar units, **current IRS legislation will be utilized to account for projected production tax credit (PTC) impacts.**
- **Both existing and projected wind and solar units will have a negative curtailment price[1] that reflects the "grossed-up" value of a PTC[2]** in accordance with applicable laws and regulations. Investment tax credits (ITC) will not be considered in the adjustment of curtailment prices unless defined in the ITP Scope. **If no PTC nor ITC is applicable, existing and projected units will have a $0/MWh curtailment price**.
- For the purposes of applying the above curtailment price modeling criteria to additional wind and solar amounts determined by the Renewable Resource Expansion Plan, **SPP and the ESWG will estimate the additional wind and solar amounts per year and use information from the Resource Siting Plan to determine appropriate curtailment price methodology for additional units.** [3]
- **If any significant changes to the PTC rules occur during an ITP assessment**, SPP staff or stakeholders can bring information to the ESWG for review and potential approval for use in the ITP assessment. Any resulting deviations from this standard curtailment pricing will be noted in the study report.

Footnotes:

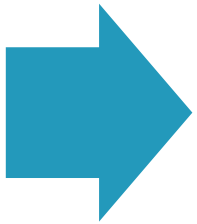
- 1 The negative curtailment price will be adjusted for inflation to the study year using a typically assumed inflation rate for the study.
- 2 Reflecting a IRS published PTC value and federal corporate income tax rate at the commencement of the study where the "grossed-up" PTC value = PTC/(1-corporate tax rate)
- 3 For example, approximate projected wind amounts per year can be determined from existing wind amounts and projected wind amounts by linear interpolation or other means and wind site rankings from the Resource Siting Plan can be used by assuming highest rank sites receive earlier in-service dates.

PREVIOUS ITP SCOPE LANGUAGE

- **CURTAILMENT PRICE**
- The curtailment price of wind will be set in accordance with IRS production tax credits**. An automatic repower for all wind units will be assumed after the expiration of the original production tax credit.** The repower will consist of the renewal of the PTCs that were originally issued based on the unit's construction start date.
- The original production tax credits will be assumed to be expired after 10 years of being in service.

CURRENT TESTING IN PROGRESS

Apply curtailment pricing to all simulation areas in 2020 ITP



Review

- Base case congestion change on needs list
- If congestion changes are significant then test a couple similar projects and see if the results change

QUESTIONS AND DISCUSSION

IRA brings in possibility of more variety of production tax credits. Can one price be used per resource type in the study?

Does the ITP Manual allow for simplified application of the IRS rules on production tax credits?

Should we continue to assume repowers and continued repower eligibility for PTCs with new pricing methodology?

RECOMMENDATION

- SPP Staff recommends that the ESWG approve the following 2024 ITP scope language for curtailment pricing:
  - An automatic repower will be assumed for all wind units after 10 years of being in service.

- Note: Further analysis and review will determine appropriate curtailment pricing outside of the scope

SPP Southwest Power Pool

2023 ITP

STATE RENEWABLE POLICY STANDARDS

KRISHADA WATSON

ESWG

NOVEMBER 2022

OBJECTIVE

- Review & Approve State Renewable Policy Standards

RENEWABLE POLICY STANDARDS FOR 2024 ITP

- States within SPP not included in this table are presumed to have no RPS requirement
- A generation type of “Both” indicates that it can be met by wind and/or solar

State	RPS Type	Generation Type	Capacity- or Energy- Based	Year 5 %	Year 10 %
Kansas	Goal	Both	Capacity	20	20
Minnesota	Mandate	Both	Energy	25	25
Missouri	Mandate	Both	Energy	15	15
North Dakota	Goal	Both	Energy	10	10
New Mexico	Mandate	Both	Energy	40	50
South Dakota	Goal	Both	Energy	10	10
Texas	Mandate	Both	Capacity	5	5

RECOMMENDATION

- SPP Staff recommends that ESWG approve State Renewable Policy Standards as they appear in slide 3

KRISHADA WATSON

Planning Specialist II, Transmission Planning

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SPP Southwest Power Pool

2024 ITP

2024 ITP SCOPE – RESOURCE PLAN

NOVEMBER 2022

ESWG

KRISHADA WATSON

OBJECTIVE

- Review Resource Plan Phase II scope items
  - Conventional Generator Prototypes
  - Resource Accreditation
  - New Resource Allocation and Assignment
- Next Steps

2024 ITP

CONVENTIONAL GENERATOR PROTOTYPES

METHODOLOGY

- Staff presents the following options for methodology:
  - Option 1: Use current methodology of assigning CCs & CTs
    - A) CTs only with option of CC waiver
    - B) Consider alternative prototypes (CCS, SMR, hydrogen, etc.) and give the opportunity to utilize on a utility by utility basis
  - Option 2: Use resource planning software to choose the best conventional generator prototypes for SPP as a whole

RISKS/BENEFITS

- Option 1: Status Quo
  - Benefits: Simple approach
  - Risks: Limited Decision Quality unless specific utility information included
- Option 2: Software
  - Benefits: Incorporates additional level of Decision Quality
  - Risks: New software, model build, learning curve

RESOURCES

- The Cost and Performance Characteristics of New Generating Technologies,1 Annual Energy Outlook 2022 – EIA (EIA-AEO)
  - 2023 data should be available in March 2023 and new information can be used if deemed necessary
- Lazard Version 15.0 LCOE report posted in October 2021

CONVENTIONAL GENERATION PROTOTYPES EIA[1] AND LAZARD[2]

Generation Type	Data Source	Tech Type	Size (MW)	Total Capital Cost ($/kW)	V O&M ($/MWh)	F O&M ($/kW-yr)	Heat Rate (Btu/kWh)
Combined Cycle (CC)	EIA AEO '22	90% CCS	377	$2,736.00	$6.11	$28.89	7,124
Combined Cycle (CC)	EIA AEO '22	Single Shaft	418	$1,201.00	$2.67	$14.76	6,431
Combined Cycle (CC)	EIA AEO '22	Multi Shaft	1083	$1,062.00	$1.96	$12.77	6,370
Combustion Turbine (CT)	EIA AEO '22	Aero	105	$1,294.00	$4.92	$17.06	9,124
Combustion Turbine (CT)	EIA AEO '22	Industrial	237	$785.00	$4.71	$7.33	9,905
Nuclear	EIA AEO '22	Small Modular Reactor	600	$6,861.00	$3.14	$99.46	10,443
Combustion Turbine (CT)	Lazard 15 (2021)	Low	240	$700.00	$4.00	$7.00	9,800
Combustion Turbine (CT)	Lazard 15 (2021)	High	50	$925.00	$5.25	$21.25	8,000
Combined Cycle (CC)	Lazard 15 (2021)	Low	550	$700.00	$2.75	$15.00	6,150
Combined Cycle (CC)	Lazard 15 (2021)	High	550	$1,300.00	$5.00	$18.00	6,900
Nuclear	Lazard 15 (2021)	Low	2200	$7,800	$4.00	$121.00	10,450
Nuclear	Lazard 15 (2021)	High	2200	$12,800	$4.50	$140.50	10,450

1 - https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf
2 -https://www.lazard.com/perspective/levelized-cost-of-energy-levelized-cost-of-storage-and-levelized-cost-of-hydrogen/

2024 ITP

RESOURCE ACCREDITATION

ACCREDITATION

Submissions through Gen Review

- Accreditation of existing renewable units will be determined by member data based on SPP Planning Criteria 7.1 submitted through the Generation Review

If no submission

- If no accreditation data is submitted for a resource, then it will default to the approximate average effective load-carrying capability (ELCC) value for the respective resource (accreditation values for projected resources).

Projected resources

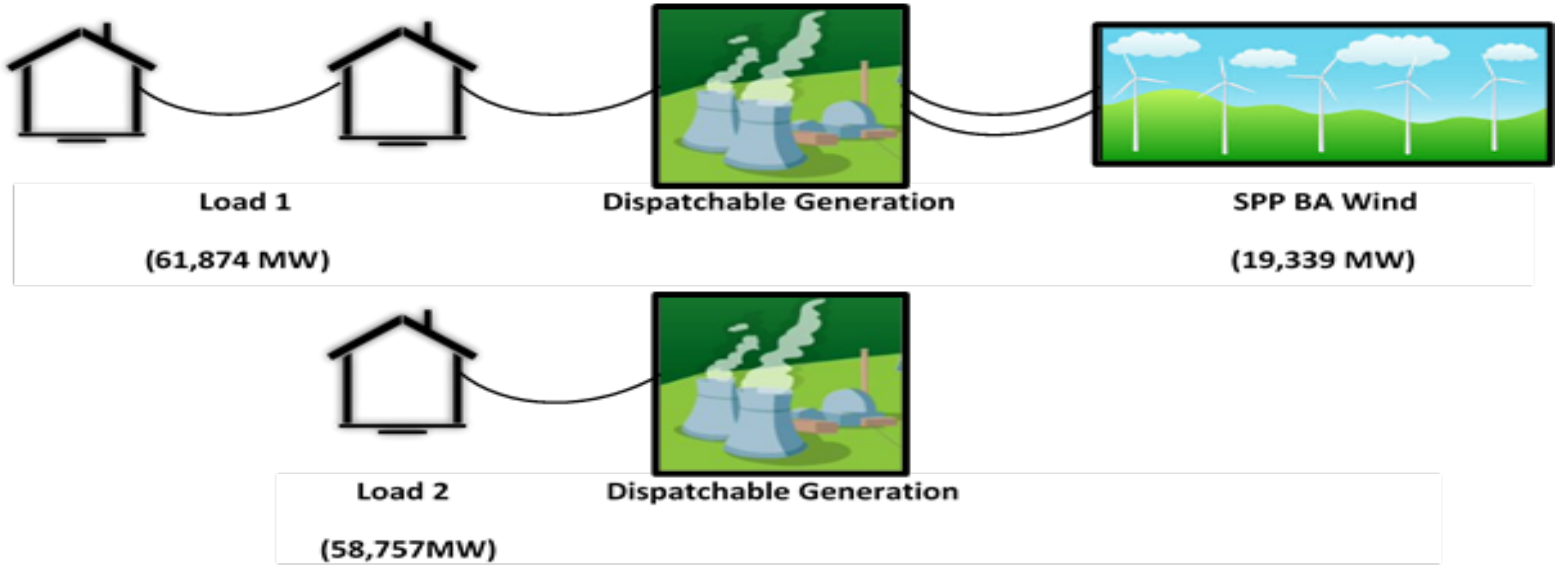
- Total projected utility scale solar, wind, and storage will be accredited based on the approximate average effective load-carrying capability (ELCC) value for the respective resource

WHAT IS ELCC?

- Effective Load Carrying Capability (ELCC) is defined as the amount of incremental load a resource can dependably and reliably serve during peak hours
  - This is accomplished by calculating the LOLE of the system with and without the studied resource
- SPP utilizes the reliability target of 1 day in 10 years which is also used in the SPP Loss of Load Expectation (LOLE) analysis

ELCC EXAMPLE

- The incremental amount of load represented by “Load 1” and “Load 2” is the ELCC MW value, while maintaining the reliability target of 1 day in 10 years
  - Load 1 = 61,874 MW
  - Load 2 = 58,757 MW
  - ELCC MW = Load 1 – Load 2 = 61,874 – 58,757 = 3,117 MW
  - ELCC % = ELCC MW/Nameplate Wind analyzed = 3,117 / 19,339 = 16.1%



2024 ITP

NEW RESOURCE ALLOCATION & ASSIGNMENT

PREVIOUS METHODOLOGY

- Previous ITP's we have utilized a 12% cap on storage/wind
  - Removed in 2022
- Used LRS for Solar and ESR, zonal reserve margin for wind
  - Moved to all LRS in 2023 ITP

Original 2022 ITP

	SOLAR	WIND	BATTERY STORAGE
ASSIGNED	Yes	No	No
ALLOCATED	Load-Ratio Share	Based on Zonal Reserve Margin	Load-Ratio Share

2023 ITP

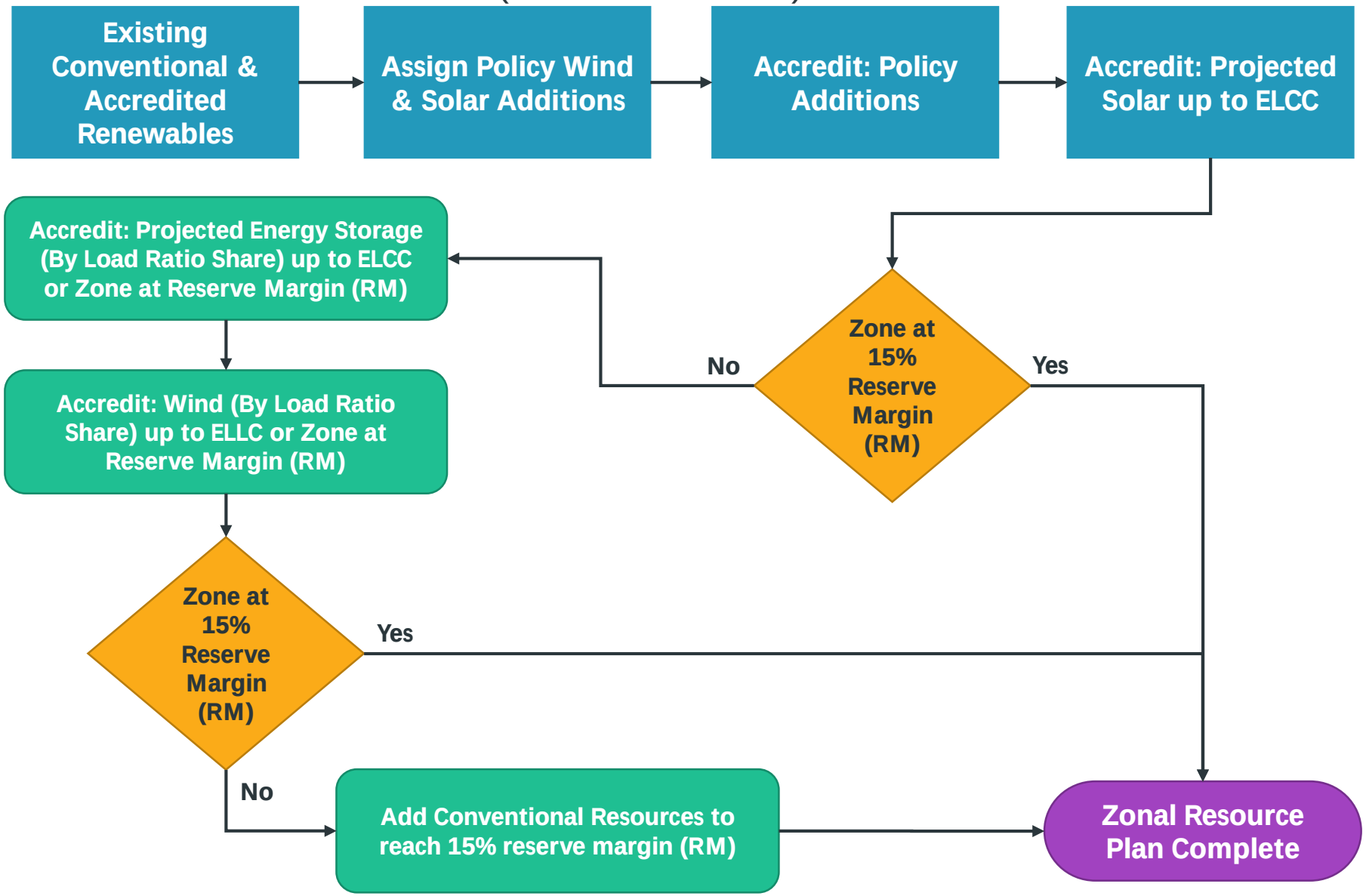
	SOLAR	WIND	BATTERY STORAGE
ASSIGNED	Yes	No	No
ALLOCATED	Load-Ratio Share	Load-Ratio Share	Load-Ratio Share

2024 ITP

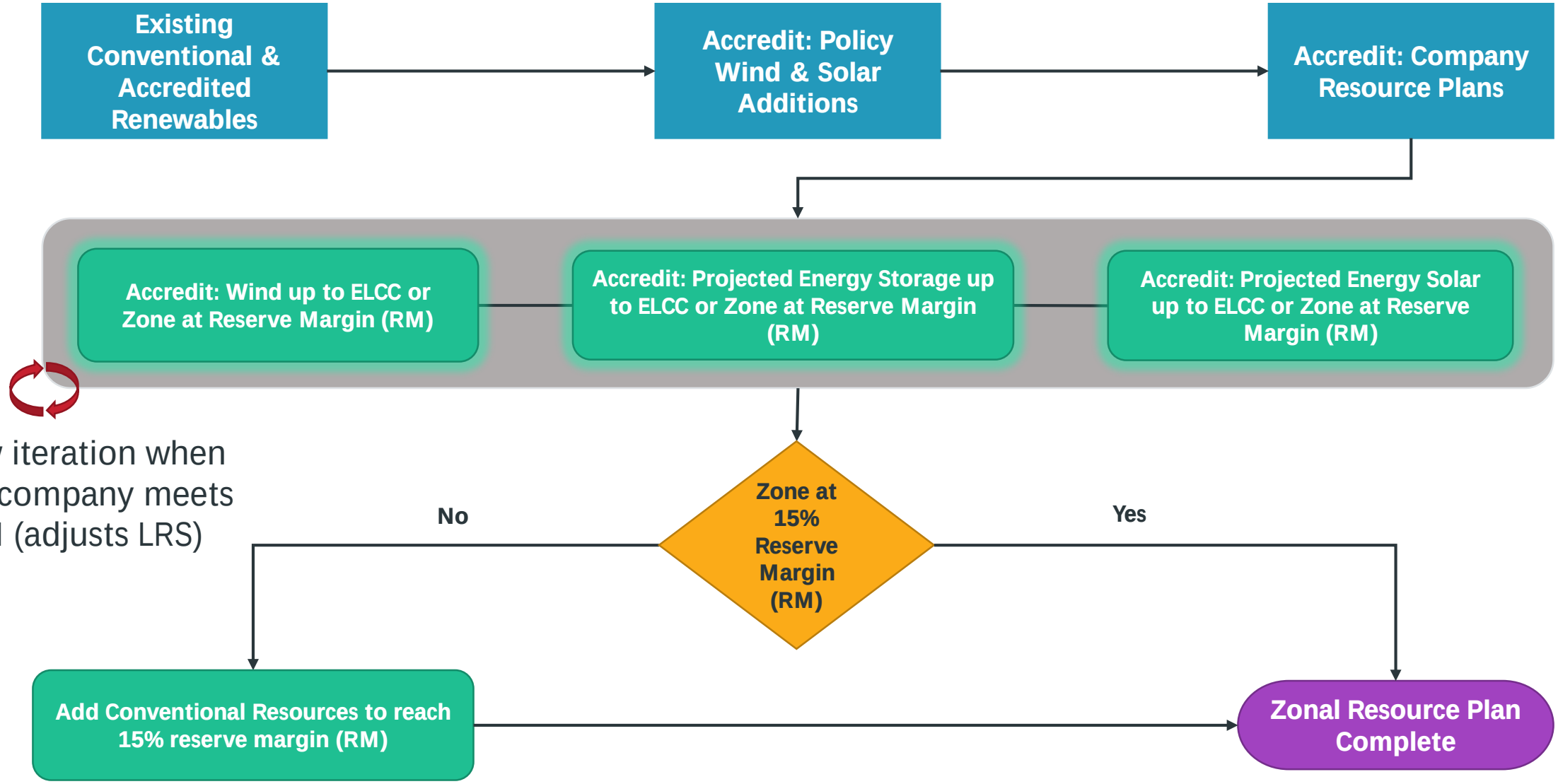
METHODOLOGY CONSIDERATIONS

- Due to resource planning template data, LRS or zonal reserve margin method may no longer be most reasonable approach
- Option 1: Status Quo
  - Continue LRS process to allocate solar, ESR, and wind
    - Benefits: Known methodology, limited changes
    - Risks: Inaccurate based upon resource planning template responses
- Option 2: Allocate renewables first based upon resource planning template responses to those utilities forecasting additions
  - Allocated to responding utilities first, if excesses available allocated based upon a standard approach, such as LRS
  - If no excess allocations available, limit allocations to responding utilities with some allocation remaining for standardized allocations.
    - Benefits: More realistic due to usage of respondent data
    - Risks: New methodology with unknown results

PREVIOUS RENEWABLE ACCREDITATION DECISION TREE
(WITH 15% PRM)



RENEWABLE ACCREDITATION DECISION TREE BASED ON CONSIDERATIONS
(WITH 15% PRM)



PLANNING RESERVE MARGIN CONSIDERATION

- Should we remove the 15% zonal reserve margin criteria in favor of a 15% regional reserve margin?
  - Assume deficient zones would purchase short-term capacity from other zones to meet reserve margin requirements instead of committing to new resource builds
  - Benefits: Likely limits conventional additions
  - Risks: May be energy deficient in our economic models

PREVIOUS OWNERSHIP (ASSIGNMENT) AFFECTS BENEFIT CALCULATION

Assigned

- Projected policy wind
- Utility solar
- Conventional

Unassigned

- Non-policy wind
- Storage

2024 ITP

NEXT STEPS

NEXT STEPS

- Feedback on differing options
  - Prototypes used to meet PRM/Use of resource planning software
  - Renewable allocation methodology
  - Zonal vs regional PRM
- Provide a recommendation in December Meeting

2024 ITP

APPENDIX

ITP MANUAL LANGUAGE

2.2.2.1.2 Conventional Resource Expansion Plan

Each pricing zone shall be assessed for resource adequacy by accounting for load projections, existing generation, new wind and solar additions, capacity accreditation for all renewable units, fleet PPAs, and DC tie accreditations. Each pricing zone's resource shortfall shall be computed based on the SPP reserve margin requirement in effect at the commencement of the resource planning milestone of the study.

The conventional resource expansion plan process begins with the identification of a publicly available source for generator prototype parameters, which shall be documented in the study scope.

SPP will identify the optimal mix of new conventional resource additions needed in all futures for the SPP region. The ESWG will review and approve the methodology for development of resource plans for each new ITP study with decisions documented in the Study Scope Document. The magnitude of resource additions will be based on resource shortfalls. Ownership of conventional unit additions will be allocated to pricing zones such that each pricing zone approximately meets the reserve margin requirement. Joint ownership of unit additions may be used to avoid excessive additions of new resources to individual pricing zones.

External regions also will be analyzed for resource shortfalls. An appropriate resource plan from the most current neighboring entity's study will be used for their region in the ITP assessment, if readily available and SPP and stakeholders find it appropriate. The use of their resource plan is future specific. If there is not a future comparable to the ITP future, as determined by SPP and the ESWG, then conventional additions to address shortfalls shall be added to external regions with a resource mix that is as close as possible to the SPP conventional resource addition mix for that future. For example, if SPP conventional resource additions include 60% combined cycles and 40% combustion turbines, a ratio as close as possible to this 60/40 ratio would be used to guide conventional resource additions in external regions.

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2024 ITP

2024 ITP SCOPE – PERSISTENT OPERATIONAL SOLUTION EVALUATIONS

NOVEMBER 2022

AHMED ALAZZAWI

OBJECTIVE

- Review previous ITP Persistent Operational Solution Evaluations methodology
- Obtain approval of proposed language to include in the 2024 ITP Scope document

ITP MANUAL V2.11 LANGUAGE

2.4 OPERATIONAL MODEL DEVELOPMENT

SPP will identify case(s) in which the reliability and manual commitment economic operational needs are present to evaluate whether the needs are addressed with proposed solutions. SPP may develop ITP planning models to replicate congested economic operational needs for solution evaluation as described in the Persistent Operational Solution Evaluations section.

ITP MANUAL V2.11 LANGUAGE

5.3.4 PERSISTENT OPERATIONAL SOLUTION EVALUATIONS

A subset of solutions will be evaluated to address persistent operational needs utilizing the filtering criteria, as approved by the TWG, ESWG and ORWG. Reliability solutions will be evaluated by the CLR and CVR metrics described in the Reliability Solution Evaluation section. SPP will track congested economic operational needs against needs identified in the current ITP, identify differences between real-time market operations and planning models, and determine the need for and impact of planning model adjustments and analysis. SPP will make a recommendation to applicable stakeholder working groups on how to address unresolved economic operational needs. Recommendations may include transmission upgrades, operational mitigations, or additional analysis to be performed in a future ITP study.

ITP MANUAL V2.11 LANGUAGE

6.1.4 PERSISTENT OPERATIONAL PORTFOLIO DEVELOPMENT

Solutions mitigating persistent operational needs are ranked by the appropriate metrics depending on whether the need is economic or reliability based. Solutions identified to mitigate persistent operational issues will be compared with the other portfolios to ensure efficiencies are gained by identifying the most cost effective projects to meet all needs. Economic solutions will be ranked based on their project cost compared to the cost incurred without the project. SPP and stakeholders will determine the criteria for development of the operational portfolio, which will be included in each study scope. Reliability solutions will be evaluated using the CLR and CVR metric concept.

2023 ITP SCOPE V1.1 – LANGUAGE

PERSISTENT ECONOMIC OPERATIONAL SOLUTION EVALUATIONS

FLOWGATES

Leading up to the 2023 ITP needs assessment, SPP will leverage the 2022 ITP economic operational needs assessment and solution evaluation outcome and continue to track on a quarterly basis operations and planning congestion throughout the 2022 ITP. SPP will make a recommendation to working groups on whether or not to address on as needed basis new and unresolved persistent operation economic congestion remaining after 2022 ITP persistent operation needs assessment and solution evaluation.

MANUAL COMMITMENT OF GENERATORS

Some transmission system issues require the manual commitment of generation by SPP in the Integrated Marketplace to provide relief on the system. The make-whole payments avoided when a proposed solution is included in the model will be considered in the solution's benefit. Each solution's one-year benefit-to-cost (B/C) ratio and its ability to reduce or eliminate the need for manual commitments will be considered during project selection.

2024 ITP SCOPE – LANGUAGE PROPOSAL

PERSISTENT ECONOMIC OPERATIONAL SOLUTION EVALUATIONS

FLOWGATES

Leading up to the 2024 ITP needs assessment, SPP will leverage the 2023 ITP economic operational needs assessment and solution evaluation outcome and continue to track on a quarterly basis operations and planning congestion throughout the 2023 ITP. SPP will make a recommendation to working groups on whether or not to address on as needed basis new and unresolved persistent operation economic congestion remaining after 2023 ITP persistent operation needs assessment and solution evaluation.

MANUAL COMMITMENT OF GENERATORS

Some transmission system issues require the manual commitment of generation by SPP in the Integrated Marketplace to provide relief on the system. The make-whole payments avoided when a proposed solution is included in the model will be considered in the solution's benefit. Each solution's one-year benefit-to-cost (B/C) ratio and its ability to reduce or eliminate the need for manual commitments will be considered during project selection.

RECOMMENDATION

- SPP Staff recommends that the ESWG approve a 2024 ITP Persistent Operational Solution Evaluations methodology consistent with the 2023 ITP Scope, as shown in slide 7

2024 ITP

APPENDIX

BACKGROUND

2022 ITP Scoping item for Persistent Operational Solution Evaluation (ESWG RR 403: Change to ITP operational model development)

- Challenge
  - Difficult to anticipate next steps as part of the 2022 ITP Scope
- Opportunity
  - Leverage current ITP staff efforts comparing ops congestion to planning solutions and congestion for various ITP milestones, specifically
    - 2021 ITP Needs Assessment and Persistent Operational Solution Evaluation Outcome using 2020 ITP Ops versus Planning congestion comparisons
    - 2021 ITP Market Economic Model and Constraint Assessment quality assurance checks that includes Ops versus Planning congestion comparisons
  - Use 2022 ITP to check and adjust as needed and if not able to accommodate then address in 2023 ITP Scope and Schedule

OVERVIEW

- On at least a quarterly basis, review status of 2023 ITP Needs Assessment and Persistent Operational Solution Evaluation Outcome using 2021 ITP Ops versus Planning congestion comparisons and 2023 ITP Market Economic Model and Constraint Assessment quality assurance checks that includes Ops versus Planning congestion comparisons. Discuss potential solutions and solution evaluation options and effort leading up to the 2024 ITP Market Economic Model Development and Needs Assessment. If 2024 ITP cannot accommodate then address in 2025 ITP Scope and Schedule

2024 ITP

2024 ITP SCOPE – PORTFOLIO CONSOLIDATION

NOVEMBER 2022

AHMED ALAZZAWI

OBJECTIVES

- Review previous ITP Portfolio Consolidation methodology
- Obtain approval of proposed Portfolio Consolidation criteria to include in the 2024 ITP Scope document

ITP MANUAL V2.11 LANGUAGE

6.2 PORTFOLIO CONSOLIDATION

To determine a recommended plan, the portfolios of potential projects must be consolidated. SPP and stakeholders will discuss, determine and document details of the study-specific consolidation criteria during each study scope development.

HISTORICAL CONSOLIDATION CONCEPTS

- Coupling Criteria
  - Generally gives more emphasis to one future over the other and allows projects from other future to be included if additional criteria is met
- Weighted Futures
  - Weighting of futures determined based on confidence in each future
  - Project selected if weighted sum of B/C ratios from futures exceeds threshold
- Individual Project Review
  - Review project drivers and benefits if B/C ratio exceeds certain threshold and present the project and justification to the appropriate stakeholder groups for approval

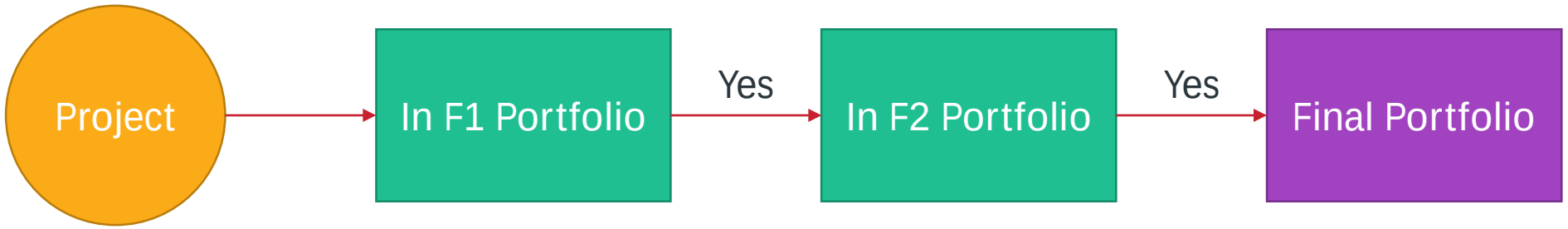
ADDITIONAL BACKGROUND

- July 2020
  - Board of Directors approved the 2021 ITP Assessment Scope with a 50/50 weighting of futures for Consolidation and to highlight any project within the 2021 ITP that otherwise would not be justified under a 60/40 weighting

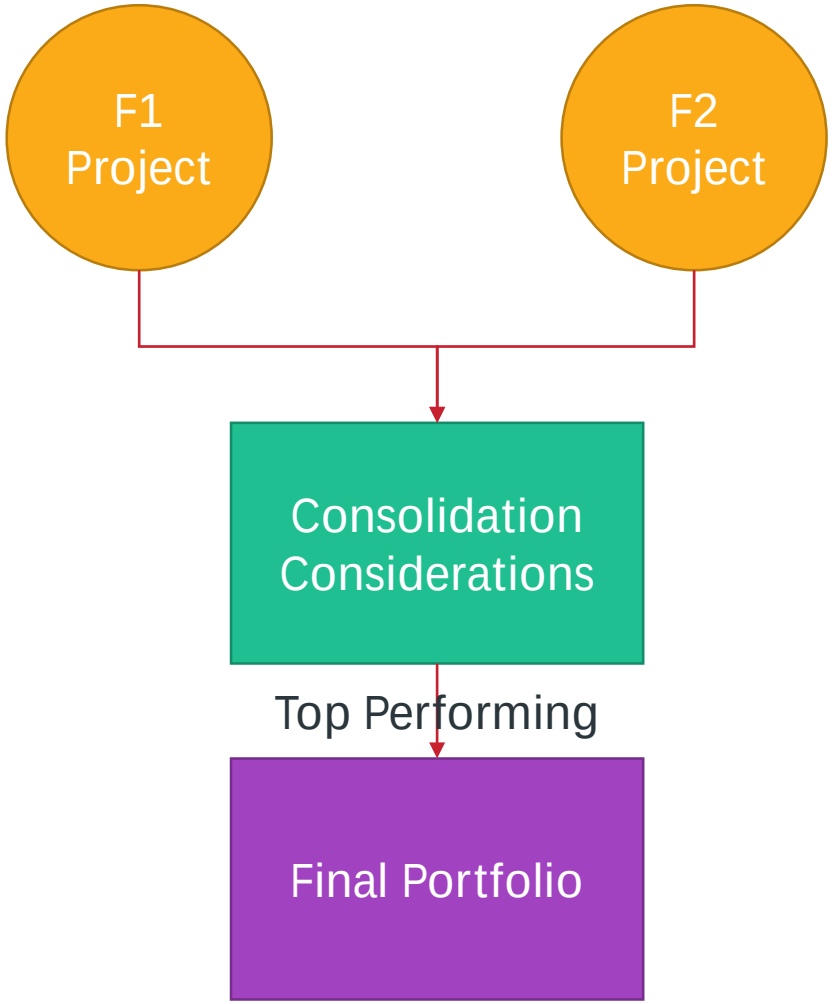
PORTFOLIO CONSOLIDATION SCENARIOS

No.	Scenarios	F1	F2	Should we build?	What should we build?
1	Same project in each future	Project A	Project A	ü	ü
2	Competing projects	Project B	Project C	ü	?
3	Projects in one future	N/A	Project D	?	ü

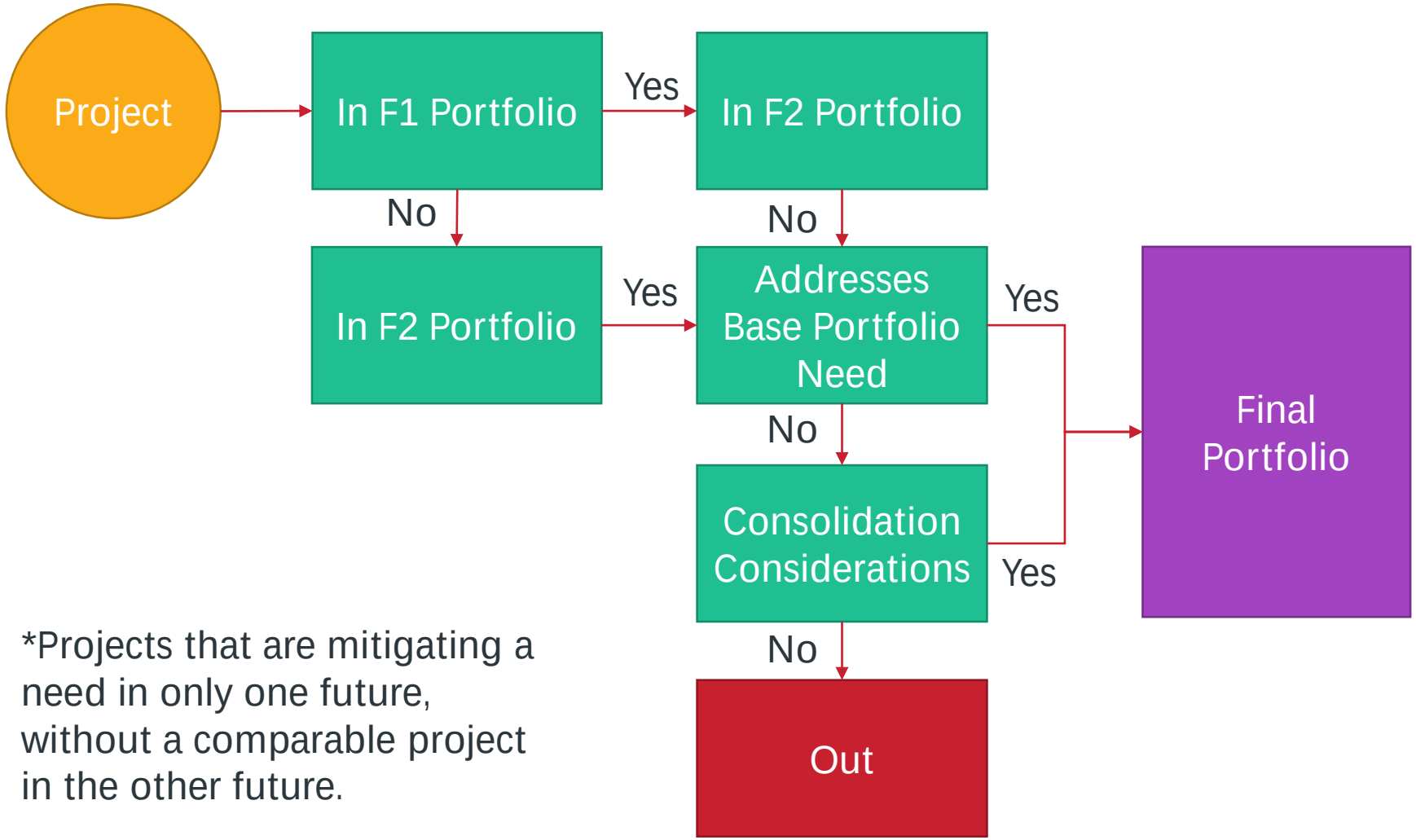
PORTFOLIO CONSOLIDATION
SAME PROJECT IN BOTH PORTFOLIOS (1)



PORTFOLIO CONSOLIDATION COMPETING PROJECTS (2)



PORTFOLIO CONSOLIDATION PROJECTS* IN ONE FUTURE'S PORTFOLIO (3)



*Projects that are mitigating a need in only one future, without a comparable project in the other future.

