Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

March 17th, 2016

8th Floor AEP Offices, Dallas, TX

• SUMMARY OF ACTIONS TAKEN •

1. Approved the completion and results of the Benchmarking milestone of the 2017 ITP10.
2. Approved the 2017 ITP10 economic models as posted on TrueShare with adjustments to 2020 carbon prices for Future 1 and Future 2 detailed in the Economic Model presentation at the 3/17 ESWG meeting, including direction to be given by the ESWG on modeling of carbon costs for APC calculation.
3. Endorsed the Wind Integration Study recommendation #5 to begin accelerating the approved ITP projects with issued NTCs, specifically PID 30843 (Cimarron – Draper 345 kV Terminal Upgrades) and PID 30844 (Amoco – Sundown 230 KV Terminal Upgrades).
4. Approved the Staff recommendation for reflecting the price of carbon in the CPP Futures of the 2017 ITP10.
    a. Include a carbon cost in the model for all fossil units as a means to affect dispatch
    b. Reflect the cost of carbon in the energy costs of affected EGUs [to be regulated under the CPP]

Southwest Power Pool

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ECONOMIC STUDIES WORKING GROUP

March 17th, 2016

8th Floor AEP Offices, Dallas, TX

• MINUTES •

Agenda Item 1 – Administrative Items

Agenda Item 1a - Call to Order, Introductions

Chair Alan Myers (ITC Great Plains) called the meeting of the Economic Studies Working Group (ESWG) to order at 8:00 AM, welcomed those in attendance, and asked for introductions.

There were 14 in-person participants and 54 web conference participants, representing 16 of 17 ESWG members. (Attachment 1 – March 17th, 2016 Attendance List)

Agenda Item 1b – Receipt of Proxies

Alan Myers (ITC Great Plains) asked for any proxy statements. One proxy was identified; Gayle Nansel (WAPA) named Josie Daggett (WAPA) as her proxy. (Attachment 2 – Proxy Statements)

Agenda Item 1c – Review of Agenda

Chair Alan Myers (ITC Great Plains) presented the agenda for review and asked for any additions or corrections. (Attachment 3 – March 17th, 2016 Agenda)

> **Kurt Stradley (LES) made a motion; seconded by Tim Owens (NPPD) to adopt the agenda as modified. The motion was approved unanimously.**

Agenda Item 2 – Review of Past Action Items

Kelsey Allen (SPP Staff) reviewed the list of past action items. (Attachment 4 – Past Action Items)

Agenda Item 3 – Consent Agenda

The consent agenda included the following items:

> Meetings Minutes – February 24th – 25th, 2016 (Attachment 5 – ESWG 02.24-25.16 Minutes)

Alan Myers (ITC Great Plains) asked if any items should be removed from the consent agenda.

> **The consent agenda was approved unanimously.**

Agenda Item 4 – Transmission Planning Improvement Task Force (TPITF) Update

Alan Myers (ITC Great Plains) gave an update on the activities of the TPITF. There is currently a draft whitepaper that will be going to the MOPC for review in April and for final approval in July. The members discussed the need to make formal comments on the whitepaper prior to MOPC approval as well as beginning discussion on the impacts that the TPITF recommendations will have on items under ESWG purview.

ACTION ITEM: Staff to include and item on the April meeting agenda to discuss details on the TPITF whitepaper and provide comments as necessary.

Agenda Item 5 – Study Schedules

Agenda Item 5a – 2017 ITP10

Juliano Freitas (SPP Staff) gave an update on the status of the 2017 ITP10. This update focused on the recent determination of the schedule impacts of including additional TPL-001-4 contingencies (beyond P0 and P1) that were approved by the MOPC. Staff proposed current options being considered by the TWG regarding the technical implementation of these events in the reliability needs assessment. Current options range from an additional 8-12 weeks needed to complete the needs assessment. The modified schedule also contains additional time that would be needed to re-perform the constraint assessment, adding 7 weeks, for a total of 15-19 weeks needed in the schedule. This would require that the end of the study be pushed to potentially April or July MOPC/BOD approval. The group discussed the need to re-perform the constraint assessment in order to mitigate some of the additional schedule impacts. It was mentioned that the current market engine may not consider these additional TPL contingencies when determining redispatch after system event and the ITP10 should be consistent with that process. Staff requested that members continue to review the options proposed and supply additional comments. (Attachment 6 – TPL in the 2017 ITP10 Schedule)

ACTION ITEM: Members to supply comments to Staff on TPL impacts to the 2017 ITP10 in preparation for discussion on a future conference call.

Agenda Item 5b – RCAR II

Juliano Freitas (SPP Staff) gave an update on the status of the RCAR II. Staff plans to begin bringing results to the group for consumption at the April face-to-face meeting. (Attachment 7 – RCAR II Schedule)

Agenda Item 6 – SPP-MISO IPSAC Update

Brett Hooton (SPP Staff) gave a report on activities at the latest SPP-MISO IPSAC meeting. There was discussion on performing another joint study starting in 2016. SPP and MISO Staff will be sending out a questionnaire to their respective stakeholders to gather feedback on potential types of transmission issues to evaluate and any suggested improvements to the previous study process.

Agenda Item 7 – RR156 (BP7650 Modifications – DPP Clarification)

Tony Green (SPP Staff) reviewed RR156 which details a request to modify BP7650, specifically relating to the criteria for determining when a project submitted via a DPP is equivalent to a transmission project in a recommended portfolio. The group had several comments and questions on the redlined portion of the “Proposed Revision(s) to SPP Documents” section. The group requested clarification where the changes discuss “similar termination points that are located no more than 1 station (sub-station, switching station, or other station as identified in the SPP Model) away”, noting that the SPP Model does not identify types of stations. While not an approval item for the ESWG, Alan Myers stated that ITC will vote no on this RR in the appropriate groups because of the timing of implementation, clarifying that these changes should be made at the end of an ITP study cycle, not in the middle. Sunflower supported ITC’s comments. (Attachment 8 – RR 156 Recommendation Report 20160218)

Agenda Item 8 – 2017 ITP10 Benchmarking

Nikki Roberts (SPP Staff) reviewed results of the benchmarking effort for the 2017 ITP10. This effort focused on comparisons of the 2017 ITP10 simulation outputs to other data sets such as SPP Operations data, EIA data, and 2015 ITP10 data. The group was generally comfortable with the results and also requested more discussion to include in the report on the factors that are driving the differences in items such as system LMPs and generation capacity factors. (Attachment 9 – 2017ITP10 Benchmarking Update)

Jody Holland (SCMCN) made a motion; seconded by Kurt Stradley (LES) to approve the completion of the Benchmarking milestone of the 2017 ITP10. The motion was approved unanimously.

Agenda Item 9 – SPP Wind Integration Study – NTC Project Acceleration

Jason Tanner (SPP Staff) reviewed recommendation #5 of the SPP Wind Integration Study to accelerate those projects with NTCs that resolve issues identified in the study and can be completed prior to the previously identified need date. Jason discussed the costs of acceleration and the potential benefits realized by accelerating the projects and asked for approval from the group. (Attachment 10 - SPP Wind Integration Study)

Jody Holland (SCMCN) made a motion; seconded by Kurt Stradley (LES) to endorse the Wind Integration Study recommendation #5 to begin accelerating the approved ITP projects with issued NTCs, specifically PID 30843 (Cimarron – Draper 345 kV Terminal Upgrades) and PID 30844 (Amoco – Sundown 230 KV Terminal Upgrades). The motion was approved with two opposed, Al Tamimi (Sunflower) and Jon Iverson (OPPD), and one abstention, Alan Myers (ITC Great Plains).

Alan Myers abstained for the following reason: "I have a lingering concern over how the benefits of the project accelerations were calculated. I don't think the benefit calculations were done in a manner consistent with present SPP practice."

Al Tamimi opposed for the following reason: "I do not think the tariff supports a reevaluation or acceleration of an NTC outside of the ITP process (Business Practice 7160). If we deviate from that, then SPP board must approve the reevaluation before it starts and to allow for accelerated study if not going through the ITP process."

Jon Iverson opposed for the following reason: "

My no vote regarding SPP accelerating certain NTCs out the Wind Integration Study (WIS) is due to the following reasons:

- **There was no indication if firm transmission service has been requested or approved for the wind generators that were causing the need to accelerate the NTC projects**
- **The presentation didn't provide sufficient detail to fully understand the how the benefits were calculated and which zones were receiving the benefits"**

Agenda Item 10 – 2017 ITP10 Study Assumptions

Agenda Item 10a – CPP Considerations

Kelsey Allen (SPP Staff) reviewed the options for reflecting the price of carbon the Future 1 and 2 of the 2017 ITP10. Staff recommended to include a carbon cost in the model for all fossil units as a means to affect dispatch and reflect the cost of carbon in the energy costs of affected EGUs [to be regulated under the CPP]. (Attachment 10 – 2017 ITP10 Analysis Methodology)

Don Le (NextEra) made a motion; seconded by Jody Holland (SCMCN) to approve the Staff recommendation for reflecting the price of carbon in the CPP Futures of the 2017 ITP10. The motion was approved with one abstention, Pat McCool (KCPL).

Agenda Item 10b – Portfolio Consolidation Methodology

[This item was not covered]

Agenda Item 10c – Metrics and Sensitivities

[This item was not covered]

Agenda Item 11 – 2017 ITP10 Economic Model

Liz Gephardt (SPP Staff) gave a brief update on the latest posting of the 2017 ITP10 economic model. Chris Jamieson (SPP Staff) reviewed the carbon prices and emissions outputs of the Future 1 and Future 2 models. Staff had to make adjustments to the 2020 carbon prices and leave some of the external regions/states outside of SPP above their 2020 emissions targets due to the lack of renewables in the external resource plan. (Attachment 12 – 2017 ITP10 Economic Model)

Kurt Stradley (LES) made a motion; seconded by Jody Holland (SCMCN) to approve the 2017 ITP10 economic models as posted on TrueShare with adjustments to 2020 carbon prices for Future 1 and Future 2 detailed in the Economic Model presentation at the 3/17 ESWG meeting, including direction to be given by the ESWG on modeling of carbon costs for APC calculation. The motion was approved with one abstention, Bethany King (EDE).

Bethany King abstained for the following reasons: "

- **The requirements needed to receive an exception for the retirement of a coal unit (Futures 1 and 2) are unclear.**
- **Exceptions have not been allowed for coal units in other aspects to the 2017 ITP10 (Example: No coal units were allowed a Must Run status even when the unit and majority ownership is outside the SPP footprint).**
- **It is EDE's belief the exceptions invalidate the retirement ranking list independently created by SPP staff and previously approved."**

<u>Agenda Item 12 – 2017 ITP10 Scope</u>

[This item was not covered]. (Attachment 13 – 2017 ITP10 Scope) (Attachment 14 – 2017 ITP10 Scope_Draft updates for April MOPC)

<u>Agenda Item 13 – MOPC Action Item 255</u>

Kelsey Allen (SPP Staff) reviewed the strawman proposal for MOPC Action Item 255. The group added a conclusion section and made some suggestions for adjustments to the recommendation section. (Attachment 15 - ESWG MOPC AI 255 Strawman_ESWG redline)

ACTION ITEM: Staff to draft a new recommendation for MOPC Action Item 255 based on member comments and send out for review and email approval.

<u>Agenda Item 14 – 2016 ESWG Meeting Schedule</u>

Kelsey Allen (SPP Staff) reviewed the ESWG Meeting Schedule for the second half of 2016. (Attachment 16 – 2016 ESWG Meeting Schedule)

<u>Closing Items</u>

Chair Alan Myers (ITC Great Plains) requested other items meriting discussion. A conference call will be scheduled the week of March 28th to complete the items on the agenda.

List of action items from the meeting:

1. Staff to include and item on the April meeting agenda to discuss details on the TPITF whitepaper and provide comments as necessary.
2. Members to supply comments to Staff on TPL impacts to the 2017 ITP10 in preparation for discussion on a future conference call.
3. Staff to draft a new recommendation for MOPC Action Item 255 based on member comments and send out for review and email approval.

The meeting was adjourned at 3:00 PM.

Respectfully Submitted,

Kelsey Allen
ESWG Secretary

Southwest Power Pool, Inc.

ECONOMIC STUDIES WORKING GROUP

March 17, 2016

AEP Office/Dallas,TX

• ATTENDANCE LIST •

Name	Company
Michael Massey	AECC
Kurt Stradley	LES
Tim Owens	NPPD
Kip Fox	AEP
Jody Holland	SCMCN
Jason Tanner	SPP
Don Le	NextEra Energy Transmission
Alan Myers	ITC
Bennie Weeks	Xcel/SPS
Wayne Penrod	Sunflower Elec
Cindy Ireland	AR PSC
Tim Soles	OCCIDENTAL
Kelsey Allen	SPP
Juliano Freitas	SPP
Jason Davis	SPP
[illegible]	[illegible]

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Yan Du	ydu@lspower.com
Zac Hager	hagerzc@oge.com

1. **Gayle Nansel (WAPA) proxy to Josie Daggett (WAPA)**

From: Nansel, Gayle [mailto:Nansel@WAPA.GOV]
Sent: Monday, March 14, 2016 10:03 AM
To: Kelsey Allen
Cc: Josephine Daggett WAPA
Subject: FW: ESWG Meeting

Kelsey:

I am not going to be able to attend Thursday's ESWG meeting.

Therefore, I would like to give my proxy to Josie Daggett.

She will be attending via WebEx.

Gayle R. Nansel | Transmission Planning Manager
Western Area Power Administration | Upper Great Plains Region
(O) 406.255.2830 | (M) 406.698.6714 | nansel@wapa.gov

ECONOMIC STUDIES WORKING GROUP

March 17th, 2016

8th Floor AEP Offices – Dallas, TX

• A G E N D A •

1. Administrative items
   - a. Call to Order, Introductions.. Alan Myers (5 minutes)
   - b. Receipt of Proxies .... Kelsey Allen (1 minute)
   - c. Review of Agenda[1] .... Alan Myers (1 minute)

2. Review of Past Action Items[1] .... Kelsey Allen (5 minutes)

3. Consent Agenda[1] (Approval Item).. Alan Myers (5 minutes)
   - a. Approval of Meeting Minutes – February 24th-25th, 2016

4. Transmission Planning Improvement Task Force (TPITF) Update[1] .... Alan Myers (5 minutes)

5. SPP-MISO IPSAC Update.. Brett Hooton (5 minutes)

6. Study Schedules[1] .... Juliano Freitas (20 minutes)
   - a. 2017 ITP10
   - b. RCAR II

7. RR 156 (BP 7650 Modifications – DPP Clarification)[1] .... Tony Green (30 minutes)

8. 2017 ITP10 Benchmarking (Approval Item)[1] .... Nikki Roberts (30 minutes)

~~9.~~1. ~~2017 ITP10 Economic Model (Approval Item)[1] .... Liz Gephardt (30 minutes)~~

~~10.~~9. .... S

PP Wind Integration Study – NTC Project Acceleration (Approval Item)[1]..... Jason Tanner (30 minutes)

~~11.~~1. ~~... M~~

~~OPC Action Item 255 (Approval Item)[1] .... Kelsey Allen (30 minutes)~~

~~12.~~10. 2

017 ITP10 Analysis Methodology (Approval Item)[1] .... Kelsey Allen (60 minutes)
   - a. CPP Considerations
   - b. Portfolio Consolidation Methodology
   - c. Metrics and Sensitivities

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[1] Background Material Included

11. 2017 ITP10 Economic Model (Approval Item)[1] .... Liz Gephardt (30 minutes)

~~13.~~12. 2

017 ITP10 Scope (Approval Item)[1] .... Kelsey Allen (30 minutes)

13. MOPC Action Item 255 (Approval Item)[1] .... Kelsey Allen (30 minutes)

14. 2016 ESWG Meeting Schedule[1] .... Kelsey Allen (15 minutes)

15. Closing Items .... All (5 minutes)

   a. Summary of Action Items (Kelsey Allen)
   b. Future Meetings
      i. April 21st, 2016: OGE Offices, Oklahoma City, OK
      ii. May 18th-19th, 2016: ~~TBD~~Embassy Suites, Omaha, NE
      iii. June 16th, 2016: 8th Floor AEP Offices, Dallas, TX

Southwest Power Pool, Inc.

ECONOMIC STUDIES WORKING GROUP

Pending Action Items Status Report

March 17th, 2016

	Action Item	Date Originated	Status	Comments
057	SPP staff will write a straw-man procedure or portion of the ITP manual that deals with conventional and wind generation planning and siting within the ITP process. The process should be in place by the Spring of 2015.	August 23rd, 2012	In Progress Staff	In preparation for scope standardization being proposed by the TPITF, a draft whitepaper will be completed for review mid-2016.
151	Staff to look into optional software tools for use in ITP studies.	May 20th, 2015	In Progress Staff	Staff is meeting with software vendors and users and expects to have a recommendation on any potential software changes by 4th quarter 2016.
153	MOPC action item 255: Review the method to determine the cost of congestion, as it relates to outages for rebuilds approved.	July 9th, 2015	In Progress ESWG	September 23rd: ERCOT does not include this cost in their analysis of transmission projects. January 21st: this item will be discussed with MOPC recommendation expected for their April meeting. February 24th: Staff develop a strawman recommendation for MOPC to be considered in March.
160	SPP Staff and the ESWG are to formalize standard procedures for data requests and member review of information related to ITP studies.	January 21st, 2016	In Progress Staff/ESWG	Combined item representative of AI148 and AI149.
161	Staff to report on carbon emissions as the 2017 ITP10 study moves forward through the different milestones.	February 24th-25th, 2016	In Progress Staff	
162	Staff to identify the schedule impact of calculating final benefit metrics on	February 24th-25th,	~~In Progress~~Com	Adequate time in schedule for 2 portfolios.

	multiple project portfolios.	2016	plete Staff	
163	Staff to review the benefit calculations performed in the SPP Wind Integration Study and report on benefits and cost to accelerate approved transmission projects at a future meeting.	February 24^{th}-25^{th}, 2016	~~In Progress~~Complete Staff	
~~164~~	~~Staff to develop a strawman recommendation for MOPC [on MOPC Action Item 255] to be considered by the ESWG in March.~~	~~February 24^{th}-25^{th}, 2016~~	~~In Progress~~ ~~Staff~~	

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

February 24th – 25th, 2016

Crowne Plaza Downtown, Kansas City, MO

• SUMMARY OF ACTIONS TAKEN •

1. None

Southwest Power Pool

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

February 24th – 25th, 2016

Crowne Plaza Downtown, Kansas City, MO

• MINUTES •

Agenda Item 1 – Administrative Items

Agenda Item 1a - Call to Order, Introductions

Chair Alan Myers (ITC Great Plains) called the meeting of the Economic Studies Working Group (ESWG) to order at 1:00 PM, welcomed those in attendance, and asked for introductions.