PREVIOUS ITP CONSOLIDATION SCORING FOR SCENARIOS 2 & 3

No.	Considerations	Possible Points	Threshold
1	40-yr (1-year) APC B/C in Selected Future	50	1.0 (0.9)
	40-yr (1-year) APC B/C in Opposite Future		0.8 (0.7)
	40-yr (1-year) APC Net Benefit in Selected Future ($M)		N/A
	40-yr (1-year) APC Net Benefit in Opposite Future ($M)		N/A
2	Congestion Relieved in Selected Future (by need(s), all years)	10	N/A
	Congestion Relieved in Opposite Future (by need(s), all years)	10	N/A
3	Operational Congestion Costs or Reconfiguration ($M/yr or hrs/yr)	10	>0
4	New EHV	7.5	Y/N
5	Mitigate Non-Thermal Issues	7.5	Y/N
6	Long Term Viability (Eg 2013 ITP20) or ARR	5	Y/N
Total Points Possible (70 point Threshold in Scenario 3)		**100**	

CONSOLIDATION CALCULATIONS CONSIDERATION 1

Scenario 2 (Competing Projects)

1. Test B/C Thresholds in Opposite Future
   - If project has less than 0.8 40-year B/C in opposite future, zero points will be awarded
   - If project meets 0.8 40-year B/C threshold in opposite future, continue calculations
2. Calculate Net APC Benefits
   - $\textit{Net APC Benefit}_{P1,AVE} = \frac{Net\ APC\ Benefit_{P1,F1} + Net\ APC\ Benefit_{P1,F2}}{2}$
   - $\textit{Net APC Benefit}_{P2,AVE} = \frac{Net\ APC\ Benefit_{P2,F1} + Net\ APC\ Benefit_{P2,F2}}{2}$
   - $\textit{Net APC Benefit}_{Max} = \textit{Maximum(Net APC Benefit}_{P1,AVE}\textit{, Net APC Benefit}_{P2,AVE}\textit{)}$
3. Calculate Points Awarded
   - $Points\ Awarded_{P1} = 50 \times \frac{Net\ APC\ Benefit_{P1,AVE}}{Net\ APC\ Benefit_{Max}}$
   - $Points\ Awarded_{P2} = 50 \times \frac{Net\ APC\ Benefit_{P2,AVE}}{Net\ APC\ Benefit_{Max}}$

CONSOLIDATION CALCULATIONS CONSIDERATION 1

Scenario 3 (Projects in one future's portfolio)

1. Test B/C Threshold in Opposing Future
   - If project has less than 0.8 40-year B/C in opposing future, zero points will be awarded
   - If project has at least 1.0 40-year B/C in opposing future, 50 points will be awarded
   - If project meets 0.8 40-year B/C threshold in opposing future, but is less than 1.0, continue calculations
2. Calculate Net APC Benefits
   - $Net\ APC\ Benefit_{P1,AVE}$
   - $Net\ APC\ Benefit_{P1',AVE} = Net\ APC\ Benefit_{P1,AVE}$ *with1.0 B/C in opposing future*
3. Calculate Points Awarded
   - $Points\ Awarded_{P1,\%} = 50 \times \frac{Net\ APC\ Benefit_{P1,AVE}}{Net\ APC\ Benefit_{P1',AVE}}$

CONSOLIDATION CALCULATIONS CONSIDERATION 1

Scenario 3 (Projects in one future's portfolio)

	Project 1	Project 1'
Total Project Cost ($M)	**10.3**	**10.3**
40-yr APC B/C in Selected Future	1.9	1.9
40-yr APC B/C in Opposite Future	0.9	1.0
40-yr APC Net Benefit in Selected Future ($M)	9.3	9.3
40-yr APC Net Benefit in Opposite Future ($M)	-1.0	0.0

1. Test B/C Threshold in Opposing Future
2. Calculate Net APC Benefits
   - $Net\ APC\ Benefit_{P1',AVE} = \frac{\$9.3M - \$1.0M}{2} = \$4.1M$
   - $Net\ APC\ Benefit_{P1',AVE} = \frac{\$9.3M + \$0.0M}{2} = \$4.6M$
3. Calculate Points Awarded
   - $Points\ Awarded_{P1,\%} = 50 \times \frac{\$4.1M}{\$4.6M} = \mathbf{44.4}$

CONSOLIDATION CALCULATIONS

- Consideration 2
  - Points for consideration two will be calculated as the percentage of total congestion relieved on the needs addressed by the project, multiplied by the points possible.

$$Points\ awarded = 10 \times \%\ Congestion\ relieved_{F1,addressed\ needs} + 10 \times \%\ Congestion\ relieved_{F2,addressed\ needs}$$

- Consideration 3
  - Points for consideration three will be calculated based on the severity of an operational issue that the project is expected to address, as a percentage of the operational needs criteria multiplied by the points possible, up to 10.
  - $Points\ awarded = \left(\frac{\$\ of\ congestion\ cost_{24\ months}}{\$10M}\right) \times 10$
  - OR
  - $Points\ awarded = \left(\frac{Hours\ of\ system\ reconfiguration_{12\ months}}{X\% \times 8{,}760}\right) \times 10$
- Consideration 4*
  - All possible points awarded if new EHV
- Consideration 5*
  - All possible points awarded if expected to mitigate non-thermal issues
- Consideration 6*
  - All possible points awarded if in SPP long-term study

*No points awarded if criteria not met

RECOMMENDATION

- SPP Staff recommends that the ESWG approve a 2024 ITP Portfolio Consolidation methodology consistent with the 2023 ITP Scope

SPP Southwest Power Pool

2024 ITP

2024 ITP SCOPE - SENSITIVITY ANALYSIS

NOVEMBER 2022

SPENCER MAGBY

OBJECTIVES

- Discuss sensitivity options for the 2024 ITP
- Approve sensitivities to include in the 2024 ITP Scope

ITP MANUAL V2.11 LANGUAGE (SECTION 7.2)

Sensitivity analyses will be defined in the scope and conducted to measure the flexibility of the final portfolio in each ITP assessment. Generally, these sensitivities will not be used to select the proposed transmission projects, nor to filter out projects. ***Sensitivities may consider variations in demand, fuel prices, renewable energy, or other relevant considerations as determined during futures development.***

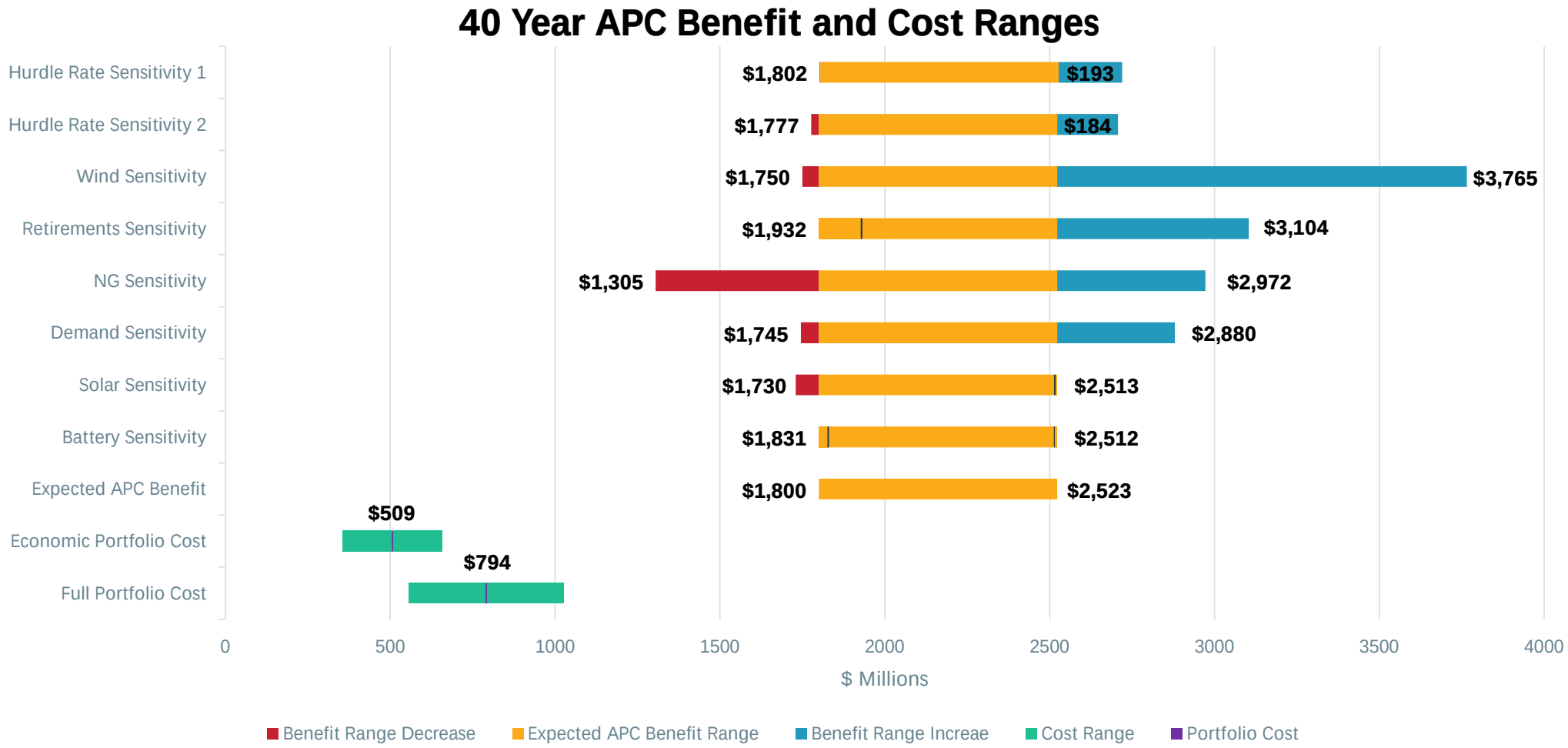
POTENTIAL SENSITIVITIES

What makes a good sensitivity?

- Impact to portfolio
- high uncertainty
- Ease of implementation

- Natural gas price
- Energy demand
- Wind levels
- Solar levels
- Storage levels
- Production Tax Credits (PTCs)
- Hurdle Rates

2020 ITP SENSITIVITY RESULTS



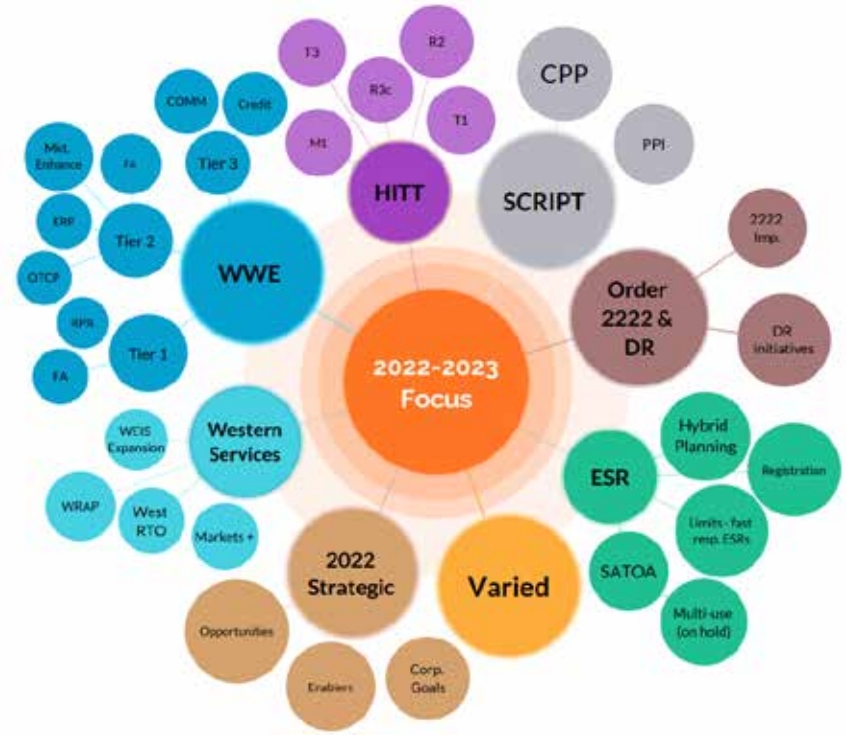
PROPOSAL

- At minimum, include natural gas, demand, and wind sensitivities in the 2024 ITP Scope
  - Survey stakeholders for prioritization of additional relevant sensitivities closer to milestone execution

2022-2023 COMPREHENSIVE ROADMAP CYCLE

ERIN CATHEY
LEAD STRATEGIC INITIATIVES COORDINATOR
NOVEMBER 2, 2022
ESWG

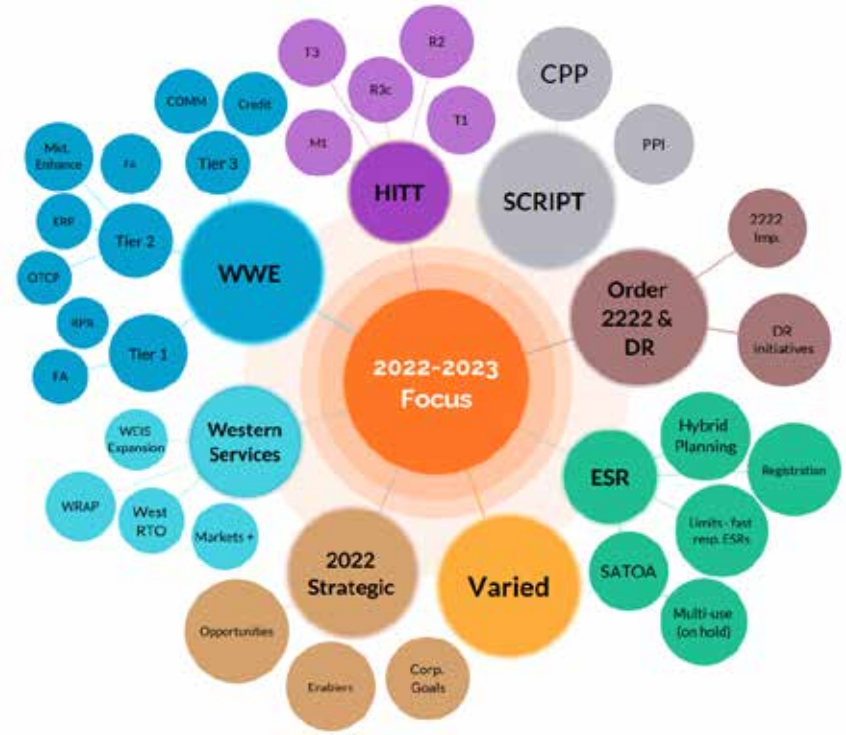
IMPORTANT DATES



- Process Education Sessions
  - **Monday,** 11/7/2022 = 10:00 a.m. – 12:00 p.m.
  - **Friday,** 11/11/2022 = 10:00 a.m. – 12:00 p.m.
    - *Registration available on SPP.org*
- Initiative Timelines
  - **Initiative Submission Timeframe**: 11/14/2022 – 12/9/2022
  - **Initiative Comment Timeframe**: 11/14/2022 – 12/14/2022

IMPORTANT DATES CONT.

- Initiative Education Session Timeframe
  - 1/2/2023 – 1/24/2023
    - Dates by Functional Area will be provided at a later time
- Initiative Prioritization Session Timeframe
  - 1/9/2023 – 2/10/2023
    - Dates by Functional Area will be provided at a later time



IMPORTANT LINKS

- Comprehensive Roadmap Webpage
- Comprehensive Roadmap Forms
- Comprehensive Roadmap Initiatives

MARKET POWERFLOW MODELS IN THE ITP - POTENTIAL RR LANGUAGE

JOSHUA PILGRIM

NOVEMBER 2022

NEW LANGUAGE ADDED

- Section 4.2.2:
  - Violations resulting from these models will be not be posted for stakeholder submitted solutions, however additional analysis will be done to ensure the issues are addressed properly.

NEW LANGUAGE ADDED

- Section 4.2.2.1:
  - The SCUC/SCED simulations in the Market Economic models honor identified constraints (specific monitored elements and contingency element pairs) by limiting the dispatch potential of the fleet of generation resources, ensuring constraints will not be overloaded. Because of this thermal violations in the Market Powerflow models are uncommon. An overloaded line could have breached its limit in the Market Powerflow models due to reactive flows not simulated in the Market Economic model or it was not identified as a constraint in the constraint assessment. In theory, a thermal violation should only be considered a reliability need if the associated constraint breached its thermal limit in the economic simulation.

NEW LANGUAGE ADDED

- Section 4.2.2.1:
  - Observed thermal overloads in the Market Economic models will receive additional review. These violations will be evaluated for reclassification as an economic need in the following ITP cycle to ensure proper evaluation of system needs. To be identified as an economic need, the constraint must meet the congestion score criteria identified in Section 4.1.2. If reclassification is justified, SPP will include the thermal violation as an economic need in the next ITP cycle. If the overloaded line and its associated contingency are already identified as a constraint, it will be invalidated as a possible need.

NEW LANGUAGE ADDED

- Section 4.2.2.2:
  - Voltage violations found in the Market Powerflow models will not be eligible to drive projects; however, they will be identified as possible reliability need and added to the following ITP cycle’s needs assessment.

REVISION REQUEST SUBMISSION FORM

SPP STAFF TO COMPLETE

RR Number: TBD Date: 10/25/2022

RR Title: Removal of Market Powerflow Models from Needs Assessment

System changes? ☒ No ☐ Yes

Process changes? ☐ No ☒ Yes

Impact analysis required? ☒ No ☐ Yes

If no, but system or process changes are expected, please explain why an Impact Analysis will not be performed. (e.g. FERC Order or work included in another Impact Analysis for a related RR):

Comprehensive Roadmap process? ☒ No ☐ Yes

If yes, provide SIR# and associated SIR#s:

SUBMITTER TO COMPLETE

SUBMITTER INFORMATION

Name: Joshua Pilgrim Company: Southwest Power Pool

Email: jpilgrim@spp.org Phone: (501) 482-2384

Submitter must be a Qualified Entity. Please check at least one applicable option:

☒ SPP Staff
☐ SPP Market Participant
☐ SPP Member
☐ An entity designated by a Qualified Entity to submit a Revision Request "on their behalf"
☐ SPP Market Monitor
☐ Staff of government authority with jurisdiction over SPP/SPP member
☐ Rostered individual of SPP committee, task force or working group
☐ Transmission customers or other entities that are parties to transactions under the SPP Tariff

RR DETAILS

Requested resolution timing: ☒ Normal ☐ Expedited ☐ Urgent Action

Reason for expedited/urgent resolution:

Type of revision (select all that apply):

☐ Correction *(revising language that is erroneous or needs clean-up for grammatical errors or inconsistency across governing documents; no changes to intent or policy)*

☐ Clarification *(revising language to better represent existing intent; no changes to functionality or policy)*

☒ Enhancement *(revising language to expand on existing intent or functionality)*

☐ New Protocol, Business Practice, Criteria, Tariff *(new language to accommodate new functionality or policy not existing today)*

☐ NERC Standard impact *(If revision relates to/or impacts NERC Standards, describe and list standard(s))*

☐ FERC mandate (list order number(s))

☐ NAESB Standard impact *(If revision relates to/or impacts NAESB Standards, describe and list standard(s))*

RR OBJECTIVES

What is the objective of this RR?

Describe the objective and end result

The Market Powerflow Models have not historically led to many projects within the Integrated Transmission Planning process. However, their development and analysis have been a bottleneck for the needs assessment milestone.

How RR addresses the objectives:

Describe how this RR addresses or solves the objectives

This RR removes MPMs from the needs assessment, which will streamline the milestone by removing one of its biggest sources of delays from the critical schedule path.

Benefits RR will provide:

- **Market benefits:**
- **Reliability benefits:**
- **Administrative benefits**:
- **Other qualitative or quantitative benefits**:

RISK DRIVERS

Are there existing risks to one or more SPP members or the bulk electric system driving the need for this RR? ☐ Yes ☒ No

If yes, explain the risk and associated timelines:

☐ Compliance (SPP Tariff, NERC, other**):**

☐ Reliability/Operations**:**

☐ Financial:

DOCUMENTS REQUIRING REVISION

Select all documents impacted by this RR and indicate the section of the document being revised.

☐ **Tariff** Section:

☐ **Market Protocols** Section: Version:

☐ **Operating Criteria** Section:

☐ **Planning Criteria** Section:

☐ **Business Practice** Number:

☒ **Integrated Transmission Planning (ITP) Manual** Section: 4.2

☐ **Minimum Transmission Design Standards for Competitive Upgrades** Section:

☐ **Reliability Coordinator and Balancing Authority Data Specifications** Section:

☐ **SPP Communications Protocols** Section:

☐ **Revision Request Process** Section:

DOCUMENT REVISIONS

In the appropriate sections below, please provide the language from the current document(s) for which you are requesting revision(s), with all edits redlined.

SPP OPEN ACCESS TRANSMISSION TARIFF

MARKET PROTOCOLS

SPP OPERATING CRITERIA

SPP PLANNING CRITERIA

SPP BUSINESS PRACTICES

INTEGRATED TRANSMISSION PLANNING (ITP) MANUAL

4.2 RELIABILITY NEEDS ASSESSMENT

The reliability needs assessment will be performed in parallel with the economic, public policy, and operational needs assessments. All needs will be identified by assessing the performance of the SPP transmission system under system intact and contingency conditions. SPP will utilize Table 1 from the NERC Standard TPL-001 as the basis for the contingencies to be assessed during the study. Contingencies that do not allow for non-consequential load loss (NCLL) or the interruption of firm transmission service (IFTS) will be analyzed during the reliability needs assessment. SPP Planning Criteria[1] will be utilized to determine if a potential regional reliability violation will be considered as a reliability need.

Commented [sam1]: Updated footnote link for SPP Planning Criteria to go to SPP Governing Documents folder (was pointed to older version)

4.2.1 BASE RELIABILITY MODEL

~~Thermal violations identified in the Market Powerflow model during the reliability assessment may not have met the constraint assessment criteria to be defined as a constraint or may be related to a defined constraint in the economic model. These potential~~Reliability needs ~~will be evaluated for reclassification as an economic need during or after the needs assessment to~~

[1] ~~SPP Planning Criteria~~SPP Planning Criteria

~~ensure proper evaluation of system needs. If reclassification is justified, SPP will include the constraint in the next ITP cycle and SPP will inform stakeholders via email or the SPP website.~~

~~Voltage violations found in the Market Powerflow models will be addressed via mitigations submitted by local Transmission Operators, and added to next year's needs assessment after SPP staff verifies that the need in question is still present.~~

~~Violations identified in the Market Powerflow models during the reliability assessment will not be eligible to drive projects. However, these violations will still be considered during portfolio development in order to guide project selection.~~

Contingency analysis for the base reliability model will consist of analyzing P0, P1, and P2.1 planning events identified in NERC Standard TPL-001 Table 1 for each of the models. The voltage level for monitored and contingent elements in the SPP footprint are described in more detail in Table 2.

	P0, P1, P2.1	
	Monitored Element	**Contingent Element**
Year 2 Summer	69 kV +	69 kV +
Year 2 Winter		
Year 2 Light Load		
Year 5 Summer		
Year 5 Winter		
Year 5 Light Load		
Year 10 Summer	100 kV+[2]	100 kV+[31]
Year 10 Winter		
Year 10 Light Load		

Table 1: NERC Standard TPL-001 Planning Events as Monitored and Contingent Elements

The base reliability models will be analyzed with the remaining contingencies from Table 1 in the NERC Standard TPL-001 that do not allow for NCLL or IFTS as detailed in Table 3.

	Other Planning Events[3]	
	Monitored Element	**Contingent Element[4]**

[2] In addition, 69 kV facilities will be both contingent and monitored elements for informational purposes only. This data will inform the solution and portfolio development process to ensure solutions can mitigate violations for the entire study period.
[3] Other planning events include P2.2, P2.3, P3.1-P3.5, P4.1-P4.5, and P.5
[4] Some planning events allow/disallow NCLL or IFTS based upon the voltage level of the contingent element.

Year 2 Summer	100 kV+	100kV/300 kV+
Year 2 Light Load	100 kV+	100kV/300 kV+
Year 5 Summer	100 kV+	100kV/300 kV+
Year 10 Summer	100 kV+	100kV/300 kV+

Table 2: Remaining Contingencies for Monitored and Contingent Elements

4.2.2 MARKET POWERFLOW MODELS

~~Contingency analysis on the Market Powerflow Model will not be completed in parallel with the Base Reliability model. Instead, it will be completed after the Needs Assessment has been posted.~~ Violations resulting from these models will be not be posted for stakeholder submitted solutions, however additional analysis will be done to ensure the issues are addressed properly.

Commented [CD2]: I don't think language on timing is important, it just has the potential to lock us down. Would rather focus on the policy that we don't have to post them for DPP submittal.

~~observed thermal overloads in the Market models will receive additional review. The SCUC/SCED simulations honor identified constraints by limiting the dispatch potential of the fleet of generation resources, ensuring constraints will not be overloaded. In theory, a thermal violation should only be considered a reliability need if a constraint was not modeled or breached its thermal limit in the economic simulation.~~ Contingency analysis for the Market ~~powerflow~~ Powerflow models will consist of analyzing P0, P1, and P2.1 planning events identified in NERC Standard TPL-001 Table 1 for each of the models. The voltage level for monitored and contingent elements in the SPP footprint are described in more detail in Table 4.

	P0, P1, P2.1	
	Monitored Element	**Contingent Element**
Reference Case Year 2 Peak	100 kV+ with select 69 kV facilities	100 kV+ with select 69 kV facilities
Reference Case Year 2 Off-Peak		
Reference Case Year 5 Peak		
Reference Case Year 5 Off-Peak		
Reference Case Year 10 Peak	100 kV+	100 kV+
Reference Case Year 10 Off-Peak		
F_X Year 5 Peak		
F_X Year 5 Off-Peak		
F_X Year 10 Peak		
F_X Year 10 Off-Peak		

Table 3: NERC Standard TPL-001 Planning Events as Monitored and Contingent Elements

The remaining contingencies in Table 1 of the NERC Standard TPL-001 that do not allow for NCLL or IFTS will be analyzed if a violation was observed in the same year/season of the base reliability model as detailed in Table 5.

Other Planning Events[5]

[5] Other planning events include P2.2, P2.3, P3.1-P3.5, P4.1-P4.5, and P.5

	Monitored Element	Contingent Element[6]
Reference Case Year 2 Peak	100 kV+	100kV/300 kV+
Reference Case Year 2 Off-Peak	100 kV+	100kV/300 kV+
Reference Case Year 5 Peak	100 kV+	100kV/300 kV+

Table 4: Remaining Contingencies for Monitored and Contingent Elements

4.2.2.1 Thermal Violations

The SCUC/SCED simulations in the Market Economic models honor identified constraints (specific monitored elements and contingency element pairs) by limiting the dispatch potential of the fleet of generation resources, ensuring constraints will not be overloaded. Because of this thermal violations in the Market Powerflow models are uncommon. An overloaded line could have breached its limit in the Market Powerflow models due to reactive flows not simulated in the Market Economic model or it was not identified as a constraint in the constraint assessment. In theory, a thermal violation should only be considered a reliability need if the associated constraint breached its thermal limit in the economic simulation.

Observed thermal overloads in the Market Powerflow models will receive additional review. These violations will be evaluated for reclassification as an economic need in the following ITP cycle to ensure proper evaluation of system needs. To be identified as an economic need, the constraint must meet the congestion score criteria identified in Section 4.1.2. If reclassification is justified, SPP will include the thermal violation as an economic need in the next ITP cycle. If the overloaded line and its associated contingency are already identified as a constraint ~~and~~, it will be invalidated as a possible need.

4.2.2.2 Voltage Violations

Voltage violations found in the Market Powerflow models will not be eligible to drive projects; however, they will be identified as possible reliability need~~.~~ and added to the following ITP cycle's needs assessment.

4.2.3

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NON-CONVERGED CONTINGENCIES

SPP will use engineering judgment to resolve non-converged cases from the contingency analysis. If these contingencies cannot be solved, the potential violations will be identified as reliability needs along with the result of the analysis (e.g. voltage collapse).

4.2.4 FIRST-TIER CONSIDERATION

During the reliability needs assessment, first-tier areas will be monitored to identify potential reliability needs. After vetting with the appropriate neighboring entity and receiving their consent, first-tier potential issues will be posted in conjunction with the SPP needs list. The first-tier potential issues list will not serve as solicitation of SPP stakeholders for solutions to address first-

[6] Some planning events allow/disallow NCLL or IFTS based upon the voltage level of the contingent element.

tier issues, but the list will be used to evaluate whether there are solutions that address SPP and first-tier issues concurrently.

~~Violation Filtering~~

~~SPP will review the list of potential violations to determine the list of valid violations that will be included in the needs assessment.~~

~~As part of the violation filtering, observed thermal overloads in the Market models will receive additional review. The SCUC/SCED simulations honor identified constraints by limiting the dispatch potential of the fleet of generation resources, ensuring constraints will not be overloaded. In theory, a thermal violation should only be considered a reliability need if a constraint was not modeled or breached its thermal limit in the economic simulation.~~ In the instance that an economic constraint or similar monitored element/contingency element pair (mon/con pair) is identified as a thermal overload in the AC contingency results, it will be invalidated as a reliability need. Invalidating these type of thermal overloads will allow the economic potential of the constraint(s) to be evaluated to determine if cost-beneficial solution is available.

4.2.~~5~~6 LOCAL PLANNING CRITERIA

Local planning criteria will be collected from SPP TOs in accordance with the SPP tariff. Auxiliary files will be updated with the latest TO local planning criteria information. SPP will request the TO's validate the updated auxiliary files which will be used during the base case and contingency analysis. The local planning criteria needs will be posted on a secure website.

4.2.~~7~~6 SHORT-CIRCUIT ANALYSIS

All short-circuit needs will be classified as reliability needs and will be identified by determining maximum available fault current on the SPP transmission system compared to the respective equipment fault-interrupting duty capabilities under system intact conditions. SPP will monitor all bulk electric system and SPP tariff facilities for the short-circuit analysis.

A year 2 summer peak ITP model will be developed for the short-circuit analysis. This short-circuit model differs from the powerflow models in that all modeled generation and transmission equipment are placed in operation to simulate the maximum available fault current.

SPP will simulate three-phase faults and single line-to-ground faults and provide the following analysis results to the TOs as requested:

- Full bus-fault current and line-out results using an automatic sequencing fault calculation
- Full bus-fault current and line-out results using an American National Standards Institute fault calculation

The TOs will be required to evaluate the results and respond to SPP if any fault-interrupting equipment will have its duty ratings exceeded by the maximum available fault current (potential violation). For equipment that is seen to have its duty rating exceeded, the TO will provide SPP with the applicable duty rating of the equipment.

Potential violations of SPP tariff facilities will be identified as a need to be included in the needs assessment. SPP will work directly with the facility owners on all remaining potential violations to ensure that proper mitigation of issues is completed.

4.3 PUBLIC POLICY NEEDS ASSESSMENT

The public policy needs assessment will be performed in parallel with the reliability, economic, and operational needs assessments, for each future and study year. Needs driven by public policy arise if the economic simulations identify conditions on the system that keep a utility from meeting its regulatory or statutory mandates and goals as defined by the renewable policy review and/or future specific public policy assumptions identified in the study scope.

4.4 PERSISTENT OPERATIONAL NEEDS ASSESSMENT

Persistent operational needs may be either economic or reliability related. The criteria for identifying these needs is described in this section. SPP may propose additional needs to account for other problematic operational issues observed in operating the transmission system not fitting the given criteria. These additional needs will be presented to the ESWG and TWG for review and endorsement.

4.4.1 ECONOMIC OPERATIONAL NEEDS

SPP will classify flowgates meeting either of the following criteria as economic needs:

1. The flowgate was congested for at least 20 percent of the previous 24 months, either in a breached or binding state in the real-time balancing market solution, or
2. The flowgate had congestion costs[7] totaling more than $10 million over the previous 24 months.

Periods of time when a flowgate's related congestion is deemed to be the result of prior outage conditions will be excluded from these criteria calculations. Congestion cost for outages will be provided for informational purposes.

SPP also will identify economic needs considering manual commitments of uneconomic generation for local area voltage support, according to either of the following criteria:

1. Manual commitment events that include startup and extension 25 percent of the year, or
2. Manual commitments that do not exceed 25 percent of the year, but cost over $1 million dollars over 24 months.

4.4.2 RELIABILITY OPERATIONAL NEEDS

SPP will classify facilities as reliability needs due to system reconfiguration using agreed upon (by SPP and the transmission operator) operational guides or load shed as a result of unsuccessful control of the system through re-dispatch if they meet the following criteria:

1. High- or low-voltage issues where system reconfiguration is implemented 10 percent of the year due to non-outage issues[8], or
2. Thermal loading issues where system reconfiguration through the use of an agreed upon operating guide has been implemented in real-time 25 percent of the year.

[7] Congestion costs will be calculated using the same methodology as the SPP violation relaxation limit process.
[8] Switched shunts and generator MVAR adjustments will be optimized prior to needs being identified. If potential non-consequential load loss is 100 MW or greater, the risk to the load would need to be present one percent of the time.

MINIMUM TRANSMISSION DESIGN STANDARDS FOR COMPETITIVE UPGRADES

RELIABILITY COORDINATOR AND BALANCING AUTHORITY DATA

SPP COMMUNICATIONS PROTOCOLS

REVISION REQUEST PROCESS

ACTION ITEM 190: TRANSMISSION OUTAGE METRIC

MARKET SUPPORT & ANALYSIS

NOVEMBER 2022

OBJECTIVE

Review Methodology for Action Item 190: Transmission Outage Metric review

HISTORY OF THE METRIC

- Full analysis performed for RCAR I in 2012/2013.
  - PROMOD 2023 Study Year
  - 12 Months of Historical Transmission Data provided by SPP for December 2011 to November 2012

Benefit =

(Base APC with outages – Change APC with outages) – ← **APC savings with outages**

(Base APC without outages – Change APC without outages) ← **APC savings without outages**

- Outage Filtering Criteria
  - Involved facilities with a nominal voltage over 230 kV and lasted 5 days or longer
  - Involved facilities with a nominal voltage over 100 kV, lasted 4 hours or longer, and had a significant impact on a defined contingency
  - Involved facilities with a nominal voltage over 100 kV, lasted 4 hours or longer, and had a significant impact on a binding constraint in the Base Case PROMOD runs

https://www.spp.org/Documents/44031/Benefit%20Metrics%20Manual%2020201106.docx
https://www.spp.org/documents/18175/20120913%20mtf%20report_approved.pdf

METHODOLOGY REVIEW

Leveraging RCAR III Runs

- RCAR III to date has been solely based on actual daily Integrated Marketplace runs
  - Production costs are captured both with the HWBW transmission and without. The difference is the benefit associated to the transmission upgrades.
  - In RCAR III (Operations Only for projects in-service for at least 2 years) 538/741 (73%) approved upgrades have been studied to date
  - No forward looking assumptions were used in completing RCAR III; actual daily values were captured and analyzed
- RCAR III included actual generation and transmission outages while in effect
- Actual wind generation on the SPP system used in RCAR III between 2018 and 2021 was 20,600 and 30,487 MW.