There were 41 in-person participants and 30 web conference participants, representing 16 of 16 ESWG members. (Attachment 1 – February 24th-25th, 2016 Attendance List)

Agenda Item 1b – Receipt of Proxies

Alan Myers (ITC Great Plains) asked for any proxy statements. Two proxies were identified; Leon Howell (OGE) named Zac Hager (OGE) as his proxy and Jon Iverson (OPPD) named Kurt Stradley (LES) as his proxy beginning 11:00am, February 25th. (Attachment 2 – Proxy Statements)

Agenda Item 1c – Review of Agenda

Chair Alan Myers (ITC Great Plains) presented the agenda for review and asked for any additions or corrections. Staff requested to move the 2017 ITP10 Analysis Methodology agenda item to the first day. (Attachment 3 – February 24th-25th, 2016 Agenda)

Natasha Henderson (GSEC) made a motion; seconded by Bethany King (EDE) to adopt the agenda as modified. The motion was approved unanimously.

Agenda Item 2 – Review of Past Action Items

Kelsey Allen (SPP Staff) reviewed the list of past action items. (Attachment 4 – Past Action Items)

Agenda Item 3 – Consent Agenda

The consent agenda included the following items:

Meetings Minutes – January 21st, 2016 (Attachment 5 – ESWG 01.21.16 Minutes)

Alan Myers (ITC Great Plains) asked if any items should be removed from the consent agenda.

The consent agenda was approved unanimously.

Agenda Item 4 – Transmission Planning Improvement Task Force (TPITF) Update

Antoine Lucas (SPP Staff) gave an update on the activities of the TPITF and reviewed the details of the model development strawman proposed by the group. The proposal includes removal of the ITP20 from the traditional planning cycle, developing a common model to be used for all planning processes, combination of the ITPNT, ITP10 and TPL processes into a single 10-year study, increased standardization of study scopes, and increased accountability for Members and Staff. Al Tamimi (Sunflower) expressed concern about potential loss of strategic direction by removing the ITP20 from the normal process. The task force envisions the ITP20 to be performed every 5 years or as directed by the Board. Tim Owens (NPPD) expressed concern over the sustainability of overlapping the model development and assessment cycles. The task force plans to bring recommendations to MOPC and the Board in April with approval/endorsement in July. (Attachment 6 – ESWG 2-24-2016 TPITF Update_rev) (Attachment 7 – TPITF_ITP_Model_Development_Strawman)

Agenda Item 5 – Study Schedules

Agenda Item 5a – 2017 ITP10

Juliano Freitas (SPP Staff) gave an update on the status of the 2017 ITP10. (Attachment 8 – 2017 ITP10 Schedule)

Agenda Item 5b – RCAR II

Juliano Freitas (SPP Staff) gave an update on the status of the RCAR II. (Attachment 9 – RCAR II Schedule)

Agenda Item 6 – 2017 ITP10 Study Assumptions

Agenda Item 6a – CPP Considerations

Kelsey Allen (SPP Staff) presented Staff's considerations regarding carbon price modeling techniques and monitoring of emissions for the CPP futures. Staff recommends reflecting the cost of carbon in the energy costs of generators regulated under the CPP rule and utilizing a carbon cost to affect dispatch but not impact energy prices for generators not regulated under the CPP, as a proxy for other potential fuel and environmental constraints not considered in the modeling that may limit operation of those units. Some members expressed concern with reflecting the cost of carbon in energy prices at all; other members expressed concern with limiting the dispatch of generators unaffected by the CPP through the use of carbon pricing.

Kelsey then reviewed discussion that began at the January meeting regarding the monitoring of emissions throughout the study process. Staff recommends that all input decisions regarding the control of emissions should be set as a function of the resource planning phase. In order to accomplish this, carbon pricing has been set in an copper sheet transmission model (unconstrained), ensuring each future is meeting its carbon emission targets. Staff proposed multiple options to handle the changes in emissions moving forward in the process after inclusion of transmission constraints as well as the development of transmission plans. After discussion and a straw poll vote, the group favored the option of developing a transmission plan following normal processes expected to facilitate a reduction in carbon emissions (reliability, economic and policy assessments) with an additional informational assessment to determine any incremental upgrades necessary to ensure compliance with emission targets within each future. (Attachment 10 – 2017 ITP10 CPP Considerations)

Agenda Item 6b – Portfolio Consolidation Methodology

Kelsey Allen (SPP Staff) reviewed the previous discussions on portfolio consolidation methodology and offered a Staff proposal for discussion. The group is divided on the relative influence each future should have on a final recommended transmission plan. Stakeholders generally agree that carbon emissions are reducing regardless of the CPP but with the uncertainty surrounding the rule, some members expressed concern supporting a plan developed utilizing CPP futures. Other members argued that the study should continue forward with the original intent and factor in results of the CPP implementation. Other members suggested that any final recommended plan will likely not meet CPP compliance, but will facilitate a reduction in emissions. Regardless of the CPP, the group needs to decide the most prudent way to perform the analysis and describe the resulting plan in that context. After much discussion, the group favored the development of two plans for consideration, a consolidated CPP portfolio and a reference case portfolio. The group requested that Staff investigate the schedule impacts of calculated final benefit metrics on two project portfolios. (Attachment 11 – 2017 ITP10 Portfolio Consolidation)

ACTION ITEM: Staff to report on carbon emissions as the 2017 ITP10 study moves forward through the different milestones.

ACTION ITEM: Staff to identify the schedule impact of calculating final benefit metrics on multiple project portfolios.

Agenda Item 6c – Project Selection Methodology

Kelsey Allen (SPP Staff) reviewed the criteria that will be used for economic project selection. The group agreed with the approach. (Attachment 12 – 2017 ITP10 Project Selection.Grouping)

Agenda Item 6d – Project Grouping Methodology

Kelsey Allen (SPP Staff) reviewed the January discussion on project grouping methodology and proposed an approach to move forward with. The group agreed with the approach. (Attachment 12 – 2017 ITP10 Project Selection.Grouping)

Agenda Item 7 – SPP Wind Integration Study

Jason Tanner (SPP Staff) reviewed the process steps and inputs to the SPP Wind Integration study performed by SPP Operations. Jason then presented recommendations of the study, including formation of a new task force to modify and develop voltage criteria for SPP and acceleration of approved transmission projects to address issues seen in the analysis. The study implemented two methodologies to proxy the benefits of accelerating transmission; by calculating APC savings for the studied hour snapshot and extrapolating those benefits over the course of the year by targeting similar historical wind penetration levels and simply assuming that benefit every hour over the course of the year. The cost to accelerate the approved transmission projects has not yet been quantified. The group expressed some concern over the tools used to perform the economic analysis (PowerGem TARA) and the methodology used to calculate benefits. The group requested that SPP Operations Staff consult with Economic Planning Staff and be prepared to bring back other takes on the benefit calculations as well as the cost of accelerating the projects to a future meeting. (Attachment 13 - SPP Wind Integration Study)

ACTION ITEM: Staff to review the benefit calculations performed in the SPP Wind Integration Study and report on benefits and cost to accelerate approved transmission projects at a future meeting.

Agenda Item 8 – MOPC Action Item 255

Kelsey Allen (SPP Staff) reviewed a proposal to incorporate the cost of congestion due to outages of potential transmission rebuild solutions into the project analysis process. Staff concluded that the analysis results are very situational and due to the limitations of the constraint assessment, the results are likely understated. The group discussed the selective nature of implementing this methodology, pointing to other approved benefit metrics that are not being incorporated in the project selection process and likely have a much greater impact on the results, recognizing that it is not feasible to include all benefit analysis at this phase. Alan Myers (ITC Great Plains) suggested that this should be considered selectively, proposing two options; recommending this generally not be implemented and allowing Staff the discretion to consider these impacts or, due to the wide variability and applicability, recommending more time be spent to determine a methodology to selectively apply the analysis in order to avoid performing it for every rebuild solution proposed. (Attachment 14 - MOPC Action Item 255)

ACTION ITEM: Staff to develop a strawman recommendation for MOPC [on MOPC Action Item 255] to be considered by the ESWG in March.

Agenda Item 9 – RCAR II Update

Juliano Freitas (SPP Staff) gave a brief update of the activities of the RCARII study, detailing current work, upcoming work, and what is expected to be ready for stakeholder review in the coming months. Wayman Smith (AEP) reminded the group of the need to overhaul the RCAR process and asked when it is expected that this work will take place. The RARTF is aware of the larger issue but suggested that the interim fixes are not unreasonable enough to halt the RCAR II process, suggesting that the process be investigated in detail beginning in August, following completion of the RCAR II analysis. (Attachment 15 – RCAR II Update)

Agenda Item 10 – 2017 ITP10 Benchmarking Update

Nikki Roberts (SPP Staff) reviewed the benchmarking process for the 2017 ITP10 and presented preliminary results. Staff requested that the members continue to review the results presented and contact the economic planning team with any questions or comments on the data. Benchmarking is expected to be complete March 10th for approval at the March 17th meeting. (Attachment 16 – 2017ITP10 Benchmarking Update)

Agenda Item 11 – 2017 ITP10 Constraint Assessment Update

Clayton Mayfield (SPP Staff) reviewed the constraint assessment methodology for the 2015 ITP10 and detailed the adjustments made for the 2017 ITP10. The constraint assessment is expected to be complete March 3rd for approval by the TWG on March 17th. (Attachment 17 – 2017 ITP10 Constraint Assessment)

<u>Closing Items</u>

Chair Alan Myers (ITC Great Plains) requested other items meriting discussion.

List of action items from the meeting:

1. Staff to report on carbon emissions as the 2017 ITP10 study moves forward through the different milestones.
2. Staff to identify the schedule impact of calculating final benefit metrics on multiple project portfolios.
3. Staff to review the benefit calculations performed in the SPP Wind Integration Study and report on benefits and cost to accelerate approved transmission projects at a future meeting.
4. Staff to develop a strawman recommendation for MOPC [on MOPC Action Item 255] to be considered by the ESWG in March.

The meeting was adjourned at 12:00 PM.

Respectfully Submitted,

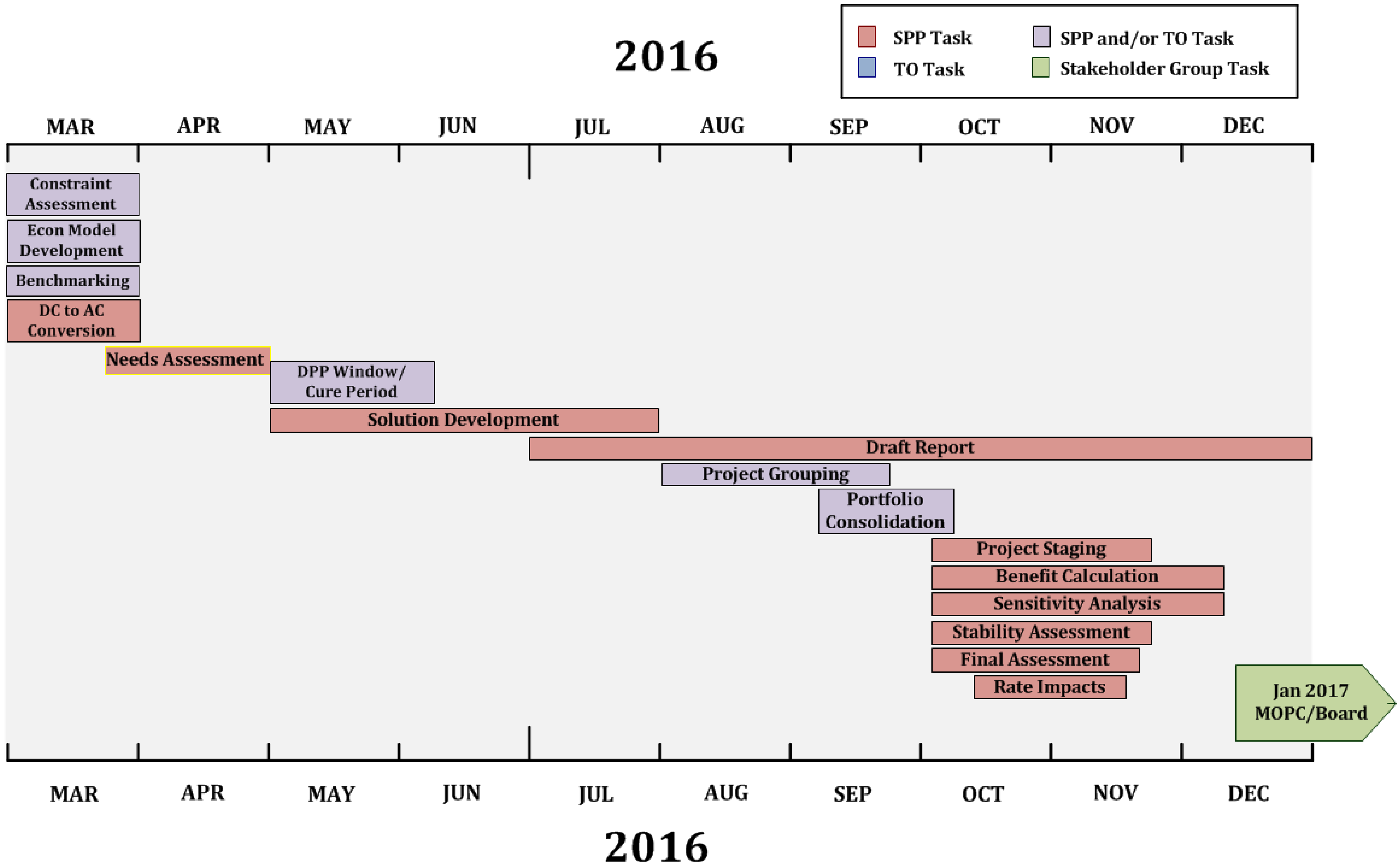
Kelsey Allen
ESWG Secretary

TPL in the 2017 ITP10

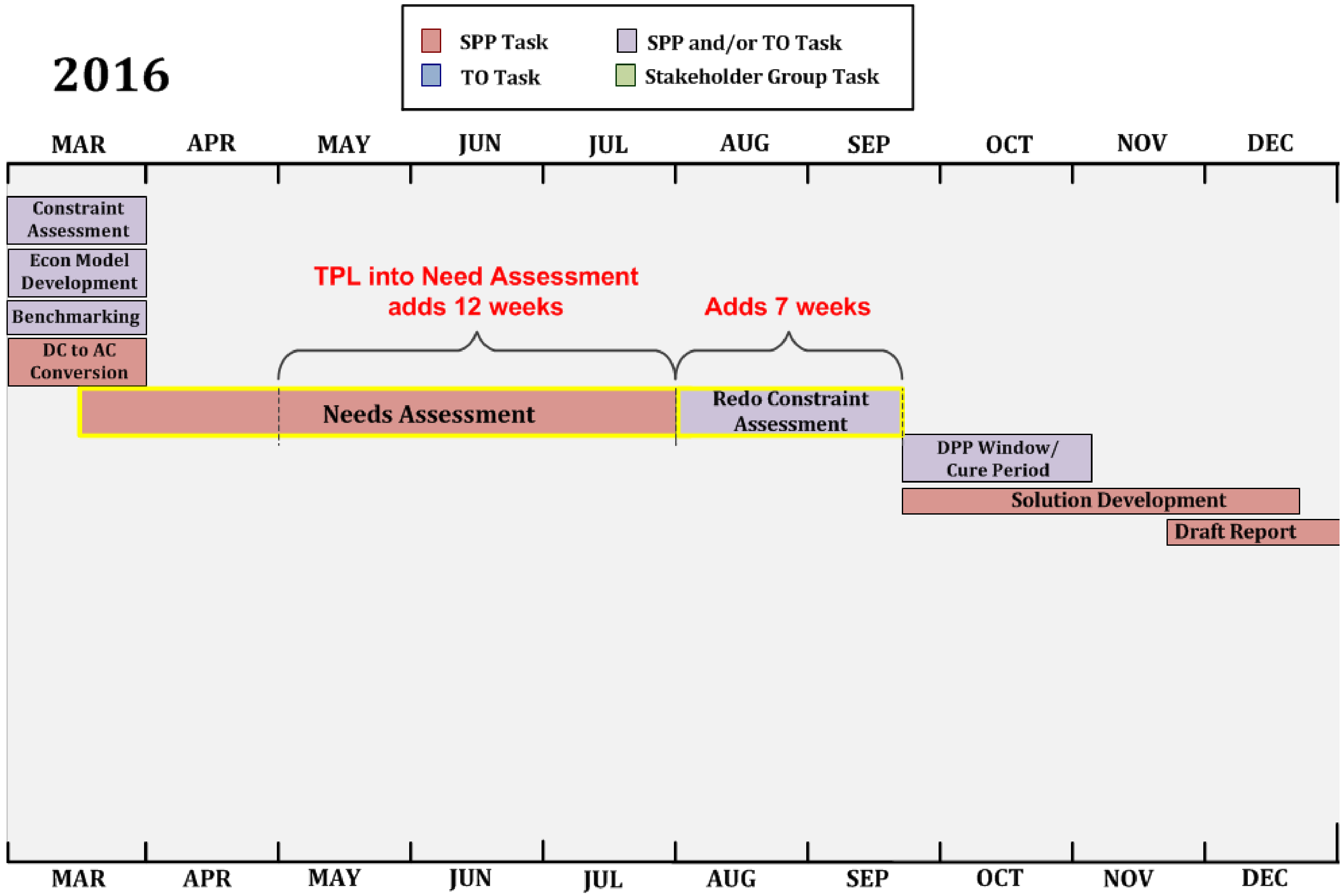
ESWG

March 17th, 2016

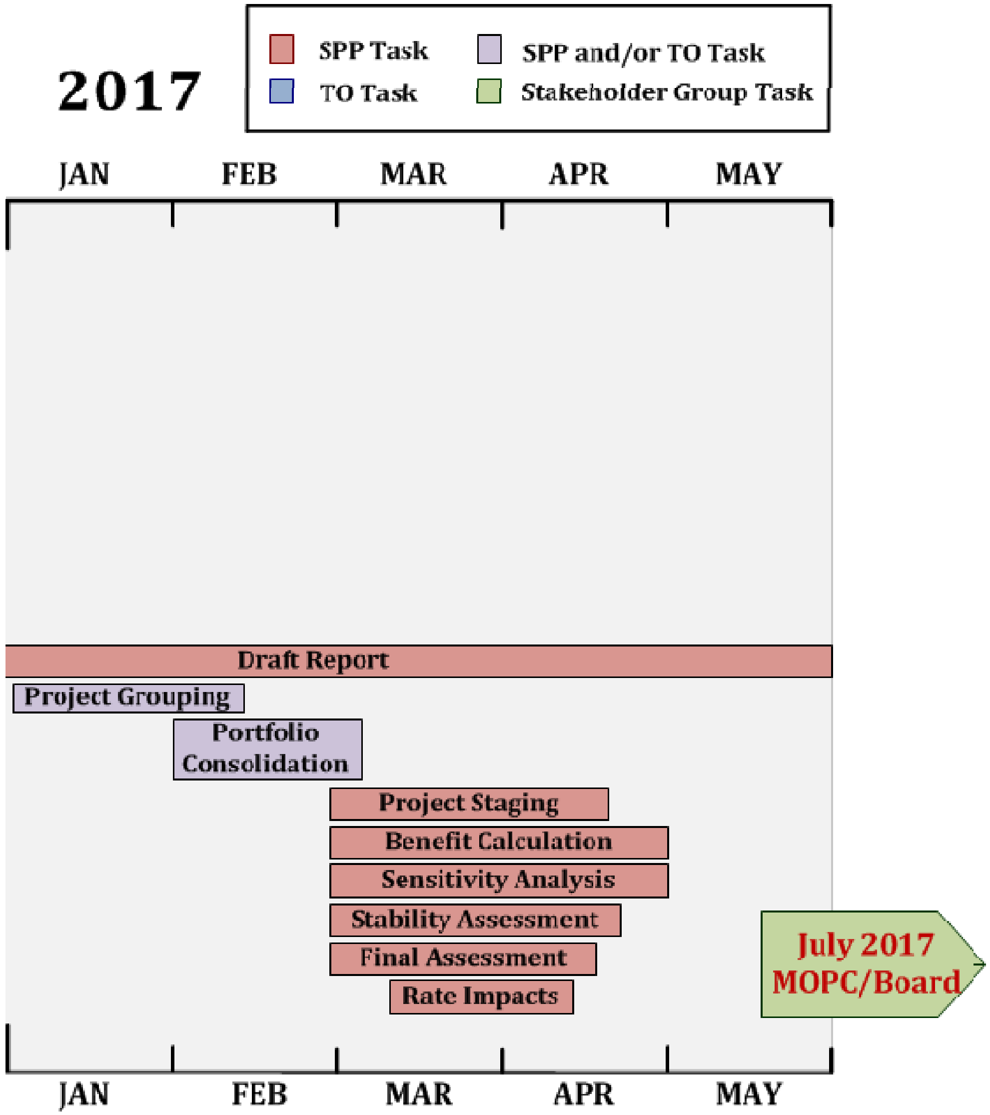
Current 2017 ITP10 Timeline



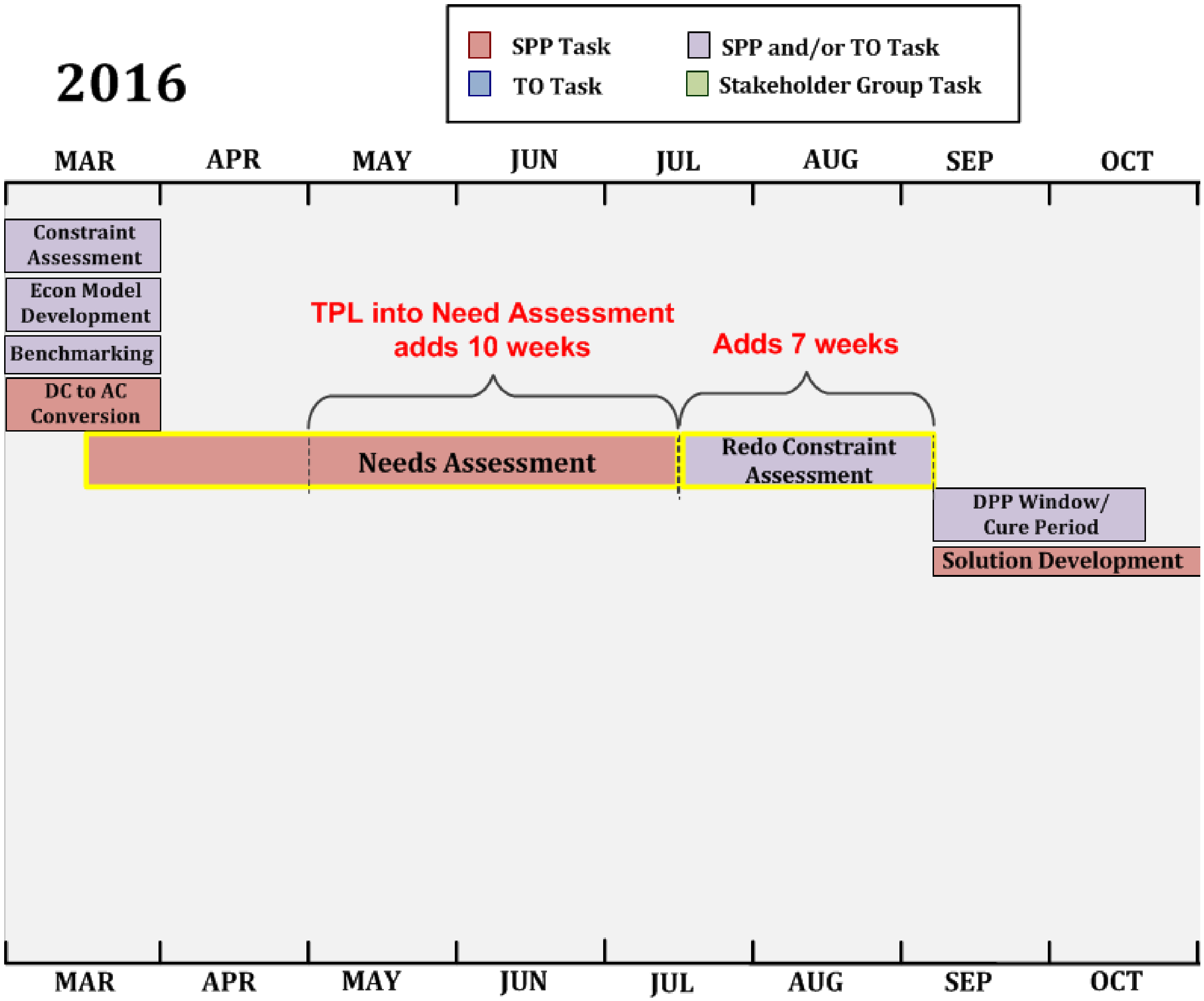
TPL Impact utilizing Proposal for February TWG meeting for 2017 ITP10



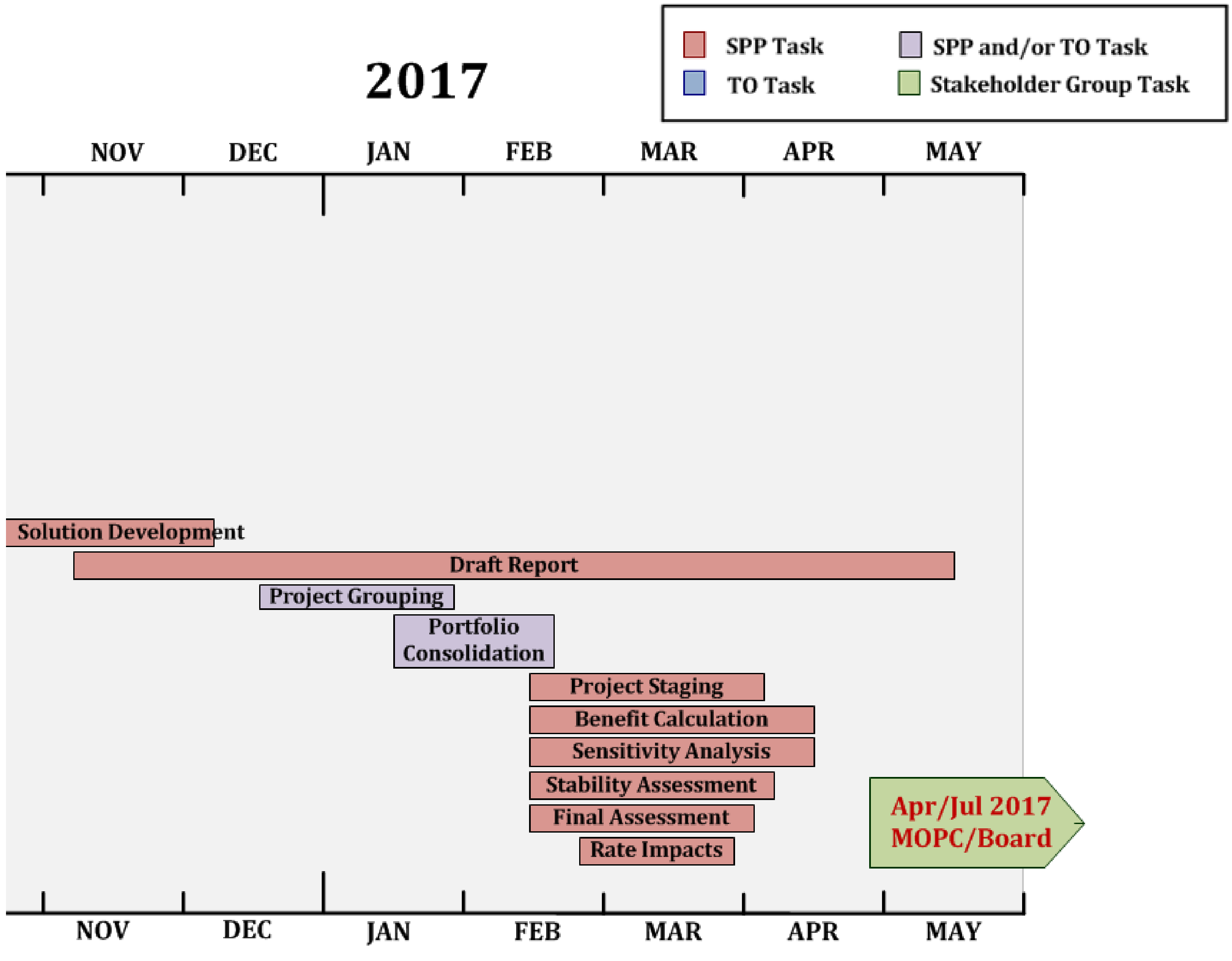
TPL Impact utilizing Proposal for February TWG meeting for 2017 ITP10



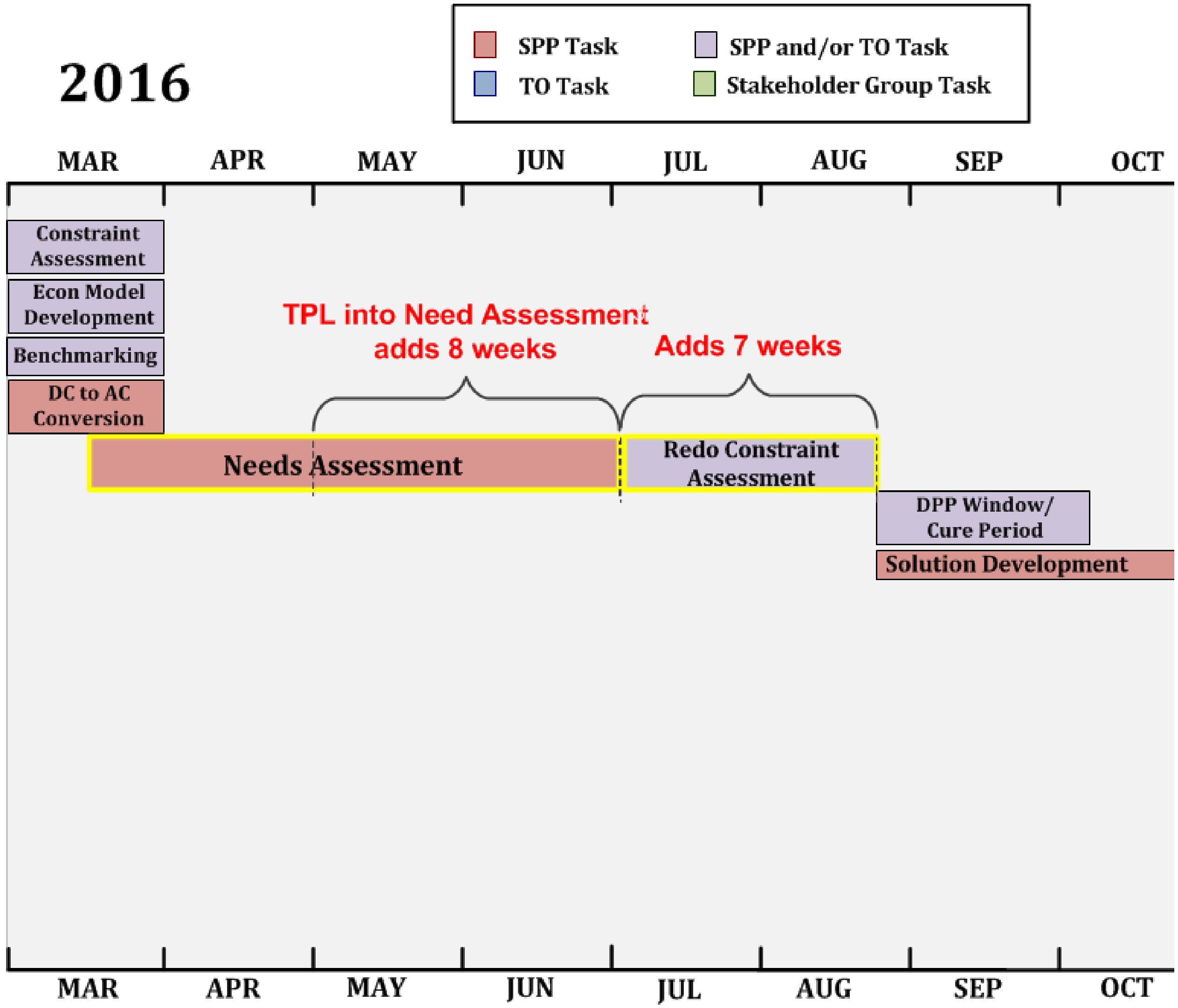
TPL Impact utilizing GSF to reduce the number of P3 events



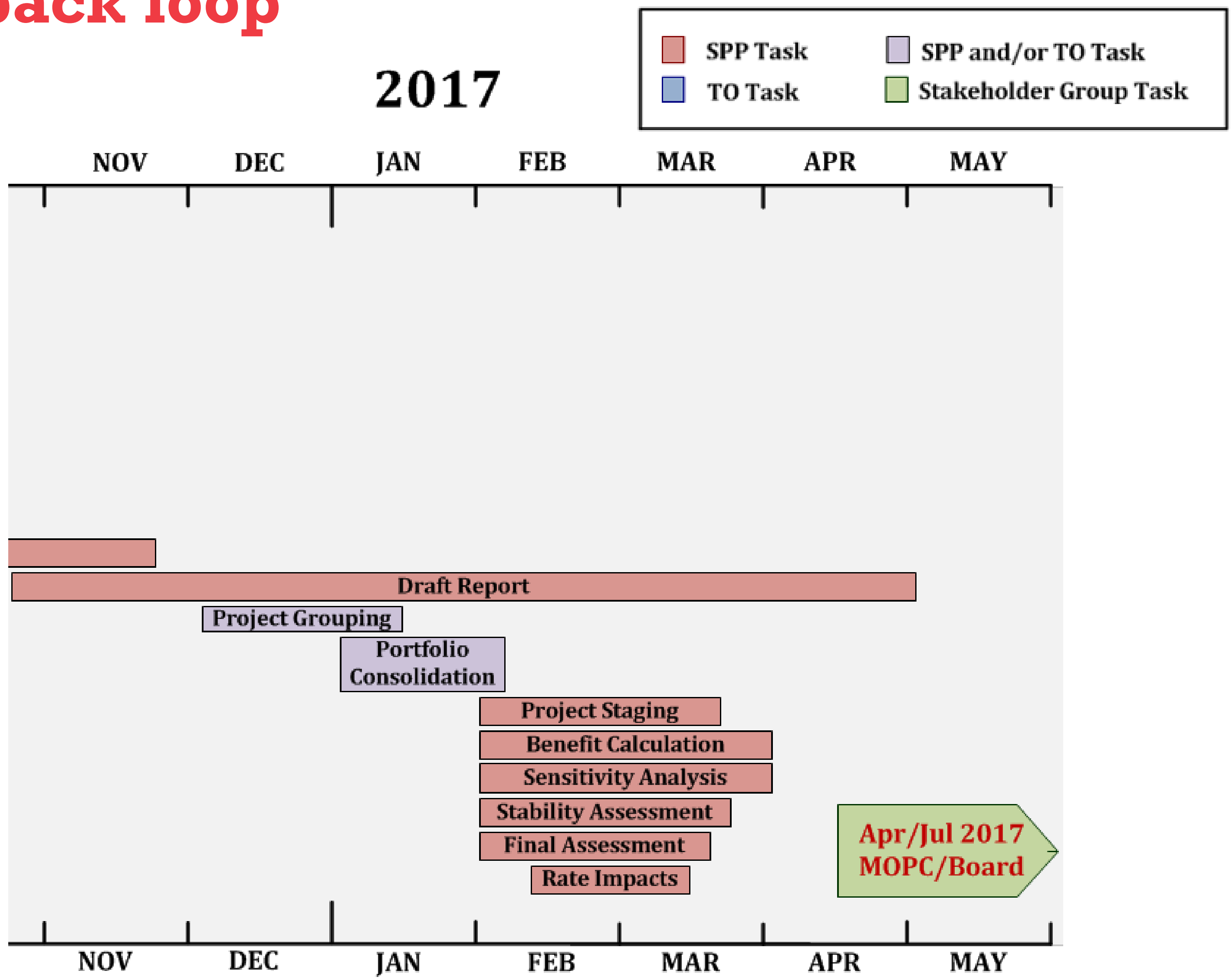
TPL Impact utilizing GSF to reduce the number of P3 events



TPL Impact utilizing GSF to reduce the number of P3 events and OPM to reduce Feedback loop



TPL Impact utilizing GSF to reduce the number of P3 events and OPM to reduce Feedback loop