METHODOLOGY REVIEW

- Use RCAR III runs as base (With Outages)
- Create New DARUC Runs without Transmission Outages
  - 120 Days From 2020 thru 2021
  - 60 Days per year
  - Top Outages days that meet the Outage Filtering Criteria below:
  - **Outage Filtering Criteria**
    - Involved facilities with a nominal voltage over 230 kV and lasted 5 days or longer
    - Involved facilities with a nominal voltage over 100 kV, lasted 4 hours or longer

NEXT STEPS

- Market Support & Analysis will begin:
  - Outage filtering
  - Develop DARUC Runs

SPP Southwest Power Pool

2023 ITP

SCHEDULE UPDATE

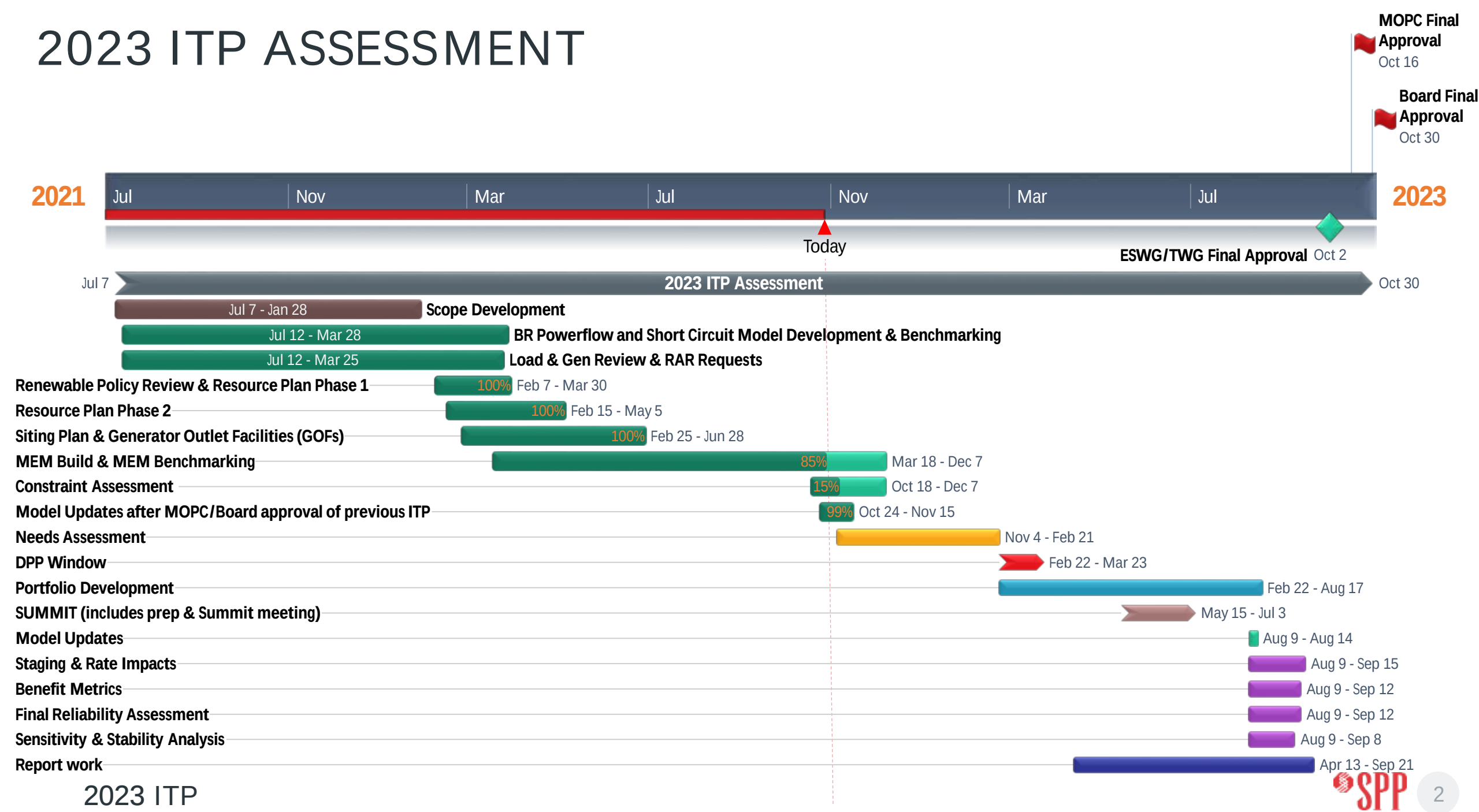
DARA SOLOMON

NOVEMBER 2022

Working together to responsibly and economically keep the lights on today and in the future.

SouthwestPowerPool SPPorg southwest-power-pool

2023 ITP ASSESSMENT



BASE RELIABILITY POWERFLOW & SHORT CIRCUIT MODELS

- Start: 7/06/2020
- Initial Final Approval: 3/28/2022 (BR & Short-Circuit)
- BR Powerflow & SC – Initial Final Approval: 3/30-31/2022 (TWG)
- BR Power & SC – Final Final Approval: Nov. 2022 (TWG)

- Member Review Time:
  - *Pass 0 – Trial 1 (Posting: 7/12/2021): 7/12/2021 – 7/23/2021 (5 days)*
  - *Pass 1 – Trial 1 (Posting: 9/10/2021): 9/13/2021 – 10/1/2021 (15 days)*
  - *Pass 1 – Trial 2 (Posting: 10/29/2021): 10/29/2021 – 11/26/2021 (3 days)*
  - ***Final Submission Deadline: 11/29/2021****
  - *Pass 2 – BR Powerflow (Posting: 1/28/2022): 1/28/2022 – 2/18/2022 (15 days)*
  - *Pass 2 – SC (Posting: 1/31/2022): 1/31/2022 – 2/18/2022 (14 days)*
  - *Pre-Initial Final Initial ITP (Posting: 3/4/2022): 3/4/2022 – 3/11/2022 (5 days)*
  - *Initial Final BR Powerflow TWG Approval (Posting: 3/18/2021): 3/21/2022 – 3/28/2022 (5 days)*
  - *Initial Final Short-Circuit TWG Approval (Posting: 3/18/2021): 3/21/2022 – 3/28/2022 (5 days)*
  - *Initial Final BR Powerflow TWG Approval requested via email: 3/28/2022*

- Staff Leader: Hugh Benfer (hbenfer@spp.org)
- Working Group Approval: TWG

*** Data Submitters** – Final Submission of Generator Additions, Retirements, Pmin & Pmax, Loads, and Interchange Corrections through MOD & EDST

MARKET ECONOMIC MODEL (MEM) BUILD

- Start: 3/18/2022
- End: 12/7/2022 (Members' Final Approval)

- Member Review Time:
  - *MEM Pass 1 – Year 2 for Review (Posting: 6/3/2022): 6/3/2022 – 6/8/2022 (5 days)*
  - *MEM Pass 1 – Year 2 for Approval (Posting: 6/21/2022): 6/21/2022 – 6/27/2022 (5 days)*
    - *Email vote for approval: 6/25/2022 – 7/1/2022*
  - *MEM – Years 5/10: for Review (Posting: 10/4/22): 10/4/2022 – 10/11/2022 (5 days)*
  - *MEM – Years 5/10 for approval (Posting: 10/17/22): 10/17/2022 – 10/24/2022 (5 days)*
  - MEM – Final Approval (Posting: 12/7/2022): 12/7/2022 – 12/14/2022 (5 days)

- Staff Leader: Charlton Hill (chill@spp.org)
- Working Group Approval: ESWG

CONSTRAINT ASSESSMENT

- Start: 10/18/2022
- End: 12/7/2022

- Staff Leader: Maurisa Hughes (mghughes@spp.org)
- Working Group Approval: ESWG

NEEDS ASSESSMENT

- Start: 11/04/2022
- End: 2/21/2023

- Member Review Time:
  - Needs Assessment scheduled to post 2/22/2023

- Staff Leaders:
  - Economic & Policy Needs: Spencer Magby (smagby@spp.org)
  - Reliability Needs: Greg Lampley (glampley@spp.org)
  - Short-Circuit Needs: Nathan Bean (nbean@spp.org)

DETAILED PROJECT PROPOSAL (DPP) WINDOW

- Start: 2/22/2023 12:00 a.m.
- End: 3/23/2023 11:59 p.m.

- Member Review Time:
  - Transmission-planning response window (30 calendar days)

- Staff Leader: Tammy Bright (tbright@spp.org)

DPP TECHNICAL VALIDATION

- Start: 3/12/2023
- End: 4/28/2023

- Staff Leader: Krishada Watson (kwatson@spp.org)

SOLUTIONS DEVELOPMENT

- Start: 2/22/2023
- End: 4/24/2023

- Staff Leader: Drake Hill (dhill@spp.org)

SOLUTIONS EVALUATION

- Start: 3/15/2023
- End: 5/05/2023

- Staff Leaders:
  - Reliability: Josh Pilgrim (jpilgrim@spp.org)
  - Economic & Policy: Ahmed Alazzawi (aalazzawi@spp.org)
  - Short Circuit: Nathan Bean (nbean@spp.org)

PORTFOLIO DEVELOPMENT (INCLUDING OPTIMIZATION AND CONSOLIDATION)

- Start: 4/28/2023
- End: 8/17/2023

- Member Review Time:
  - TBD

- Staff Leaders:
  - Reliability: Greg Lampley (glampley@spp.org)
  - Economic & Policy: Maurisa Hughes (mghughes@spp.org)
  - Consolidation: Antonio Barber (abarber@spp.org)

- Working Group Approval: ESWG/TWG

STUDY COST ESTIMATES

- Start: May 2023 (specific date TBD)
- End: July 2023 (specific date TBD)

- Staff Leader: John O’Dell (jodell@spp.org)

PLANNING SUMMIT

- Start: June 2023 (specific date TBD)
- End: July 2023 (specific date TBD)

- Staff Leader: Tammy Bright (tbright@spp.org)

MODELING UPDATES FOR FINAL ASSESSMENTS

- Start: 8/09/2023
- End: 8/14/2023

- Staff Leader: Hugh Benfer (hbenfer@spp.org)
- Working Group Approval: TWG

PROJECT STAGING

- Start: 8/09/2023
- End: 8/22/2023

- Member Review Time:
  - TBD

- Staff Leader: Krishada Watson (kwatson@spp.org)
- Working Group Approval: TWG/ESWG

FINAL RELIABILITY ASSESSMENT

- Start: 8/09/2023
- End: 9/12/2023

- Member Review Time:
  - TBD

- Staff Leader: Joshua Pilgrim (jpilgrim@spp.org)
- Working Group Approval: TWG

SENSITIVITY ANALYSIS

- Start: 8/09/2023
- End: 9/08/2023

- Member Review Time:
  - TBD

- Staff Leader: Spencer Magby (smagby@spp.org)
- Working Group Approval: ESWG

STABILITY ANALYSIS

- Start: 8/09/2023
- End: 9/08/2023

- Member Review Time:
  - TBD

- Staff Leader: Greg Lampley (glampley@spp.org)
- Working Group Approval: TWG

RATE IMPACTS/ATRR

- Start: 8/22/2023
- End: 9/15/2023

- Member Review Time:
  - TBD

- Staff Leader: Susanna Padilla (spadilla@spp.org)
- Working Group Approval: ESWG/TWG

FINAL REPORT

- Start: 4/13/2023
- End: 09/21/2023

- Member Review Time:
  - TBD

- Staff Leader: Tammy Bright (tbright@spp.org)
- Working Group Approval: ESWG/TWG

TWG/ESWG FINAL APPROVALS

- Start: October 2023
- End: October 2023

- Member Review Time:

- Staff Leaders:
  - TWG – Sherri Maxey (smaxey@spp.org)
  - ESWG – Joshua Norton (jnorton@spp.org)

MOPC AND SPP BOARD

- MOPC: 10/16/2023
- BOD: 10/31/2023

CONTACT INFO

Dara Solomon, SPP Staff

dsolomon@spp.org

SPP Southwest Power Pool

2024 ITP

SCHEDULE UPDATE

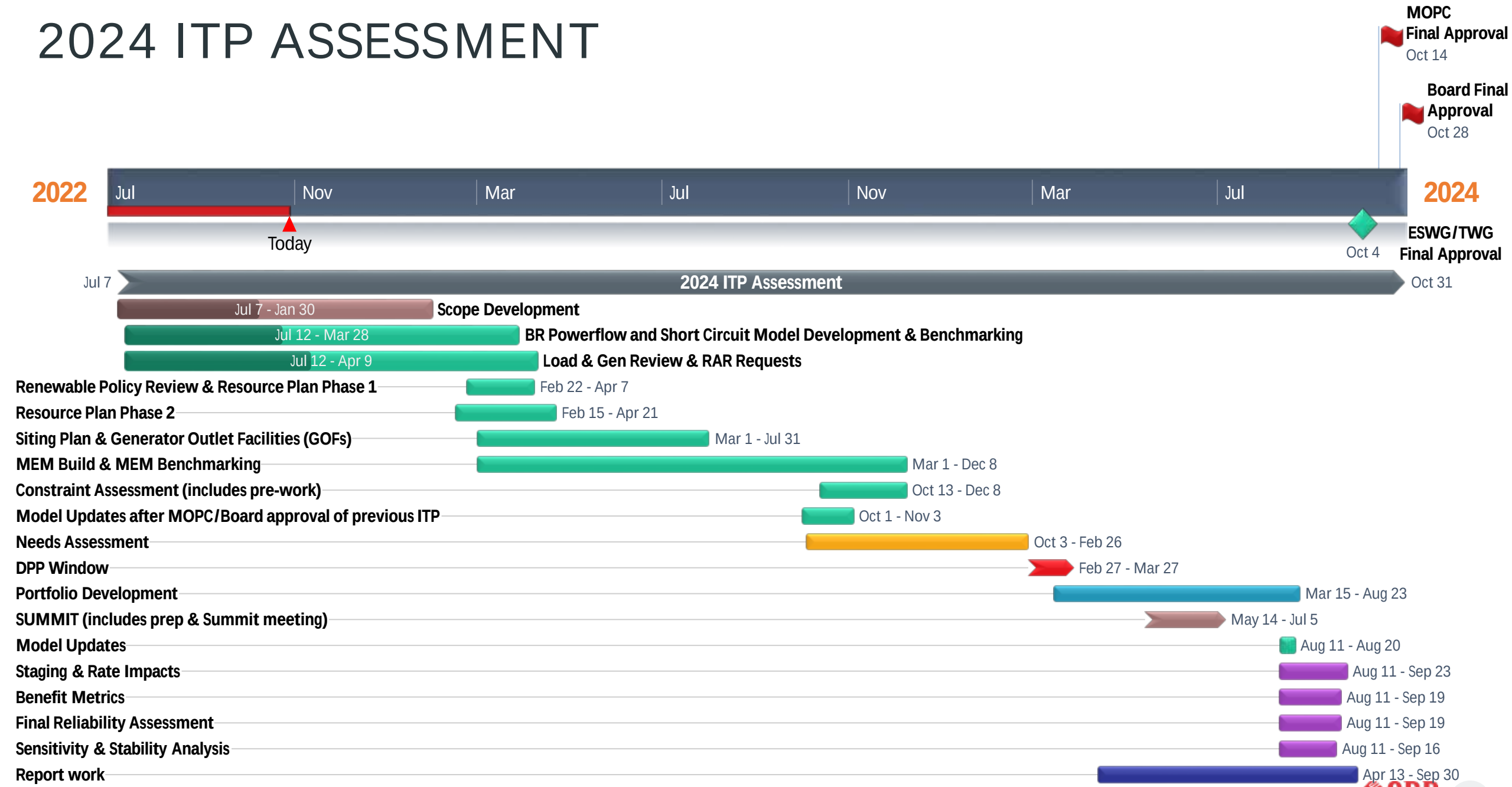
DARA SOLOMON

NOVEMBER 2022

Working together to responsibly and economically keep the lights on today and in the future.

SouthwestPowerPool SPPorg southwest-power-pool

2024 ITP ASSESSMENT



SCOPE DEVELOPMENT

- Start: 7/7/2023
- End: 1/21/2024 (Member's Final Approval)
  - December 2023: TWG/ESWG approval
  - MOPC Approval: 1/13/2024

	2022						2023
Topic	JUL	AUG	SEPT	OCT	NOV	DEC	JAN
Futures Development	ESWG - TWG - SPC - MOPC						
Project Schedule			ESWG - TWG				
Must Run Units			ESWG				
Curtailment Price			ESWG				
Model Series			ESWG - TWG				
Integrated Resource Plans (IRPs)			ESWG				
Hurdle Rates and Interchange			ESWG				
Conventional Generator Prototypes			ESWG				
Renewable Accreditation			ESWG				
State Renewable Portfolio Standards			ESWG				
New Resource Allocation and Assignment			ESWG				
Resource Plan Modeling			ESWG				
Persistent Operational Solution Evaluations				ESWG - TWG			
Consolidation				ESWG - TWG			
Sensitivities				ESWG			
Voltage Stability Assessment				TWG			
Final Scope Document					ESWG - TWG		MOPC

- Staff Leader: Josh Norton (jnorton@spp.org)
- Working Group Approvals: ESWG, TWG, SPC and MOPC

BASE RELIABILITY POWERFLOW & SHORT CIRCUIT MODELS

- Start: 7/11/2022
- BR Powerflow & SC – Initial Final Approval: 3/27/2023 (TWG)
- BR Power & SC – Final Final Approval: Nov. 2023 (TWG)

- Member Review Time:
  - *Pass 0 – Trial 1 (Posting: 7/22/2022)*
  - *Pass 1 – Trial 1 (Posting: 9/9/2022): 9/12/2022 – 9/30/2022 (15 days)*
  - Pass 1 – Trial 2 (Posting: 10/28/2022): 10/28/2022 – 11/02/2022 (3 days)
  - **Final Submission Deadline: 11/23/2022***
  - Pass 2 – Trial 1 (Posting: 1/16/2023): 1/09/2023 – 1/09/2023 (9 days)
  - Pass 2 – Trial 2 (Posting: 2/10/2023)
  - Initial Final Pass (Posting: 3/17/2023): 3/20/2023 – 3/24/2023 (5 days)
  - Initial Final TWG Approval (Posting: 3/27/2023)

- Staff Leader: Hugh Benfer (hbenfer@spp.org)
- Working Group Approval: TWG

*** Data Submitters** – Final Submission of Generator Additions, Retirements, Pmin & Pmax, Loads, and Interchange Corrections through MOD & EDST

LOAD REVIEW

- Start: 8/30/2022
- End: 4/9/2023 (Member's Final Approval)

- Member Review Time:
  - *Load Pass 1 – Trial 1 (Posting: 9/30/2022): 10/3/2022 – 10/14/2022 (5 days)*
  - Load Pass 2 (Posting: 2/14/2023): 2/15/2023 – 2/21/2023 (5 days)
  - Final Load Review Posting for Approval: 3/24/2023
  - Final Stakeholder Review: 3/27/2023 – 3/31/2023 (5 days)
  - Request Load Review approval from ESWG via email vote: 3/31/2023
  - Final approval: 4/6/2023 (dependent upon ESWG email vote)

- Staff Leader: David Duhart(dduhart@spp.org)
- Working Group Approval: ESWG

GENERATION REVIEW & RESOURCE ADDITION REQUESTS (RARS)/WAIVERS

- Start: 8/30/2023
- End: 4/6/2024 (Member's Final Approval)

- Member Review Time:
  - *RAR & Waiver Application Request (Posting: 9/30/2022): 10/3/2022 – 11/03/2022 (20 days)*
  - *Gen Pass 1 – Trial 1 (Posting: 9/30/2022): 10/3/2022 – 10/14/2022 (5 days)*
  - Gen Pass 2 (Posting: 2/14/2023): 2/15/2023 – 2/21/2023 (5 days)
  - Final Gen Review Posting for Approval: 3/24/2023
  - Final Stakeholder Review: 3/27/2023 – 3/31/2023 (5 days)
  - Request Gen Review approval from ESWG via email vote: 3/31/2023
  - Final approval: 4/6/2023 (dependent upon ESWG email vote)

- Staff Leader: David Duhart (dduhart@spp.org)
- Working Group Approval: ESWG

RENEWABLE POLICY REVIEW

- Start: 2/22/2023
- End: 3/30/2023

- Member Review Time:
  - ESWG Approval: 3/22/2023 – 3/29/2023 (5 days)

- Staff Leader: Krishada Watson (kwatson@spp.org)
- Working Group Approval: ESWG

CONTACT INFO

Dara Solomon, SPP Staff

dsolomon@spp.org

SCOPE AND STUDY EXECUTION ACTION ITEMS

SHERRI MAXEY

ESWG NOVEMBER 2022

OVERVIEW

- Staff's Approach
- Action Items identified – Updates shown in red; completed items in green
- Data source

STAFF'S APPROACH

- Purpose: Identify 20-Year Assessment scope and study execution items to be addressed with stakeholders
- Action: Take chronological approach by ITP study milestone
- Goal: Bring back 1-2 months prior to start of milestone work for stakeholder discussion and decision

ACTION ITEMS

ID	Description	Milestone(s)	Status Update
1	Load growth distribution and approach to non-conforming load (partial overlap with item 2)	Powerflow Models / Load Review	*Completed*
2	Implementing future drivers in generation and load review, and market economic model (MEM) Supply side items: Ø Emissions target and gas retirements (F3/F4), modeling and monitoring Ø Electric storage additions - transmission, energy or capacity asset, or all of the above? ü Distributed resource forecasts and modeling ü Fuel forecasts extrapolation and adjustments Demand side items: ü Load shape changes (will complete in MEM) ü General electrification (*e.g.*, 20YR - F3/F4) ü Electric vehicle growth and distribution ü Demand response ü Energy efficiency	Generation and Load Review / Resource Plan (RP2) / MEM	*Completed*
3	Renewable policy extrapolation	Renewable Policy Review	*Completed*

ACTION ITEMS - CONTINUED

ID	Description	Milestone(s)	Status Update
4	Renewable pricing and PTC assumptions/expirations for new and existing units	Gen Review / RP2 / Siting	*Completed – related language added to 2023 ITP Scope*
5	Wind methodology for aging wind fleet (repowering assumptions)	Gen Review	*Completed*
6	Possible use of resource planning software in 20-Year Assessment; or should we adjust the traditional resource additions?	RP2	*Completed – will be using resource planning software*
7	Resource Plan strategy for renewables: • Renewable and storage ownership • ELCC implementation (renewable accreditation)	RP2	*Completed*
8	Identification of additional batteries beyond F1 and F2 scoped amounts (requires Scope change); including hybrid issues	RP2	*Completed*
9	External region resource plan and siting approaches	RP2	*Completed – considered complete once Item #13 was approved (using MTEP 21)*

ACTION ITEMS - CONTINUED

ID	Description	Milestone(s)	Status Update
10	Review 12% cap on renewables for reserve margin requirements	RP2	*Completed*
11	Determine resource addition strategy	Siting / Generator Outlet Facilities (GOFs) / Constraint Assessment	*Completed*
12	EPRI transmission capacity hosting tool/SPP initiative for siting	Siting / GOFs / Constraint Assessment	*Completed*
13	MTEP Futures compatibility (2022 ITP & 20YA)	External (Load & Gen Review / RP2 / Siting)	*Completed*
14	Hybrid Solar/Renewable and Battery Modeling and GI Surplus Capacity	Siting / MEM	*Completed*
15	Generator outlet facilities (GOFs) decision on inclusion in 20-Year Assessment	GOFs	*Completed*
16	Constraint Assessment on each future; come up with EHV portfolio; monitor everything 100 kV and above? Bring methodology back for review.	Constraint Assessment	*Presentation at September ESWG meeting (9/01/22) – Completed*

ACTION ITEMS - CONTINUED

ID	Description	Milestone(s)	Status Update
17	20-Year objective function for developing portfolios by future • Approaches to non-SPP APC savings benefits (*e.g.*, SPP-Other, SPP economy export APC savings benefits to non-SPP regions) • Approach to seams issues and solutions	Portfolio Development	
18	HV and EHV needs versus HV and EHV solution tradeoffs	Portfolio Development	
19	Identification of sensitivities	Sensitivity Analysis	

Group	MONTH	DATE	Day 1 Time (CT)	Day 2 Time (CT)
TWG	Meeting 1	Jan 3-4	9-3	9-3
ESWG	Meeting 1	Jan 4-5	9-3	8-12
TWG	Meeting 2	Jan. 30-31	1-5	9-3
ESWG	Meeting 2	Feb. 1-2	8-12	8-12
TWG	Meeting 3	Feb. 27-28	1-5	9-3
ESWG	Meeting 3	Mar 1-2	1-5	8-12
TWG	Meeting 4	Mar 28-29	9-5	9-5
ESWG	Meeting 4	Mar 29-30	9-5	8-12
TWG	Meeting 5	May 1-2	1-5	9-3
ESWG	Meeting 5	May 3-4	1-5	8-12
TWG	Meeting 6	May 29-30	1-5	9-3
ESWG	Meeting 6	May 31-Jun 1	8-12	8-12
TWG	Meeting 7	Jun 27-28	9-5	9-5
ESWG	Meeting 7	Jun 28-29	9-5	8-12
TWG	Meeting 8	Jul 31-Aug 1	1-5	9-3
ESWG	Meeting 8	Aug 2-3	1-5	8-12
TWG	Meeting 9	Aug. 28-29	1-5	9-3
ESWG	Meeting 9	Aug. 30-31	8-12	8-12
TWG	Meeting 10	Sep 26-27	9-5	9-5
ESWG	Meeting 10	Sep. 27-28	9-5	8-12
TWG	Meeting 11	Oct. 30-31	1-5	9-3
ESWG	Meeting 11	Nov. 1-2	8-12	8-12
TWG	Meeting 12	Nov 27-28	1-5	9-3
ESWG	Meeting 12	Nov 29-30	8-12	8-12

2023 ESWG-TWG SCHEDULE

LOCATION	ALT. LOCATION	Type Mtg
Net Conference Only		WebEx
Net Conference Only		WebEx
Net Conference Only		WebEx
Net Conference Only		WebEx
SPP Corporate Offices – Aud. B		In Person
SPP Corporate Offices – Aud. B		In Person
Evergy (Kansas City, MO)	SPP - Aud. B	In Person
Evergy (Kansas City, MO)	SPP - Aud. B	In Person
Evergy (Kansas City, MO)	SPP - Aud. B	In Person
Evergy (Kansas City, MO)	SPP - Aud. B	In Person
Net Conference Only		WebEx
Net Conference Only		WebEx
SPP Corporate Offices – Aud. B	Evergy (Kansas City, MO)	In Person
SPP Corporate Offices – Aud. B	Evergy (Kansas City, MO)	In Person
Evergy (Kansas City, MO)		In Person
Evergy (Kansas City, MO)		In Person
Net Conference Only		WebEx
Net Conference Only		WebEx
Tri-State (Denver, CO)	SPP - Aud. B	In Person
Tri-State (Denver, CO)	SPP - Aud. B	In Person
Net Conference Only		WebEx
Net Conference Only		WebEx
Net Conference Only		WebEx
Net Conference Only		WebEx

Notes	Availability
Pre-MOPC - JOINT	
Pre-MOPC - JOINT	
	Tri State- no; Tenaska - no
	SPP - yes
Pre-MOPC - JOINT	Tenaska - no; Evergy - yes
Pre-MOPC - JOINT	SPP - yes
	Tenaska - no; Evergy - yes
	SPP - yes
Pre-MOPC - JOINT	SPP - yes
Pre-MOPC - JOINT	Evergy - yes
	GRDA - no, because room cap is 26
	Evergy - yes; SPP - 8/1-3 only
Pre-MOPC - JOINT	Evergy - no
Pre-MOPC - JOINT	Tri-State - yes; SPP - yes

SPP Southwest Power Pool

2024 ITP

2024 ITP SCOPE – HURDLE RATES & INTERCHANGE

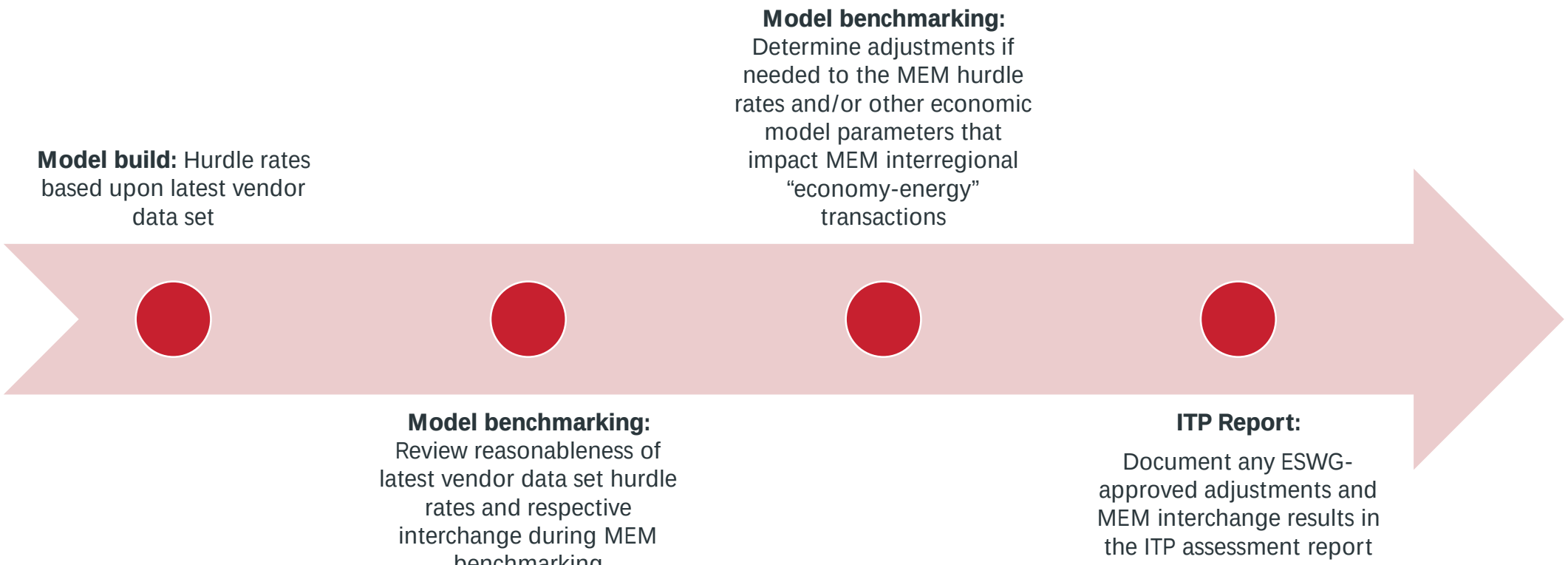
NOVEMBER 2022

JOSHUA NORTON

OBJECTIVES

- Review previous ITP scope language for hurdle rates and interchange
- Obtain approval of proposed language to include in the 2024 ITP Scope document

OVERVIEW OF PROCESS

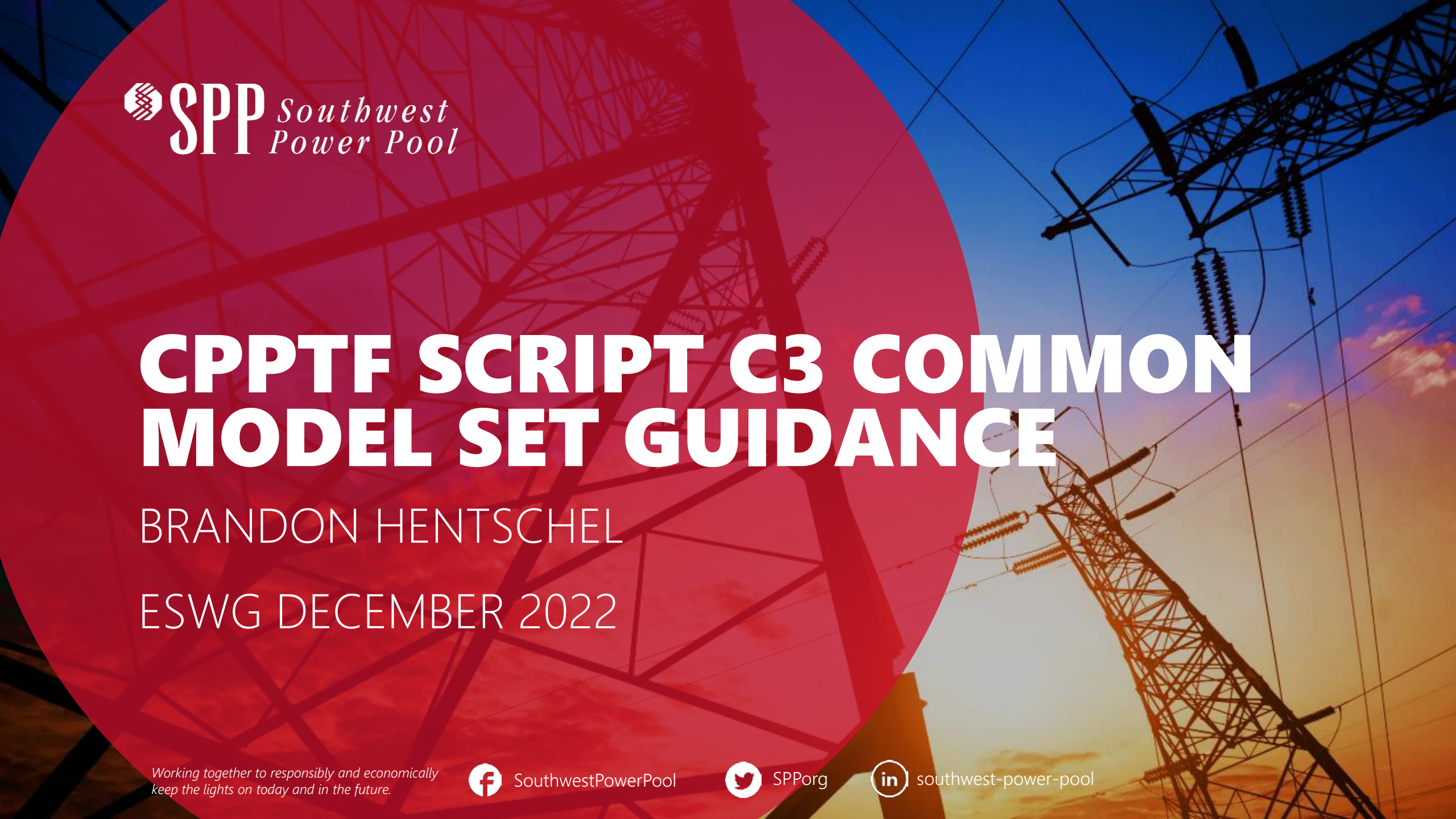


SCOPE LANGUAGE

- **HURDLE RATES AND INTERCHANGE**
- Hurdle rates for all futures will be based upon the latest vendor data set. However, prior to and during the MEM benchmarking and initial year 5 and year 10 MEM builds, SPP and ESWG will be reviewing the reasonableness of the latest vendor data set hurdle rates and respective interchange. SPP and ESWG may utilize, as appropriate, previous ITP MEMs in this review. This review may result in adjustments to the MEM hurdle rates and/or other economic model parameters that impact MEM interregional "economy-energy" transactions. Any ESWG-approved adjustments and MEM interchange results will be documented in the ITP assessment report.