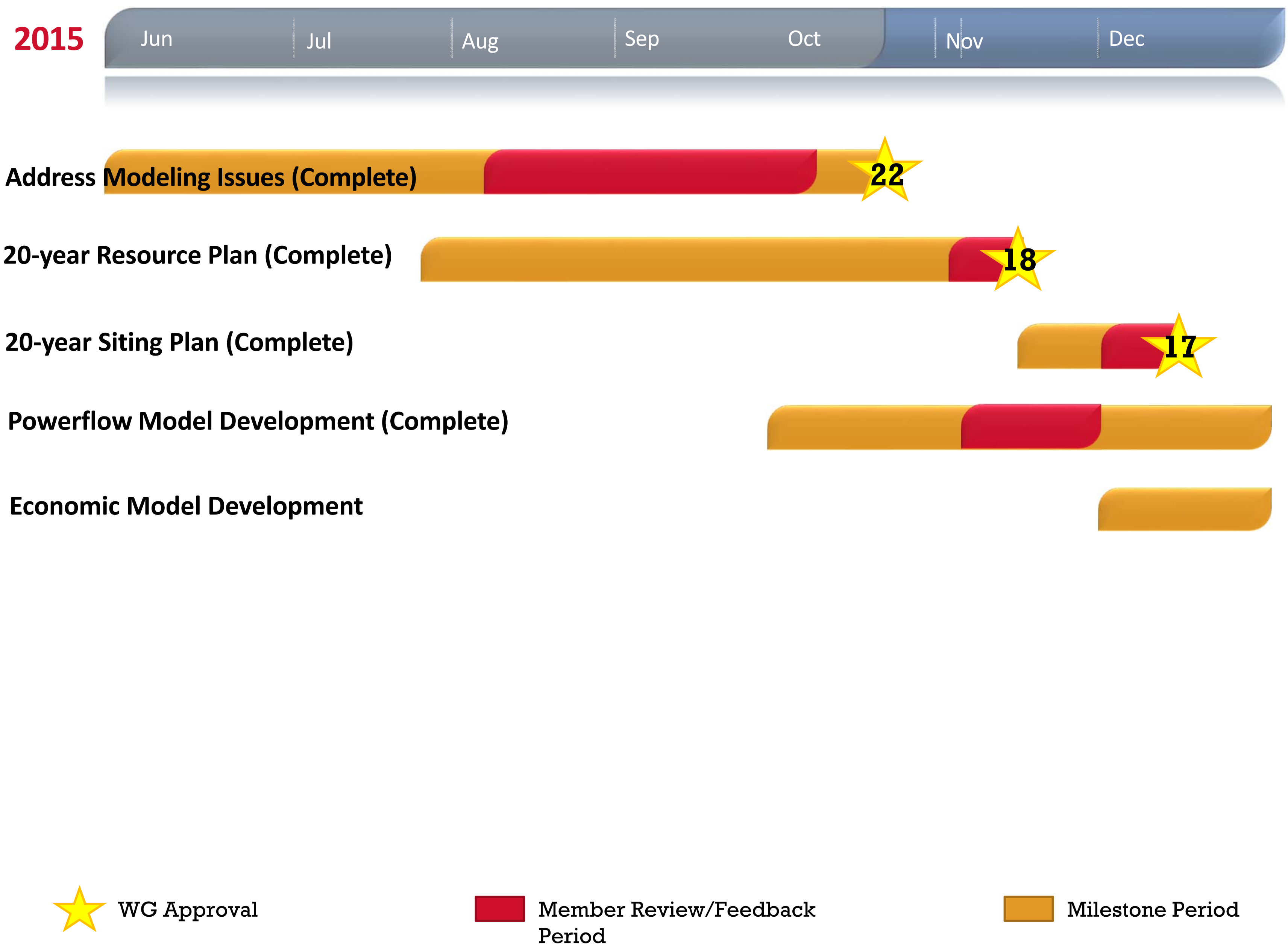
Potential Downstream Impacts

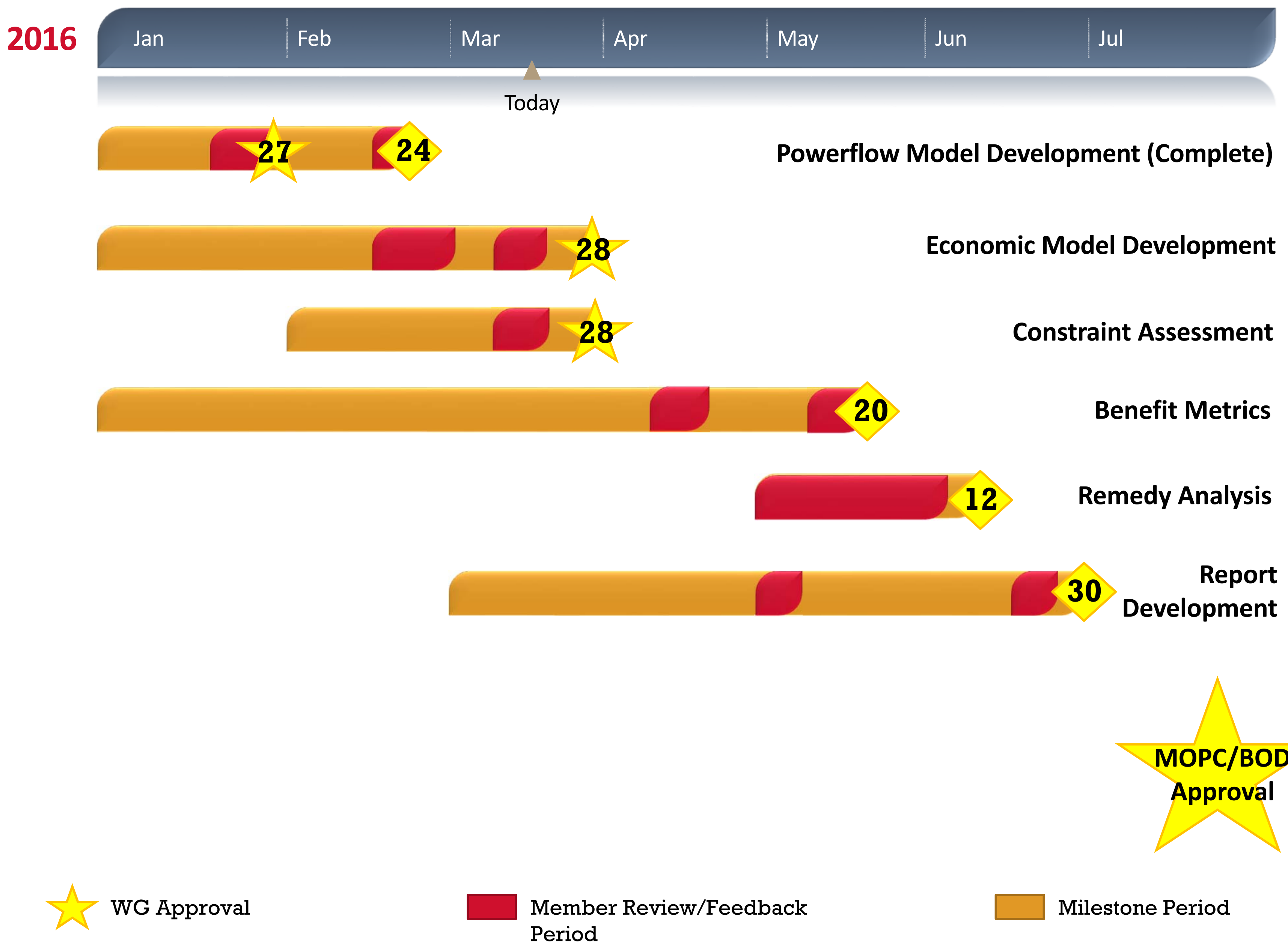
- Additional processing time:
  - Needs
  - Reliability Metric calculation
  - Solution development
  - Study Cost Estimates
  - Portfolio Consolidation
  - Reliability Assessment

RCAR II Schedule

ESWG

March 17, 2016


2015
Jun
Jul
Aug
Sep
Oct
Nov
Dec
2015
Address Modeling Issues (Complete)
22
20-year Resource Plan (Complete)
18
20-year Siting Plan (Complete)
17
Powerflow Model Development (Complete)
Economic Model Development
WG Approval
Member Review/Feedback Period
Milestone Period


2016
Jan
Feb
Mar
Apr
May
Jun
Jul
2016
Today
27
24
Powerflow Model Development (Complete)
28
Economic Model Development
28
Constraint Assessment
20
Benefit Metrics
12
Remedy Analysis
30
Report Development
MOPC/BOD Approval
WG Approval
Member Review/Feedback Period
Milestone Period

RCAR II Milestone Schedule Summary

Task Name	Start	Finish	Review Period	Feedback Cutoff	End of Milestone
Address Modeling Issues	**April '15**	**October '15**	Multiple Reviews	10/15/15	10/22/15
20-year Resource Plan	**July '15**	**November '15**	11/02/15 – 11/09/15	11/09/15	11/18/15
20-year Siting Plan	**October '15**	**December '15**	11/12/15 - 12/10/15	12/10/15	12/17/15
Powerflow Model Development	**October '15**	**February '16**	Multiple Reviews	1/20/16	2/16/16
Economic Model Development	**November '15**	**March '16**	02/16/16 – 03/01/16, 03/11/16 – 03/15/16	03/01/16, 03/15/16	03/15/16
Constraint Assessment	**February '16**	**March '16**	03/11/16 – 03/18/16	03/18/16	03/28/16
Benefit Metrics	**January '16**	**April '16**	April, May '16		05/20/16
Remedy Analysis	**May '16**	**June '16**	May, June '16		06/12/16
Report Development	**March '16**	**June '16**	May, June '16		06/30/16
Study Concludes		**July '16**			Late July, 2016

Note: Most review period dates are subject to change based on future WG meeting schedules.

RCAR II Summary

- Current work
  - Constraint Assessment
  - Finalizing Economic Model
  - Powerflow-based Metrics

- Upcoming work
  - Economic-based Metrics
  - Verification of metric results
  - Presentation of metric results

- Staff will be presenting metric results at April and May ESWG meetings

Revision Request Recommendation Report

RR #: 156	Date: 2/12/2016
RR Title: Modification to Business Practice 7650 DPP clarification	

SUBMITTER INFORMATION	
Submitter Name: Tony Green	**Company:** SPP
Email: tgreen@spp.org	**Phone:** 501-688-1789
EXECUTIVE SUMMARY AND RECOMMENDATION FOR MOPC AND BOD ACTION	
OBJECTIVE OF REVISION	

Objectives of Revision Request:
This will clarify the steps taken in determining which Detailed Project Proposals (DPP) may be equivalent to transmission projects selected within a portfolio eligible for the Transmission Owner Selection Process.

The changes to the DPP Selection Criteria will further enhance SPP's ability to efficiently and accurately execute the DPP Process within the required timelines of the Integrate Transmission Planning (ITP) studies.

SPP STAFF ASSESSMENT

IMPACT

Will the revision result in system changes ☒ **No** ☐ **Yes**

Summarize changes:

Will the revision result in process changes? ☒ **No** ☐ **Yes**

Summarize changes:

Is an Impact Assessment required? ☒ **No** ☐ **Yes**

If no, explain:

Estimated Cost: $	**Estimated Duration:** months
Primary Working Group Score/Priority:	

SPP DOCUMENTS IMPACTED

☐ **Market Protocols**	**Protocol Section(s):**	**Protocol Version:**
☐ **Operating Criteria**	**Criteria Section(s):**	**Criteria Date:**
☐ **Planning Criteria**	**Criteria Section(s):**	**Criteria Date:**
☐ **Tariff**	**Tariff Section(s):**	
☒ **Business Practice**	**Business Practice Number:** 7650	

WORKING GROUP REVIEWS AND RECOMMENDATIONS List Primary and any Secondary/Impacted WG Recommendations as appropriate	
Primary Working Group: **BPWG**	**Date: 2/18/2016** **Action Taken: Approved** **Abstained:** **Opposed: ITC Great Plains**
Reasons for Opposition: ITC opposed the Motion to approve the RR, stating that while they supported the changes being made, they could not support the changing of the process once it had already begun, in effect, "changing the process mid-stream."	
Secondary Working Group: **CTPTF**	**Date: 2/12/2016** **Action Taken: Approved** **Abstained: None** **Opposed: One**
Reasons for Opposition: ITC opposed the Motion to approve the RR, stating that while they supported the changes being made, they could not support the changing of the process once it had already begun, in effect, "changing the process mid-stream."	
Secondary Working Group:	**Date:** **Action Taken:** **Abstained:** **Opposed:**
Reasons for Opposition:	
Secondary Working Group:	**Date:** **Action Taken:** **Abstained:** **Opposed:**
Reasons for Opposition:	
MOPC	**Date:** **Action Taken:** **Abstained:** **Opposed:**
Reasons for Opposition:	

BOD/Member Committee	**Date:** **Action Taken:** **Abstained:** **Opposed:**
Reasons for Opposition:	
COMMENTS	
Comment Author:	
Date Comments Submitted:	
Description of Comments:	
Status:	
PROPOSED REVISION(S) TO SPP DOCUMENTS	
Market Protocols	

Tariff (OATT)

SPP Operating Criteria

SPP Planning Criteria

SPP Business Practices

7650 Order 1000: Detailed Project Proposal

Business Practice:

The purpose of this Business Practice is to describe the process for submission and treatment of a Detailed Project Proposal ("DPP") during the Integrated Transmission Planning ("ITP") study process as outlined in Attachment O of the SPP Tariff. After the applicable ITP study scope has been approved, and the needs assessment has been performed, SPP staff shall notify stakeholders of the identified transmission needs and provide a transmission planning response window of thirty (30) days during which any stakeholder may submit a DPP. The information supplied by the stakeholder in the DPP must be sufficient to allow SPP staff to evaluate the project described by the DPP pursuant to Section III.8.b of Attachment O of the Tariff.

If the project described in a DPP is selected and approved for construction as a Competitive Upgrade, the submitting stakeholder may be eligible to receive incentive points pursuant to the eligibility requirements described in Section III.2.f.iv of Attachment Y of the Tariff.

Notification of Open Window for DPP Submittal

SPP will provide notification via the SPP website and email exploder when transmission needs have been posted for a specific ITP study and post the 30-day response window when a stakeholder may submit a DPP. Requirements for the submission of a DPP are contained in Section III.8.b of Attachment O of the Tariff.

DPP Submittal

To propose a DPP, stakeholder(s), hereinafter referred to as "Submitter," shall submit the necessary information to SPP via the Request Management System (RMS). The necessary information must be submitted within the prescribed 30-day transmission planning response window in order to qualify as a DPP. The information required for a DPP submittal is included in the DPP Submittal Form that is found in Exhibit A. The DPP Submittal Form must be used when submitting the DPP to SPP staff.

DPP Receipt and Response

Upon receipt of the DPP submittal, SPP will verify that the DPP was received within the 30-day DPP transmission planning response window, based on the time and date stamp in the RMS of such submittal, and verify that the submittal is complete. If a DPP submittal is received outside of the 30-day transmission planning response window, SPP staff will notify the Submitter via email that its submittal does not qualify for incentive points.

Notification to Submitter of an Incomplete DPP

If SPP staff determines a DPP Submittal Form is incomplete, SPP staff will notify the Submitter via email. The notification will be sent to the Submitter no later than 10 business days after the close of the transmission planning response window.

The Submitter is permitted to remedy the deficiencies by the latest date of the following (cure period):

- The end of the transmission planning response window; or
- 10 business days after SPP issues the notification using the date stamp of the issued email.

If the missing information is not received within the required timeframe, or if the DPP is still incomplete at the end of the cure period, the proposed project will not qualify as a DPP and will not be eligible to receive incentive points if the project is ultimately approved for construction during that ITP. SPP will notify the Submitter that DPP submittal is disqualified from consideration for incentive points.

Notification to Submitter of Accepted or Disqualified DPP

SPP will notify the Submitter via email of the acceptance or the disqualification of its DPP. A stakeholder that submits a DPP Submittal Form that is equivalent to a DPP or a Transmission Provider identified project in a previous ITP assessment during the current three-year ITP planning cycle shall not be eligible for incentive points unless the stakeholder is the original Submitter. SPP retains the right to use the suggested project in its planning process even if the submitter of the project does not qualify for incentive points.

Cost Estimates for DPP Projects

It is not a requirement that a DPP include a transmission cost estimate. Cost estimates will be developed throughout the study process. The development of the cost estimate will be the responsibility of SPP. The cost estimate included at the time of project approval by the SPP Board of Directors will be at a +/-30% level of confidence.

DPP Selection

SPP staff will use the following criteria to determine when a project submitted via a DPP is ~~the~~ equivalent to~~same as~~ a transmission project in the recommended portfolio:

- The project submitted via a DPP must solve at least the same needs as the selected transmission project;
- ~~•~~The project submitted via a DPP must have the same ~~T~~transmission line voltage as the selected transmission project~~ (same)~~;
- The project submitted via a DPP must have the same or similar[99] ~~•T~~termination points including transformers as the selected transmission project~~(same or similar)~~ ~~[99]~~;
- The project submitted via a DPP must have an
- ~~•E~~equipment rating in MVA within +50% of lines and transformers as the selected transmission project~~ in MVA (within +50%)~~;
- The project submitted via a DPP must have an impedance within
- ~~•Impedance (within~~ +/-25% of the selected transmission project~~)~~; and
- The project submitted via a DPP ~~•Viability: D~~does not create additional reliability issues not already addressed~~ and solves the same needs as the selected transmission project~~.

Selection Notification

After the SPP Board of Directors approves an ITP portfolio of projects, SPP staff will notify each of the Submitters in writing whether or not it~~'~~s DPP was approved for construction by the SPP Board of Directors where the Transmission Owner will be selected utilizing the Transmission Owner Selection Process as described in Attachment Y of the Tariff. Concurrent with written notification to each of the Submitters, SPP Staff will post on the SPP website the names of the approved ITP Portfolio of projects that has associated DPPs pursuant to the Transmission Owner Selection Process as described in Attachment Y of the Tariff.

99 Similar termination points determined if they are located no more than 1 ~~bus Physical~~ station (sub-station, switching station, or other station as identified in the SPP Model) away ~~and~~ or within 15 linear miles from the~~a~~ Board approved project.

2017 ITP10 Benchmarking

Nikki Roberts

2017 ITP10 Benchmarking Process

1. Develop "Model QA Checklist" that outlines what outputs need to be compared/verified between historical data and current ITP10 model(s)
2. Gather historical statistics and measurements
3. Make all necessary PROMOD runs for comparison and assessment
4. Compare 2017 ITP10 Future 3(BAU) model to historical data and 2015 ITP10 Future 1 (BAU) following the "Model QA Checklist".
5. Validate 2017 ITP10 CPP Futures following the "Model QA Checklist".

5. Adjust inputs if needed for reasonable model behavior

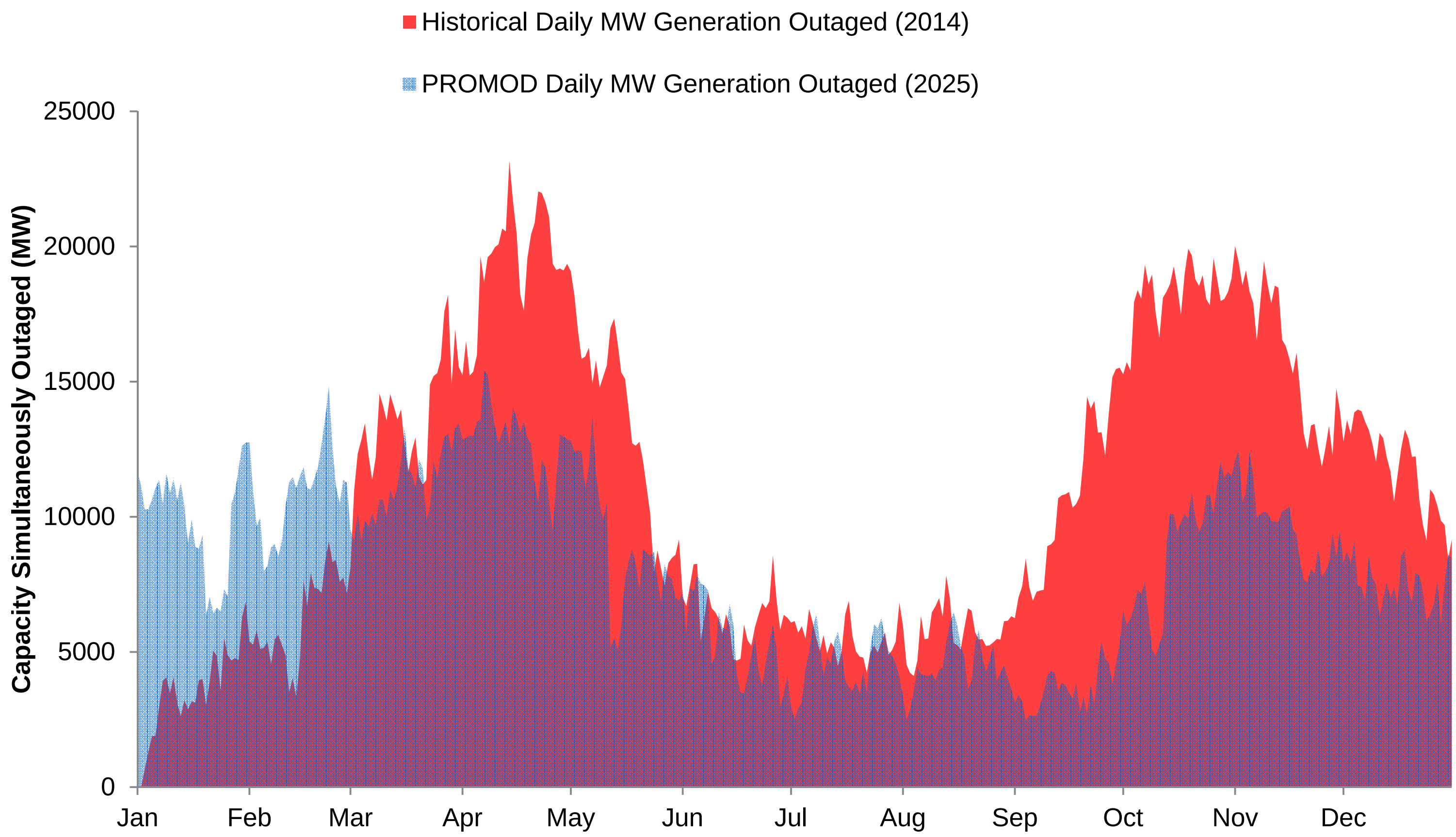
6. Apply necessary changes to current ITP10 models

Compare to Historical Data

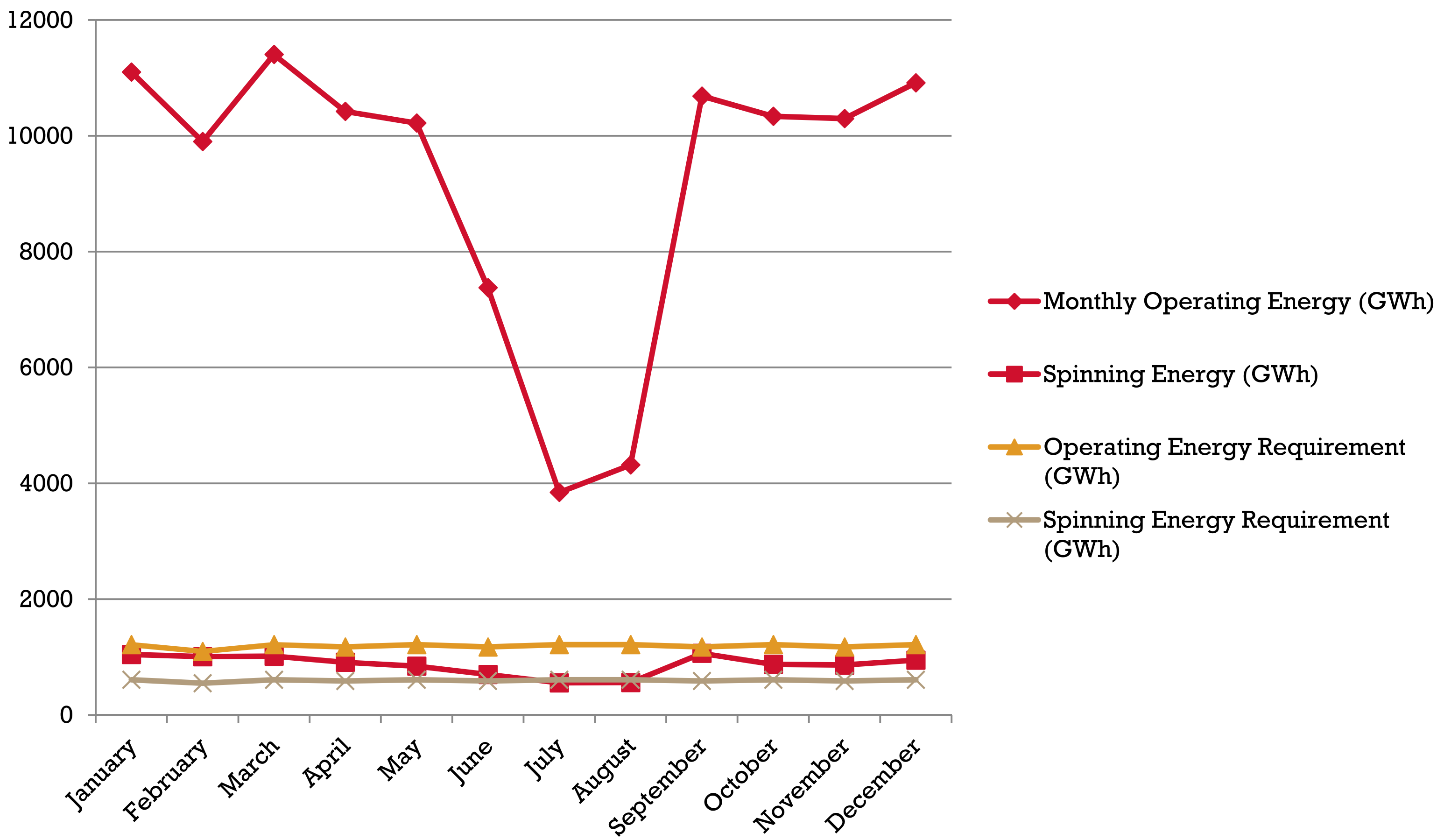
- Capacity Factor by Unit Type (comparison covered in next section)
- Maintenance Outages
- Operating and Spinning Reserves
- Flowgate Loading – internal look at "usual suspects"

*All results based on unconstrained model unless otherwise noted

Generator Outages



Operating and Spinning Reserves



Benchmark against 2015 ITP10 model

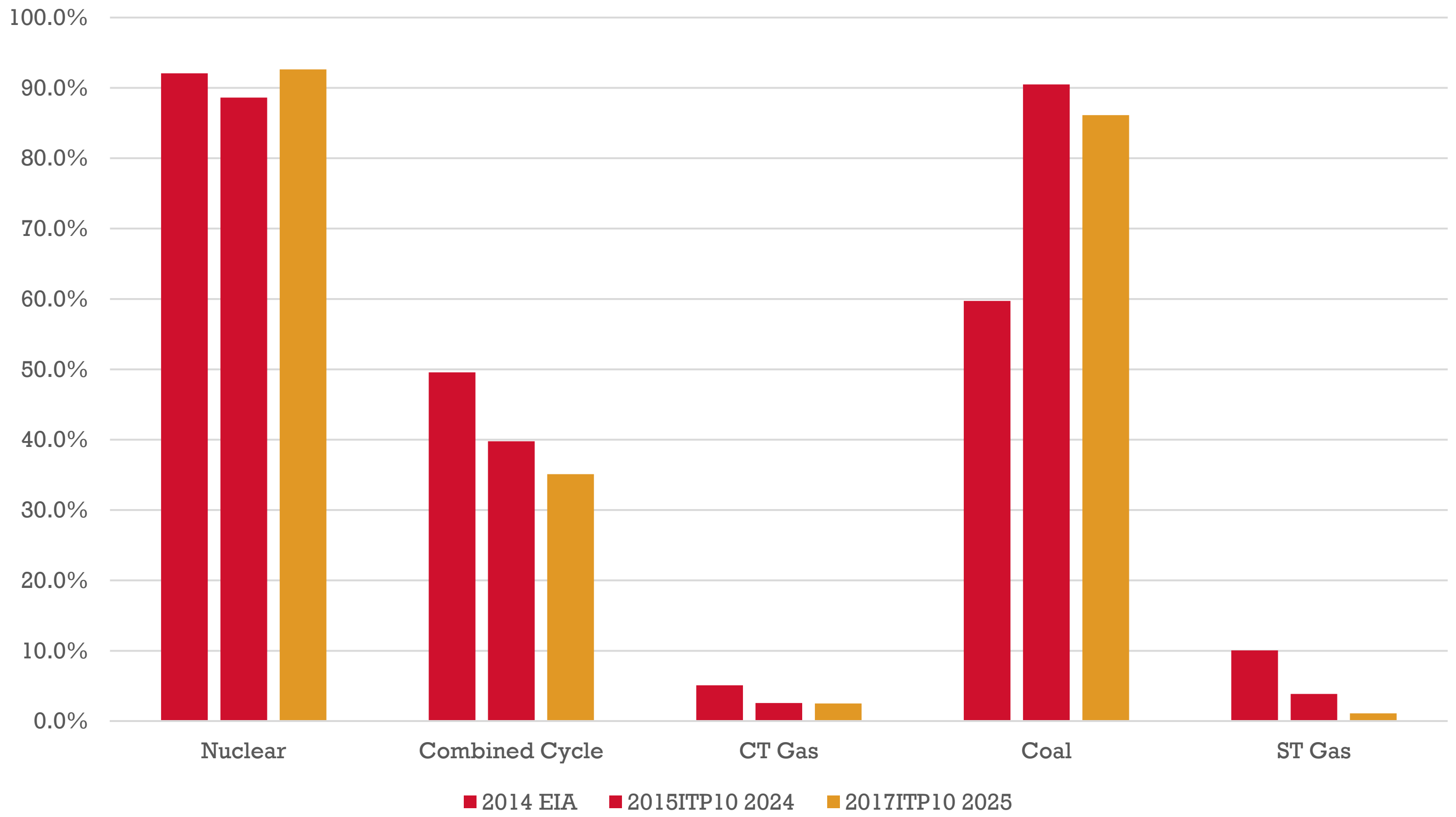
- Capacity Factors and Average Cost per MWH
- System LMPs
- Interchange (Import/Export)
- Renewable Generation Profiles (Solar and Wind Output)
- Zonal Purchases and Sales (APC comparison)

*All results based on unconstrained model unless otherwise noted

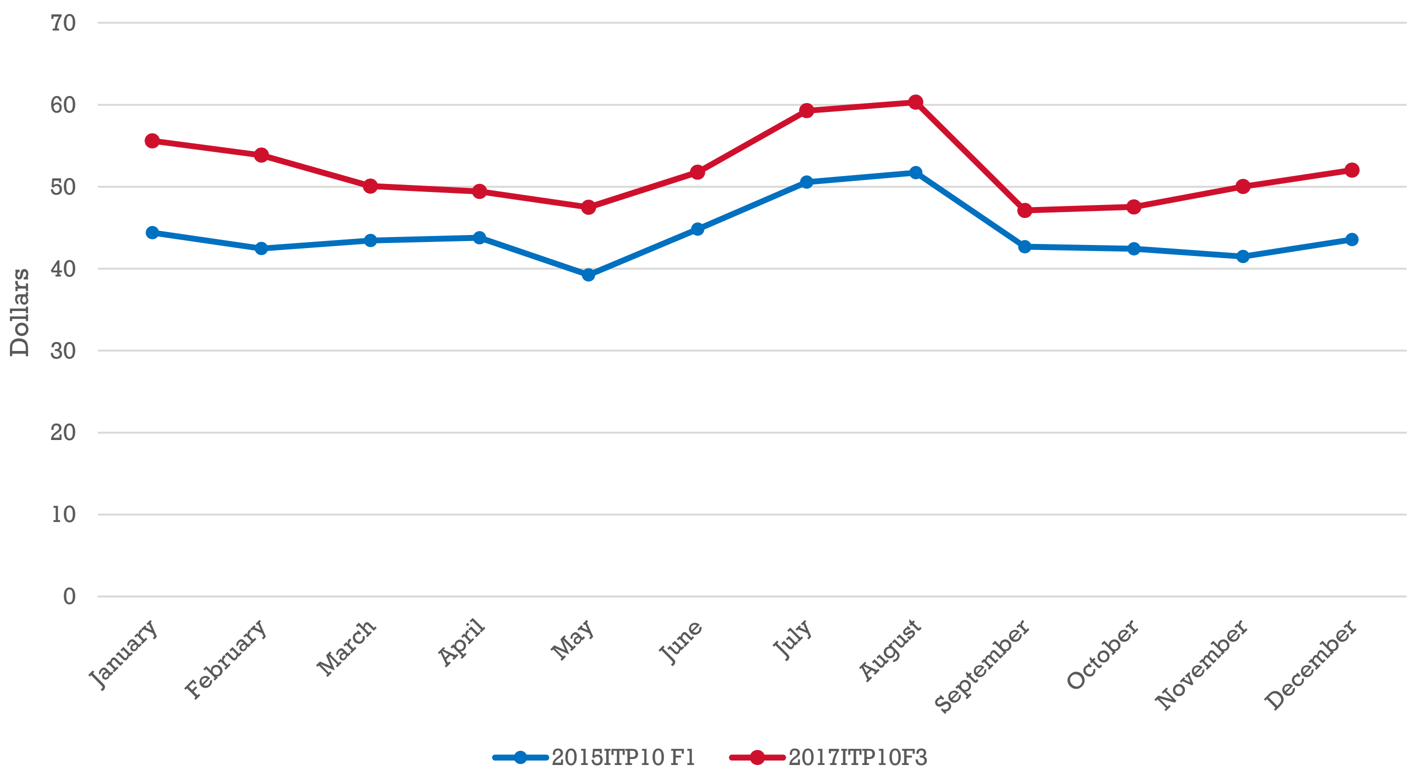
Capacity Factors and Average Cost

Unit Type	2014 EIA Capacity Factor	2015ITP10 F1 2024 Capacity Factor	2015ITP10 F1 2024 Average Energy Cost ($/MWh)	2017ITP10 F3 2025 Capacity Factor	2017ITP10 F3 2025 Average Energy Cost ($/MWh)
Nuclear	92.1%	88.6%	16.00	92.6%	16.07
Combined Cycle	49.6%	39.8%	49.44	35.1%	56.09
CT Gas	5.1%	2.6%	77.78	2.5%	87.37
Coal	59.7%	90.5%	26.59	86.1%	31.79
ST Gas	10.1%	3.9%	55.95	1.1%	88.42