RECOMMENDATION

- SPP Staff recommends that the ESWG approve a 2024 ITP Hurdle rates and interchange methodology consistent with the 2023 ITP Scope



CPPTF SCRIPT C3 COMMON MODEL SET GUIDANCE

BRANDON HENTSCHEL

ESWG DECEMBER 2022

SCRIPT C3 COMMON MODEL SET GUIDANCE

C3 COMMON MODEL SET SUB-RECOMMENDATIONS OVERVIEW

RECOMMENDATION	NAME	PRIMARY	SECONDARY
C3.1	Common Base Model Set Configuration	MDAG	TWG, ESWG, GIUF, TSUF
C3.2	Common Model Set Dispatch Assumptions	CPPTF	TWG, MDAG, ESWG, GIUF, TSUF
C3.3	MPM Model Development	ESWG	TWG
C3.4	Base Model Set Automation	Staff	CPPTF, TWG, ESWG, MDAG
C3.5	Base Model Benchmarking Consolidation	MDAG	TWG

CPPTF Approved SCRIPT C3 Common Model Set Guidance Document

C3.1 SUB-RECOMMENDATION

NAME	ASSOCIATED SCRIPT C3 REQUIREMENT	CPPTF IDENTIFIED IMPROVEMENTS
Common Base Model Set Configuration	• The base reliability models should meet NERC TPL and MOD planning standards such as TPL-001, MOD-030 and MOD-032. • The new base reliability models will be utilized for the Eastern Interconnection Reliability Assessment Group Multi-Regional Model Development Working Group (ERAG MMWG) submission. • The new base reliability models will be the starting base model assumptions utilized to build out customer service and transmission assessment scopes and requirements.	• Combine MDAG and ITP BR reliability model series • Optimal timing for annual model development and external data consideration • Base reliability model "initial-final" to "approved final" shelf-life and late data submission process improvement • Generator Interconnection model maintenance reduction

C3.1 DRAFT COMMON TOPOLOGY

NAME	TOPOLOGY
Common Topology (MOD – Models on Demand)	• EXISTING EQUIPMENT ➢ CORRECTIONS AND UPDATES • SPP-APPROVED UPGRADES ➢ NTC PROJECTS • TO PLANNED PROJECTS • AQ ➢ Approved load delivery points ➢ Associated upgrades or topology changes • GI ➢ GIA or IGIA and not on suspension

C3.1 COMMON MODEL SET CASE SELECTION EXAMPLE

- Likely 2023 Series MMWG Power Flow

Year	Season
2024	Spring Light Load
2024	Summer Peak
2024/25	Winter Peak
2025	Spring Light Load
2025	Summer Peak
2025/26	Winter Peak
2028	Spring Min Load
2028	Summer Shoulder
2028	Summer Peak
2028/29	Winter Peak
2033	Summer Peak
2033/34	Winter Peak

- 2024 ITP Power Flow

Year	Season
2024	Summer Peak
2024	Fall
2024/25	Winter Peak
2025	Spring Light Load
2025	Spring
2025	Summer Peak
2025	Fall
2025/26	Winter Peak
2028	Spring Min Load
2028	Summer Peak
2028/29	Winter Peak
2033	Spring Min Load
2033	Summer Peak
2033/34	Winter Peak

- Common Model Set

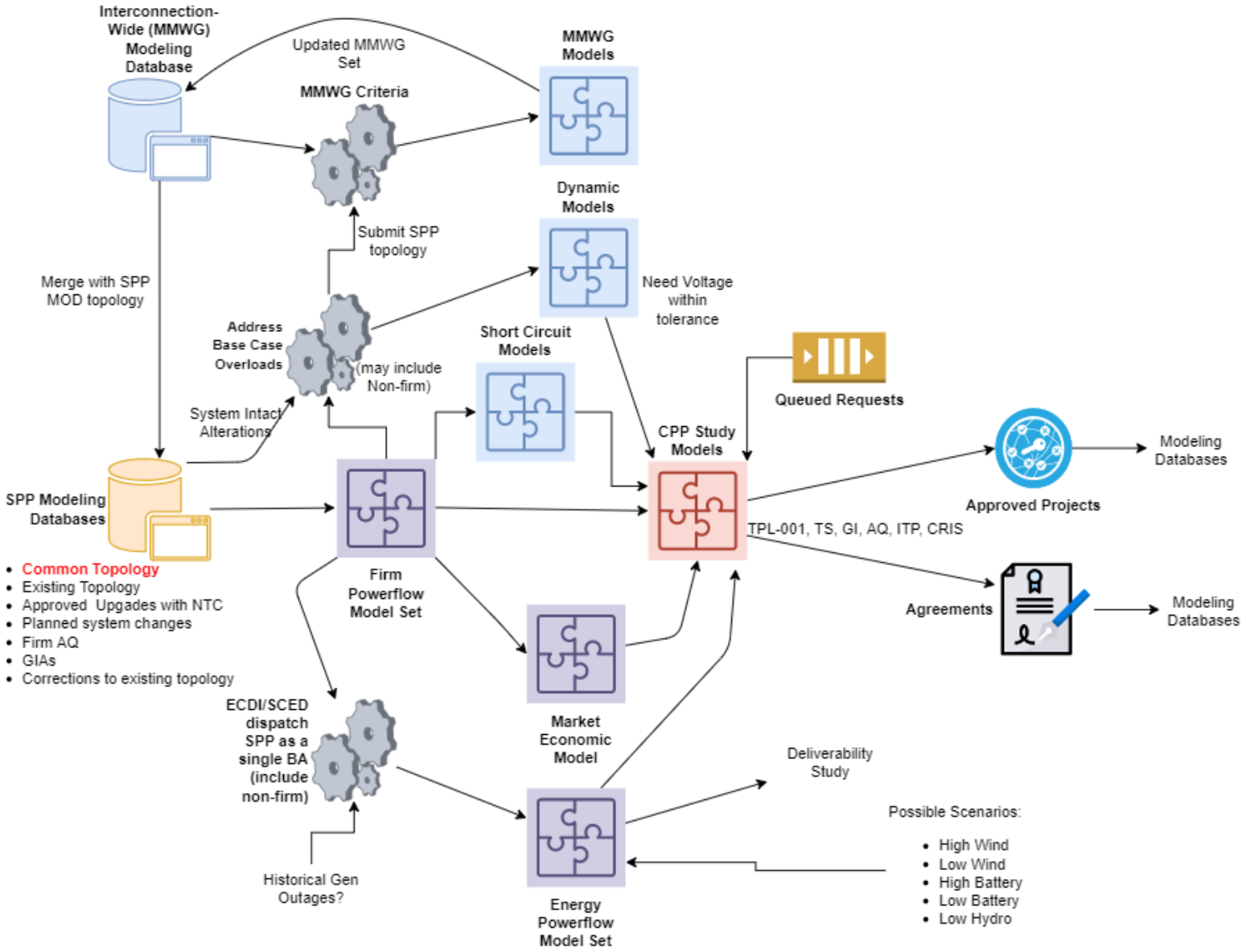
Year	Season
2024	Spring Light Load
2024	Summer Peak
2024	Fall
2024/25	Winter Peak
2025	Spring Light Load
2025	Spring
2025	Summer Peak
2025	Fall
2025/26	Winter Peak
2028	Spring Min Load
2028	Summer Shoulder
2028	Summer Peak
2028/29	Winter Peak
2033	Spring Light Load
2033	Summer Peak
2033/34	Winter Peak

MMWG CRITERIA:

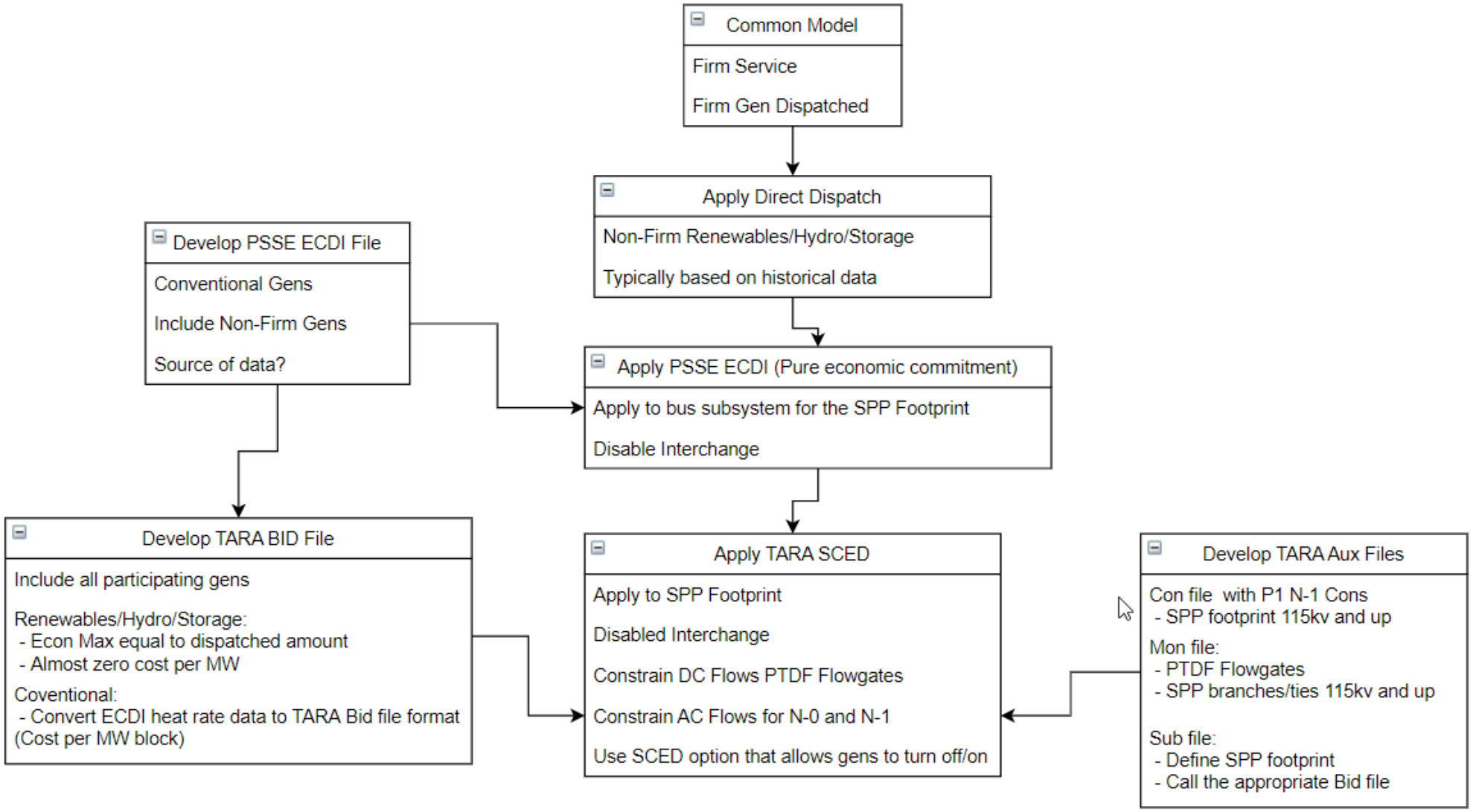
- Before submitting the SPP region to the MMWG, changes must be made to the Common Models to address voltage or thermal base case flows that are outside the ranges in the criteria below per the MMWG procedure manual.
  - Voltage for buses ≥ 100 kV
    - Conditions not allowed: VM > 1.1 p.u., VM < 0.9 p.u.
    - Document exceptions
  - Branch Overloads
    - Branches ≥ 69kV
    - Transformers ≥ 69kV
      - Two buses (of three) with BASKV ≥ 69kV
    - Overloads in the Near-Term with no plans to correct are not allowed. Ten-year cases often contain branches or transformers that will be upgraded but no plans exist. Transformers checked for loading in MVA, non-transformer branches in current.

https://rfirst.org/ProgramAreas/ESP/ERAG/MMWG/ERAG%20%20MMWG%20Library/MMWG_Procedural_Manual_V30.pdf

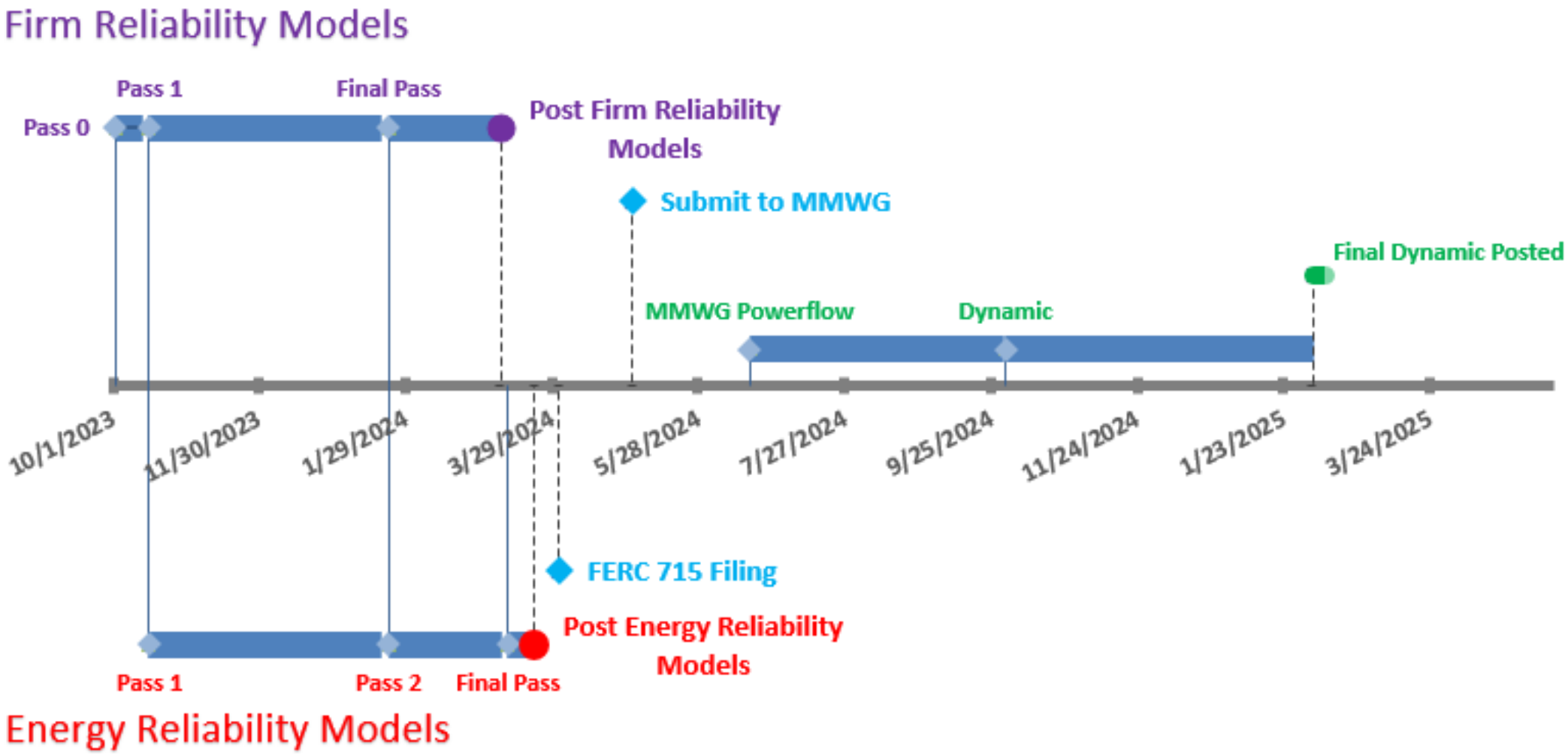
INITIAL DRAFT: CPP COMMON MODEL FLOWCHART (OPTION 1)



INITIAL DRAFT: ENERGY MODEL DISPATCH



INITIAL DRAFT: CPP MODEL TIMELINE EXAMPLE



MDAG RECOMMENDATIONS:

- Define the CPP Common Model Topology as:

NAME	TOPOLOGY
Common Topology (MOD – Models on Demand)	• EXISTING EQUIPMENT ➢ CORRECTIONS AND UPDATES • SPP-APPROVED UPGRADES ➢ NTC PROJECTS • TO PLANNED PROJECTS • AQ ➢ Approved load delivery points ➢ Associated upgrades or topology changes • GI ➢ GIA or IGIA and not on suspension

MDAG RECOMMENDATIONS:

- At a minimum, the Common Model Topology set in MOD should include the year/seasons necessary for the next MMWG and also include any additional year/seasons desired for the CPP process.

QUESTIONS?

PURPOSE

Update BOD on the Action Item for HITT M1

Provide awareness on the proposed Staff Recommendation to the CAWG, RSC and BOD

ESSENTIAL POINTS

- Review Staff Recommendation
  - Hybrid approach of Transmission and Congestion Hedging Market changes
  - Focus first on equity allocation of awards then focus on additional awards
  - Holistic changes include, Transmission, LTCR Allocation, ARR Allocation and Excess Auction Revenues

SPP Southwest Power Pool

HITT M1 STAFF RECOMMENDATION

OCTOBER 25, 2022

Working together to responsibly and economically keep the lights on today and in the future.

SouthwestPowerPool SPPorg southwest-power-pool

WHY ARE WE HERE

At the April Board meeting, the Board of Directors instructed SPP Staff to:

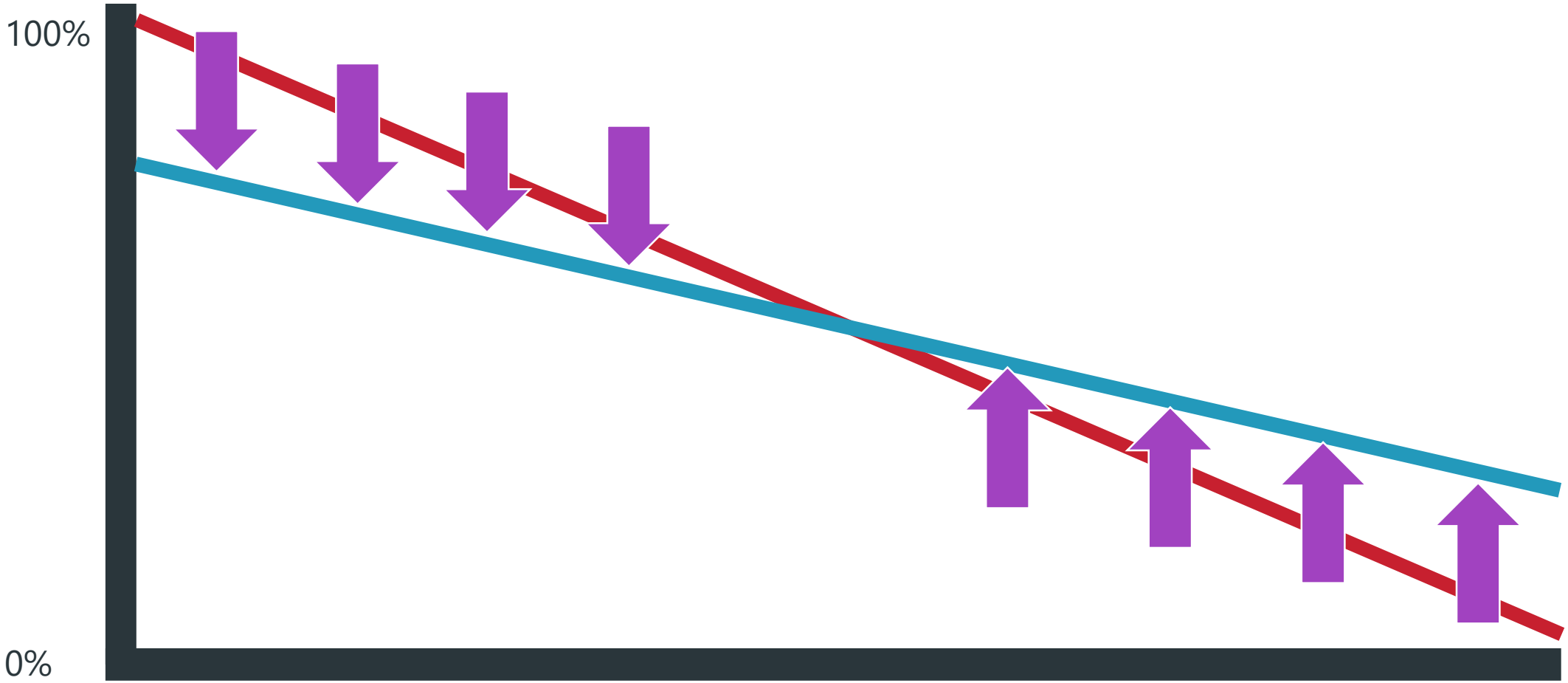
- Survey the MMU, MOPC, RSC and CAWG
- Deliver survey results to the BOD
- Provide opportunity for stakeholders to give feedback on potential recommendations
- Present a final recommendation/proposal to the board in October

KEY OBJECTIVES

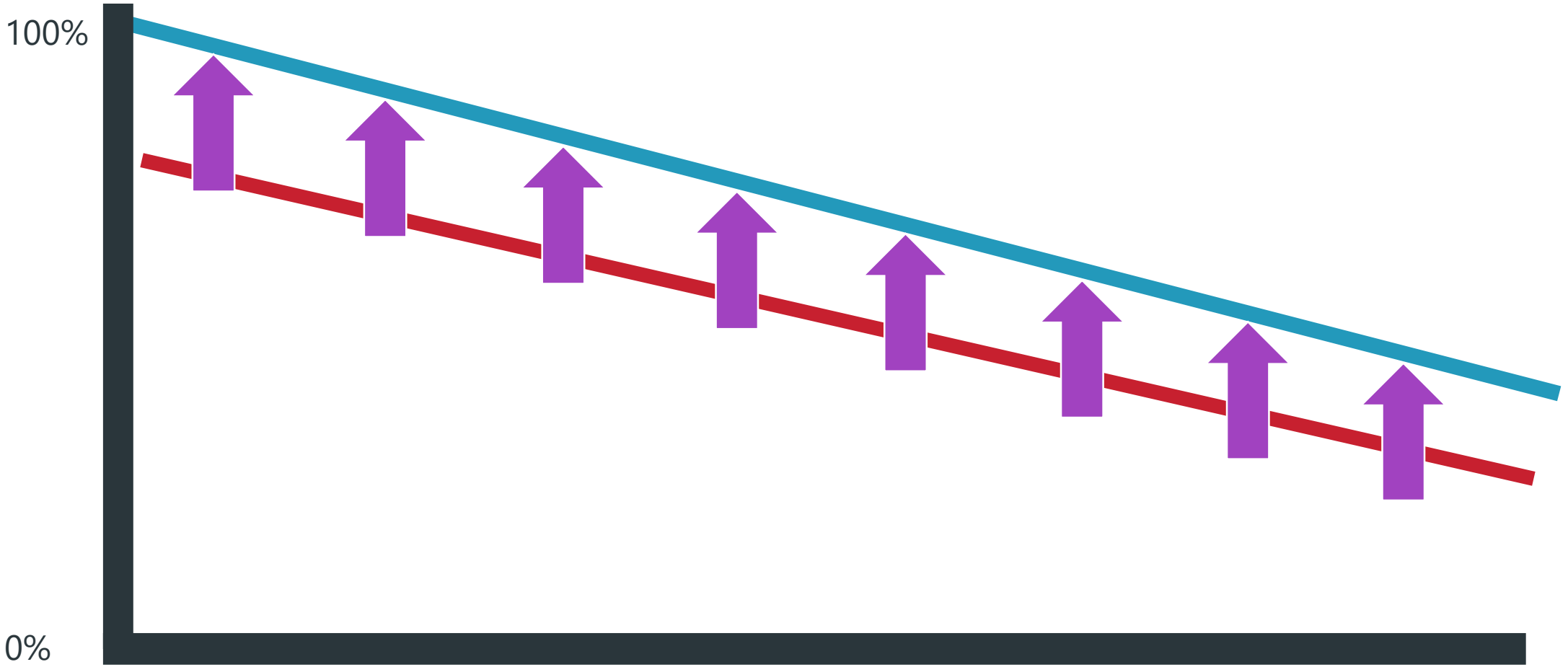
Review Staff Recommendation to address HITT M1: Implement Congestion Hedging Improvements

STAFF RECOMMENDATION

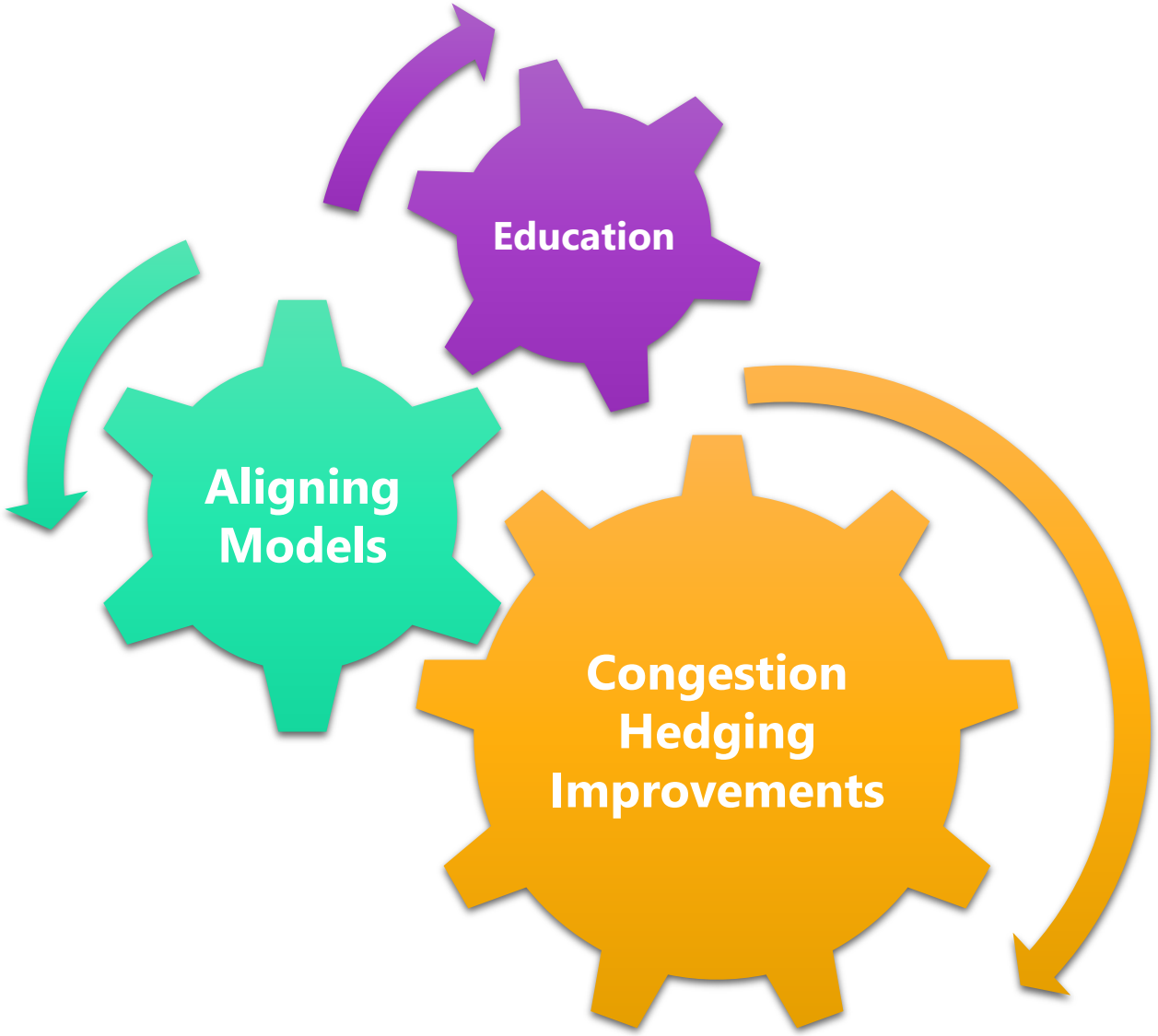
1) INCREASE EQUITY AND FAIRNESS



2) INCREASE AWARDS



HYBRID APPROACH – TRANSMISSION AND MARKET



STAFF RECOMMENDATION

- Re-set LTCR awards every 10 years to give more opportunities to all participants to receive LTCR awards
- Modify the LTCR Round 2 nomination capacity from 100% to an incremental percentage up to 100% to more equitably award LTCRs in the Annual process
- Modify the nomination capacity calculation for Round 1 of the Annual ARR process for a more equitable allocation of ARRs
- Modify the ARR Round 1 nomination capacity from 50% to an incremental percentage up to 50% to more equitably award ARRs in the Annual process
- Distribution of Excess Auction Revenues

STAFF RECOMMENDATION

- Update load modeling to better align with transmission service studied
- Update generator modeling to better align with transmission service studied
- Coordinate with Planning to review Firm Transmission assumptions used in transmission planning processes
- Provide Stakeholder education on how to use existing tools to increase awards

CONGESTION HEDGING IMPROVEMENTS

MODIFICATIONS TO LTCR

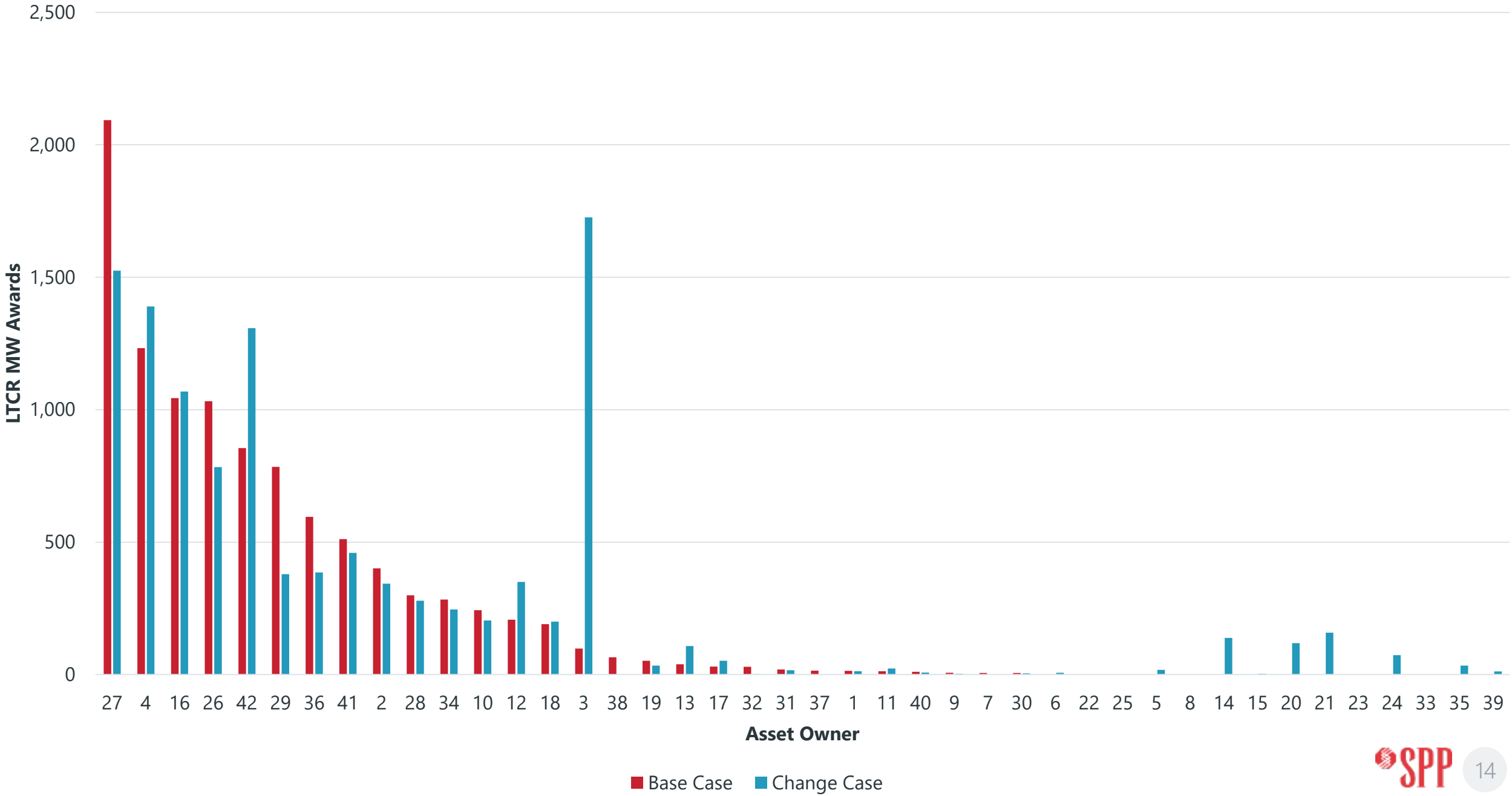
- LTCR Positions expire at 10 years
  - Once a participant has held an LTCR position for 10 years, the capacity is released to the market
  - Participant may re-nominate the expired position in Round 2

Benefits	Considerations
• Puts similarly situated rights holders on equal footing • Gives opportunities to all participants to receive LTCR awards	• Potential risk of losing previously awarded LTCR MWs at year 10

LTCR RESET STUDY ASSUMPTIONS

- Started with 2021 Annual Congestion Hedging process model
- Removed all baseloaded LTCR RD1 awards
- Re-nominated LTCR RD1 awards with existing RD2 Nominations

Base v Change Case LTCR Awards - 2021 TCR Year



MODIFICATIONS TO LTCR

- LTCR Round 2 nomination capacity incremental percentage up to 100%
  - Example: 5 iterations of 20% nomination cap up to 100%

Benefits	Considerations
• More equitable allocation on constrained paths • Maintain participant latitude of nominations	• May reduce Round 2 LTCR awards

NOMINATION CAP CHANGES TO ANNUAL ARR PROCESS

- Modify Nomination Capacity Calculation for Annual ARR Round 1
  - Current Calculation: [Global Nom Cap – LTCR Awards]*50%
  - Modified Calculation: [Global Nom Cap]*50% - LTCR Awards

Benefits	Considerations
• More equitable allocation on constrained paths • No participants receive awards greater than 50% of their global Nomination Capacity	• Reduces overall ARR awards

NOM CAP CALCULATION STUDY ASSUMPTIONS

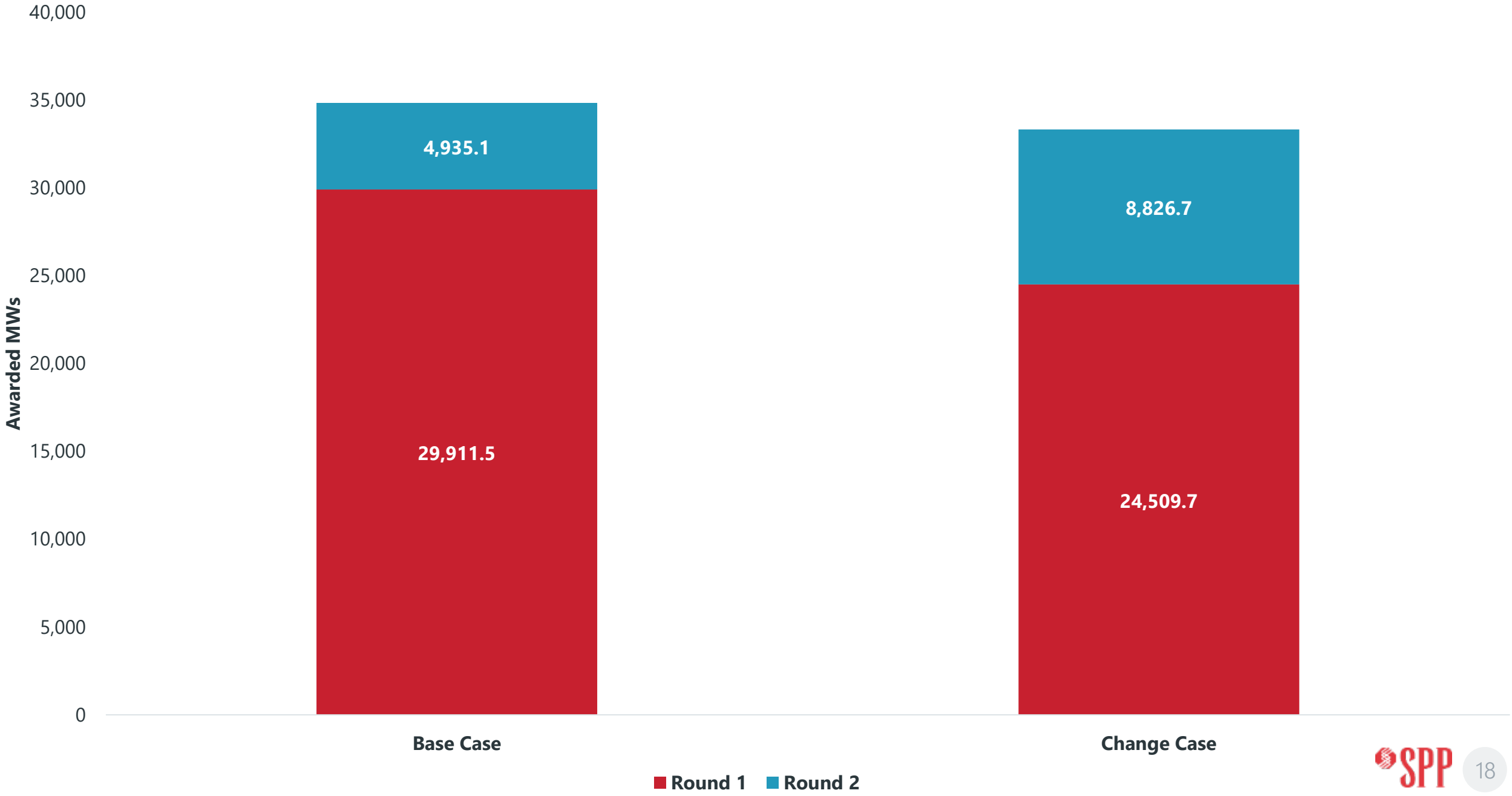
Based on 2019 Annual Congestion Hedging process model

- Analysis of June Period only

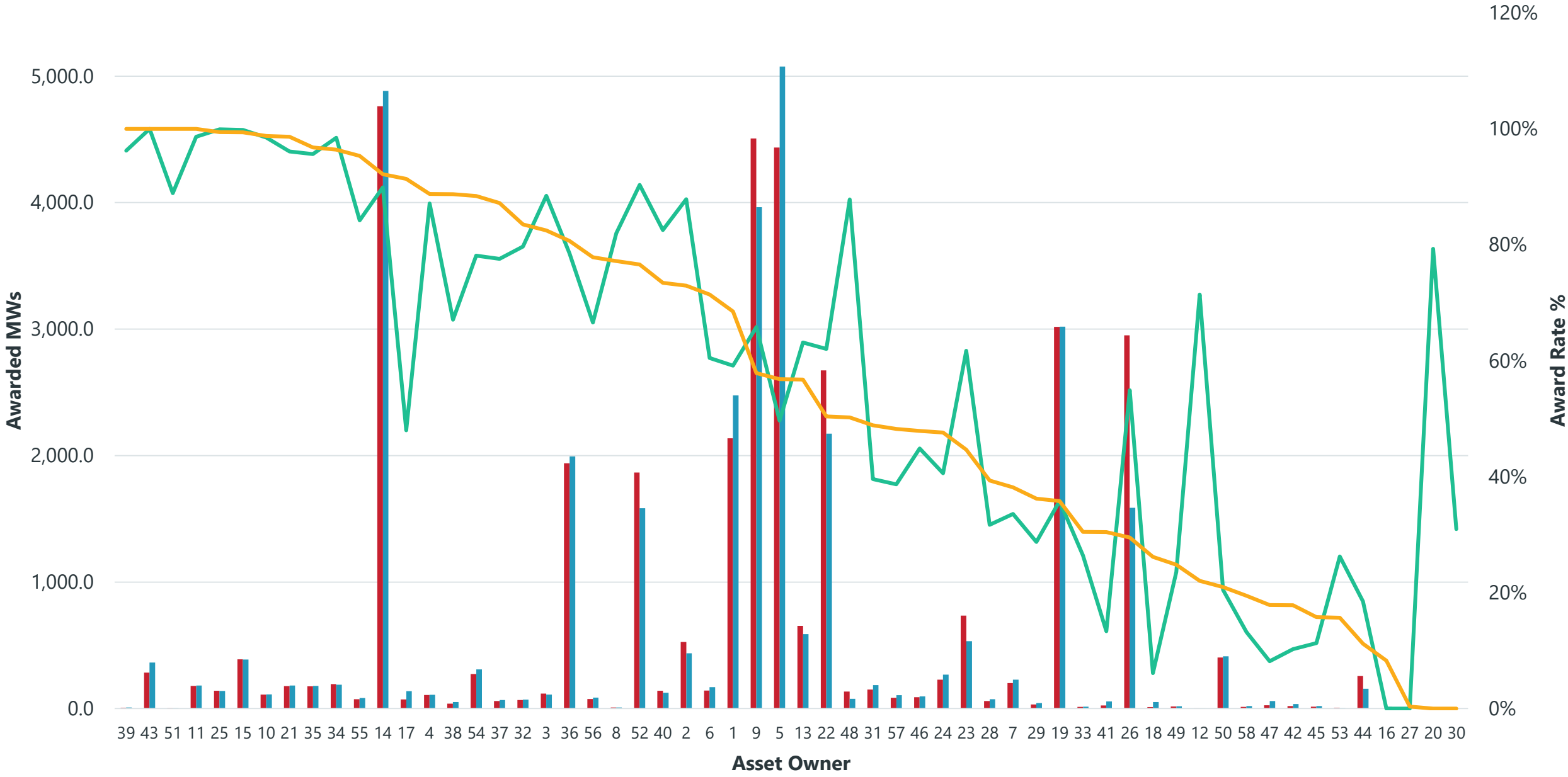
50% of ARR Nomination Cap less the sum of awarded LTCRs from Candidate LTCRs