Capacity Factors by Unit Type

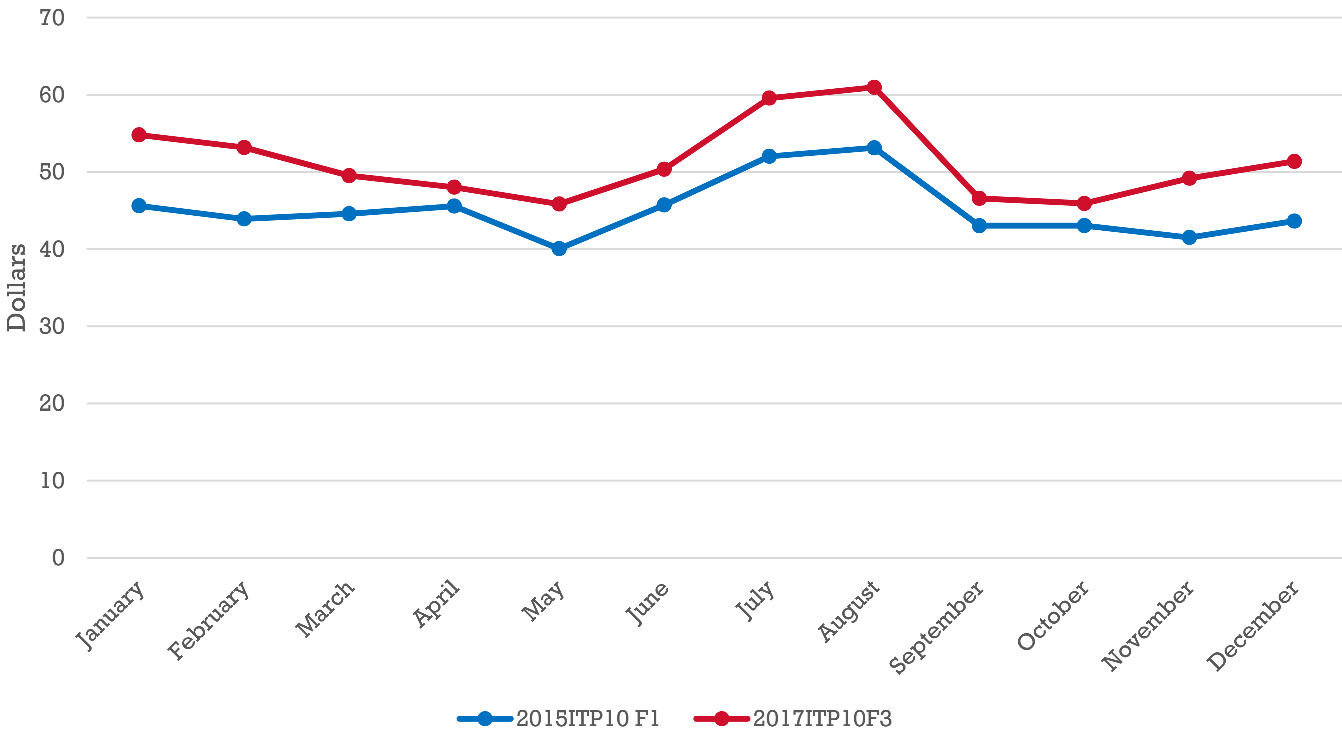


System LMPs – SPP Average



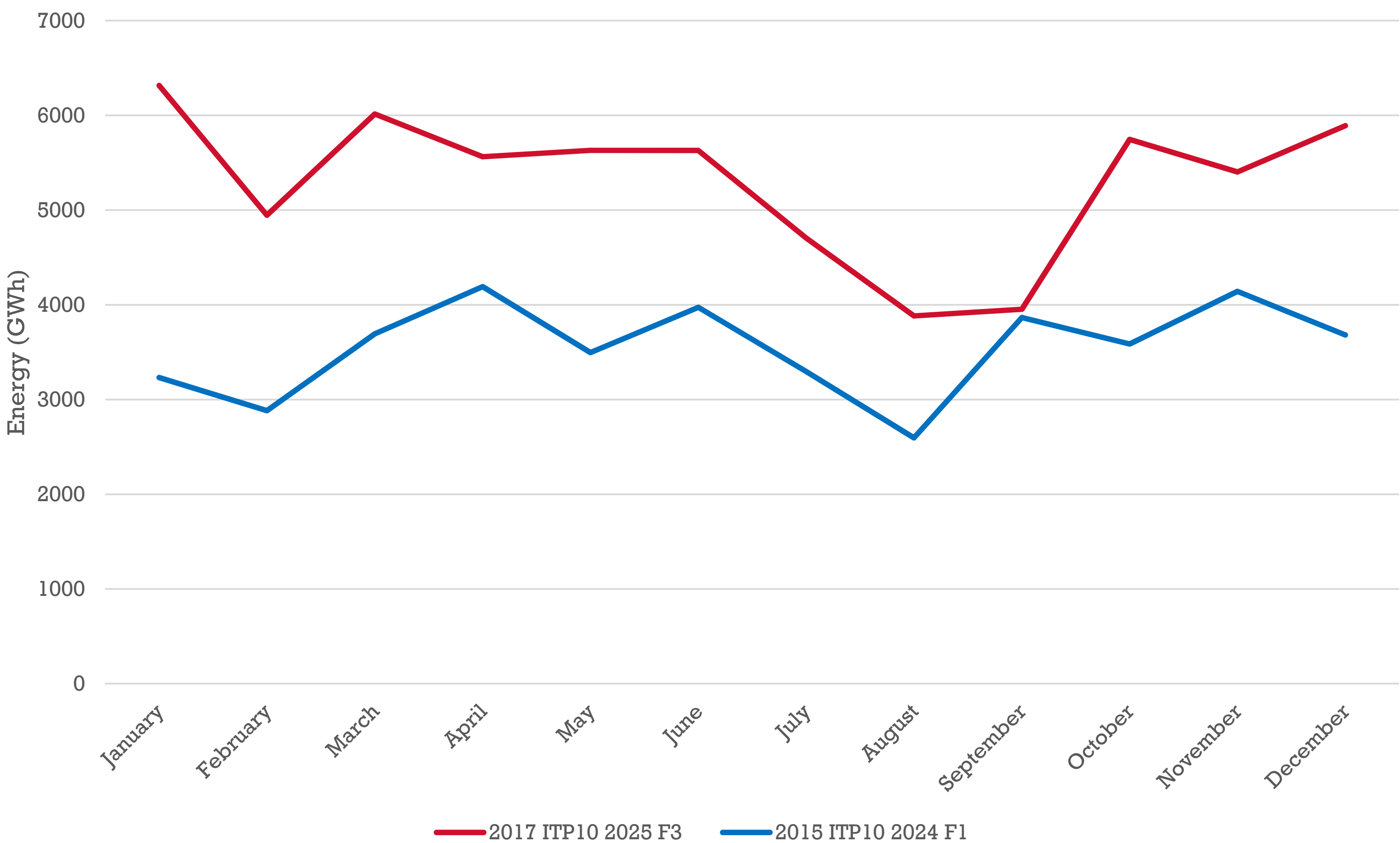
Unconstrained model

System LMPs – SPP Average

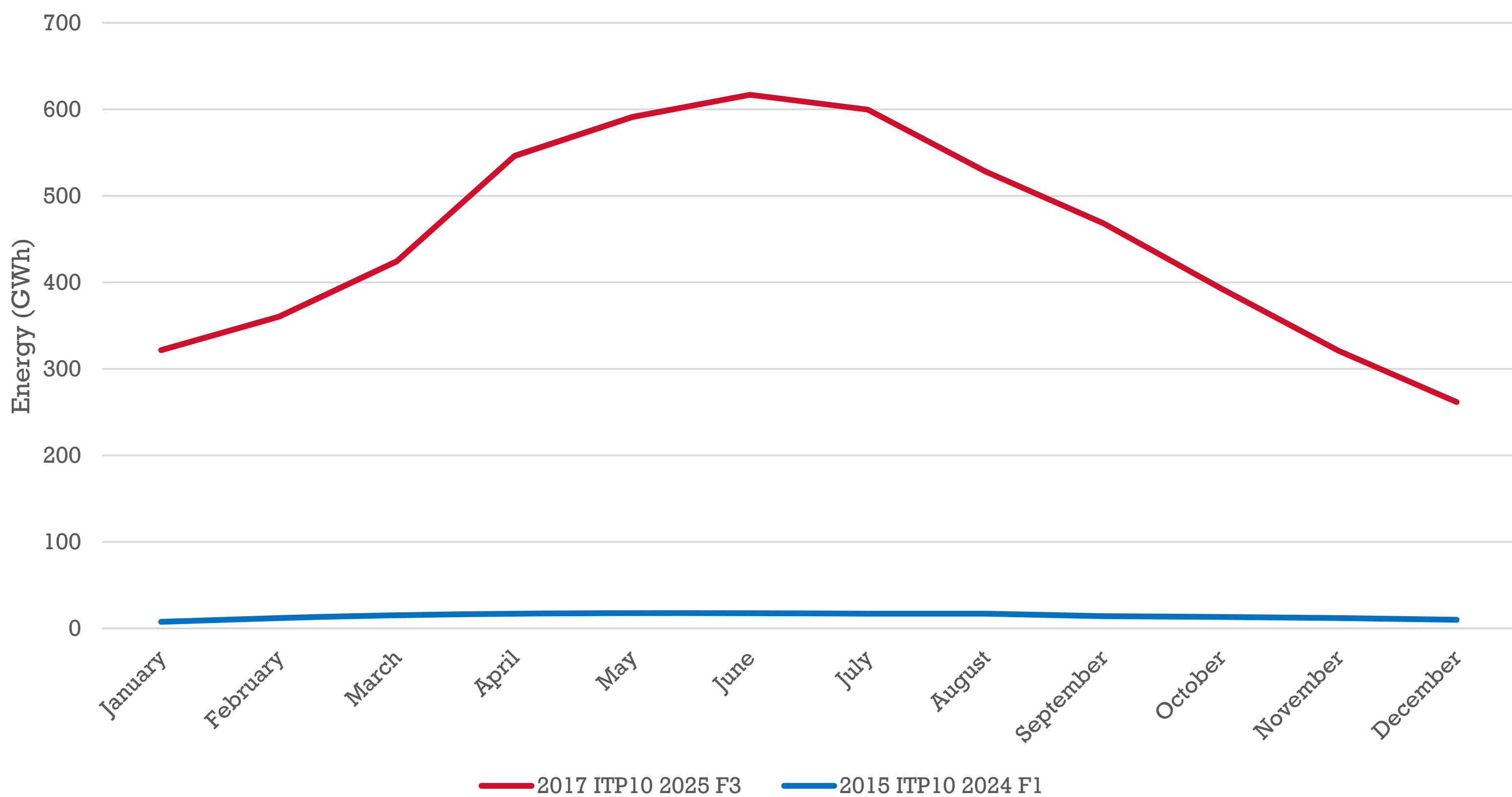


BOF Event File model

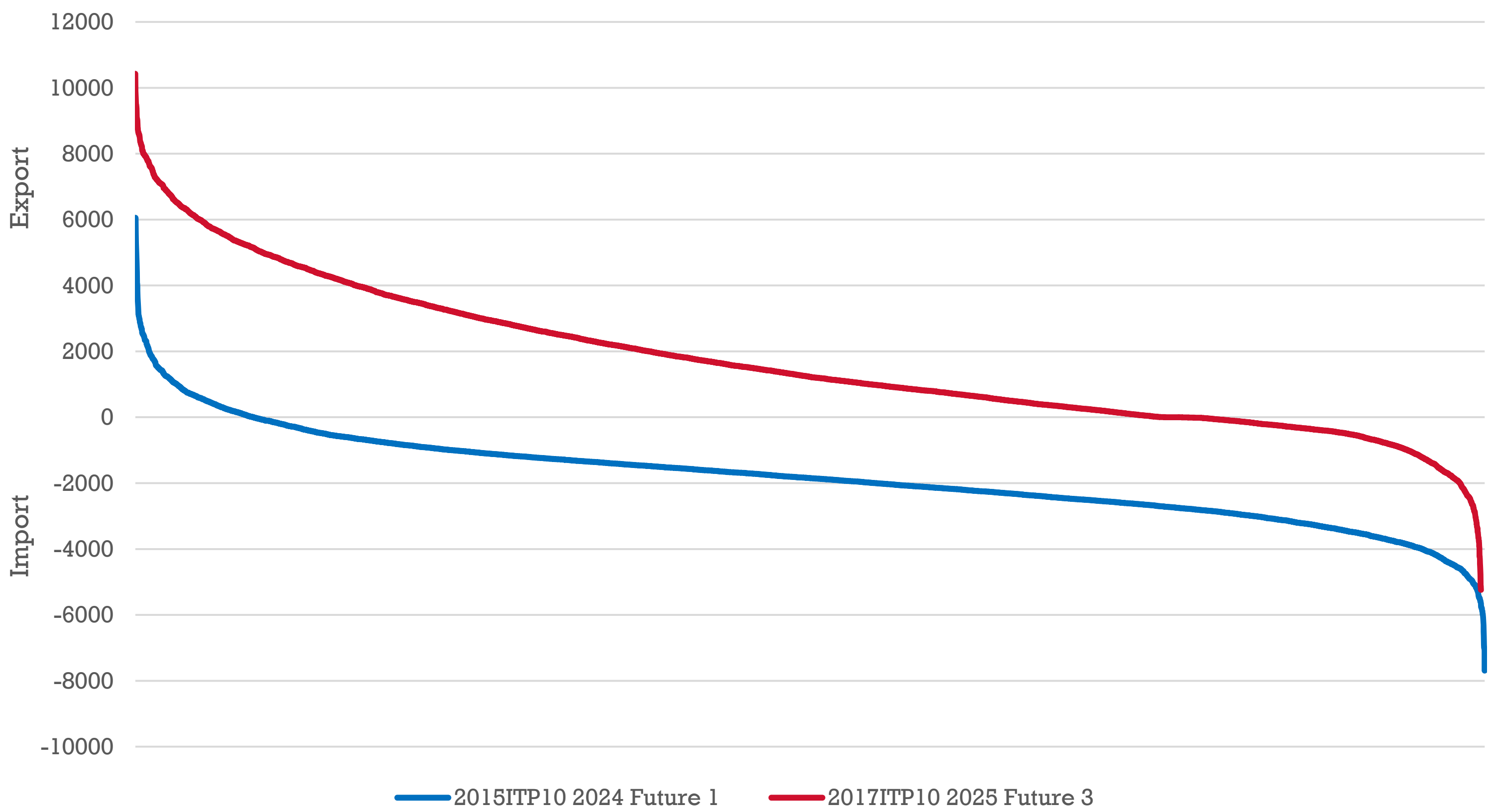
SPP Wind Output



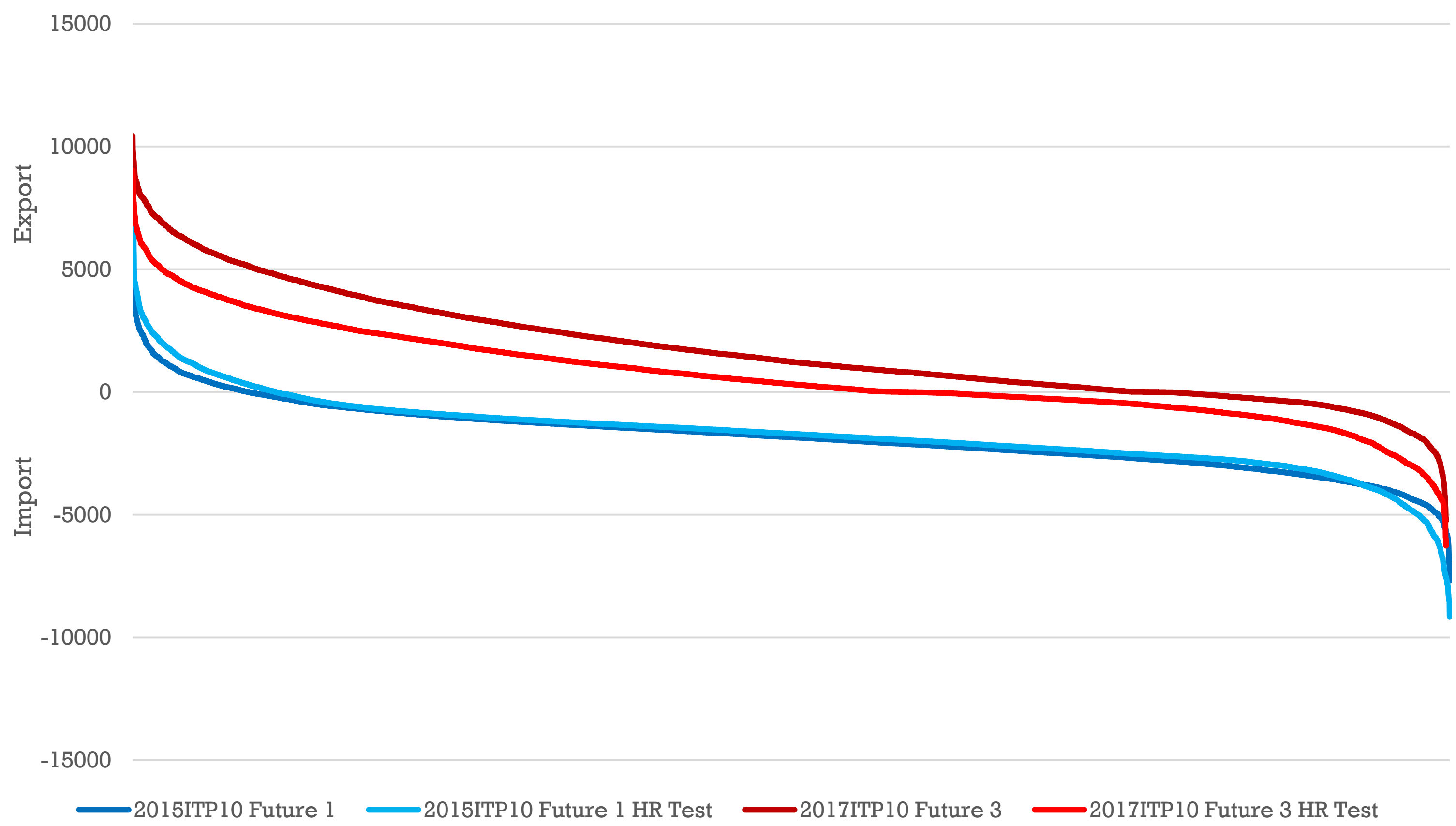
SPP Solar Output



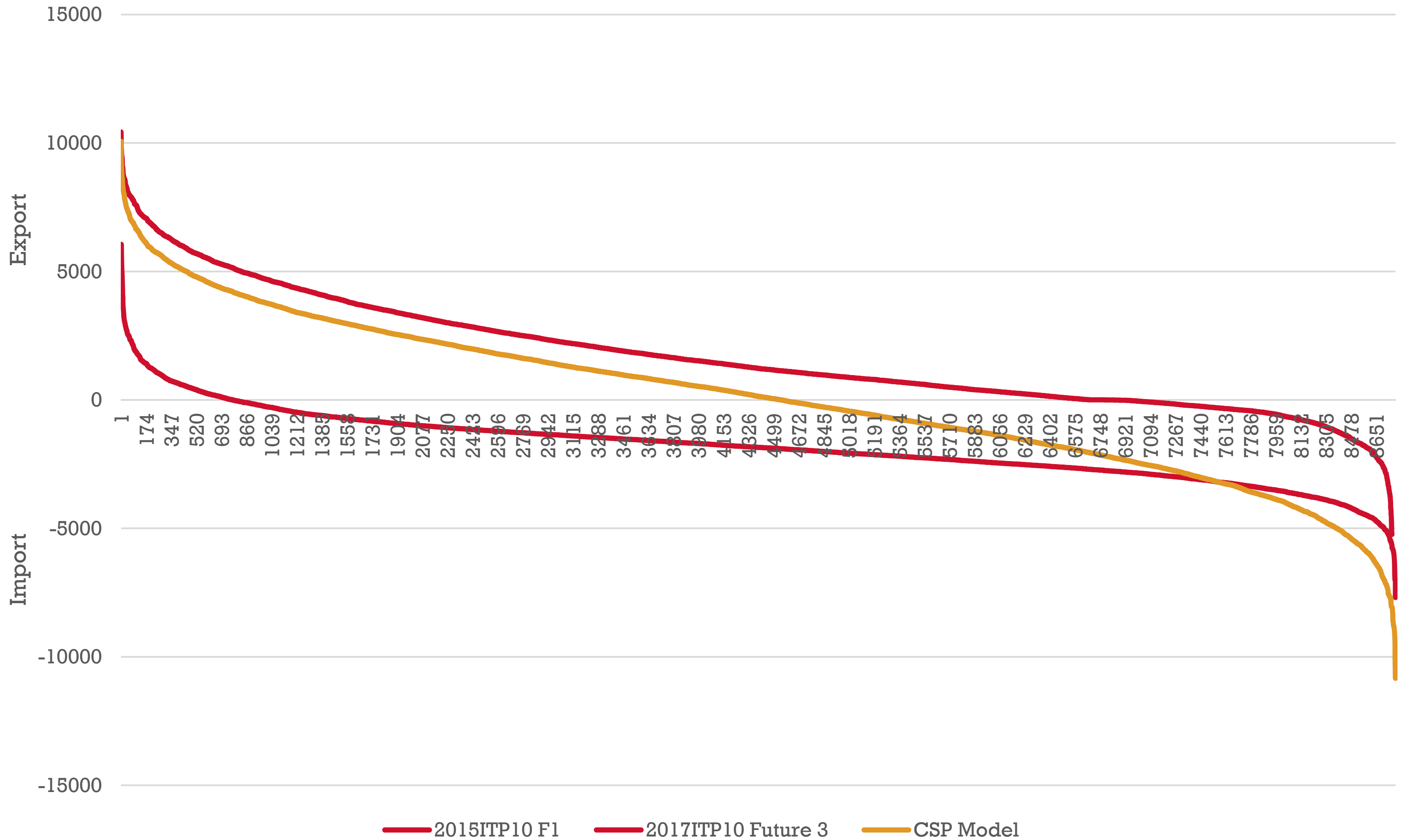
Interchange



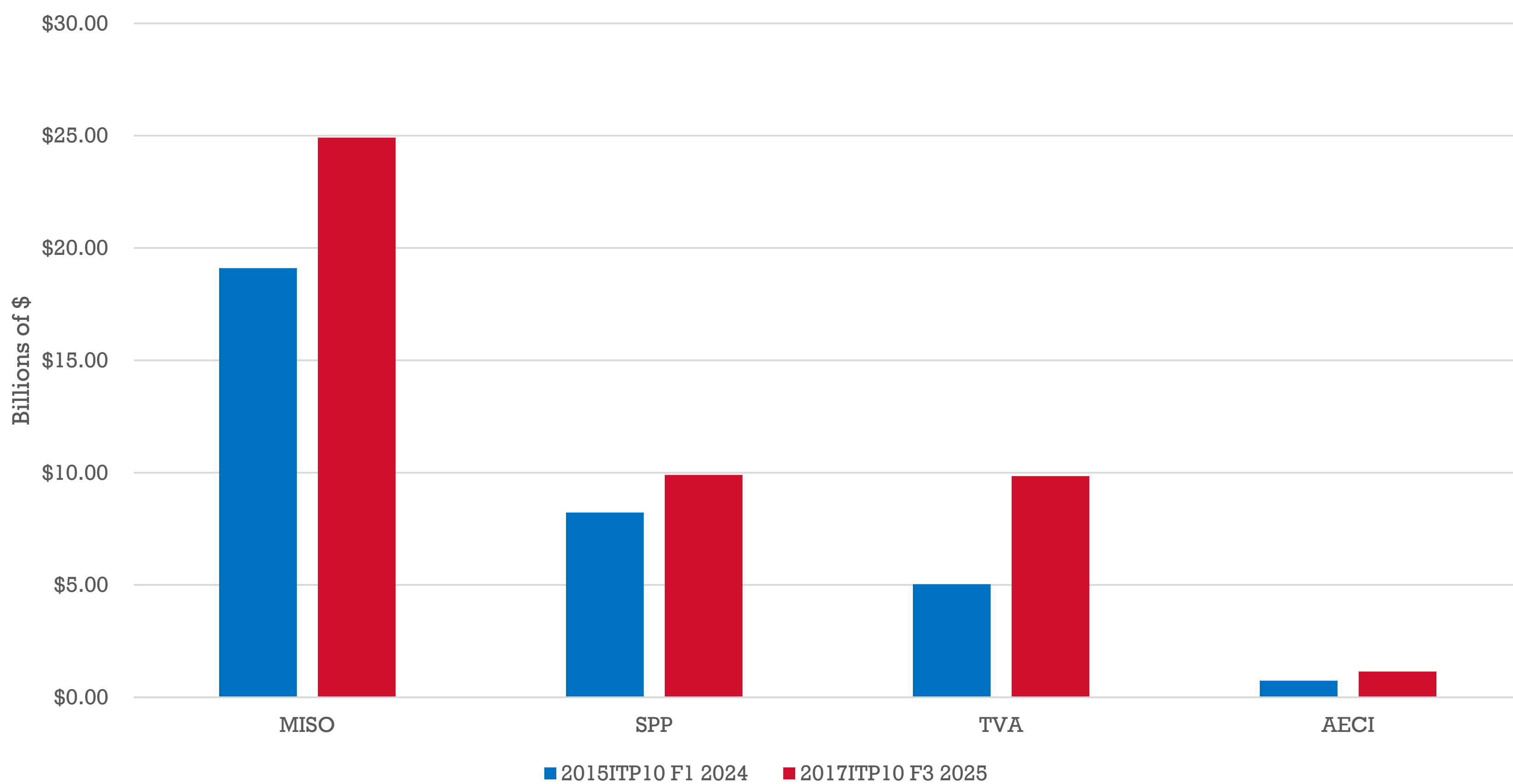
Hurdle Rate Testing



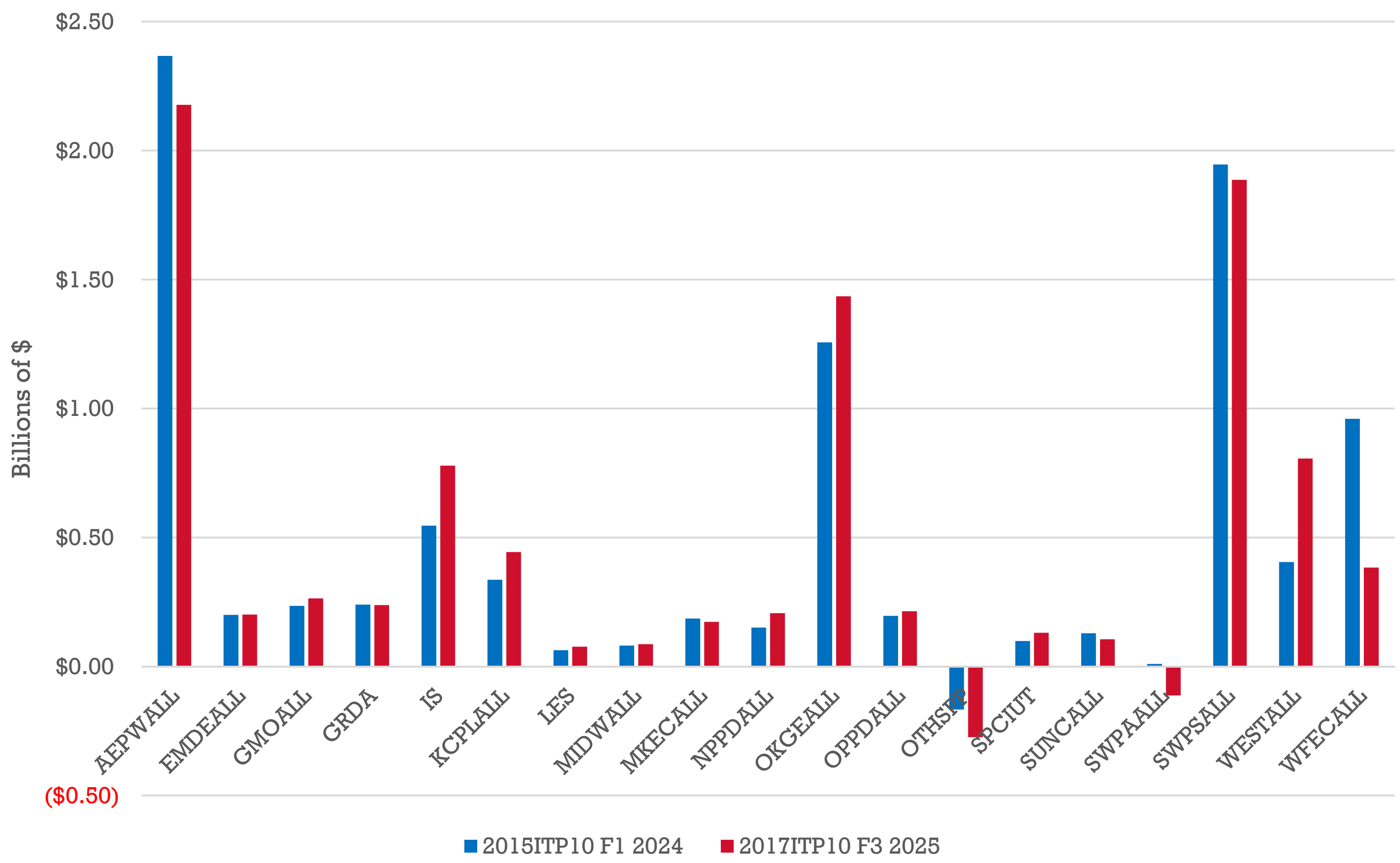
CSP Model Comparison



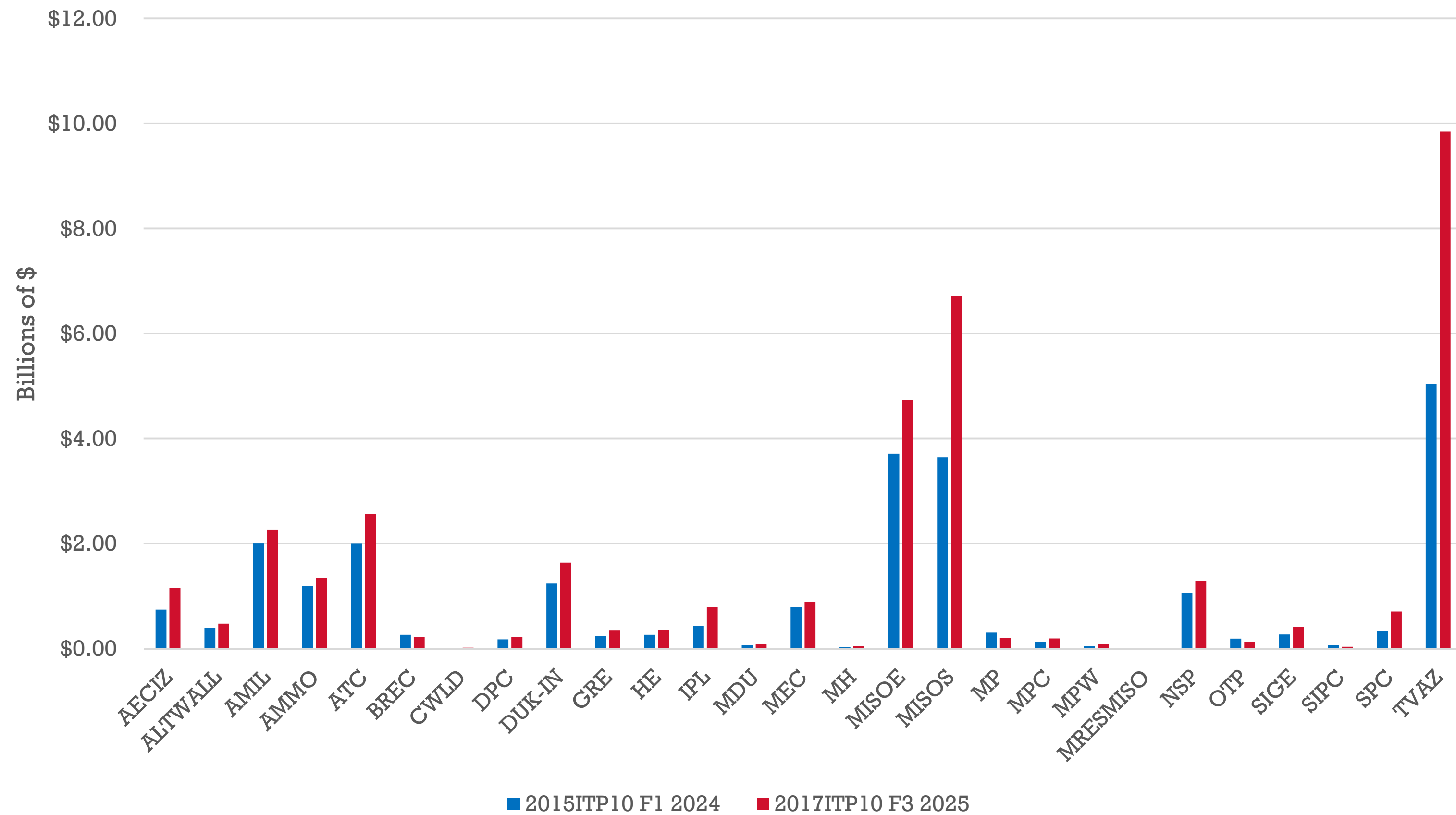
Production Costs by Region



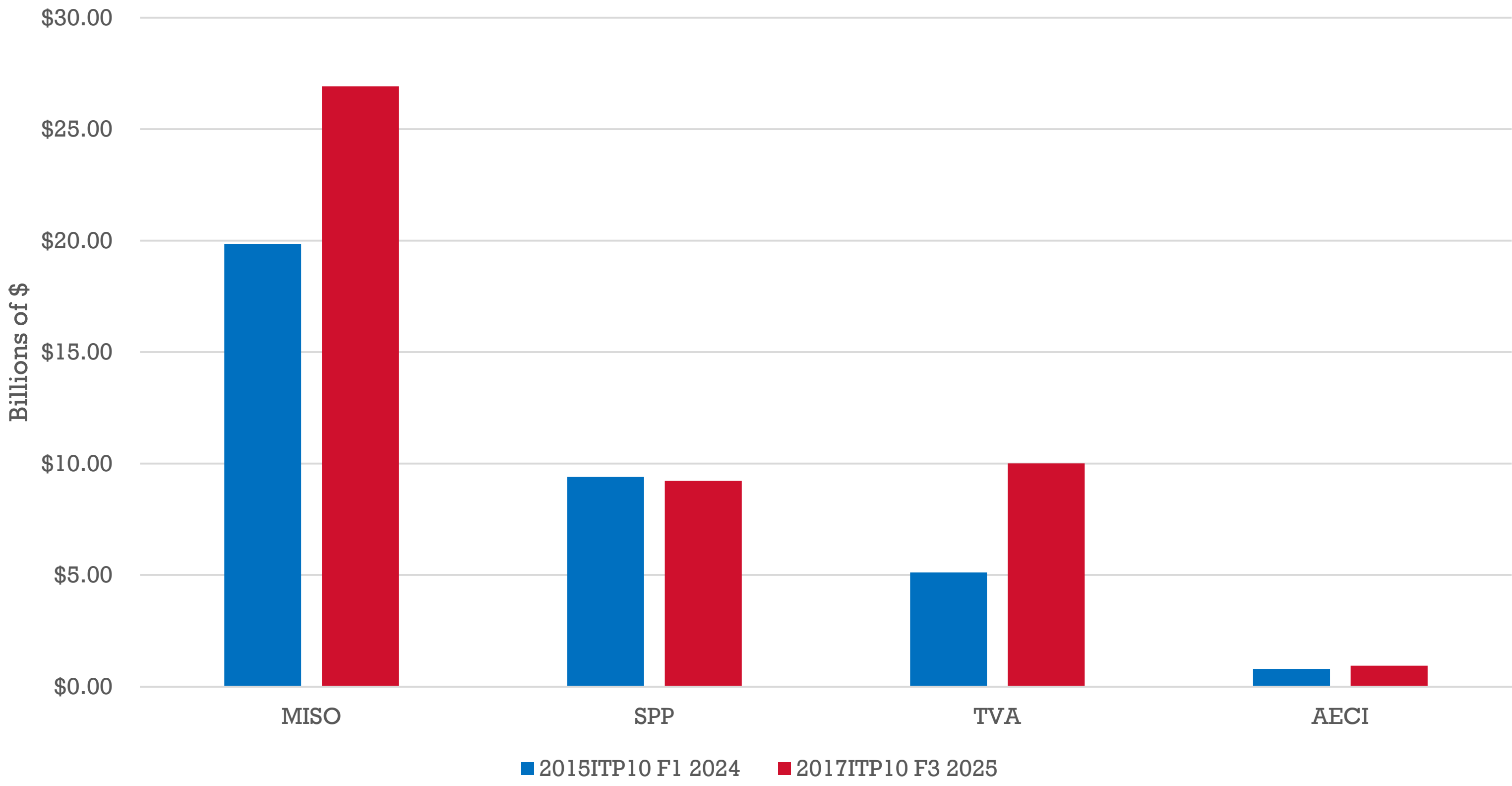
Production Costs by Zone - SPP



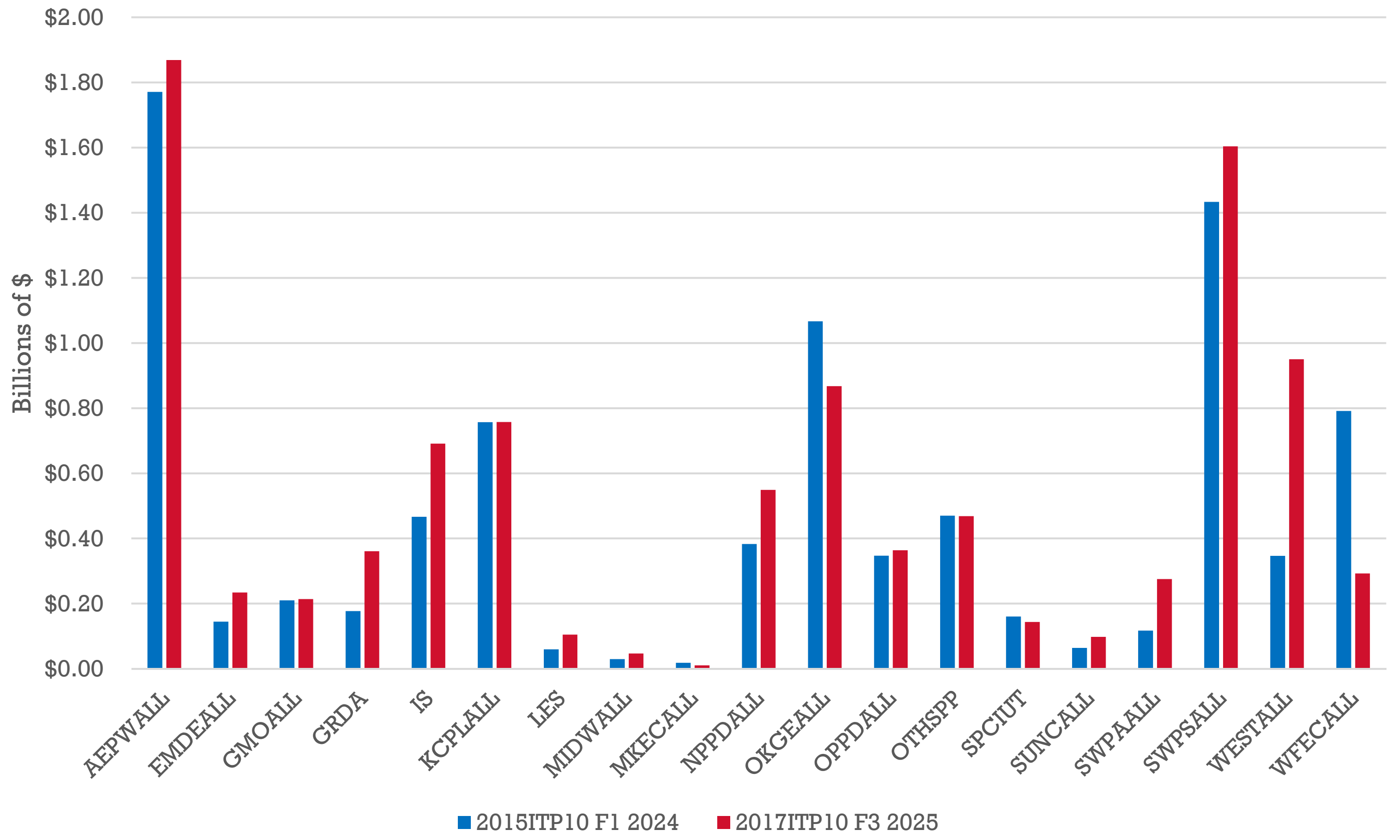
Production Costs by Zone - External



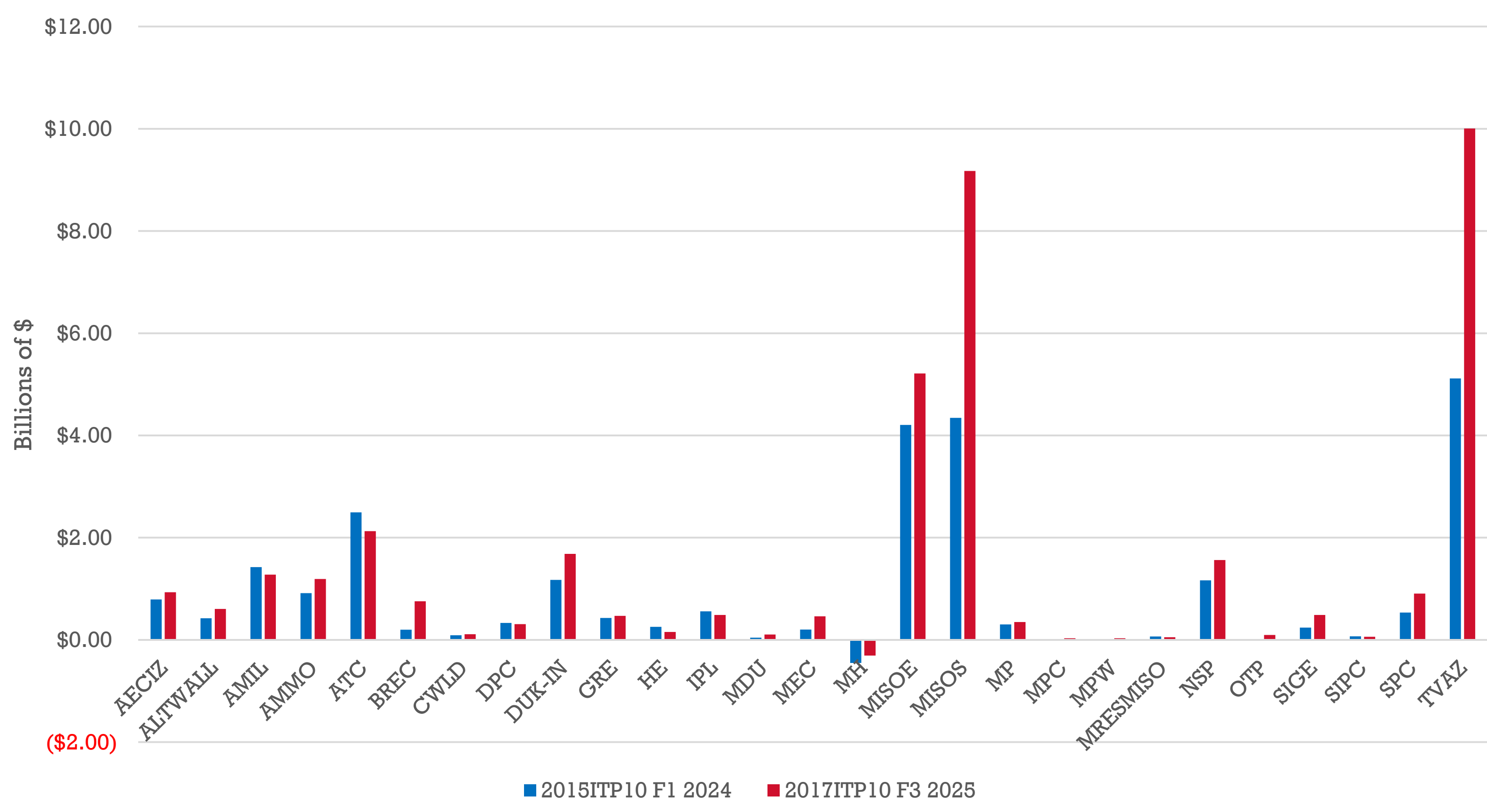
APC Comparison by Region



APC Comparison by Zone - SPP



APC Comparison by Zone - External



CPP Future Validation

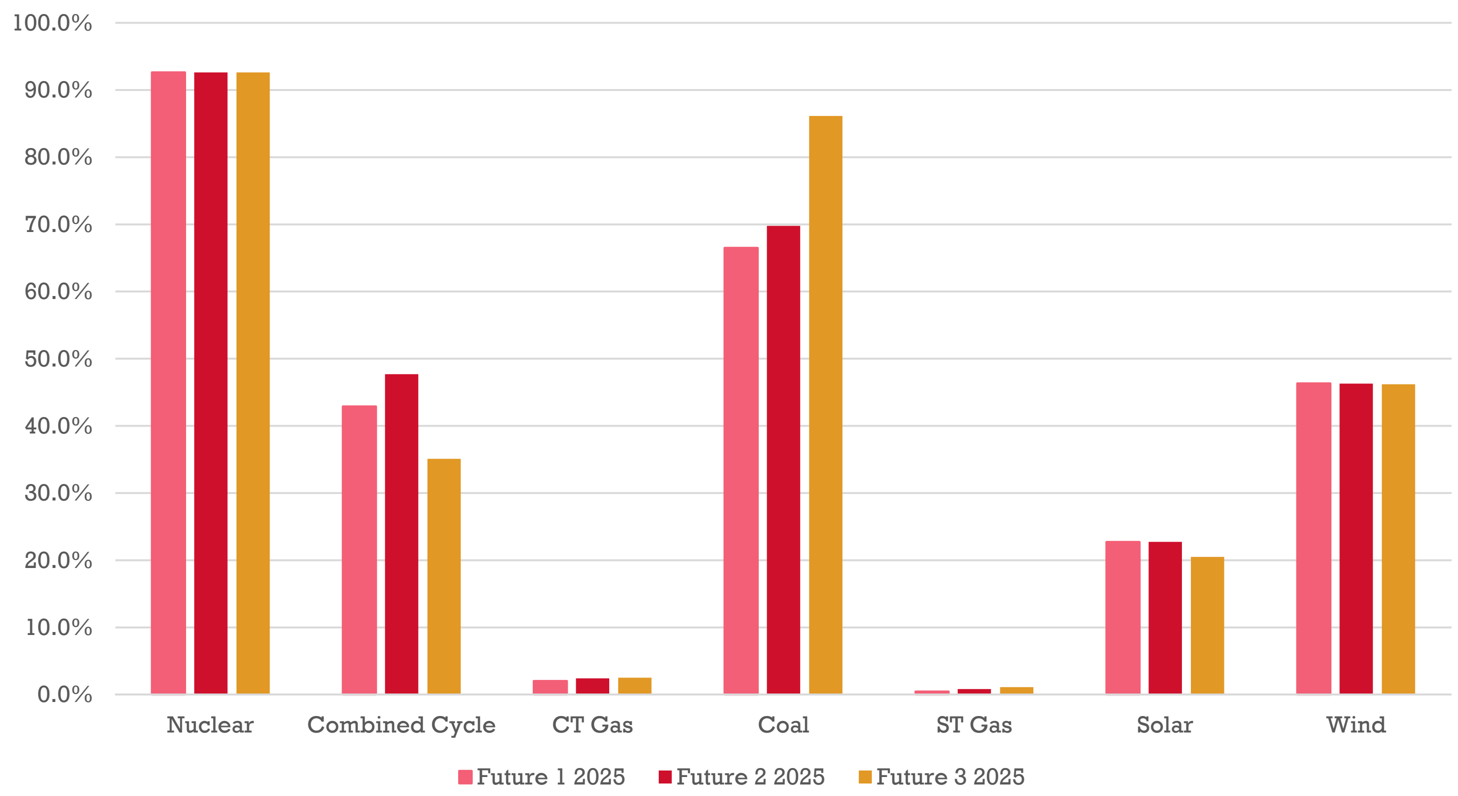
- Capacity Factors and Average Cost per MWH
- Interchange (Import/Export)
- Renewable Generation Profiles
- Conventional Unit Behavior
- Zonal Purchases and Sales (APC comparison)
- System LMPs

*All results based on unconstrained model unless otherwise noted

Capacity Factors by Unit Type

Unit Type	Future 1 2025	Future 2 2025	Future 3 2025
Nuclear	92.6%	92.6%	92.6%
Combined Cycle	42.9%	47.7%	35.1%
CT Gas	2.0%	2.4%	2.5%
Coal	66.5%	69.8%	86.1%
ST Gas	0.5%	0.8%	1.1%
Solar	22.7%	22.7%	20.5%
Wind	46.3%	46.3%	46.2%

Capacity Factors by Unit Type



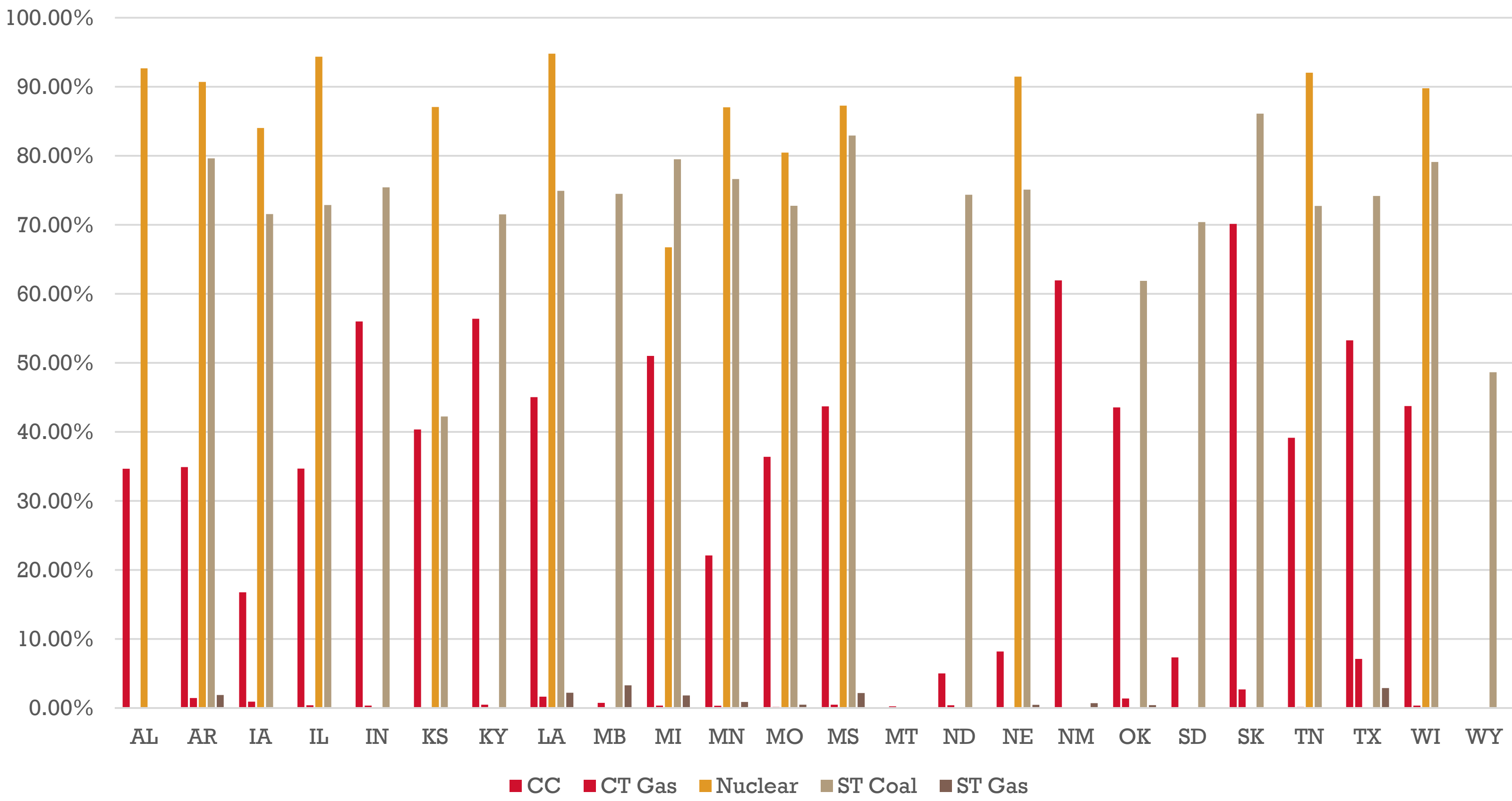