- Round 1 Nomination = (0.5 * ARR Nomination cap) – LTCR Awards
- Round 2 Nomination = Original 2019 nomination target – Round 1 awards

Total ARR Awards Comparison - 2019 TCR Year June Period



Awards by Asset Owner



NOMINATION CAP CHANGES IN ANNUAL ARR PROCESS

- Annual ARR Round 1 nomination capacity incremental percentage up to 50%
  - Example: 5 iterations of 20% nomination cap up to 100% of the original 50% nomination cap

Benefits	Considerations
• More equitable allocation on constrained paths • Maintain participant latitude of nominations	• Reduces overall ARR awards

ITERATIVE ARR NOMINATIONS STUDY ASSUMPTIONS

Started with 2020 Annual Congestion Hedging process model	Utilized nominations from round 1 of the 2020 ARR Allocation	Kept base loading from LTCR allocation	Performed study for all seasons of annual process
	• 50% of nomination cap		

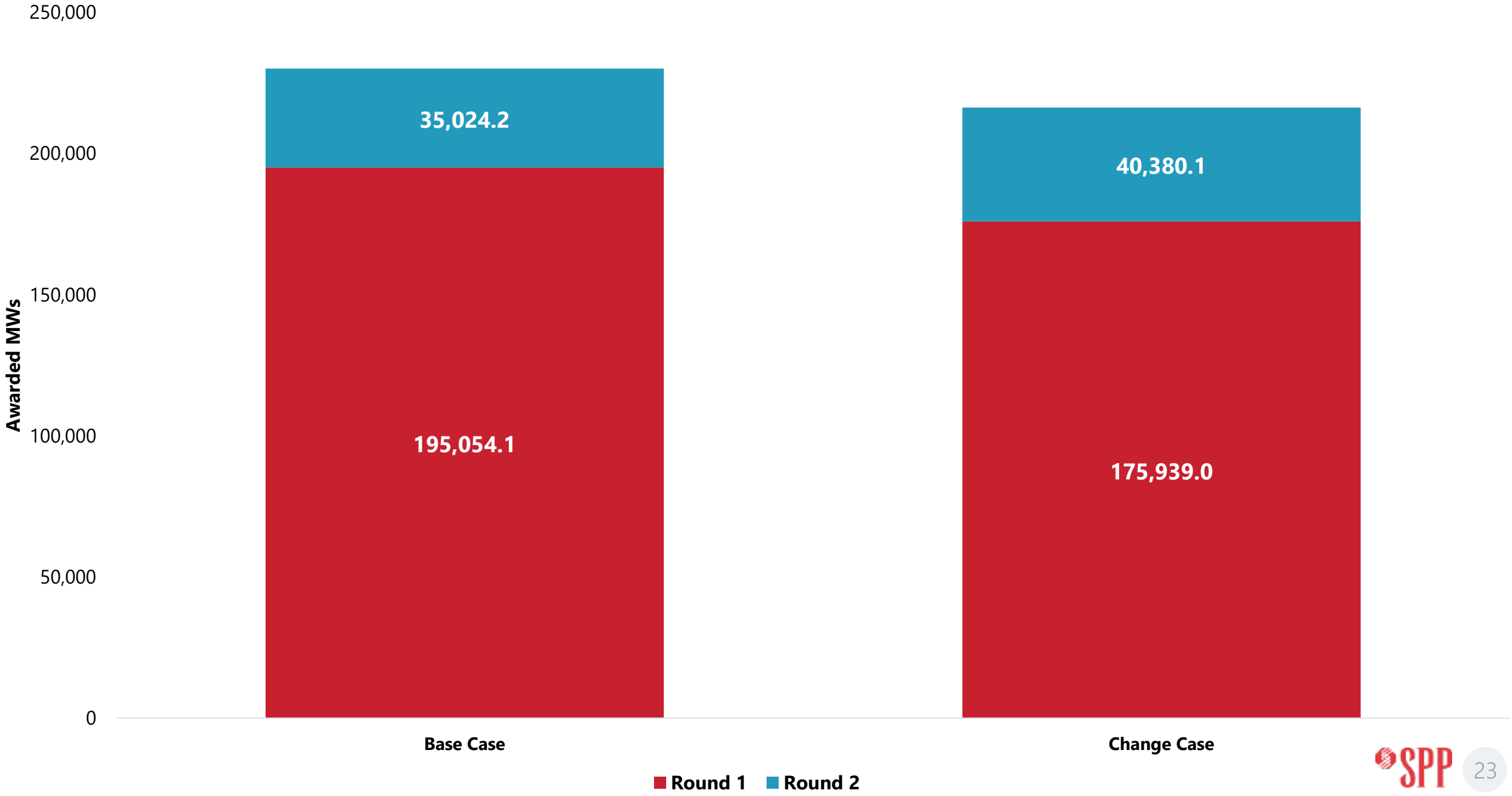
ITERATIVE NOMINATIONS STUDY ASSUMPTIONS

The nominations for each iteration were determined using the following criteria:

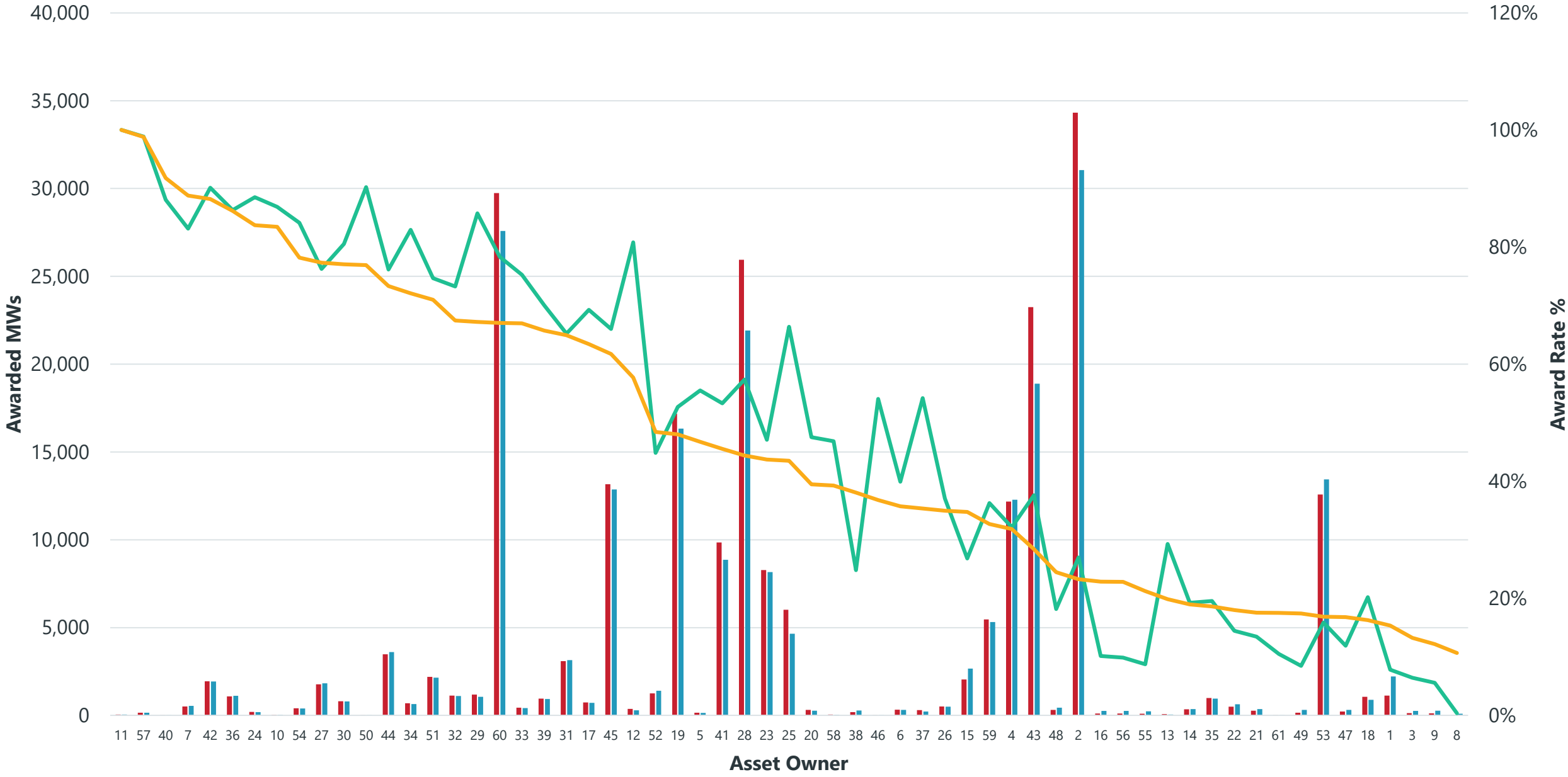
- First iteration: 20% of round 1 annual nominations
- Second iteration: 40% of round 1 annual nominations – all previous iterations awards
- Third iteration: 60% of round 1 annual nominations – all previous iteration awards
- Fourth iteration: 80% of round 1 annual nominations – all previous iteration awards
- Fifth iteration: 100% of round 1 annual nominations – all previous iteration awards

Each iterations awards were added to base loading for the following iteration

Total ARR Awards Comparison (All Annual Periods Rounds 1 & 2)



Awards by Asset Owner



DISTRIBUTION OF EXCESS AUCTION REVENUES

- Transition from:
  - Ratio share by nomination capacity; to
  - Curtailment of ARRs (working on details)

Benefits	Considerations
• Money available to purchase TCRs in the upcoming Auctions • Compensation for ARRs not awarded • No double dipping of value	• Does not provide the value of a TCR

ALIGNING MODELS

ALIGNING COMMERCIAL AND TRANSMISSION MODELS - COMMERCIAL MODEL

- Load modeling
  - Load Settlement Location must match the delivery points in the customer's Network Integrated Transmission Service Agreement (NITSA)

Benefits	Considerations
• Added granularity results in increased ARR awardability • Better aligns planning and market load modeling	• Entities with multiple NITSAs would have to nominate one load settlement location for each NITSA • Increased changes in commercial model

ALIGNING COMMERCIAL AND TRANSMISSION MODELS - COMMERCIAL MODEL

- Generator modeling
  - Fleet purchases must map to a Resource Hub
  - Unregistered source/sink locations will not default to POR/POD
    - All sinks and market gen sources will map to a SL

Benefits	Considerations
• Better aligns candidate ARRs mappings with generation in DAMKT	• Increased changes in commercial model

FIRM SERVICE ASSUMPTIONS

- Review the assumptions for Firm Transmission Service used in the transmission planning processes
- More discussion is needed to review the dispatch assumptions

Benefits	Considerations
• Closer alignment of TS and CH feasibility studies	• Will take time to engage other stakeholders

BUILD MORE TRANSMISSION

- Increasing system capacity in congested areas may result in more ARR awards

Benefits	Considerations
• Provides physical and financial congestion relief • Improves congestion hedging feasibility • Lowers energy costs across the SPP Region	• Takes time and will routinely lag congestion hedging needs of Firm Transmission Service customers • Changes to congestion flow

EDUCATION

STAKEHOLDER EDUCATION

- Educate stakeholders and demonstrate how to utilize Round 3 of the Annual process to provide additional ARR MW

Benefits	Considerations
• Stakeholders are in control of their constraint-relieving nominations • Requires no software changes	

APPENDIX

DEFINITIONS

Transmission Service Reservations (TSRs)	• Your right to ship power
Auction Revenue Rights (ARRs)	• Your right to revenue from the TCR Auction
Transmission Congestion Rights (TCRs)	• Your right to congestion revenue from the DA Market
Prevailing Flow	• Flow in a direction that results in a payment to the TCR holder
Counterflow	• Flow in a direction that results in a charge to the TCR holder
Asset Owner	• Market participant can have multiple asset owners. Asset owners are "financial containers" for settlements.

DEFINITIONS

Marginal Congestion Component (MCC)	• A Locational Marginal Price (LMP) component representing congestion's marginal cost. The MCC is used to calculate the value of a TCR position.
Constraint	• System limitations, typically flowgates and monitored elements
Nomination Cap	• Maximum MWs an MP can nominate in the Allocation Process
Self Converted ARR	• Participant attains financial right in the TCR Auction by "converting" ARR into TCR • MP receives a value for ARR and an inverse value for TCR netting to zero dollars
Settled ARR	• Participant places entitlement up for auction and settles the ARR at the ACP in the TCR Auction • ARR holder either gets paid or pays the *ACP x MW* value
Simultaneous Feasibility Test	•Analysis performed during each round of the Auction Revenue Right (ARR) Nomination Process to ensure nominated Candidate ARRs do not violate any normal transmission-line thermal ratings under normal system conditions, and do not violate short-term emergency transmission-line thermal ratings following a single contingency

MICHA BAILEY

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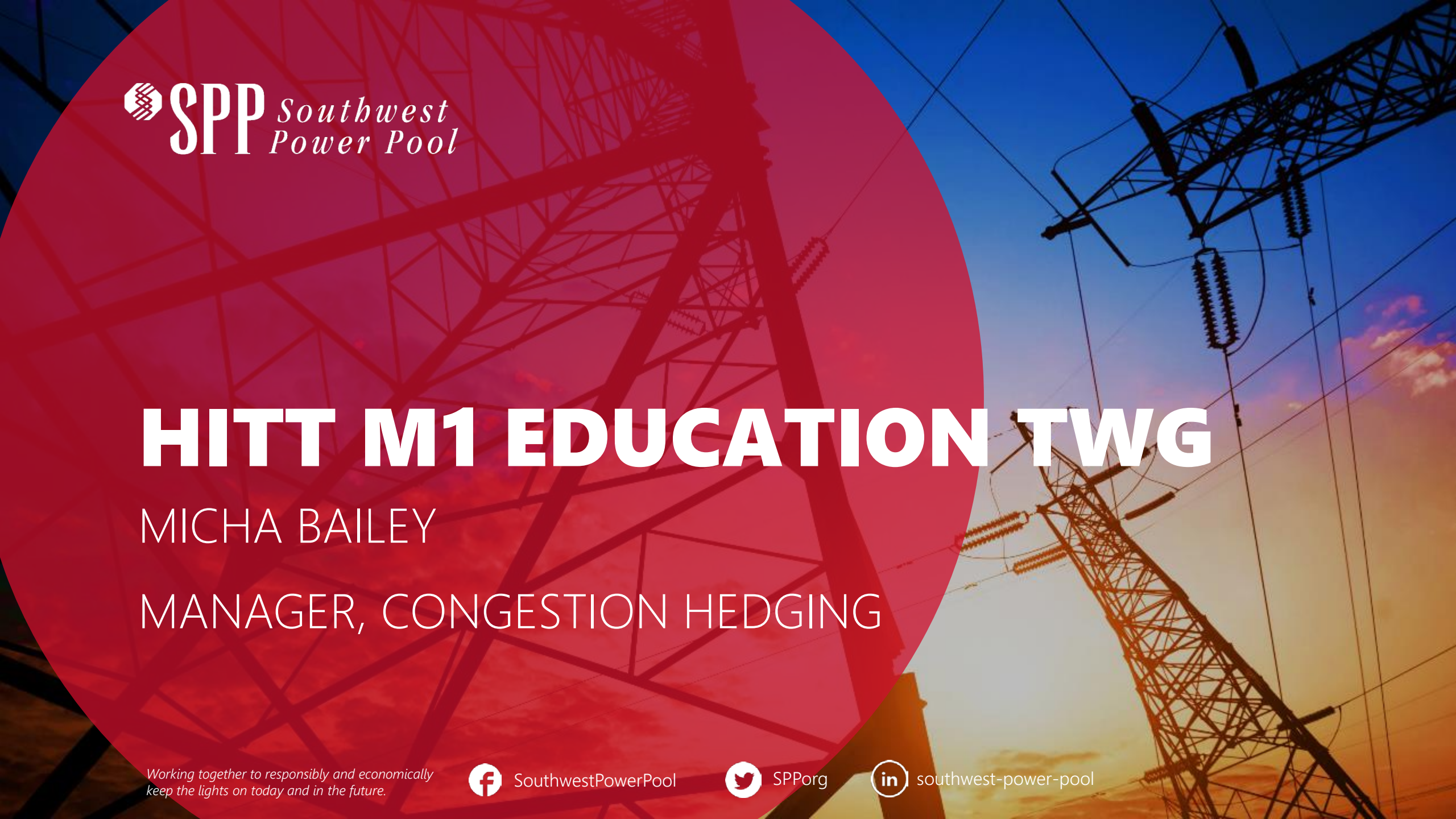


SPP Southwest Power Pool

HITT M1 EDUCATION TWG

MICHA BAILEY

MANAGER, CONGESTION HEDGING

Working together to responsibly and economically keep the lights on today and in the future.

SouthwestPowerPool SPPorg southwest-power-pool

WHY ARE WE HERE

At the April Board meeting, the Board of Directors instructed SPP Staff to:

- Survey the MMU, MOPC, RSC and CAWG
- Deliver survey results to the BOD
- Provide opportunity for stakeholders to give feedback on potential recommendations
- Present a final recommendation/proposal to the board in October

KEY OBJECTIVES:

- High level discussion on Transmission Service Reservation (TSR) Study Process
- Education on the Congestion Hedging process
- Review potential changes to address HITT M1 Implement Congestion Hedging Improvements

TSR STUDY PROCESS

TYPES OF FIRM TSRs

Network Integrated Transmission Service (NITS) – Part III of Tariff

- Delivery from a generation station (or stations) to a network load
  - Network Resources (Designated Network Resources – DNR)
  - Delivery Point/Network Loads

Firm Point-to-Point (FPTP) – Part II of Tariff

- Delivery from a one location on the grid to another location on the grid.
  - Identified as path from specific source to specific sink
  - Today, used primarily for exports/imports into SPP

Grandfathered Agreements (GFAs)

- A pre-existing contractual agreement prior to SPP Tariff that is the network equivalent to NITS

TRANSMISSION SERVICE RESERVATION PROCESS

Transmission service is required to meet capacity obligations by Load Serving Entity (LSE)

Transmission Service Reservation (TSR) reserves a specific amount of:

Capacity in megawatts (MW)

Across a specific transmission system path

(*i.e. from Source A to Sink B*)

For a given timeframe

HOW DOES TRANSMISSION SERVICE RELATE TO THE CONGESTION HEDGING ALLOCATIONS?

Candidate Long Term Congestion Rights (LTCRs)/ Candidate Auction Revenue Rights (ARRs) are equivalent to firm TSRs

- A financial position that relates to a TSR path
- Defined Source, Sink, and MW

Participants have a choice to nominate on which Candidate LTCRs/ARRs path in the Allocations

- None, some, or all* positions

* Up to Round Nomination Cap

ALLOCATION PROCESSES

CONGESTION HEDGING PROCESSES

LTCR ALLOCATION PROCESS OVERVIEW

Is a long term financial instrument with roll over rights

Any LTCR MW awards are automatically converted into TCRs for all periods in the Annual ARR/TCR processes

Participants may renew LTCR positions annually

ALLOCATION PROCESS OVERVIEW

No financial participation bidding in allocation (not a market), Only physical rights holders participate

The Simultaneous Feasibility Test (SFT) attempts to maximize ARR awards without violating any constraint limits

Awarded ARRs are obligations that have value

ARRs settle in TCR Auction

TSR COMPARED TO ARR

Identified differences between the two study processes

Transmission Service Reservations

1. Firm service sold is included up to modeled load (i.e. includes counter-flow)
2. Service granted incrementally 2x year
3. 3% cutoff factor
4. Uses Planning Model
5. Full Gen/Load dispatch
6. No outages

Auction Revenue Rights

1. Participants nominate desired service (i.e. limited counter-flow)
2. Rights awarded annually, as requested
3. No cutoff factor
4. Uses Market Model
5. Only requested rights
6. Outages forecasted

ARR VALUE

Awarded ARRs are Obligation positions and therefore can be a credit (benefit) or charge (liability) based on value of the path

- When the value of the source is less than the sink, the awarded rights holder will receive a payment from the market
- When the value of the source is greater than the sink, the awarded rights holder must pay into the market

Traditionally, participants do not nominate positions that would result in a payment to the market

- This allows participants to keep the congestion paid to committed resources in the Day-Ahead Market

NOMINATION PROCESS EXAMPLE – TSR STUDY

- A customer has a portfolio of source to sink paths. Each source to sink path has a TSR for MWs below.

Source

Sink

100 MWs

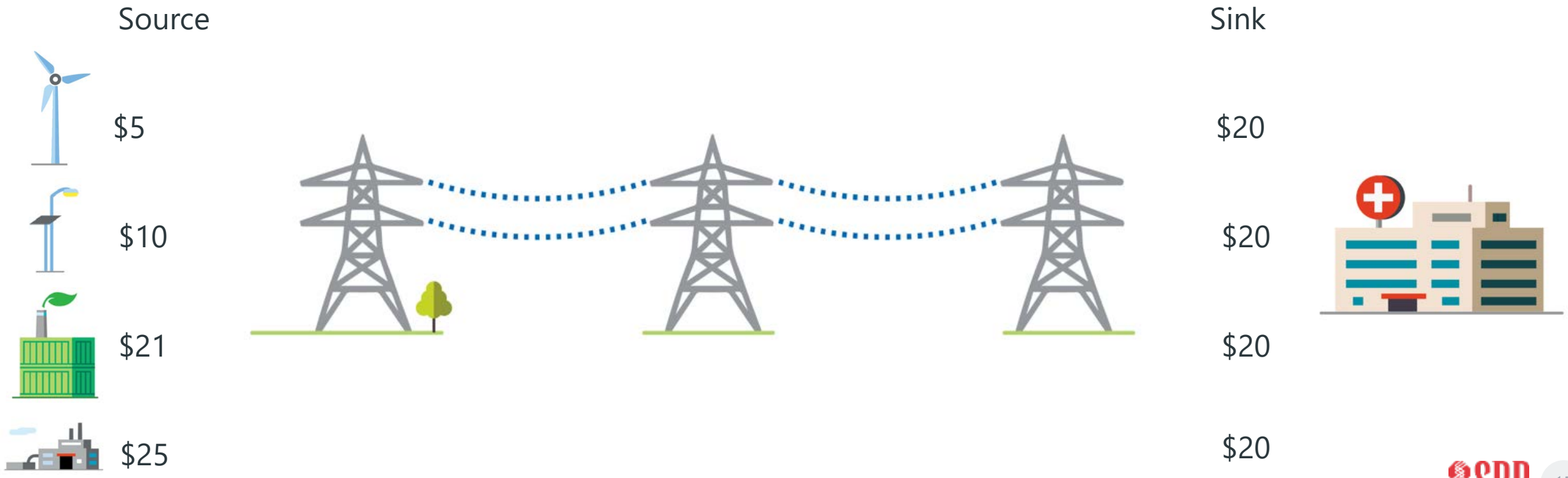
100 MWs

50 MWs

50 MWs

NOMINATION PROCESS EXAMPLE

- The customer forecasts their 200MW load and generation MCCs



NOMINATION PROCESS EXAMPLE

- Since the customer has a nomination cap of only 200 MWs from 300 MWs total TSRs, the customer decides to nominate only on their valuable paths.





Source		Sink
$5	Nominated ARR Path	$20
$10	Nominated ARR Path	$20
$21		$20
$25		$20

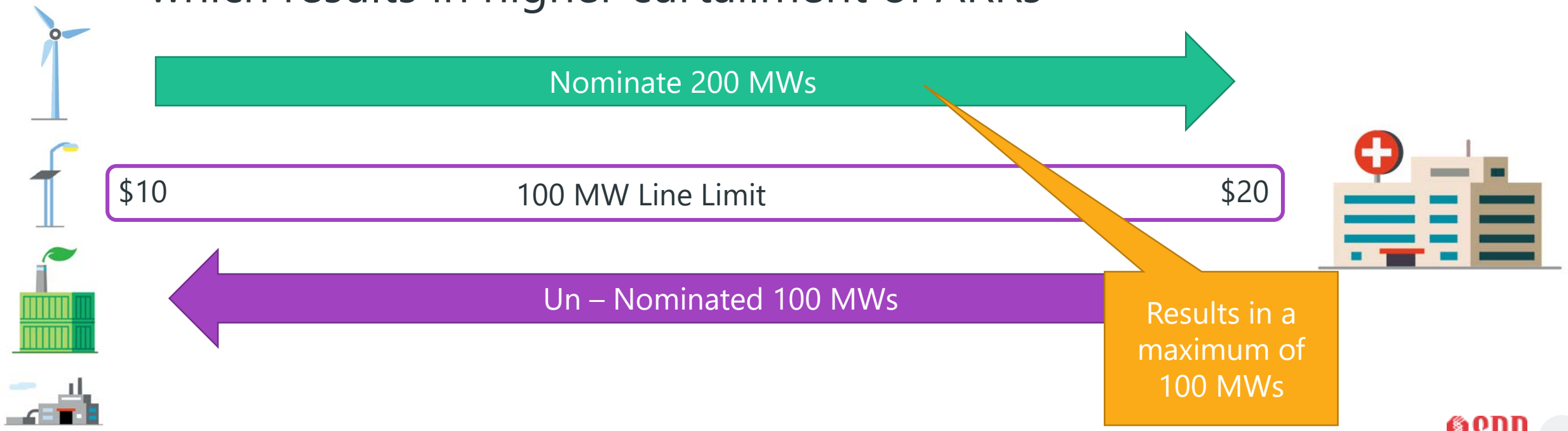
NOMINATION PROCESS EXAMPLE

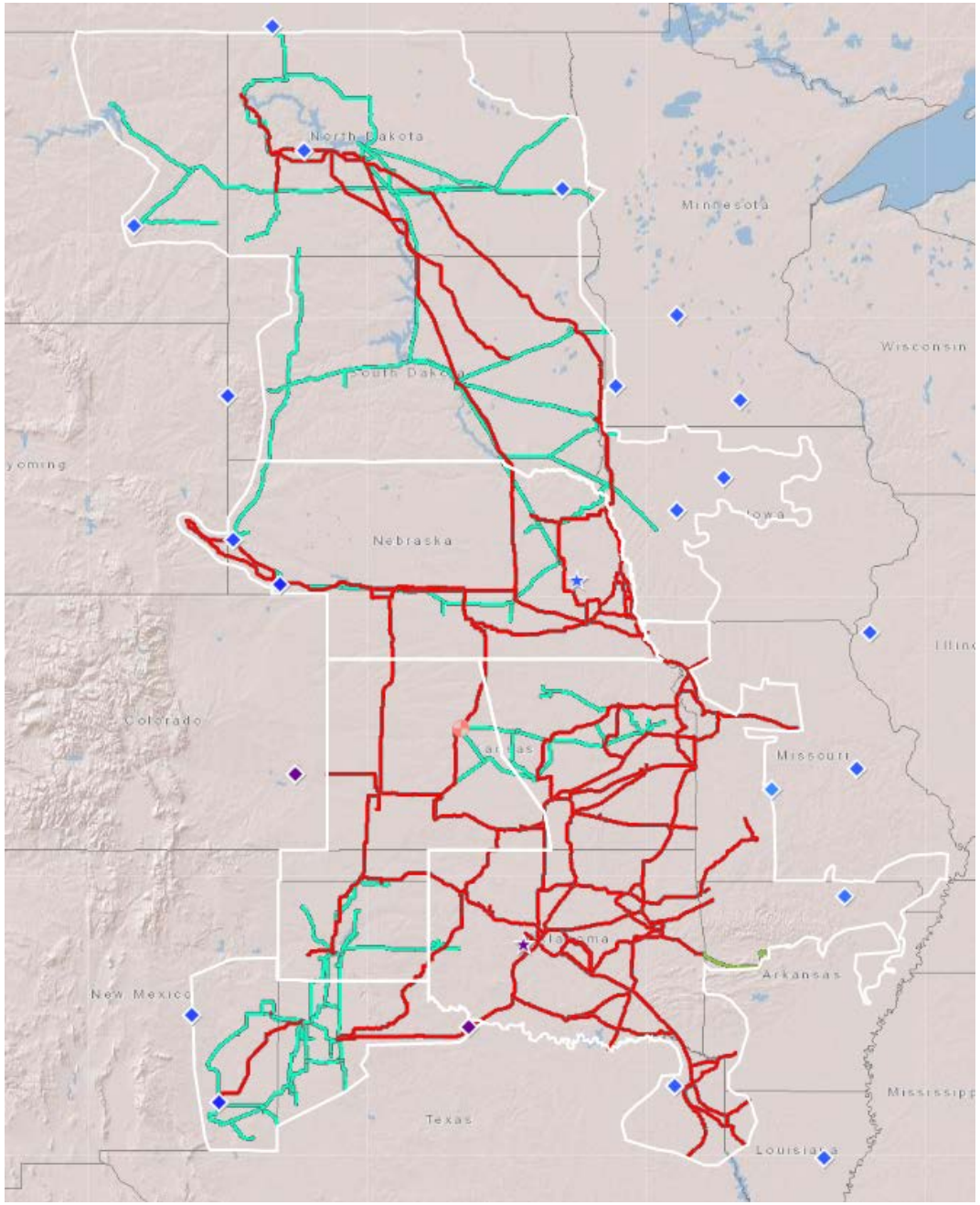
- The un-nominated paths are not utilized in the ARR Allocation process. This results in less optimal ARR awards.

Source		Sink
$5	Nominated ARR Path	$20
$10	Nominated ARR Path	$20
$21	Un - Nominated ARR Path	$20
$25	Un - Nominated ARR Path	$20

NOMINATION PROCESS EXAMPLE – A STEP FURTHER

- Flows that net each other allow more TSRs in the Transmission Service Process. When nominating in the ARR Allocation, MPs typically do not nominate counterflow paths which results in higher curtailment of ARRs




North Dakota
Minnesota
Wisconsin
Nebraska
Colorado
Missouri
Arkansas
New Mexico
Texas

NEXT STEPS

FIRM SERVICE ASSUMPTIONS

- Review the assumptions for Firm Transmission Service used in the transmission planning processes
- More discussion is needed to review the dispatch assumptions

Benefits	Considerations
• Closer alignment of TS and CH feasibility studies	• Will take time to engage other stakeholders

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2024 **ITP**

2024 ITP SCOPE – RESOURCE PLAN

DECEMBER 7-8, 2022

ESWG

KRISHADA WATSON

OBJECTIVE

- Review Assumptions
- Review & Approve Resource Plan scope items
  - Conventional Generator Prototypes
  - Resource Accreditation
  - New Resource Allocation
  - Ownership Assignment
- Approve Resource Plan methodology
- Next Steps

ASSUMPTIONS

- Planning reserve margin
  - For the 2024 ITP the PRM assumption is 15%
- Performance based accreditation
  - SPP staff believes that PBA in its current form is not complete and for that reason we believe it should not be implemented in the 2024 ITP

2024 **ITP**

CONVENTIONAL GENERATOR PROTOTYPES

METHODOLOGY

- Staff presents the following methodology:
  - Use current methodology of assigning CTs
    - Offer waiver for alternative prototypes
      - CC – single shaft or 90% CCS
      - ~~SMR~~ Small Modular Reactor

RESOURCES

- The Cost and Performance Characteristics of New Generating Technologies,1 Annual Energy Outlook 2022 – EIA (EIA-AEO)
  - 2023 data should be available in March 2023 and new information can be used if deemed necessary
- Lazard Version 15.0 LCOE report posted in October 2021

CONVENTIONAL GENERATION PROTOTYPES EIA[1]

Generation Type	Data Source	Tech Type	Size (MW)	Total Capital Cost ($/kW)	V O&M ($/MWh)	F O&M ($/kW-yr)	Heat Rate (Btu/kWh)
Combined Cycle (CC)	EIA AEO '22	90% CCS	377	$2,736.00	$6.11	$28.89	7,124
Combined Cycle (CC)	EIA AEO '22	Single Shaft	418	$1,201.00	$2.67	$14.76	6,431
Combustion Turbine (CT)	EIA AEO '22	Industrial	237	$785.00	$4.71	$7.33	9,905
Nuclear	EIA AEO '22	Small Modular Reactor	600	$6,861.00	$3.14	$99.46	10,443

- SPP considered hydrogen, but after further research, Lazard indicated that it is not cost competitive due to its electrolyzer costs and the cost of electricity

1 - https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf

SCOPE LANGUAGE

- CONVENTIONAL GENERATOR PROTOTYPES

- Generator prototype parameters will be set using the Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022 – EIA (EIA-AEO). Industrial combustion turbine (CT) will be the default. Members will be allowed to request an exception to the combustion turbine utilizing the ~~multi~~ single-shaft combined cycle (CC), the 90% carbon capture combined cycle, or the small modular reactor prototypes from the EIA-AEO. Exceptions must be approved by the ESWG. The table below details the characteristics of the approved prototypes in 2022 dollars for currency values.

RECOMMENDATION

- SPP Staff recommends that ESWG approve the methodology for conventional generator prototypes for 2024 ITP scope

RECOMMENDATION

- SPP Staff recommends that ESWG approve the methodology for conventional generator prototypes for 2024 ITP scope, but drop SMR option and staff review VOM assumptions for units relative to existing PROMOD model data for similar resources

2024 **ITP**

RESOURCE ACCREDITATION

ACCREDITATION

Submissions through Gen Review

- Accreditation of existing renewable units from the latest SPP ELCC study results will be supplied by members through the Generation Review

If no submission

- If no accreditation data is submitted for a resource, then it will default to the approximate average effective load-carrying capability (ELCC) value for the respective resource (accreditation values for projected resources).

Projected resources

- Total projected utility scale solar, wind, and storage will be accredited based on the approximate average effective load-carrying capability (ELCC) value for the respective resource

SCOPE LANGUAGE

- Accreditation of existing renewable units from the latest SPP ELCC study results will be supplied by members through the Generation Review. If no accreditation data is submitted for a resource, then it will default to the approximate average effective load-carrying capability (ELCC) value for the respective resource (accreditation values for projected resources). Total projected utility scale solar, wind, and storage will be accredited based on the approximate average effective load-carrying capability (ELCC) value for the respective resource.

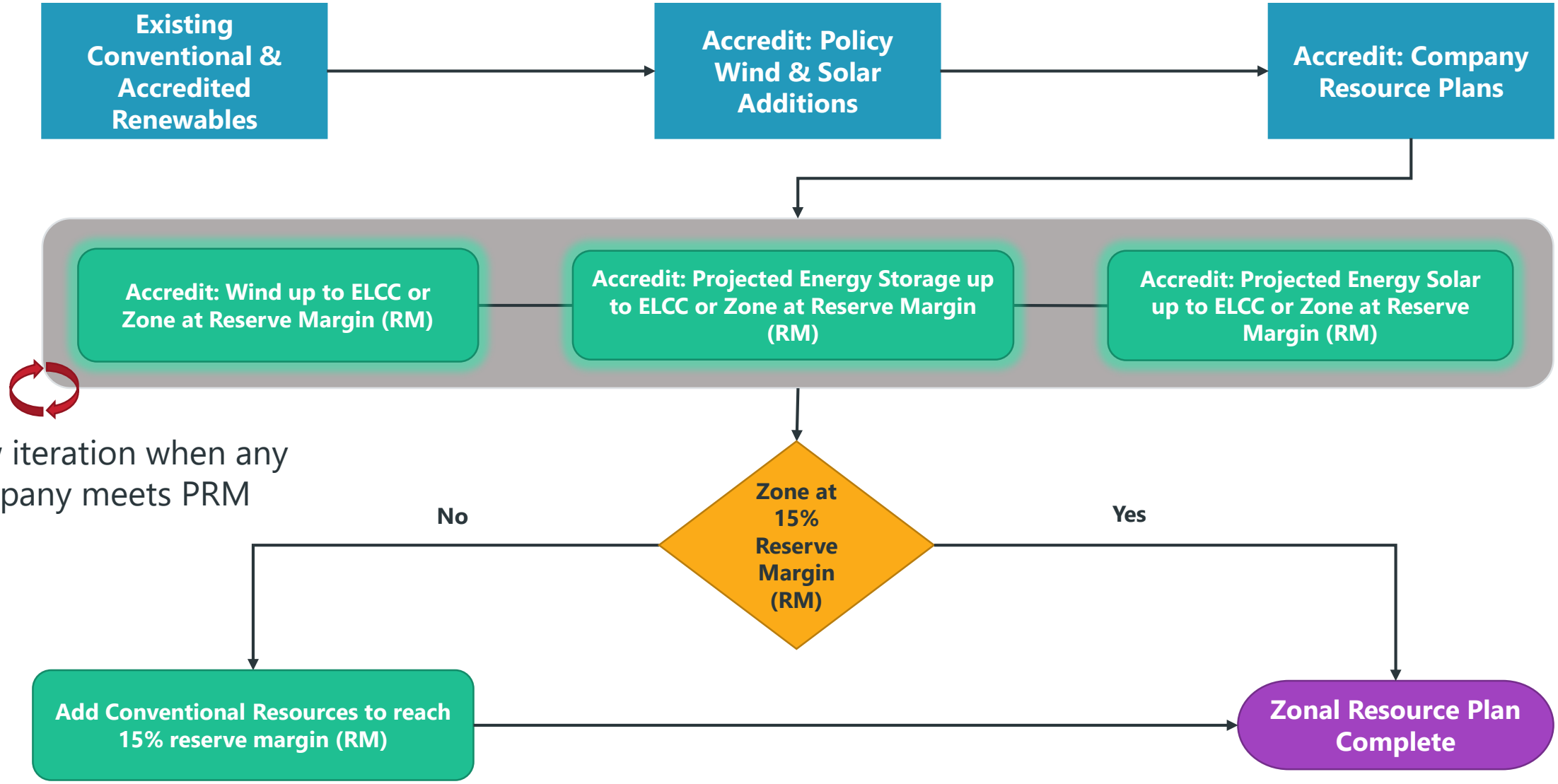
RECOMMENDATION

- SPP Staff recommends that ESWG approve the methodology for accreditation of existing resources for 2024 ITP scope

2024 **ITP**

NEW RESOURCE ALLOCATION

RENEWABLE ACCREDITATION DECISION TREE BASED ON CONSIDERATIONS
(WITH 15% PRM)



PROPOSED METHODOLOGY BASED UPON THE USAGE OF RESOURCE PLANNING TEMPLATES

- Allocate renewables first based upon resource planning template responses to those utilities forecasting additions
  - Excess Scenario: Excess ELCC to allocate after allocating full amounts to entities who submitted resource planning template
    - How do we allocate excess ELCC?
  - Deficit Scenario: Not enough ELCC to allocate to entities who submitted resource planning template
    - How do we allocate among respondents?
    - Should non-respondents receive some of the allocation?

EXCESS SCENARIO EXAMPLE

- ~~2000~~ 2500 MW wind accreditation available after considering existing ownership and capacities from gen review
- 8 utilities
  - 4 responses to resource planning template requesting 1600 MW of accreditation
  - 4 did not respond
- Resource planning template respondents – ~~1600~~ 2100 MW allocated 100% of requested amount
  - Utility 1 – 800 MW
  - Utility 2 – 900 MW
  - Utility 3 – 200 MW
  - Utility 4 – 200 MW
- Non-respondents – 400 MW remaining*
  - TBD

* Any remaining accreditation will be allocated to zones in short fall

ALLOCATION METHODOLOGY

- Previously utilized methodologies (all fuel types)
  - Load Ratio Share (LRS)
  - LRS of utilities with shortfall
  - 1 MW at a time regardless of LRS
- In 2023 ITP, ELCC allocated as follows (***in order***)
  - Solar allocated by LRS
  - Storage allocated by LRS to zones *(with shortfall)*
  - Wind allocated by LRS to zones *(with shortfall)*

HOW SHOULD WE ALLOCATE TO NON RESPONDENTS IN 2024 ITP?

- Due to resource planning template utilization, allocating in order (solar → storage → wind) may no longer be the best method of allocating ELCC
  - Option 1: 1 MW at a time (all 3 fuel types) until all ELCC allocated, capped at PRM
  - Option 2: Allocate pro rata (all fuel types) based upon shortfall, capped at PRM
- Staff recommends Option 2

DEFICIT SCENARIO EXAMPLE

- 1400 MW wind accreditation available after considering existing ownership and capacities from gen review
- 8 utilities
  - 4 responses to resource planning template requesting ~~1600~~ 2100 MW of accreditation
  - 4 did not respond
- Resource planning template respondents – ~~1600~~ 2100 MW requested, which is more than is available
  - Utility 1 – 800 MW
  - Utility 2 – 900 MW
  - Utility 3 – 200 MW
  - Utility 4 – 200 MW
- Non-respondents – TBD

- **Option 1:**
  - Responding utilities awarded 100% of requested MW's based upon pro rata share
    - Non-respondents get no accreditation
- **Option 2:**
  - Responding utilities awarded 80% of requested MW based upon pro rata share
    - Non-respondents get some accreditation
    - For non-respondents, follow same approach defined previously in Excess Scenario ~~1~~
- Staff Recommends Option 2 and award at 80% of requested MW

RECOMMENDATION

- SPP Staff recommends that ESWG approve the methodology for allocation:
  - Excess Scenario: Allocate pro rata (all fuel types) based upon shortfall to non-respondents, capped at PRM
  - Deficit Scenario: Responding utilities awarded 80% of requested MW based upon pro rata share
    - For non-respondents, follow same approach defined previously in Excess Scenario

SCOPE LANGUAGE

- To be developed based upon recommendation

2024 **ITP**

OWNERSHIP ASSIGNMENT

PREVIOUS DISCUSSION: RESOURCE ASSIGNMENT

- Benefits of sales from assigned proxy resources are:
  - Given to the assigned utility, not the 'SPP Other' bucket
  - Considered in the portfolio development process
- ESWG feedback from November meeting
  - Respondent's non-policy requests (all fuel types) should be assigned to the requestor

PREVIOUS OWNERSHIP (ASSIGNMENT) AFFECTS BENEFIT CALCULATION

Assigned

- Projected policy additions
- Utility solar
- Conventional

Unassigned

- Non-policy wind
- Storage

SUGGESTED BASED UPON ESWG FEEDBACK
AFFECTS BENEFIT CALCULATION

Assigned

- Conventional
- Projected policy renewable additions

Assigned

- Requested Solar
- Requested Wind
- Requested Storage

Unassigned

- Non-requested Solar
- Non-requested Wind
- Non-requested Storage

ASSIGNMENT METHODOLOGY

- Remaining questions
  - How much (%) should we assign to respondent utilities?
  - How should we determine which resources should be assigned?

RECOMMENDATION

- SPP Staff recommends that 100% of requested non-policy wind, solar, and storage resources should be assigned to requesting utilities.
- The specific resource assignments should be made in parallel with the siting milestone for the 2024 ITP

NEXT STEPS

NEXT STEPS

- Finalize scope language
- Resource Plan Phase II Preliminary work

2024 **ITP**

APPENDIX

ITP MANUAL LANGUAGE

2.2.2.1.2 Conventional Resource Expansion Plan

Each pricing zone shall be assessed for resource adequacy by accounting for load projections, existing generation, new wind and solar additions, capacity accreditation for all renewable units, fleet PPAs, and DC tie accreditations. Each pricing zone's resource shortfall shall be computed based on the SPP reserve margin requirement in effect at the commencement of the resource planning milestone of the study.

The conventional resource expansion plan process begins with the identification of a publicly available source for generator prototype parameters, which shall be documented in the study scope.

SPP will identify the optimal mix of new conventional resource additions needed in all futures for the SPP region. The ESWG will review and approve the methodology for development of resource plans for each new ITP study with decisions documented in the Study Scope Document. The magnitude of resource additions will be based on resource shortfalls. Ownership of conventional unit additions will be allocated to pricing zones such that each pricing zone approximately meets the reserve margin requirement. Joint ownership of unit additions may be used to avoid excessive additions of new resources to individual pricing zones.

External regions also will be analyzed for resource shortfalls. An appropriate resource plan from the most current neighboring entity's study will be used for their region in the ITP assessment, if readily available and SPP and stakeholders find it appropriate. The use of their resource plan is future specific. If there is not a future comparable to the ITP future, as determined by SPP and the ESWG, then conventional additions to address shortfalls shall be added to external regions with a resource mix that is as close as possible to the SPP conventional resource addition mix for that future. For example, if SPP conventional resource additions include 60% combined cycles and 40% combustion turbines, a ratio as close as possible to this 60/40 ratio would be used to guide conventional resource additions in external regions.

KRISHADA WATSON

Planning Specialist II, Transmission Planning

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SPP Southwest Power Pool

2024 **ITP**

2024 ITP SCOPE – PERSISTENT OPERATIONAL SOLUTION EVALUATIONS

DECEMBER 2022

SPP STAFF

OBJECTIVE

- Review member feedback on Persistent Operational Solution Evaluations scope language since November ESWG
- Obtain approval of proposed language to include in the 2024 ITP Scope document

2024 ITP SCOPE – LANGUAGE PROPOSAL CONSISTENT WITH PREVIOUS SCOPES

PERSISTENT ECONOMIC OPERATIONAL SOLUTION EVALUATIONS

FLOWGATES

Leading up to the 2024 ITP needs assessment, SPP will leverage the 2023 ITP economic operational needs assessment and solution evaluation outcome and continue to track on a quarterly basis operations and planning congestion throughout the 2023 ITP. SPP will make a recommendation to working groups on whether or not to address on as needed basis new and unresolved persistent operation economic congestion remaining after 2023 ITP persistent operation needs assessment and solution evaluation.

MANUAL COMMITMENT OF GENERATORS

Some transmission system issues require the manual commitment of generation by SPP in the Integrated Marketplace to provide relief on the system. The make-whole payments avoided when a proposed solution is included in the model will be considered in the solution's benefit. Each solution's one-year benefit-to-cost (B/C) ratio and its ability to reduce or eliminate the need for manual commitments will be considered during project selection.

FEEDBACK

- Do not want issues pushed to next study cycle
- Would like to use this process to solve “issues” (related flowgates) instead of individual flowgates
- Provide clarity on methodology used to evaluate economic operational constraint
- Consider options for addressing operational issues without requiring them to be in a planning model
- Perform review once per cycle instead of quarterly

UPDATES AND CONSIDERATIONS

- Remove quarterly tracking from scope language
- Consider performing well in advance of Needs Assessment for timely discussion at stakeholder groups
- Some feedback should be addressed through ITP Manual
  - Grouping flowgates
  - Changing threshold
- SCRIPT T3
  - Improve practices related to persistent operational issues in regional and interregional planning.

2024 ITP SCOPE – UPDATED LANGUAGE PROPOSAL WITH EDITS

FLOWGATES

Leading up to the 2024 ITP needs assessment, SPP will perform the ~~leverage the 2023 ITP~~ persistent operational needs assessment and ~~solution evaluation outcome and continue to track on a quarterly basis operations and planning congestion throughout the 2023 ITP. SPP will~~ make a recommendation to working groups on whether or not to address on as needed basis new and unresolved persistent operational economic congestion according to ITP Manual section 4.4. ~~remaining after 2023 ITP persistent operation needs assessment and solution evaluation.~~

MANUAL COMMITMENT OF GENERATORS

Some transmission system issues require the manual commitment of generation by SPP in the Integrated Marketplace to provide relief on the system. The make-whole payments avoided when a proposed solution is included in the model will be considered in the solution's benefit. Each solution's one-year benefit-to-cost (B/C) ratio and its ability to reduce or eliminate the need for manual commitments will be considered during project selection.

2024 ITP SCOPE – UPDATED LANGUAGE PROPOSAL WITH EDITS

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Prior to the 2024 ITP benchmarking milestone, SPP will perform the ~~leverage the 2023 ITP~~ persistent operational needs assessment. ~~solution evaluation outcome and continue to track on a quarterly basis operations and planning congestion throughout the 2023 ITP. SPP will~~ As part of the 2024 ITP needs assessment, SPP will make a recommendation to working groups on whether or not to address ~~on as needed basis new and unresolved~~ persistent operational needs according to ITP Manual section 4.4. ~~remaining after 2023 ITP persistent operation needs assessment and solution evaluation.~~

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Some transmission system issues require the manual commitment of generation by SPP in the Integrated Marketplace to provide relief on the system. The make-whole payments avoided when a proposed solution is included in the model will be considered in the solution's benefit. Each solution's one-year benefit-to-cost (B/C) ratio and its ability to reduce or eliminate the need for manual commitments will be considered during project selection.

2024 ITP SCOPE – UPDATED LANGUAGE PROPOSAL

FLOWGATES

Prior to the 2024 ITP benchmarking milestone, SPP will perform the persistent operational needs assessment. As part of the 2024 ITP needs assessment, SPP will make a recommendation to working groups on whether or not to address persistent operational needs according to ITP Manual section 4.4.

MANUAL COMMITMENT OF GENERATORS

Some transmission system issues require the manual commitment of generation by SPP in the Integrated Marketplace to provide relief on the system. The make-whole payments avoided when a proposed solution is included in the model will be considered in the solution's benefit. Each solution's one-year benefit-to-cost (B/C) ratio and its ability to reduce or eliminate the need for manual commitments will be considered during project selection.

RECOMMENDATION

- SPP Staff recommends that the ESWG approve the updated 2024 ITP Persistent Operational Solution Evaluations methodology

2024 **ITP**

APPENDIX

GOVERNING DOCUMENTS

ITP MANUAL V2.11 LANGUAGE

2.4 OPERATIONAL MODEL DEVELOPMENT

SPP will identify case(s) in which the reliability and manual commitment economic operational needs are present to evaluate whether the needs are addressed with proposed solutions. SPP may develop ITP planning models to replicate congested economic operational needs for solution evaluation as described in the Persistent Operational Solution Evaluations section.

ITP MANUAL V2.11 LANGUAGE

4.4 PERSISTENT OPERATIONAL NEEDS ASSESSMENT

Persistent operational needs may be either economic or reliability related. The criteria for identifying these needs is described in this section. SPP may propose additional needs to account for other problematic operational issues observed in operating the transmission system not fitting the given criteria. These additional needs will be presented to the ESWG and TWG for review and endorsement.

4.4.1 ECONOMIC OPERATIONAL NEEDS

SPP will classify flowgates meeting either of the following criteria as economic needs:

1. The flowgate was congested for at least 20 percent of the previous 24 months, either in a breached or binding state in the real-time balancing market solution, or

2. The flowgate had congestion costs totaling more than $10 million over the previous 24 months.

Periods of time when a flowgate's related congestion is deemed to be the result of prior outage conditions will be excluded from these criteria calculations. Congestion cost for outages will be provided for informational purposes.

SPP also will identify economic needs considering manual commitments of uneconomic generation for local area voltage support, according to either of the following criteria:

1. Manual commitment events that include startup and extension 25 percent of the year, or

2. Manual commitments that do not exceed 25 percent of the year, but cost over $1 million dollars over 24 months.

ITP MANUAL V2.11 LANGUAGE

4.4.2 RELIABILITY OPERATIONAL NEEDS

SPP will identify facilities as reliability needs due to system reconfiguration using agreed upon (by SPP and the transmission operator) operational guides or load shed as a result of unsuccessful control of the system through re-dispatch if they meet the following criteria:

1. High- or low-voltage issues where system reconfiguration is implemented 10 percent of the year due to non-outage issues37, or
2. Thermal loading issues where system reconfiguration through the use of an agreed upon operating guide has been implemented in real-time 25 percent of the year.

ITP MANUAL V2.11 LANGUAGE

5.3.4 PERSISTENT OPERATIONAL SOLUTION EVALUATIONS

A subset of solutions will be evaluated to address persistent operational needs utilizing the filtering criteria, as approved by the TWG, ESWG and ORWG. Reliability solutions will be evaluated by the CLR and CVR metrics described in the Reliability Solution Evaluation section. SPP will track congested economic operational needs against needs identified in the current ITP, identify differences between real-time market operations and planning models, and determine the need for and impact of planning model adjustments and analysis. SPP will make a recommendation to applicable stakeholder working groups on how to address unresolved economic operational needs. Recommendations may include transmission upgrades, operational mitigations, or additional analysis to be performed in a future ITP study.

ITP MANUAL V2.11 LANGUAGE

6.1.4 PERSISTENT OPERATIONAL PORTFOLIO DEVELOPMENT

Solutions mitigating persistent operational needs are ranked by the appropriate metrics depending on whether the need is economic or reliability based. Solutions identified to mitigate persistent operational issues will be compared with the other portfolios to ensure efficiencies are gained by identifying the most cost effective projects to meet all needs. Economic solutions will be ranked based on their project cost compared to the cost incurred without the project. SPP and stakeholders will determine the criteria for development of the operational portfolio, which will be included in each study scope. Reliability solutions will be evaluated using the CLR and CVR metric concept.

2024 INTEGRATED TRANSMISSION PLANNING ASSESSMENT SCOPE

By SPP Engineering

Published on DATE

Version 0.1

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
12/01/2022 v0.1	SPP Staff	Initial Draft Scope	• Sections highlighted yellow are language from the 2023 ITP scope and will be replaced depending on approvals in the December meetings. • Sections in green have not been reviewed individually in prior meetings and would remain in the scope document as is unless feedback is received, in which any updates will be redlined prior to final approval of the scope document. • All other sections should match previous approvals by either ESWG, TWG, or both groups depending on the scoping schedule. Please review these for completeness and provide any feedback on the incorporation of prior approvals into the scope document.

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SECTION 1: OVERVIEW

This document presents the scope and schedule of work for the 2024 Integrated Transmission Planning (ITP) Assessment. The Economic Studies Working Group (ESWG) and Transmission Working Group (TWG) are responsible for the creation and review of this document with approvals from the Market Operations and Policy Committee (MOPC) and the board of directors (Board).

OBJECTIVE

The objective of the 2024 ITP Assessment is to develop a regional transmission plan that provides reliable and economic delivery of energy and facilitates achievement of public policy objectives, while maximizing benefits to the end-use customer. This 2024 ITP Assessment Scope contains assumptions to be utilized in the 2024 ITP Assessment that are not standardized in the ITP Manual. These documents should be reviewed together for a comprehensive view of the 2024 ITP process and assumptions.

SECTION 2: MODELING DETAILS AND ASSUMPTIONS

MODEL YEAR DEFINITIONS

The 2024 ITP seasonal models for the 2024 ITP years two, five, and ten are listed below based on the Model Development Procedure Manual developed by the Model Development Advisory Group.

2024 ITP & NERC TPL Assessment Study Years	
ITP & TPL Assessment (Study Year)	2024
Year One	2024
Year two	2025
Year five	2028
Year ten	2033

Table 1: Model Year Definitions

MARKET ECONOMIC MODEL OVERVIEW

FUTURES

The ESWG developed two futures with input from the Strategic Planning Committee (SPC) and TWG. The MOPC reviewed both futures in October 2022.

	DRIVERS				
KEY ASSUMPTIONS	**Year 2**	**Future 1 – Reference Case**		**Future 2 – Emerging Technologies**	
	2	**5**	**10**	**5**	**10**
Peak Demand Growth Rates	As submitted in load forecast	Increase due to electric vehicle growth		Higher Increase due to electric vehicle growth	
Energy Demand Growth Rates	As submitted in load forecast	Increase due to electric vehicle growth		Higher Increase due to electric vehicle growth	
Natural Gas Prices	Current industry forecast	Current industry forecast		Current industry forecast	

KEY ASSUMPTIONS	DRIVERS				
	Year 2	Future 1 – Reference Case		Future 2 – Emerging Technologies	
	2	5	10	5	10
Coal Prices	Current industry forecast	Current industry forecast		Current industry forecast	
Emissions Prices	Current industry forecast	Current industry forecast		Current industry forecast	
Fossil Fuel Retirements	Current forecast	based on IRP feedback; subject to generator owner (GO) review		based on IRP feedback; subject to generator owner (GO) review	
Environmental Regulations	Current regulations	Current regulations		Current regulations	
Demand Response[1]	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	
Distributed Generation (Solar)	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	
Energy Efficiency	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	
Storage	Existing + RARs	*30% of projected solar* (2.1. GW / 4.2 GW)		*40% of projected solar* (4.4 GW / 8.8 GW)	
Total Renewable Capacity					
Solar (GW)	Existing + RARs	**7.1**	**14**	**11**	**22**
Wind (GW)	Existing + RARs	**43.8**	**49.9**	**48.2**	**54.9**

Table 2: Future Drivers

MUST-RUN UNITS

Must-run designations for SPP areas will be assigned to co-generation, nuclear, landfill gas, and hydroelectric units, unless an exception is requested during the generation review and approved by the ESWG. Co-generation units will be identified based on EIA 860 data, as well as ABB simulation-ready data. If a unit was originally identified as a must-run in a previous study, but was removed as an exception, it will not be identified as a must-run in the 2024 ITP. External areas will have the same

[1] As defined in the SPP Model Development Procedure Manual

criteria, with the deviation that external co-generation units will be assigned a must-run status subject to SPP review.

CURTAILMENT PRICE

An automatic repower will be assumed for all wind units after 10 years of being in service.

HURDLE RATES AND INTERCHANGE

Hurdle rates for all futures will be based upon the latest vendor data set. However, prior to and during the MEM benchmarking and initial year 5 and year 10 MEM builds, SPP and ESWG will be reviewing the reasonableness of the latest vendor data set hurdle rates and respective interchange. SPP and ESWG may utilize, as appropriate, previous ITP MEMs in this review. This review may result in adjustments to the MEM hurdle rates and/or other economic model parameters that impact MEM interregional "economy-energy" transactions. Any ESWG-approved adjustments and MEM interchange results will be documented in the ITP assessment report.

RESOURCE PLAN

CONVENTIONAL GENERATOR PROTOTYPES

Generator prototype parameters will be set using the Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2021 – EIA (EIA-AEO).[2] Multi-shaft combined cycle (CC) and industrial combustion turbine (CT) prototypes will be used as the available alternatives. While both the multi-shaft CC and industrial CT prototypes were approved, the resource plan will initially consist of the industrial CT prototypes based upon a waiver of the ITP Manual requirement to use resource planning software. The waived requirement to utilize resource planning software was based upon historical performance of the resource planning software and the cost curves associated with the conventional prototypes considered for the 2024 ITP. If any exceptions for the resource plan are requested, the multi-shaft CC prototype data will be used. Table details the characteristics of the approved prototypes, in 2020 dollars for currency values.

Generation Type	Data Source	Technology Type	Size (MW)	Total Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (Btu/kWh)
Combined Cycle (CC)	EIA-AEO 2020	Multi-Shaft	1,083	$957	$1.88	$12.26	6,370

[2] https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf

Generation Type	Data Source	Technology Type	Size (MW)	Total Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (Btu/kWh)
Combustion Turbine (CT)	EIA-AEO 2020	Industrial	237	$709	$4.52	$7.04	9,905

Table 3: Generator Prototype Parameters

RESOURCE ACCREDITATION

Accreditation of existing renewable units will be determined by member data based on SPP Planning Criteria 7.1.6 (7)(8)[3] submitted through the Generation Review. If no accreditation data is submitted for a resource, then it will default first to previous ITP study data and secondly to the average of the submitted data for the existing resources in the 2024 ITP, capped at the accreditation values for projected resources. A projected resource that is assigned ownership to a load-serving entity within the modeled SPP footprint is eligible for capacity credit. Total projected utility scale solar, wind, and storage will be accredited based on the approximate average effective load-carrying capability (ELCC) value for the respective resource.

Accreditation of existing and future conventional…. Performance based…

STATE RENEWABLE PORTFOLIO STANDARDS

The following values will be used in accordance with Section 2.2.1.3 of the ITP Manual:

STATE	RPS TYPE	GENERATION TYPE	CAPACITY- OR ENERGY- BASED	YEAR 5 %	YEAR 10 %
Kansas	Goal	Both	Capacity	20	20
Minnesota	Mandate	Both	Energy	25	25
Missouri	Mandate	Both	Energy	15	15
North Dakota	Goal	Both	Energy	10	10
New Mexico	Mandate	Both	Energy	40	50
South Dakota	Goal	Both	Energy	10	10
Texas	Mandate	Both	Capacity	5	5

Table 4: ITP RPS by State

NEW RESOURCE ALLOCATION AND ASSIGNMENT

[3] SPP Planning Criteria

	SOLAR	WIND	BATTERY STORAGE
ASSIGNED	Yes	No	No
ALLOCATED	Load-Ratio Share	Load-Ratio Share	Load-Ratio Share

Table 5: Resource assignment and allocation

Projected utility scale solar will be assigned and allocated by load-ratio share. Projected wind will be unassigned and allocated to maximize accreditation to deficient zones. Projected battery storage will be unassigned and allocated by load ratio share. Policy additions will be met with 50 percent wind and 50 percent solar, based on the active, non-suspended GI queue requests. The accreditation process is as shown in Figure 1 below:

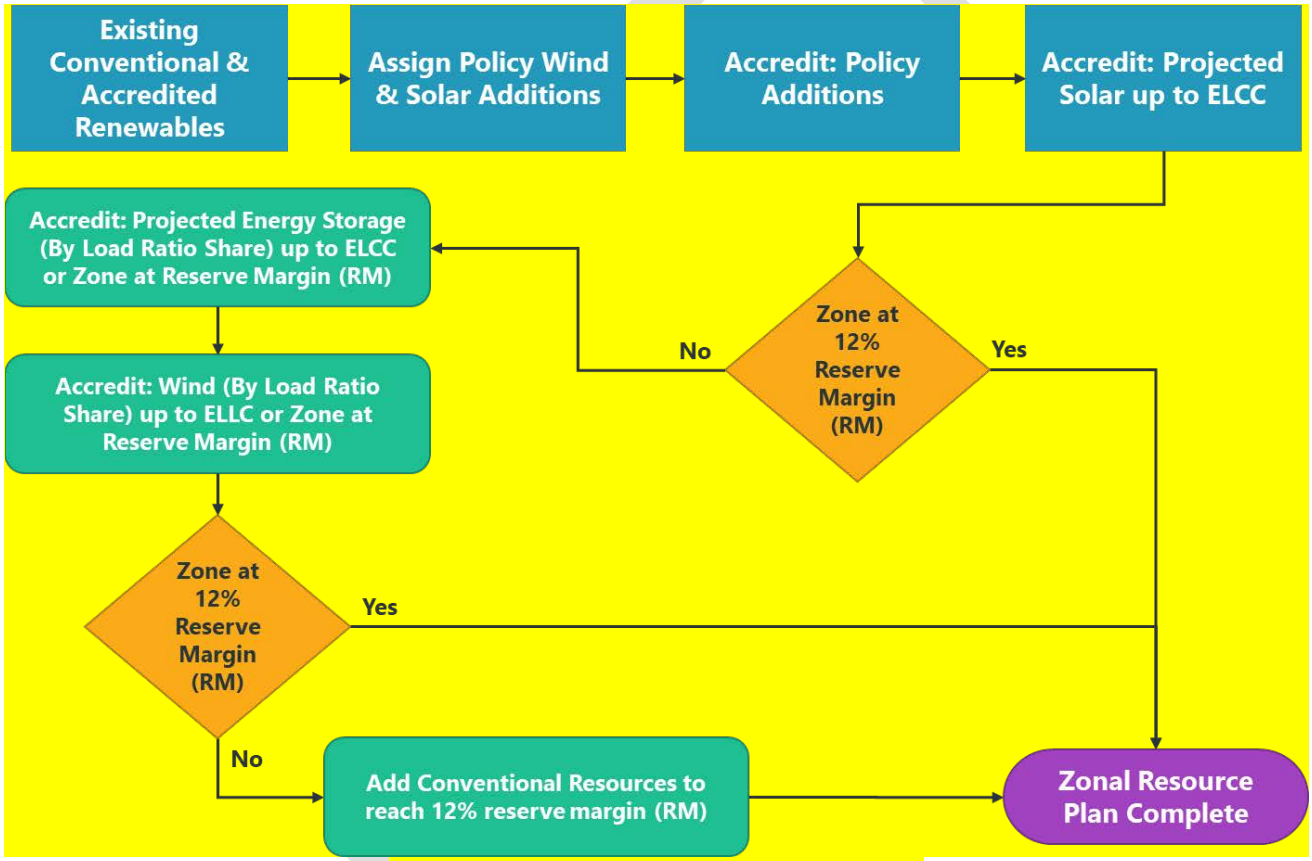


Figure 1: Renewable accreditation process flowchart

RESOURCE PLAN MODELING

As noted in the ITP Manual, the market powerflow models (MPM) will contain system topology consistent with their respective market economic model (MEM). This topology consistency does not include the reactive power settings of the resource plans because they are not considered in the MEM. The following parameters will guide how the resource plans, both internal and external, are modeled

with regards to reactive settings, such as maximum and minimum VAR support and voltage schedule. Stakeholders are given the opportunity to review certain reactive device settings during the MPM review period described in Section 2.3.2 of the ITP Manual.

All resources included in the internal or external resource plans (excluding distributed generation, such as rooftop solar) will be modeled as directly injecting power at the point of interconnection (*i.e.,* ESWG-approved site). Maximum and minimum reactive capability of generators will be determined by utilizing a .95 power factor and the maximum real power capability of the resource. Resources sited where existing generation is already interconnected will follow the voltage schedule and remote bus determination of the existing resource. The following information is resource fuel type specific and references settings observed in the powerflow modeling software utilized in the ITP process. The following settings apply to both the internal and external resource plans.

CONVENTIONAL GENERATION

The control mode for conventional generation will be set to "Not a wind machine." The voltage schedule (*i.e.,* vsched) will be set at 1.015 per unit for system peak models and 1.00 per unit for off-peak models, unless a voltage set point warning is observed. For sites with no existing generation, the remote bus will be the point of interconnection of the new resource.

SOLAR, WIND, OR ENERGY STORAGE RESOURCES

The control mode for renewable and energy storage resources will be "+ or – Q limits based on WPF[4]". WPF will be set at .95. The voltage schedule will be set at 1.015 per unit for system peak models and 1.00 per unit for off peak models, unless a voltage set point warning is observed. For sites with no existing generation, the remote bus will be the point of interconnection of the new resource.

[4] Wind power factor

SECTION 3: SOLUTION EVALUATION & PORTFOLIO DEVELOPMENT

PERSISTENT ECONOMIC OPERATIONAL SOLUTION EVALUATIONS

FLOWGATES

Leading up to the 2024 ITP needs assessment, SPP will leverage the 2022 ITP economic operational needs assessment and solution evaluation outcome and continue to track on a quarterly basis operations and planning congestion throughout the 2022 ITP. SPP will make a recommendation to working groups on whether or not to address on as needed basis new and unresolved persistent operation economic congestion remaining after 2022 ITP persistent operation needs assessment and solution evaluation.

MANUAL COMMITMENT OF GENERATORS

Some transmission system issues require the manual commitment of generation by SPP in the Integrated Marketplace to provide relief on the system. The make-whole payments avoided when a proposed solution is included in the model will be considered in the solution's benefit. Each solution's one-year benefit-to-cost (B/C) ratio and its ability to reduce or eliminate the need for manual commitments will be considered during project selection.

CONSOLIDATION

SPP must consolidate the future-specific portfolios into a single set of projects to determine a recommended plan. The methodology by which this consolidation will occur is based on individual project performance. A systematic approach to evaluate each project's merits and an SPP-developed narrative of each project's drivers will guide the decision for inclusion in the recommended plan. Three different scenarios could occur during the consolidation of the future-specific portfolios into a recommended plan:

1. The same project is addressing the same or similar needs in both futures
2. Different projects are addressing the same or similar needs in both futures
3. A project addresses certain needs only in one future

Projects applicable to scenario one will be considered for the recommended plan. Projects applicable to scenarios two and three will be given a score based on the point system detailed in Table 6. Each

project will be awarded points based on its performance or ability to meet six different considerations, up to 100 total possible.

No.	Considerations	Points Possible	Threshold
1	40-year (1-year) APC B/C in Selected Future	50	1.0 (0.9)
	40-year (1-year) APC B/C in Opposite Future		0.8 (0.7)
	40-year (1-year) APC Net Benefit in Selected Future ($M)		N/A
	40-year (1-year) APC Net Benefit in Opposite Future ($M)		N/A
2	Congestion Relieved in Selected Future (by need(s), all years)	10	N/A
	Congestion Relieved in Opposite Future (by need(s), all years)	10	N/A
3	Operational Congestion Costs or Reconfiguration ($M/year or hours/year)	10	>0
4	New EHV	7.5	Y/N
5	Mitigate Non-Thermal Issues	7.5	Y/N
6	Long Term Viability (e.g. 2013 ITP20, 2022 20-Year Assessment) or Improved Auction Revenue Right (ARR) Feasibility	5	Y/N
	Total Points Possible	**100**	

Table 6: Consolidation Considerations Scoring Table

For two projects (P1 and P2) applicable to scenario two, points for consideration one will be calculated as follows:

1. Test B/C thresholds in opposite future
    - If project has less than 0.8 40-year B/C in opposite future, zero points will be awarded
    - If project meets 0.8 40-year B/C threshold in opposite future, continue calculations
2. Calculate 40-year net adjusted production cost (APC) benefits
    - Net APC $\text{benefit}_{P1,AVE}$
    - Net APC $\text{benefit}_{P2,AVE}$
    - Net APC benefit_{Max} = Maximum(Net APC $\text{benefit}_{P1,AVE}$,Net APC $\text{benefit}_{P2,AVE}$)
3. Calculate points awarded
    - $Points\ awarded_{P1,\%} = 50 \times \frac{Net\ APC\ benefit_{P1,AVE}}{Net\ APC\ benefit_{Max}}$
    - $Points\ awarded_{P2,\%} = 50 \times \frac{Net\ APC\ benefit_{P2,AVE}}{Net\ APC\ benefit_{Max}}$

For individual projects (P1) applicable to scenario three, points for consideration one will be calculated as follows:

1. Test B/C threshold in opposite future

- If project has less than 0.8 40-year B/C in opposite future, zero points will be awarded
- If project has at least 1.0 40-year B/C in opposite future, 50 points will be awarded
- If project meets 0.8 40-year B/C threshold in opposite future, but is less than 1.0, continue calculations

2. Calculate net APC benefits
   - Net APC $benefit_{P1,AVE}$
   - Net APC $benefit_{P1',AVE}$ = Net APC $benefit_{P1,AVE}$ with 1.0 40-year B/C in opposite future
3. Calculate points awarded
   - $Points\ awarded_{P1,\%} = 50 \times \frac{Net\ APC\ benefit_{P1,AVE}}{Net\ APC\ benefit_{P1',AVE}}$

Points for consideration two will be calculated as the percentage of total congestion relieved on the needs addressed by the project, multiplied by the points possible.

$$Points\ awarded = 10 \times \%\ Congestion\ relieved_{F1,addressed\ needs} + 10 \times \%\ Congestion\ relieved_{F2,addressed\ needs}$$

Points for consideration three will be calculated based on the severity of an operational issue that the project is expected to address, as a percentage of the operational needs criteria[5] multiplied by the points possible, up to 10.

$$Points\ awarded = \left(\frac{\$\ of\ congestion\ cost_{24\ months}}{\$10M}\right) \times 10$$

OR

$$Points\ awarded = \left(\frac{Hours\ of\ system\ reconfiguration_{12\ months}}{X\%^{6} \times 8{,}760}\right) \times 10$$

All points possible for considerations four, five, and six will be awarded if the project meets the description of the consideration.

For projects applicable to scenario two, the project with the highest score will be considered the favorable project based on the systematic approach. Projects applicable to scenario three with a total score of 70 or greater will be considered for the final recommended plan.

SPP may use engineering judgement or other analysis to support or oppose results of the systematic approach described above. SPP will bring consolidation results and a recommendation for all projects selected for a future-specific portfolio to the ESWG and TWG for review and feedback.

[5] Flowgate congestion cost totaling more than $10M over the last 24 months or system reconfiguration through an agreed-upon operating guide implemented 25 percent of year.

[6] X equals 25 percent for operational thermal issues. X equals 10 percent for operational voltage issues.

SECTION 4: FINAL ASSESSMENTS

SENSITIVITIES

Sensitivities will be conducted on the final consolidated portfolio in both futures to measure the flexibility of the portfolio with respect to the uncertainties of certain assumptions. Economic analysis will be performed for the sensitivities below:

- High and low natural gas prices
- High and low demand levels
- High and low wind levels

Additional sensitivities will be determined via stakeholder survey leading up to this analysis, and will be documented in the ITP assessment report.

VOLTAGE STABILITY ASSESSMENT

A voltage stability assessment will be conducted in both futures using the final consolidated portfolio to assess the megawatt transfer limit under two scenarios:

- Increasing renewable generation in SPP and decreasing conventional thermal generation in SPP.
- Increasing renewable generation in SPP and decreasing conventional thermal generation in external areas.

The transfer limit will be determined by examining voltage performance during power transfers across SPP. The stability assessment consists of a dispatch analysis to determine if the dispatched generation in the year 10 summer and light-load models can be dispatched without the occurrence of voltage collapse or thermal violations.

SECTION 5: SCHEDULE

The 2024 ITP assessment began in July 2022 and will be completed by October 2024.[7] Figure 2 and Table 7 detail the study timeline.

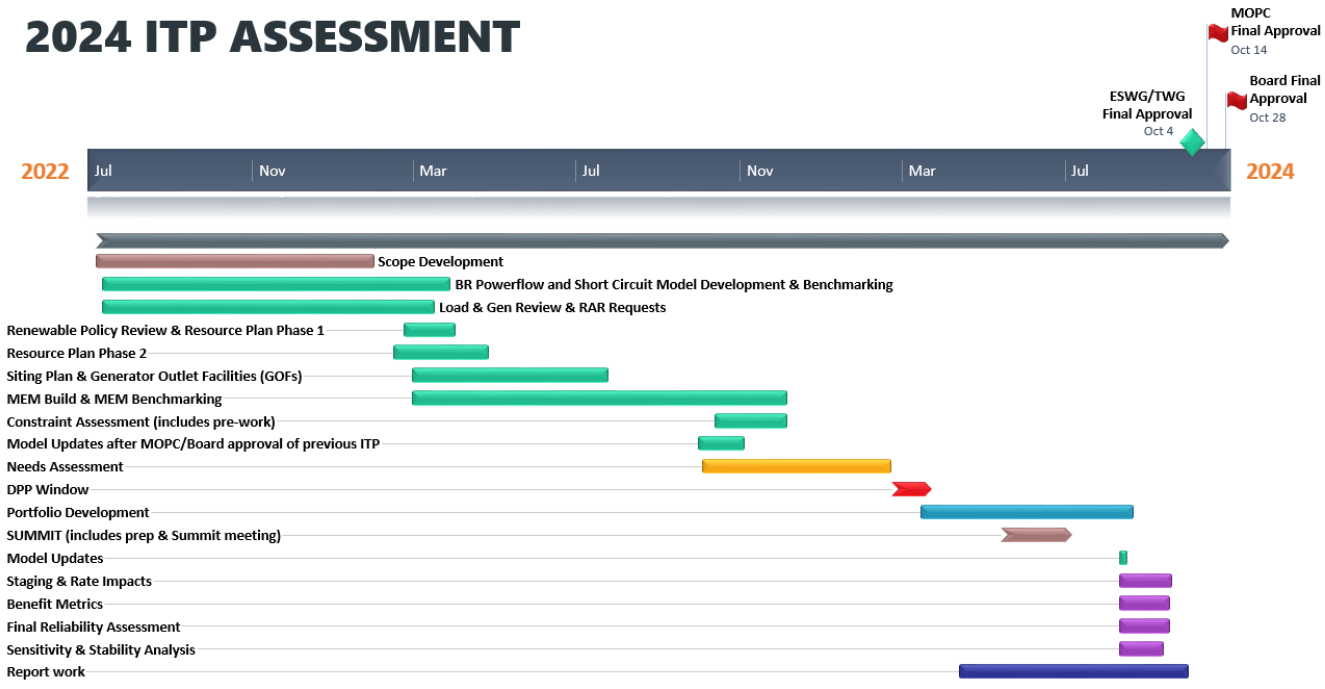


Figure 2: 2023 ITP Timeline

[7] Dates are subject to change.

MILESTONE NAME	GROUP(S) TO REVIEW/ENDORSE	START DATE	COMPLETION DATE
Scope Development	ESWG, TWG, MOPC, SPC	Jul 2022	Jan 2023
Base Reliability Powerflow & Short Circuit Model Development	TWG	Jul 2022	Mar 2023
Load and Generation Review	ESWG, TWG, MDAG	Jul 2022	Mar 2023
Renewable Policy Review	ESWG	Jan 2023	Mar 2023
Renewable Resource Plan (RP1)	ESWG, CAWG	Feb 2023	Mar 2023
Conventional Resource Plan (RP2)	ESWG	Mar 2023	May 2023
Siting Plan & Generator Outlet Facilities (GOFs)	ESWG	Mar 2023	Jul 2023
Powerflow Model Development	TWG	Mar 2023	Nov 2023
Short Circuit Model Development	TWG	Mar 2023	Nov 2023
Economic Model Development	ESWG	Mar 2023	Dec 2023
Model Benchmarking	ESWG, TWG	Jul 2023	Sept 2023
Model Updates after 2023 ITP Approval MOPC/Board (NTC/Re-evaluations)	TWG	Oct 2023	Nov 2023
Constraint Assessment	TWG	Nov 2023	Dec 2023
Needs Assessments	ESWG, TWG	Nov 2023	Mar 2024
Detailed Project Proposal (DPP) Window	ESWG, TWG	Mar 2024	Apr 2024
Solutions Development	ESWG, TWG	Mar 2024	May 2024
Project Grouping	ESWG, TWG	Apr 2024	May 2024
Study Cost Estimates		Jun 2024	Aug 2024
Summit		July 2024	July 2024
Final Portfolio Development	ESWG, TWG	July 2024	Aug 2024
Portfolio Optimization / Consolidation	ESWG, TWG	Aug 2024	Sep 2024
Project Staging	ESWG, TWG	Aug 2024	Sep 2024
Benefit Metrics Calculations	ESWG	Aug 2024	Sep 2024
Stability Analysis	TWG	Aug 2024	Sep 2024
Sensitivity Analysis	ESWG	Aug 2024	Sep 2024
Final Reliability Assessment	TWG	Aug 2024	Sep 2024
Review Draft Report with Recommended Solutions	ESWG, TWG	Aug 2024	Sep 2024
Final Report with Recommended Solutions	ESWG, TWG	Sep 2024	Sep 2024
	RSC, SPC, SSC	October 2024	
	MOPC, SPP Board		
	MOPC, SPP Board		

Table 7: 2023 ITP Schedule

SECTION 6: CHANGES IN PROCESS AND ASSUMPTIONS

To protect against changes in process and assumptions that could present a significant risk to the completion of the 2024 ITP Assessment, any changes to this scope or assessment schedule must be appropriately vetted and follow the process outlined in the stakeholder accountability section of the ITP Manual as time allows.

Russell Solar – 20 MW
2024 ITP RAR

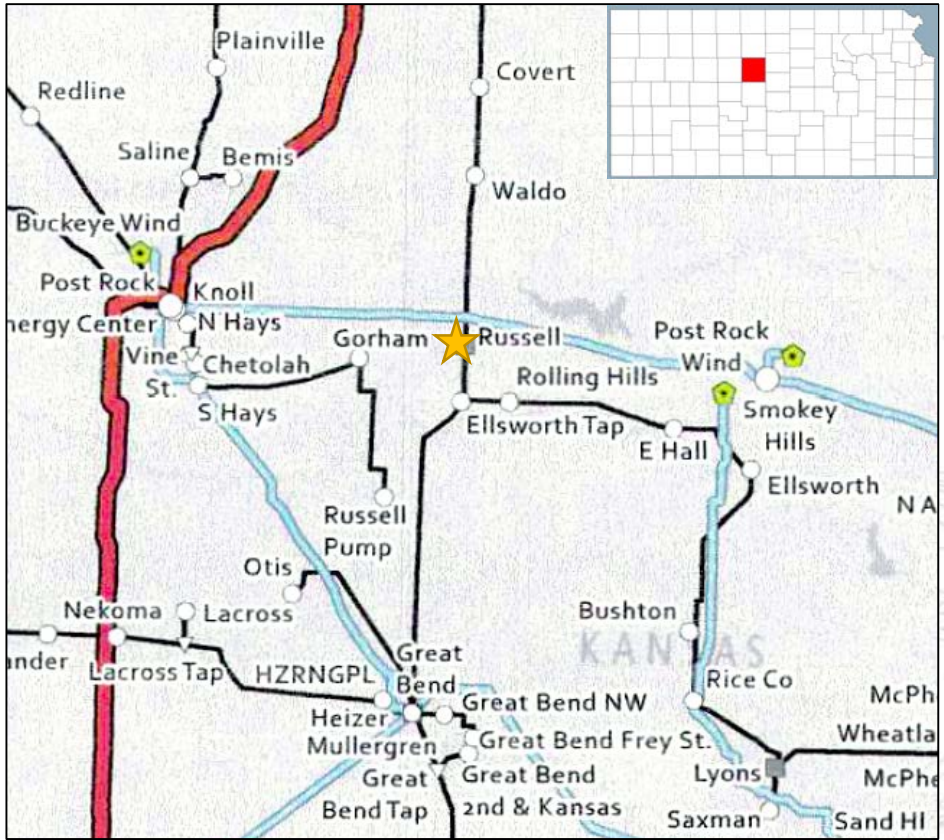
November 2024

SUNFLOWER ELECTRIC POWER CORPORATION

A Touchstone Energy® Cooperative

Russell Solar

- Sunflower is requesting GEN-2020-056 (DISIS-2020-001) be included in the 2024 ITP Base Reliability and Economic Models.
  - Location: Russell 115 kV Substation
  - Generation: 20 MW of Solar
  - Commercial Operation: Year-end 2024



Russell Solar

- Russell Solar is a Sunflower supported project
  - No projects are expected outside of facility interconnection (DISIS-2020-001)
  - A land lease agreement has been completed
  - Fully Executed interim GIA
  - Environmental permit is being drafted
  - Equipment, including the GSU, has been purchased and delivered
  - Sunflower Board agreed to pursue facility ownership
  - Construction scheduled from January 2024 to December 2024

- This request was previously approved for the 2023 ITP (11/3/21)

SPP Southwest Power Pool

2023 ITP

ANADARKO-GRACEMONT NTC RE-EVALUATION MODEL CORRECTION

EDDIE WATSON

ESWG DECEMBER 7-8, 2022

Working together to responsibly and economically keep the lights on today and in the future.

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KEY TAKEAWAYS

- Provide background information that resulted in the 2023 ITP model correction
- Provide TWG members update on model corrections applied to latest 2023 ITP models

BACKGROUND – RE-EVALUATION INFORMATION

- *September 2022:* Anadarko-Gracemont 138 kV Rebuild Out-of-Cycle Re-Evaluation Requested
  - Reasoning: "due to right-of-way issues and future wind generation interconnections"
- *October 2022:* SPP Board approved the out-of-cycle request reevaluate NTC 210586 projects PID 81617:
  - UID 122753 - Anadarko - Gracemont 138 kV circuit 2 rebuild
  - UID 122577 - Anadarko - Gracemont 138kV circuit 1 rebuild
  - UID 122755 - Gracemont 138 kV circuit 2 terminal equipment

BACKGROUND – RE-EVALUATION UPGRADE DETAILS

NTC	Upgrade ID	Upgrade Name	Upgrade Scope	Owner
210586	122753	Anadarko-Gracemont 138 kV circuit 2 rebuild	Rebuild 5.09-mile 138 kV line from Anadarko to Gracemont as double circuit and add/upgrade any necessary equipment to achieve a summer emergency rating of 353 MVA for circuit 2	WFEC
210586	122577	Anadarko-Gracemont 138 kV circuit 1 rebuild	Rebuild 5.09-mile 138 kV line from Anadarko to Gracemont as a double circuit and install/upgrade any necessary terminal equipment to achieve a summer emergency rating of 353 MVA for circuit 1	WFEC
210589	122755	Gracemont 138 kV circuit 2 terminal equipment	Install terminal equipment at Gracemont 138 kV to support a second 138 kV line from Anadarko to Gracemont to achieve a summer emergency rating of 353 MVA for circuit 2	OGE

BACKGROUND – 2023 ITP MODEL IMPACTS

- After the 2023 ITP base reliability (BR) powerflow models were posted and voting had begun, staff identified that the Anadarko-Gracemont 138 kV circuits 1 and 2, which are subject to the SPP board approved re-evaluation in the 2023 ITP, were not reverted back to existing system configuration in the models.
- In accordance with RR500, the data was submitted and approved on time but was missed by SPP and now has been incorporated as a model correction update

MODEL CORRECTION

Model	Stage applied at
2023 ITP Base Reliability (BR) Powerflow	Approved final set
2023 ITP Short Circuit	Proposed final and reposted
2023 TPL Dynamics	Pending proposed final models
2023 ITP Market Economic Models	• MEM utilized for constraint assessment • Will be included in proposed final models
2023 ITP Market Powerflow Models *(if needed)*	Included via MEM/ ITP BR updates

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2023 ITP

TWG/ESWG

DECEMBER 2022

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2023 **ITP**

CONSTRAINT ASSESSMENT UPDATE

MAURISA HUGHES

OVERVIEW

- Constraint Assessment initial posting information
- Updates since initial posting
  - Model changes
  - Simulation updates
- Constraint Assessment posting workbook updates
- Voting and final posting
- Process flow

CONSTRAINT ASSESSMENT INITIAL POSTING INFO

- An initial list of constraints for the 2023 ITP Assessment was posted on Nov 18, 2022 for stakeholder review and feedback
  - Included Gracemont-Anadarko 138 kV reevaluation update
    - The Constraint Assessment was re-performed only for Future 2 Year 10 models; the resulting constraints have been applied across all scenarios
  - SPSNMTIES interface update
    - Incorrectly included the Hobbs-Roadrunner 345 kV circuits
    - Interface rating: -9999/1589/-9999/1589
  - Included correct data for fixed and variable O&M and curtailment price, which was previously missed due to an automation issue
    - Staff updated the data and observed a < 1% difference in adjusted production cost for Future 2 Year 10 MEM. Therefore, this change is not impactful to the 2023 ITP constraint assessment.
- Stakeholder feedback was due by November 29, 2022

MODEL CHANGES SINCE INITIAL POSTING

- Update to Blackwater and Eddy DC Tie Buses- Removed loads from the Y10 MEMs
- Rating updates
- Staff corrected the SPSNMTIES interface definition in the 2023 event file by removing the Hobbs - Roadrunner 345 kV lines

SIMULATION UPDATES SINCE INITIAL POSTING

- Staff noticed increased run times of PROMOD simulations with the posted draft constraint assessment event files
  - Ancillary co-optimization flag is a contributor
  - Battery dispatch could be contributing to extended run time
  - Increased quantity of events due to model corrections identified prior to initial posting
- Observed non-optimal 168 hours with flow violations in Y10 scenarios

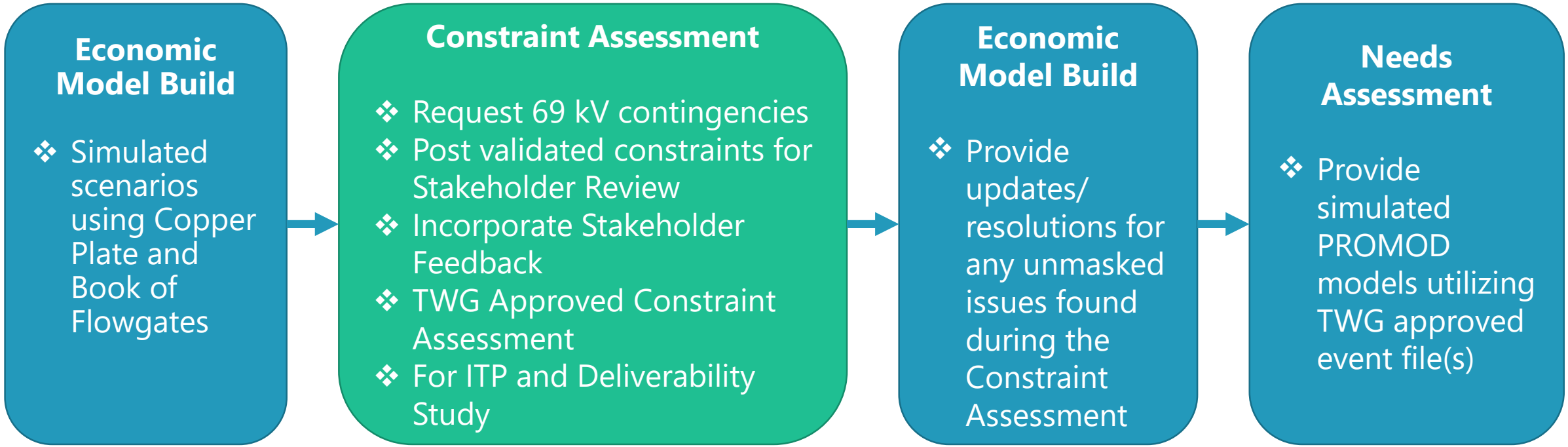
CONSTRAINT ASSESSMENT POSTING WORKBOOK UPDATES

- Includes an additional sheet of removed market economic constraints from initial posting
- Highlights changes since initial posting
  - Including stakeholder feedback
- Includes congestion scores
- Corrects the Area column on the “Interfaces” sheet
- Corrects the contingency’s Facility Name and Contingency Name in the “SPP Market Economic Constraints” sheet

VOTING AND FINAL POSTING

- The final Constraint Assessment Recommendation workbook and event files will be posted for stakeholder review during the week of December 5
- A voting window to approve the Constraint Assessment results, via an email vote, will follow

PROCESS FLOW



2023 **ITP**

APPENDIX

ECONOMIC CONSTRAINT ASSESSMENT OVERVIEW

- Method of determining elements that limit the incremental transfer of power throughout the system
  - System intact and contingency situations
- SPP utilizes constraints to reliably manage the flow of energy across the physical bottlenecks of the transmission system in the least costly manner

ECONOMIC CONSTRAINT ASSESSMENT OVERVIEW

- The Constraint Assessment identifies future bottlenecks and fine-tunes the PROMOD models
  - This helps to develop study-specific constraints that play a critical role in determining Transmission Needs
- Due to PROMOD limitations, it is not possible to monitor all combinations of transmission elements for issues, so the Constraint Assessment narrows constraint focus to most impactful as determined by ITP Future assumptions

GOVERNING DOCUMENTS - ITP MANUAL

2.2.3 CONSTRAINT ASSESSMENT

- SPP maintains a list of flowgates to monitor based on reliability and economic issues seen in real-time. The constraint assessment is used to identify potential future constraints for each future and year of study.
- To create these additional constraints, SPP will perform economic simulations to identify additional or breaching elements in the system that occur during the reliability peak and off-peak hours[23]. System flows under two levels of constraint will be analyzed:
  - Copper Plate: No defined constraints
  - Initial constraint list based on NERC and SPP flowgates

2.3 SPP BA POWERFLOW MODEL OVERVIEW

- **Peak Hour:** Hour with the highest total megawatt output of wind resources within SPP selected from the top 1% of SPP coincident peak load hours
- **Off-Peak Hour:** Hour with the highest wind penetration between April and May between the hours of 12 a.m. – 6 a.m.

[23] Defined in the Market Powerflow Model Overview section

GOVERNING DOCUMENTS - ITP MANUAL

2.2.3.1 Contingency Screening

- Due to software and time limitations, large contingency lists are not feasible. The contingency lists will be created with the goal of including the most impactful contingencies for constraint identification.
- After the initial economic simulation dispatch results have been created, the resulting contingencies will be limited to the following types of planning events identified in the NERC Standard TPL-001 for the 100 kV-and-above transmission system:
  - P1.2 and P1.3 single-branch contingencies on the 100 kV and above system exceeding 50 percent loading in the peak and off-peak hours under system intact conditions for the translated areas.
  - P1.2 and P1.3 single-branch contingencies on the 200 kV and above system exceeding 25 percent loading in the peak and off-peak hours under system intact conditions for the SPP footprint.
  - Contingencies included in the SPP permanent and temporary flowgates, including P7 events.
  - Other P1, P2, P4 and P5 events as potential contingencies.
- Contingencies meeting these criteria that are inconsistent with operation of the SPP Integrated Marketplace or create simulation anomalies may be excluded from further evaluation.

GOVERNING DOCUMENTS - ITP MANUAL

2.2.3.2 Constraint Identification

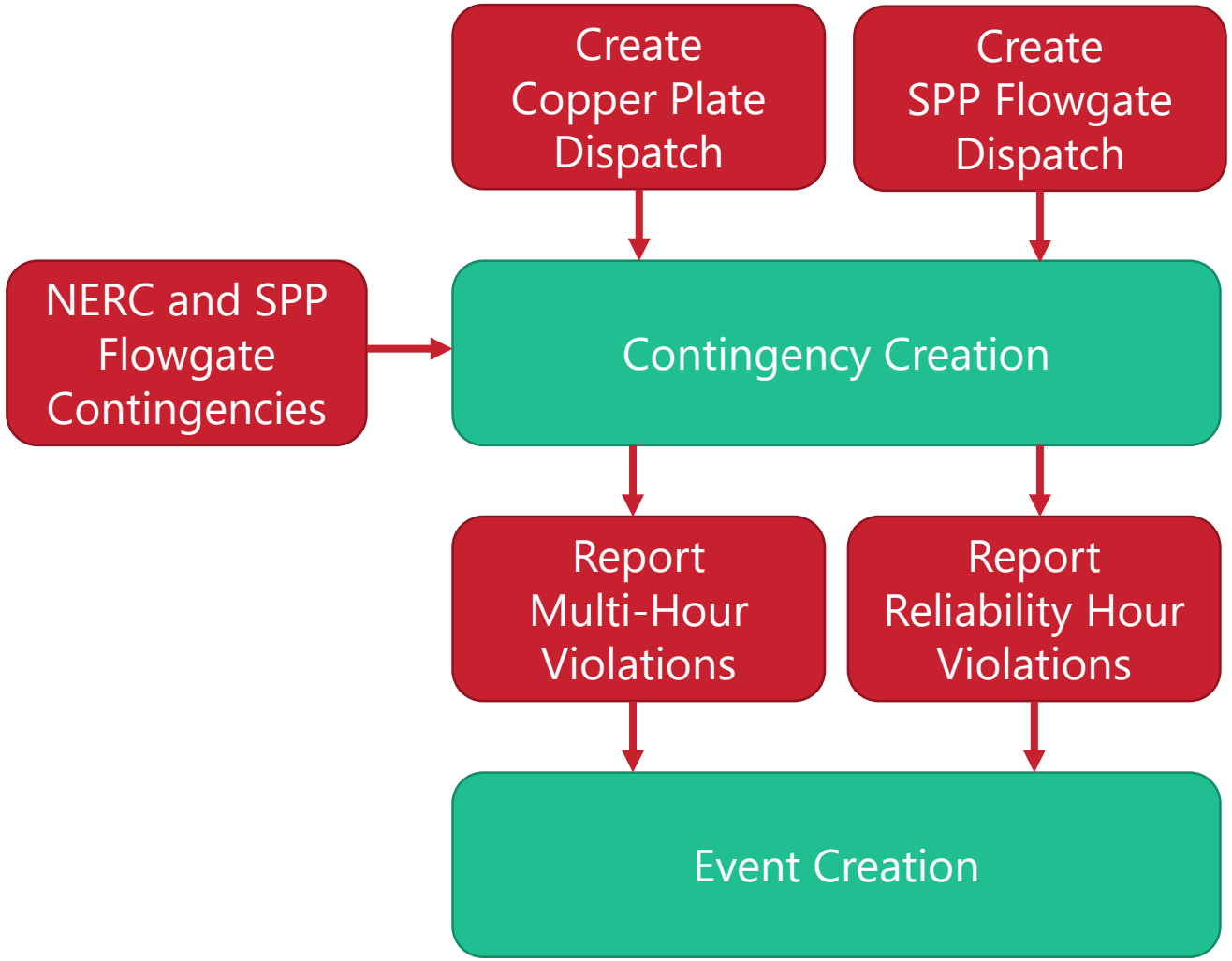
- Facilities exceeding their thermal limits under system intact and contingency conditions will be assessed for potential inclusion as constraints. Flow violations occurring in either of the reliability hours will be automatically included unless SPP and stakeholders deem otherwise during the constraint review. Flow violations occurring in the annual hourly simulations will be considered for inclusion based on the following information, at a minimum:
  - Number of violation hours and/or violation loading thresholds.
  - The ability of the simulation to reach a valid[24] dispatch solution due to a given constraint[25].
  - Preliminary economic model simulation results.
  - Performance of constraints in prior SPP expansion plan studies.
- The ESWG and TWG will be given the opportunity to review the resulting constraints. After the review is completed, TWG approval will be requested before completion of the milestone.
- In addition to the approved list of constraints, some 69 kV constraints may be included in the constraint list as needed to properly control the dispatch of resources on the 69 kV system and capture congestion in developing 100 kV and above solutions. These constraints will be suggested or provided by SPP stakeholders.

[24] All constraints and generating parameters honored
[25] A constraint may be removed and considered as a reliability need during the Market Powerflow analysis

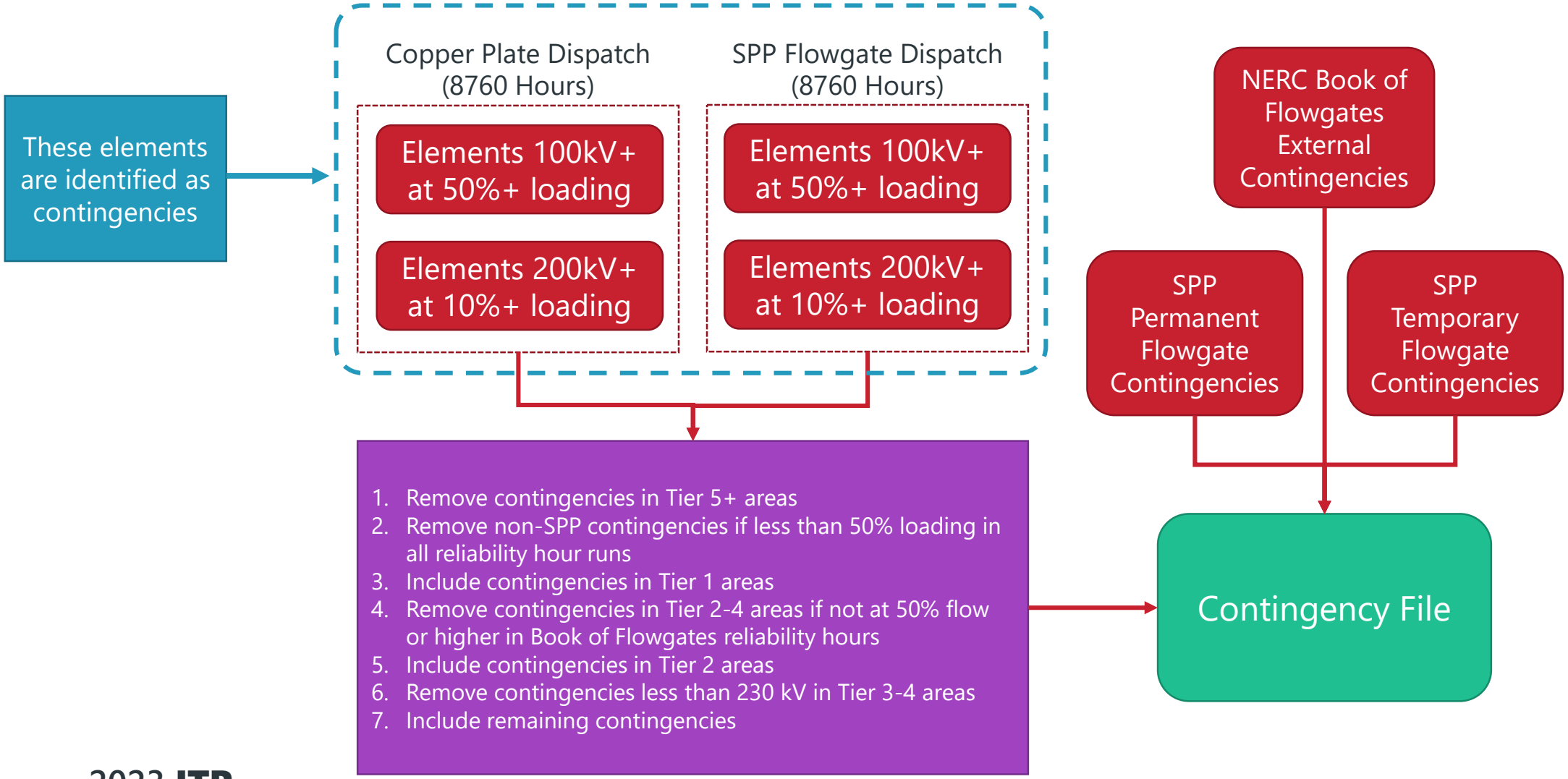
PROMOD ANALYSIS TOOL (PAT)

- Primary tool utilized for Constraint Assessment
  - Includes a tool that develops outages and associated monitored branches utilizing PROMOD dispatch and other criteria
  - Includes a tool that creates and analyzes event files to reduce errors and PROMOD run times
- Software developed specifically for in-depth analysis of PROMOD results by utilizing the following output files generated by PROMOD
  - HRX, HRY, EVE, PFF, LIB

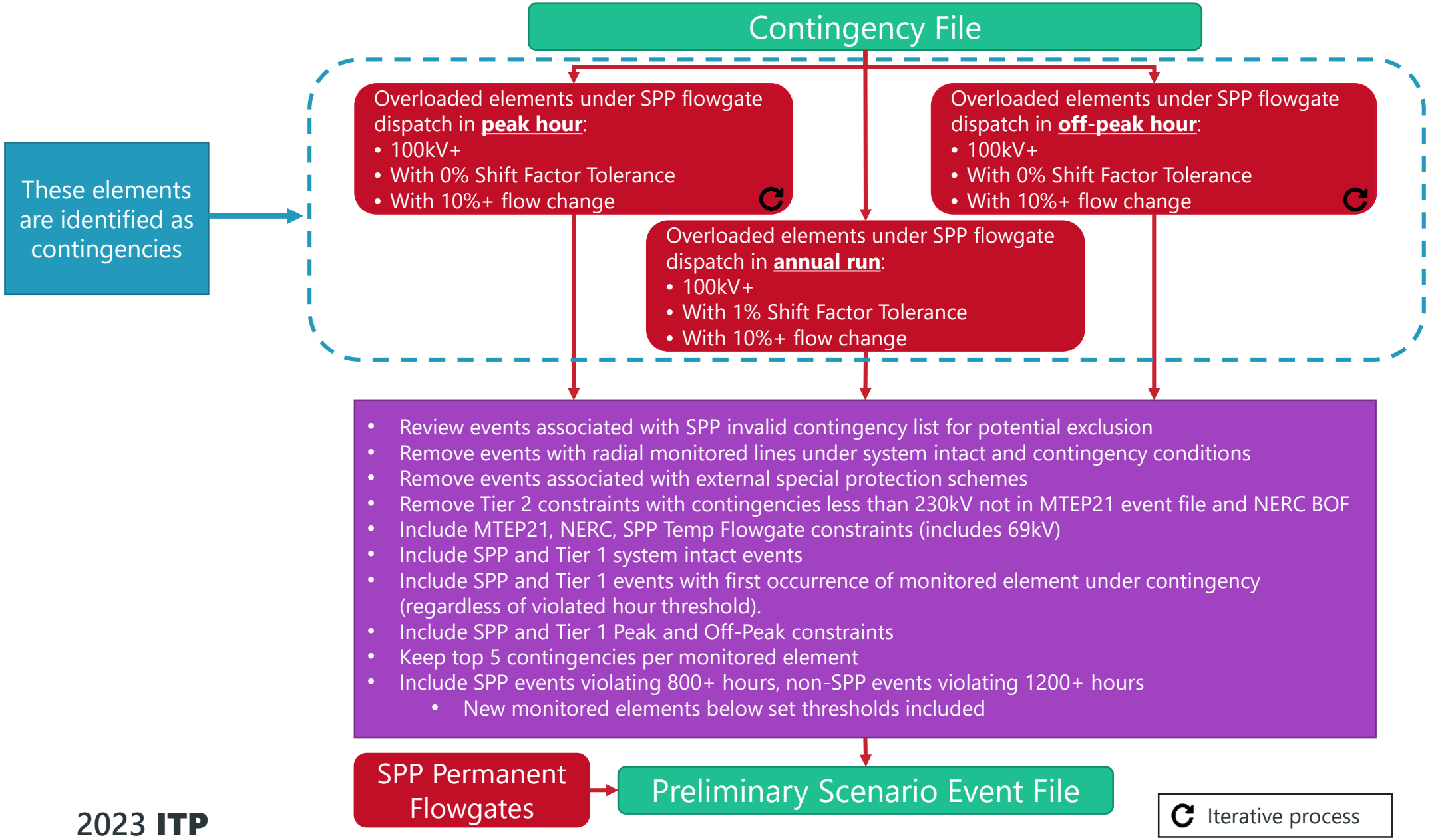
METHODOLOGY OVERVIEW BY SCENARIO



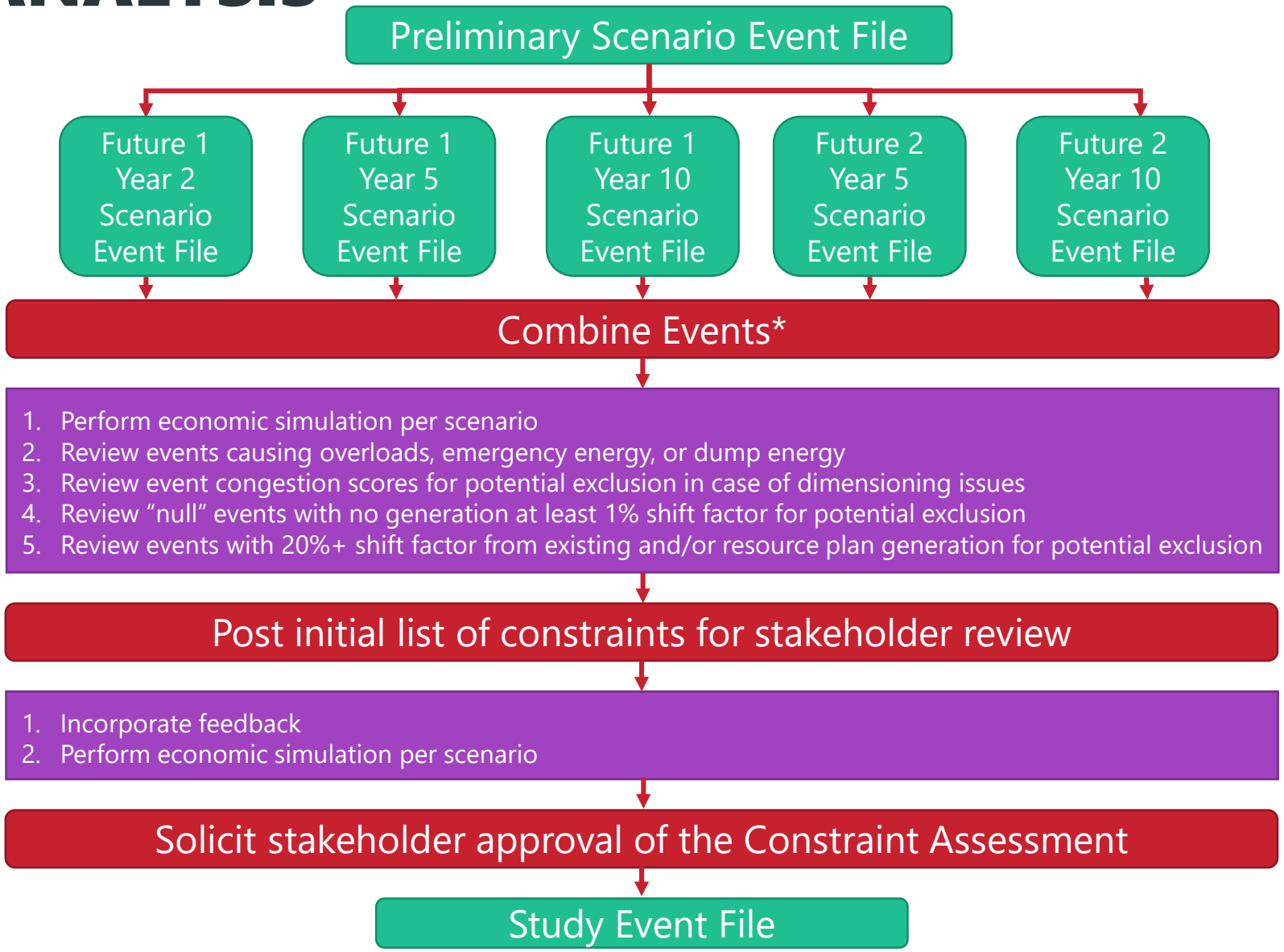
CONTINGENCY CREATION - BY SCENARIO



EVENT CREATION - BY SCENARIO



EVENT ANALYSIS



*To the extent possible with topology changes amongst scenarios

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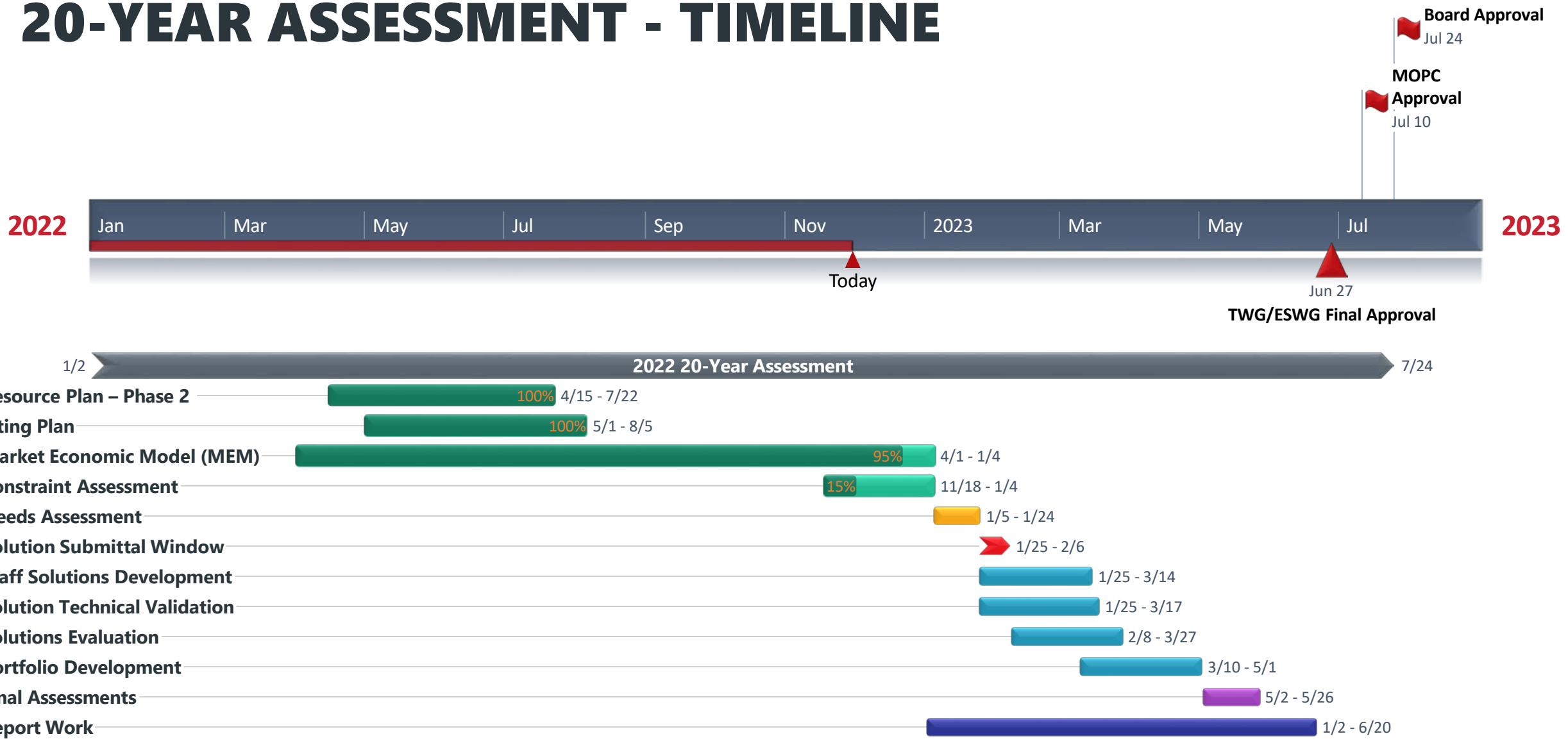
ITP

ACTIVE ITP STUDIES - SCHEDULE UPDATES

DARA SOLOMON

DECEMBER 2022

20-YEAR ASSESSMENT - TIMELINE

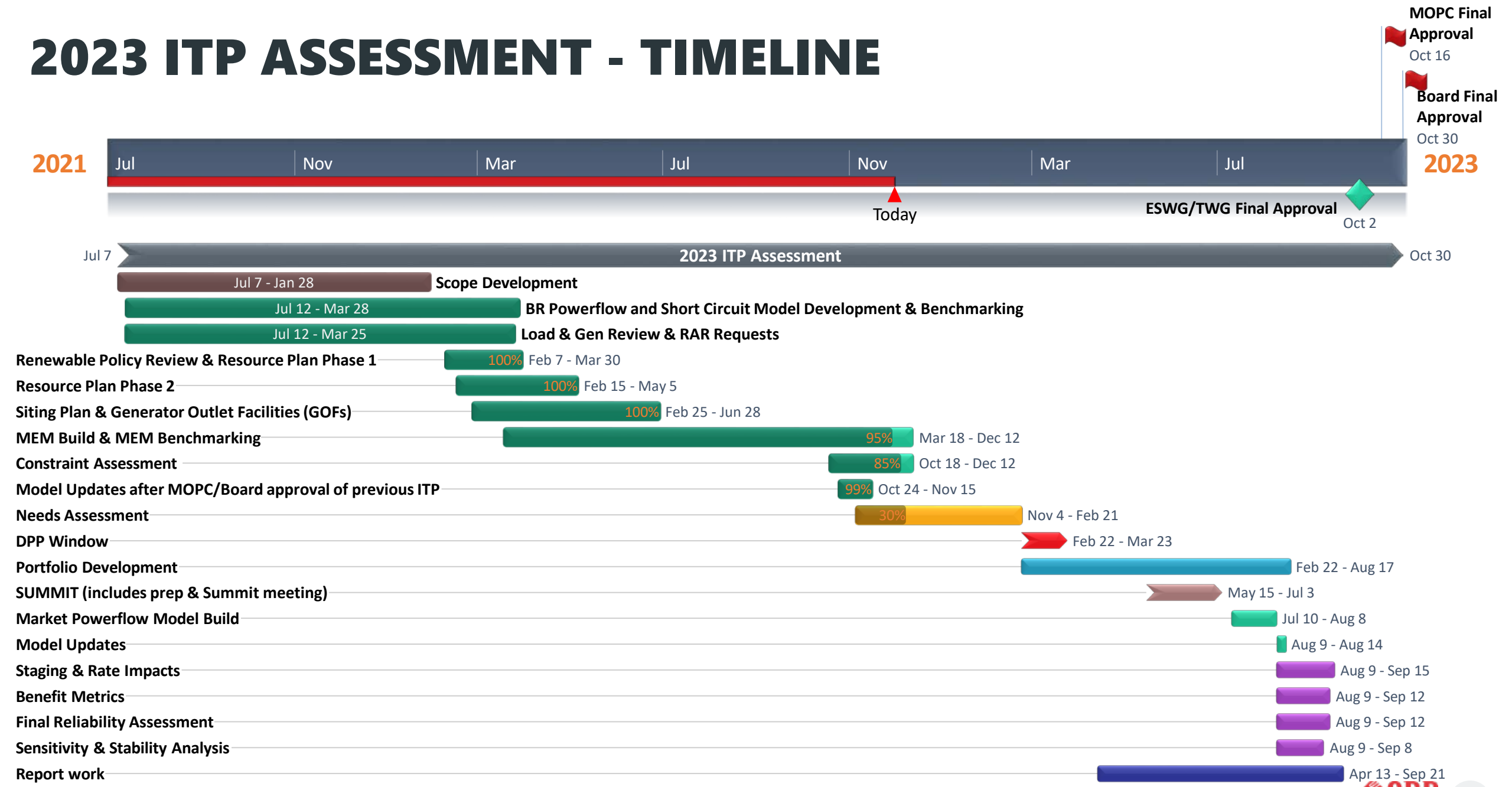


20-YEAR ASSESSMENT
EXECUTIVE SUMMARY & UPCOMING POSTINGS

- The 20-Year Assessment study is in progress and is scheduled to complete by the July 2023 MOPC and Board cycle
  - The study was originally scheduled to complete in 2022; however, given competing priorities the timeline needed to be adjusted. SPP staff discussed with stakeholders possible mitigation strategies including extending the timeline which led to the study schedule being re-baselined
- The Market Economic Model team successfully resolved the issues found in the complex 20-year models. The models have now been delivered to the Constraint Assessment team and that milestone is currently in progress.
- In addition to the study work, SPP staff is also working with Legal to draft a FERC waiver to allow SPP to formalize the extension of the study timeline

Milestone & Posting Description	Posting Date
Final MEM & Constraint Assessment	1/04/2023
Solution Submittal Window	1/25/2023 – 2/6/2023

2023 ITP ASSESSMENT - TIMELINE

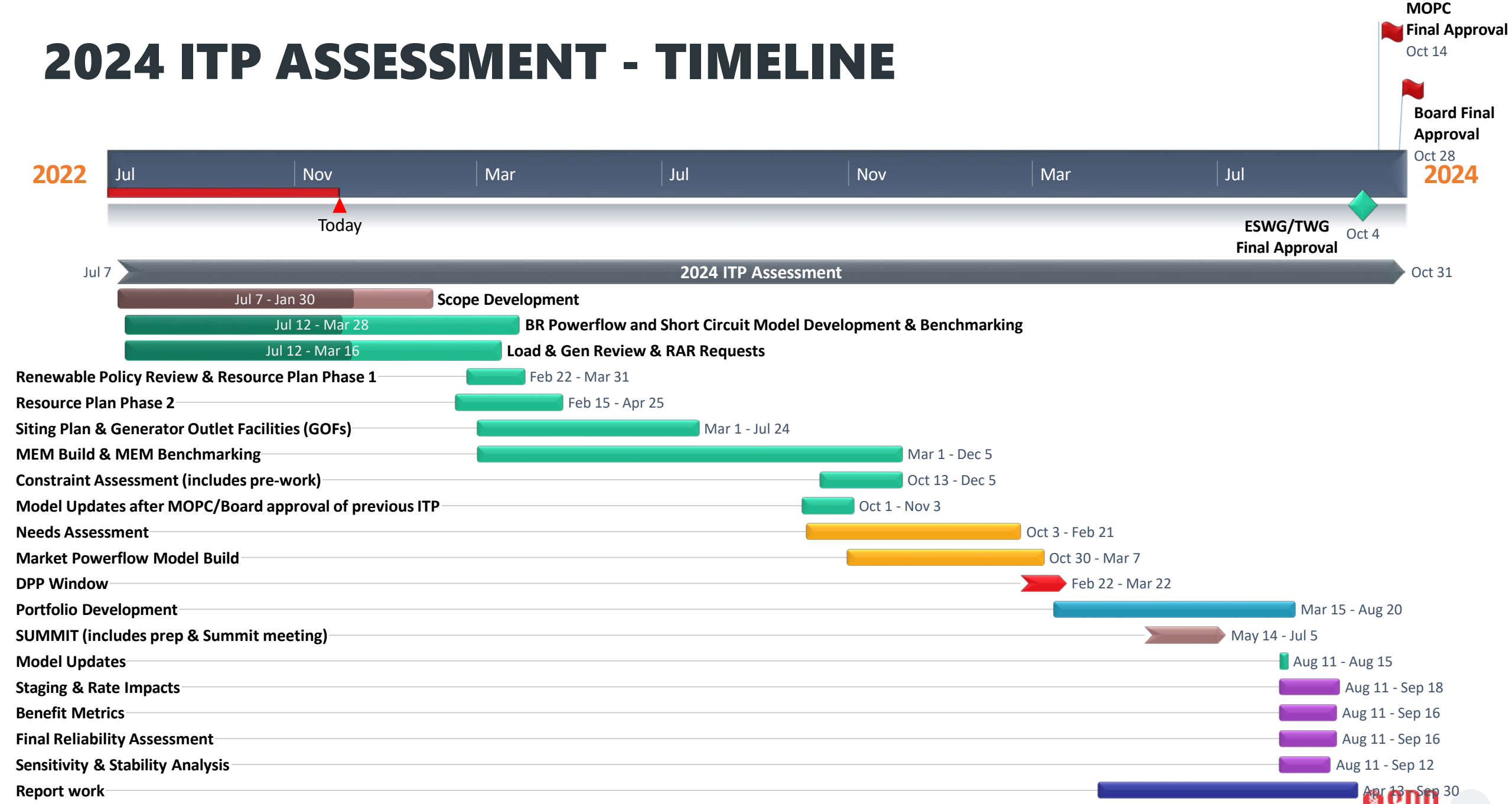


2023 ITP ASSESSMENT
EXECUTIVE SUMMARY & UPCOMING POSTINGS

- The 2023 ITP is in progress, on track, and scheduled to complete by the October 2023 MOPC and Board cycle
- The study is currently in the constraint assessment and needs assessment milestones
- Additional efforts outside study work include amending the project schedules to account for the changes related to the utilization of the market powerflow models and efficiencies identified in MOPC action item 314

Milestone & Posting Description	Posting Date	Stakeholder Review Dates
Final MEM & Constraint Assessment – Approval	12/05/2022	12/06/2022-12/12/2022
Needs Assessment – Preliminary Violations Received from Stakeholder	1/06/2023	

2024 ITP ASSESSMENT - TIMELINE



2024 ITP ASSESSMENT
EXECUTIVE SUMMARY & UPCOMING POSTINGS

- The 2024 ITP has only been underway for 6 months and is scheduled to complete by the October 2024 MOPC and Board cycle
- The study is currently in the scope development phase with the scope tentatively being set for approval at the January 2023 MOPC and SPC cycle
- Load and Generation review milestones are also in progress and on track
- Additional schedule updates will be made to the 2024 ITP study as the study progresses

Milestone & Posting Description	Posting Date	Stakeholder Review Dates
Load Review – pass 2 for stakeholder review*	1/13/2023	1/16/2023-1/30/2023
Generation Review – pass 2 for stakeholder review*	2/15/2023	2/16/2023-3/01/2023

* **November 23, 2022** is the deadline for data submitters to provide Transmission Service Inputs (AG1) Data, review Pass 2 models/data submission through MOD, and **final updates to load and generation** (Pmax, Pmin, retirement) reports/reconcile transaction discrepancies, as well as Geomagnetic Model Updates

UPCOMING POSTING & STAKEHOLDER REVIEW DATES

DECEMBER 2022 – IMPORTANT DATES

20 Year Assessment

2023 ITP

- SPP will post the Constraint Assessment and MEM for final approval on 12/05/2022. Stakeholders will be asked to review from 12/6/2022 – 12/12/2022 (5 days)

2024 ITP

JANUARY 2023 – IMPORTANT DATES

20 Year Assessment

- SPP will post the MEM for final approval on 1/4/2023.
- SPP will post the Constraint Assessment for final approval on 1/4/2023.
- Stakeholders can submit project solutions between 1/25/2023 - 2/6/2023 (10 days)

2023 ITP

2024 ITP

- SPP will seek approval for the scope from MOPC on 1/17/2023
- SPP will post Load Review Pass 2 for review on 1/13/2023. The review period will be 1/17/2023 – 1/23/2022 (5 days)

FEBRUARY 2023 – IMPORTANT DATES

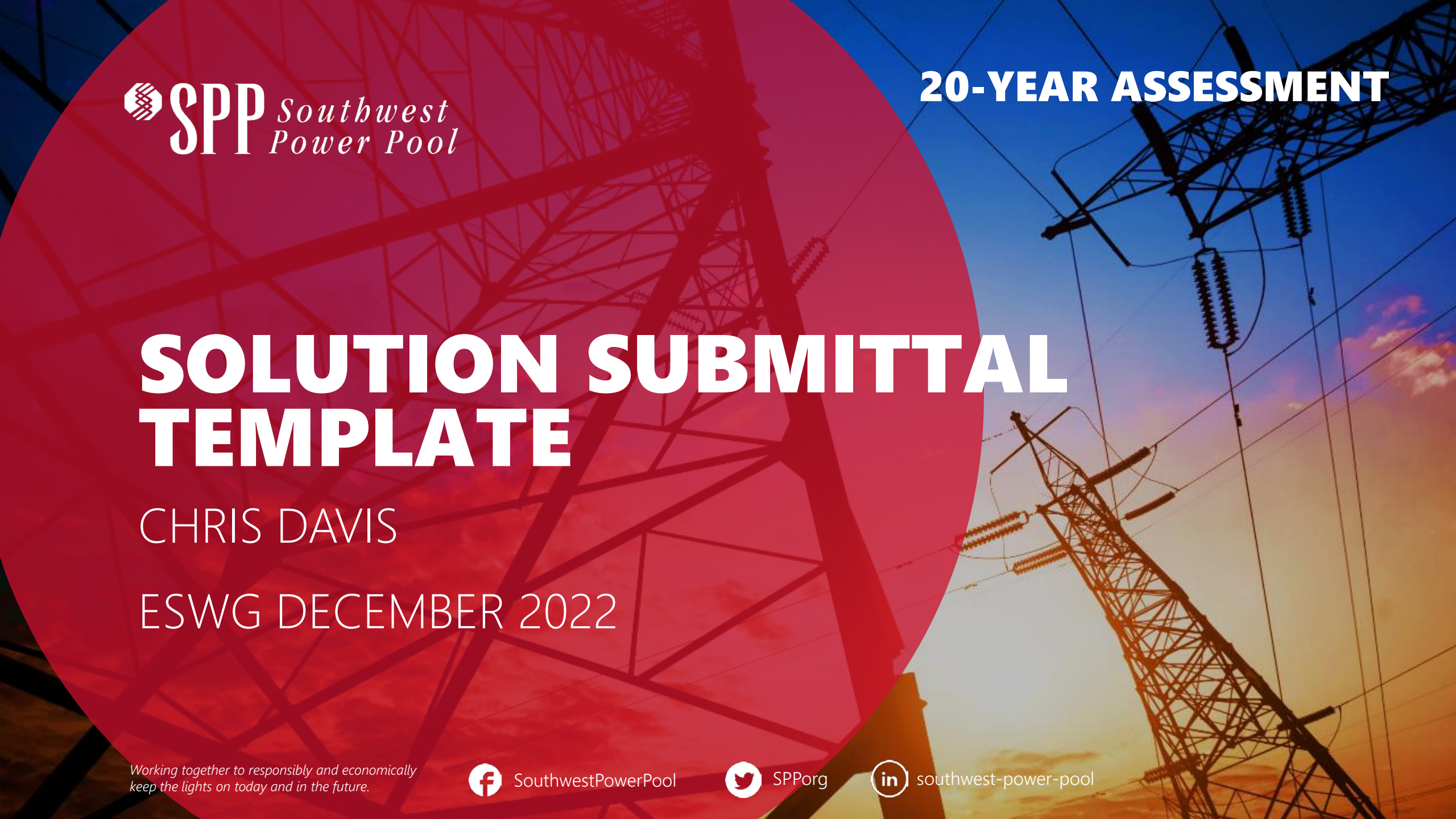
20 Year Assessment

2023 ITP

- SPP will post the Needs Assessment on 2/21/2023
- The DPP Window will be open from 2/22/2023 – 3/23/2023

2024 ITP

- SPP will post Gen Review Pass 2 for review on 2/15/2023. The review period will be 2/16/2023 – 3/01/2022 (10 days)



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20-YEAR ASSESSMENT

SOLUTION SUBMITTAL TEMPLATE

CHRIS DAVIS

ESWG DECEMBER 2022

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SOLUTION SUBMITTAL WINDOW

- SPP staff will open up a solution submittal window for 300 kV+ solutions to address economic and public policy needs for Year 20
  - Expected open: January 25, 2023
  - Expected close: February 6, 2023
- SPP will not use the standard DPP form used in the ITP
- A 20YA Solution Submittal template has been posted with January TWG/ESWG materials
- RMS system will be standard form of communication for solution submittals

SUBMITTAL TEMPLATE OVERVIEW

GENERAL DETAILS

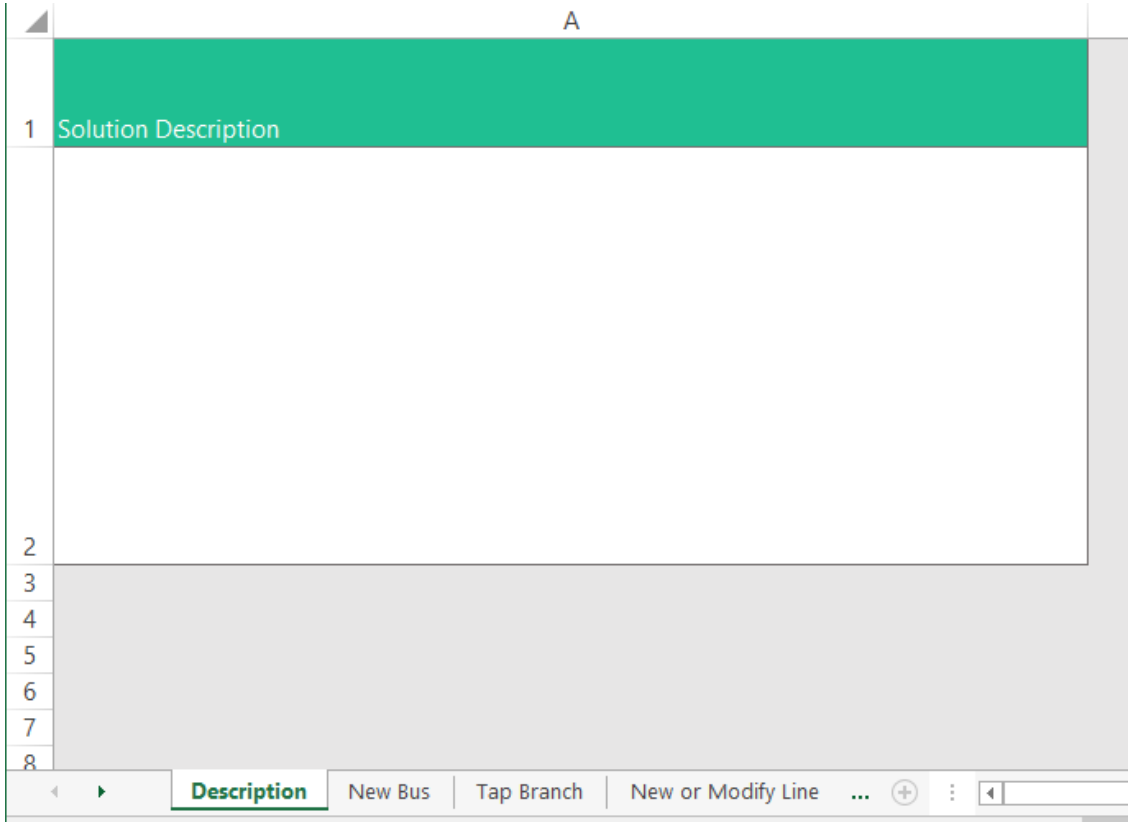
- SPP staff has created an Excel template for submitting solution details
  - Template is intended to be a replacement for the DPP form and PSSE .idv files (for the 2022 20YA only!)
- Template includes high-level validation of data entry
  - Bus numbers must be 6 digits
  - Highlights any missing data entries
  - Etc…
- SPP staff will use excel data to create necessary PSS®E .idv files to enter and evaluate solutions
- SPP may need to contact submitter for any needed clarification

REASON FOR TEMPLATE

- Little to no “model correction” submissions expected
- Automated conversion of template data to projects that meet SPP minimum design standards
- Reduced need for manual review and validation of submission
  - Fast track to project evaluation
- PSS®E .idv files will still be accepted if necessary, but use of submission template is recommended

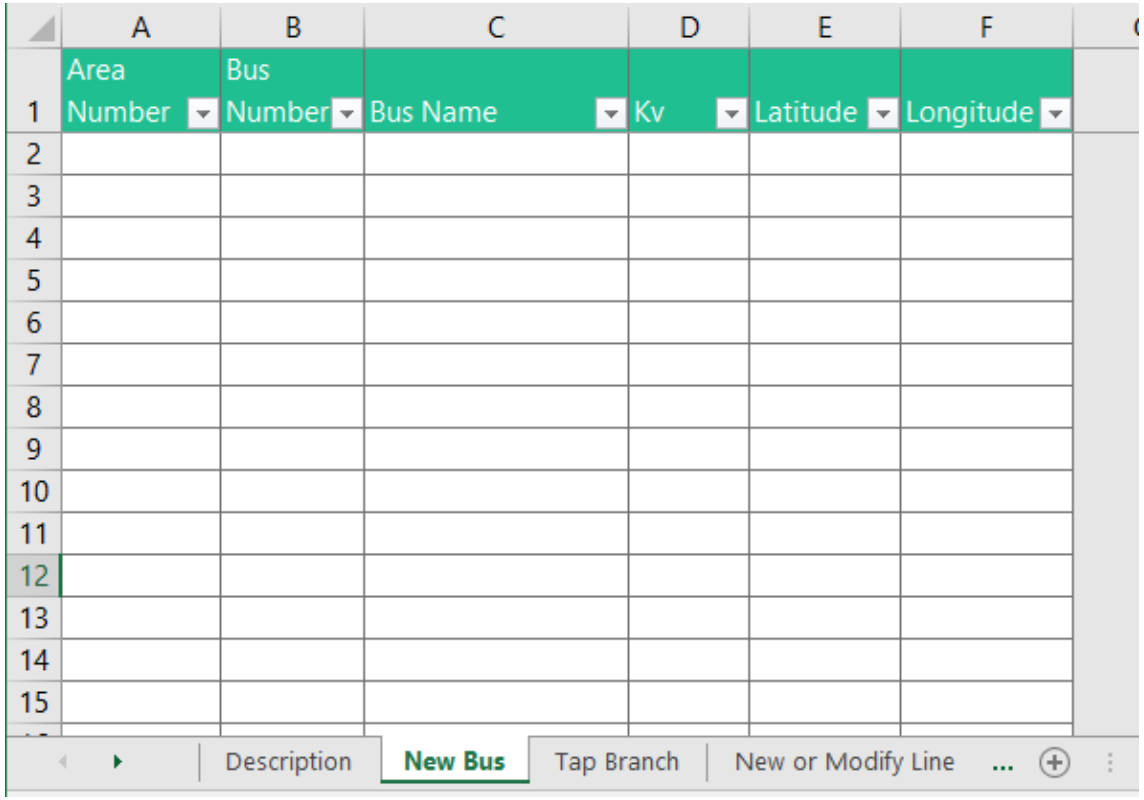
DESCRIPTION TAB

- Text description of the project
- Recommend to include
  - Description of topology change(s), such as from/to buses
  - Expected needs to be resolved
  - Any details to assist with cost estimation



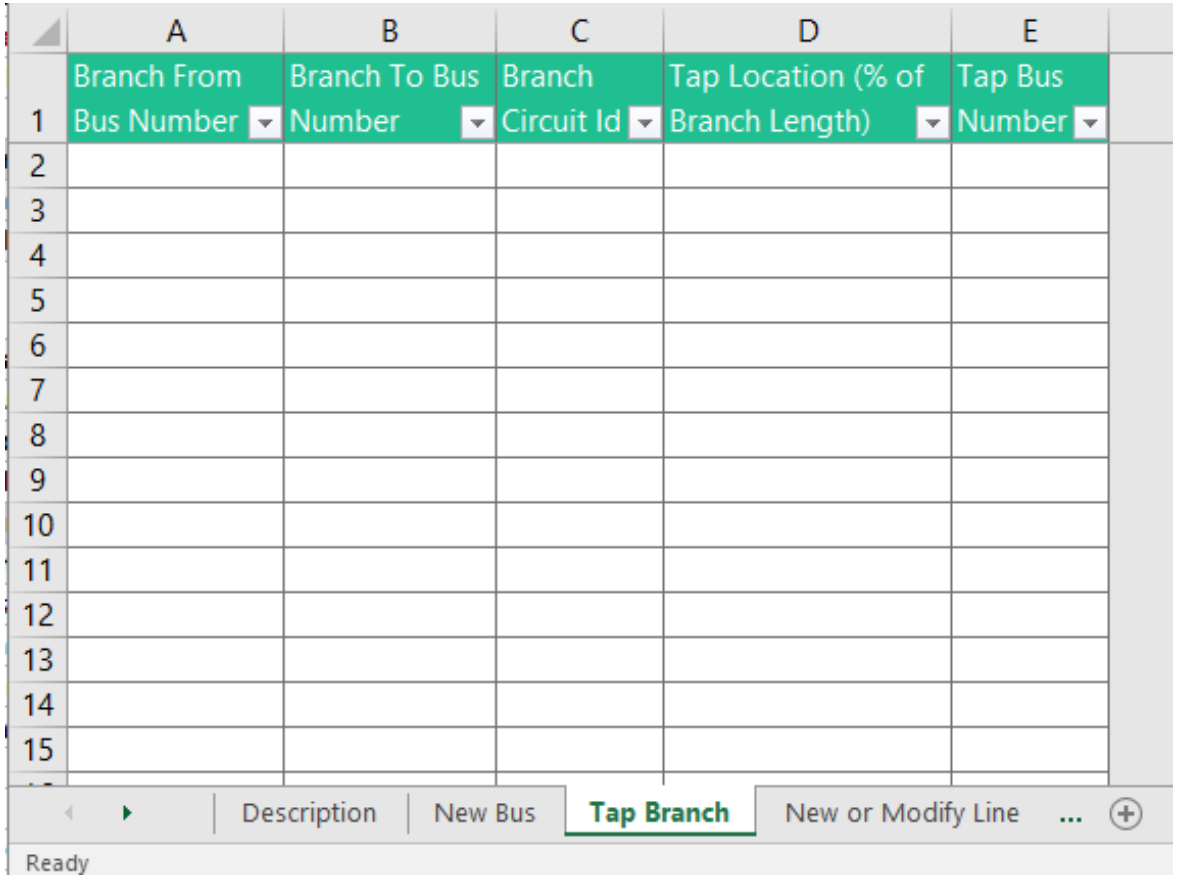
NEW BUS TAB

- Used when new buses need to be added to accommodate solution
- All fields required, including Latitude/Longitude to determine connecting transmission line lengths



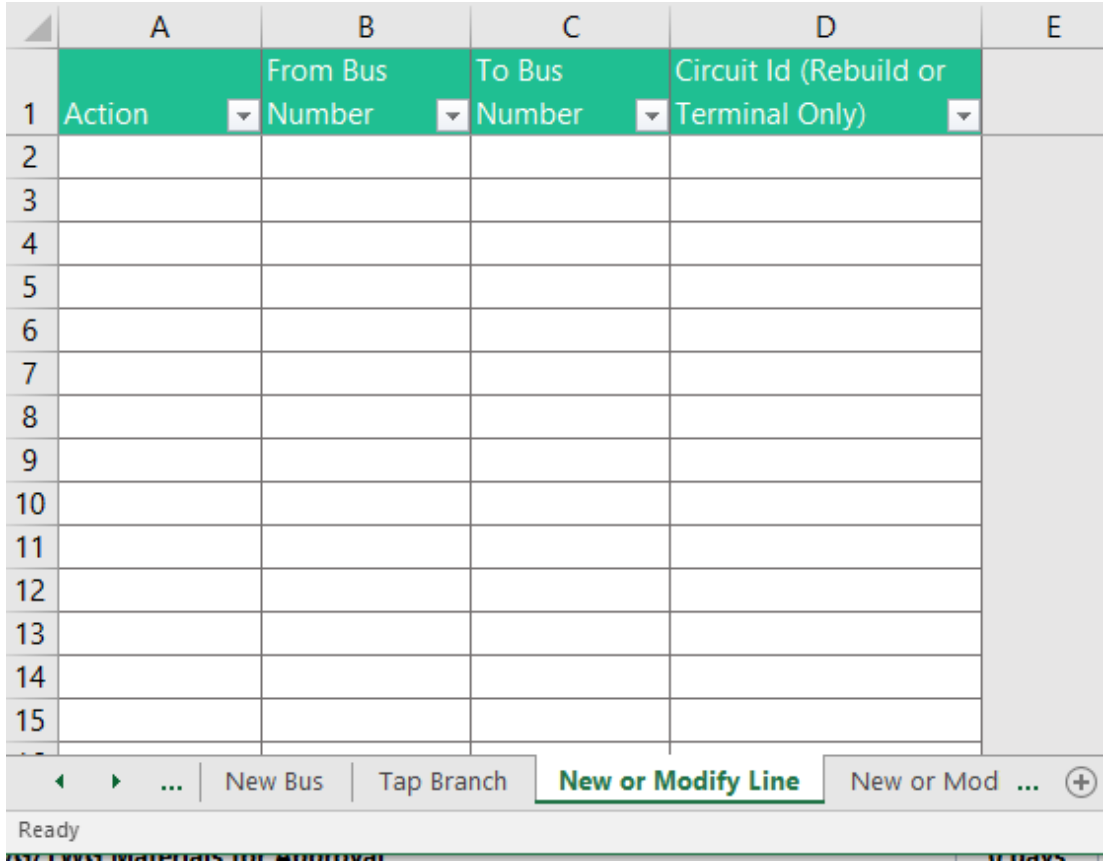
TAP BRANCH TAB

- For use when tapping an existing branch
- All fields required
  - Tap Location % is percentage of line length from the FROM bus
  - Tap Bus Number must be an un-used bus number (do not enter on **New Bus** tab)
  - Additional lines connecting to tap must be specified on the **New or Modify Line** tab



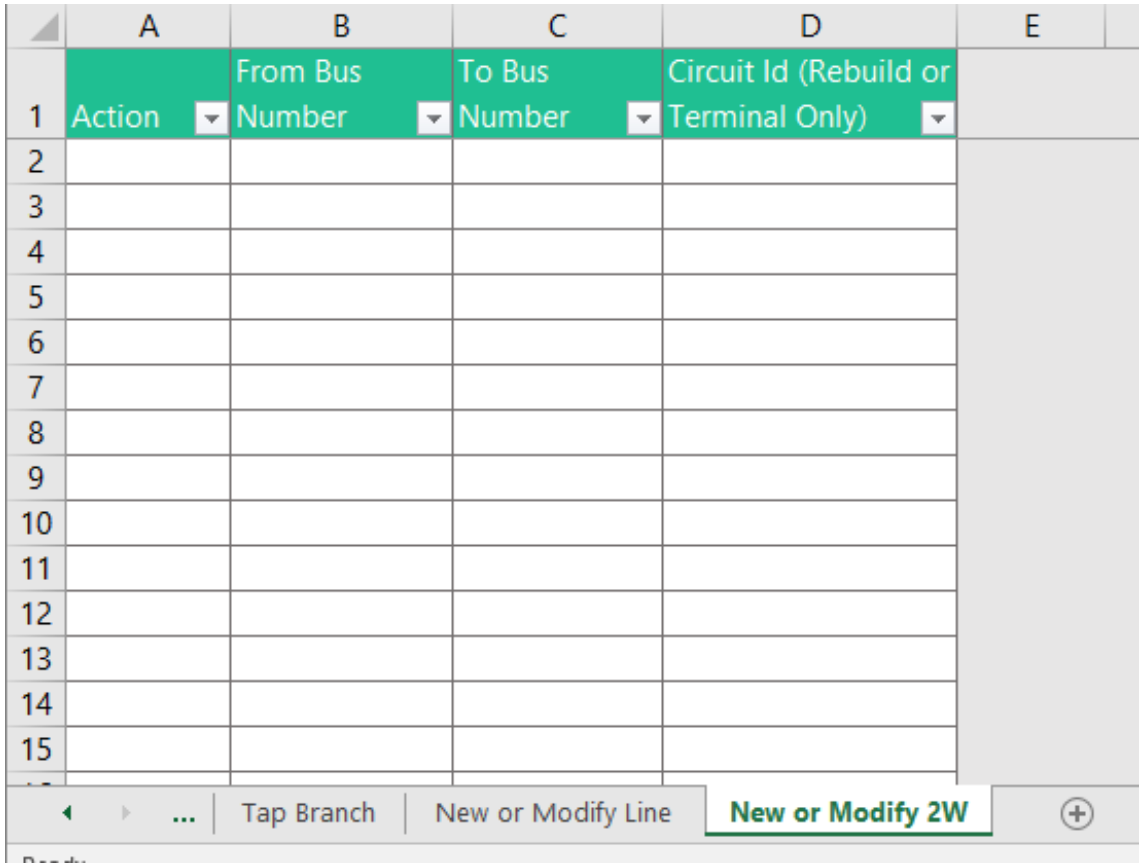
NEW OR MODIFY LINE TAB

- Used for
  - New transmission lines
  - Rebuild existing lines
  - Line terminal equipment upgrades
- From/To buses required
- Circuit ID only required for upgrading existing circuits



NEW OR MODIFY 2W TAB

- Used for
  - New 2-winding transformers
  - Rebuild existing 2Ws
  - 2W terminal equipment upgrades
- From/To buses required
- Circuit ID only required for upgrading existing circuits



QUESTIONS?

SOUTHWEST POWER POOL, INC.
ECONOMIC STUDIES WORKING GROUP

Action Items Status Report
December 7-8, 2022

	Action Item	Date Originated	Status	Comments
190	Utilize the results from RCAR III to determine the ratio of APC benefit to Transmission Outages benefit to be applied in the ITP assessments.	10/12/17	In progress	Working with SPP operations on additional APC benefit with outages included. Mar: Ops is planning to perform after RCAR III and Value of Transmission study. Sept 29: Estimated start date is 2022 Q2 Aug: Estimated to complete by 2022 EOY Nov '22: Methodology on agenda
~~210~~	~~Create list of 20YA items to review~~	~~01/07/21~~	~~In Progress~~	~~June: Continue review of list and discussion of items~~ ~~Jan: Several items on the agenda for discussion~~ ~~Feb: Several items on the agenda for discussion~~ ~~Mar: Emissions target analysis being discussed~~ ~~Aug 4: Update presented~~ ~~Aug 31-Sep 1: Constraint Assessment on agenda~~
~~211~~	~~Revisit the SPP Other bucket and how we use those resources in Resource Plan Phase II Accreditation~~	~~05/19/21~~	~~In progress~~	~~July: Review process in upcoming meeting~~ ~~Sept 29: Resource Accreditation is being discussed as part of 2023 ITP Scope.~~ ~~Feb: To be discussed as part of 2024 ITP Scope development ~June 2022~~ ~~Nov '22: Accreditation methodology on agenda~~ ~~**Dec '22: Accreditation methodology on agenda**~~
~~212~~	~~Review ELCC Accreditation~~	~~11/03/21~~	~~In progress~~	~~Feb: To be discussed as part of 2024 ITP Scope development ~June 2022~~ ~~May: Begin discussions~~ ~~Nov '22: ELCC accreditation on agenda~~ ~~**Dec '22: ELCC accreditation on agenda**~~
~~213~~	~~Discuss incorporation of Utility Integrated Resource Plans in the ITP~~	~~11/03/21~~	~~In progress~~	~~Feb: To be discussed as part of 2024 ITP Scope development ~June 2022~~ ~~May: Begin discussions~~ ~~Aug: Will be discussed at ESWG meeting.~~ ~~Nov '22: final piece for 2024 ITP scope on agenda as part of accreditation process~~

	Action Item	Date Originated	Status	Comments
				~~**Dec '22: final piece for 2024 ITP scope on agenda as part of accreditation process**~~
216	Address PROMOD battery modeling issues	03/30/22	In Progress	Mar 30: Action Item added.
217	Review modeling issues surrounding hybrid and co-located resources in economic models	05/05/22	In Progress	May 5: Action Item added