Annual Cost of SPP Units

Unit Type	F1 2025 Avg $/MW	F1 2025 Avg $/MW w/out CO2 cost	F2 2025 Avg $/MW	F2 2025 Avg $/MW w/out CO2 cost	F3 2025 Avg $/MW
Nuclear	16.04	16.68	16.04	16.68	16.07
CC	65.04	56.58	60.60	56.23	56.09
CT Gas	105.29	93.51	97.71	90.99	87.37
Coal	58.06	32.71	53.67	33.78	31.79
ST Gas	114.60	91.64	101.40	91.99	88.42

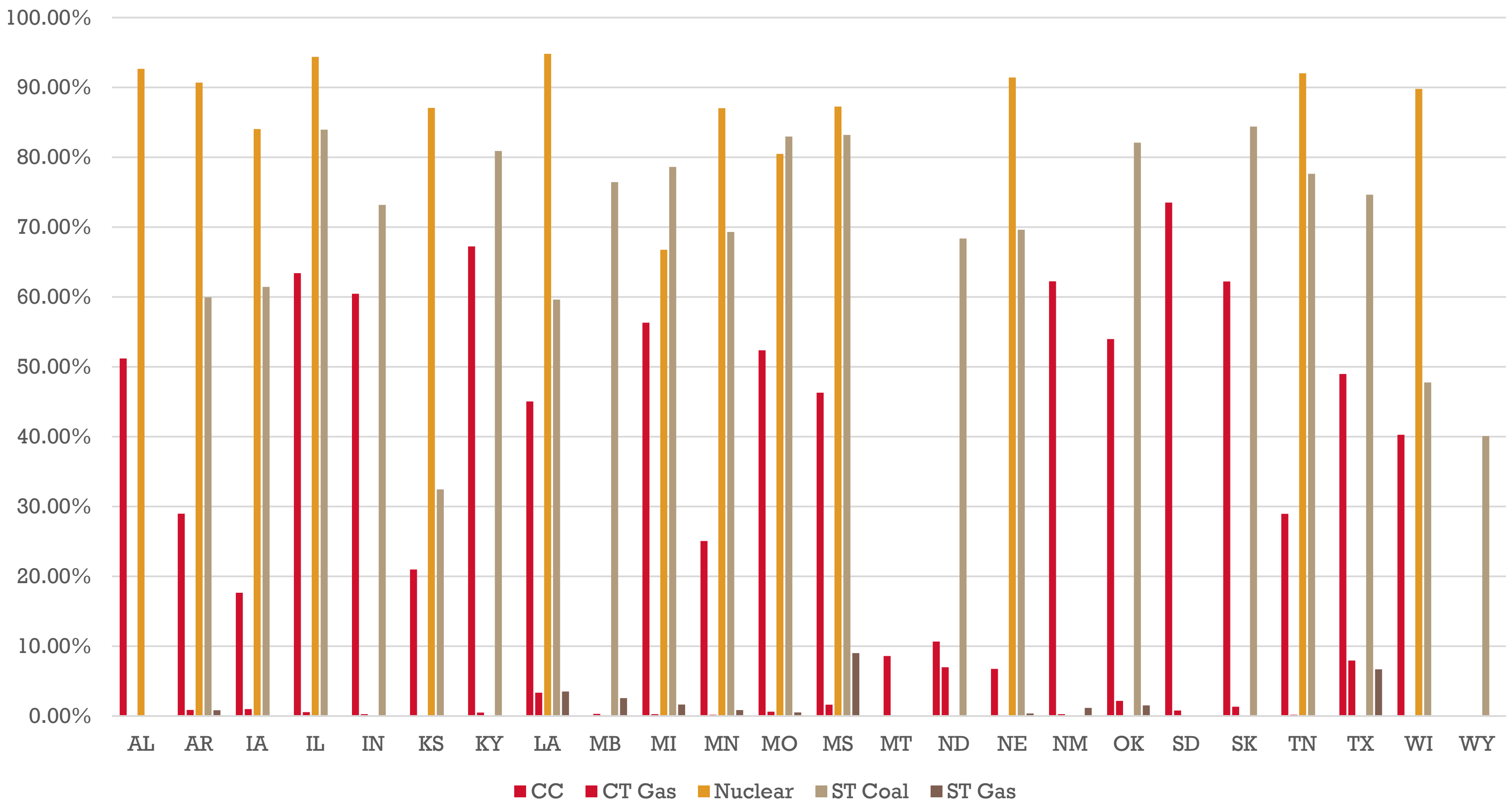
Capacity and Energy by Future

Unit Type	F1 2025 Capacity (GW)	F1 2025 Annual Energy (GWh)	F2 2025 Capacity (GW)	F2 2025 Annual Energy (GWh)	F3 2025 Capacity (GW)	F3 2025 Annual Energy (GWh)
Nuclear	2.762	21764	2.762	21759	2.762	21760
CC	19.748	73302	20.298	83777	16.970	51483
CT Gas	11.349	1917	11.583	2358	13.791	2938
Coal	22.206	127646	21.406	129797	23.099	171913
ST Gas	10.368	425	10.309	761	10.309	1022

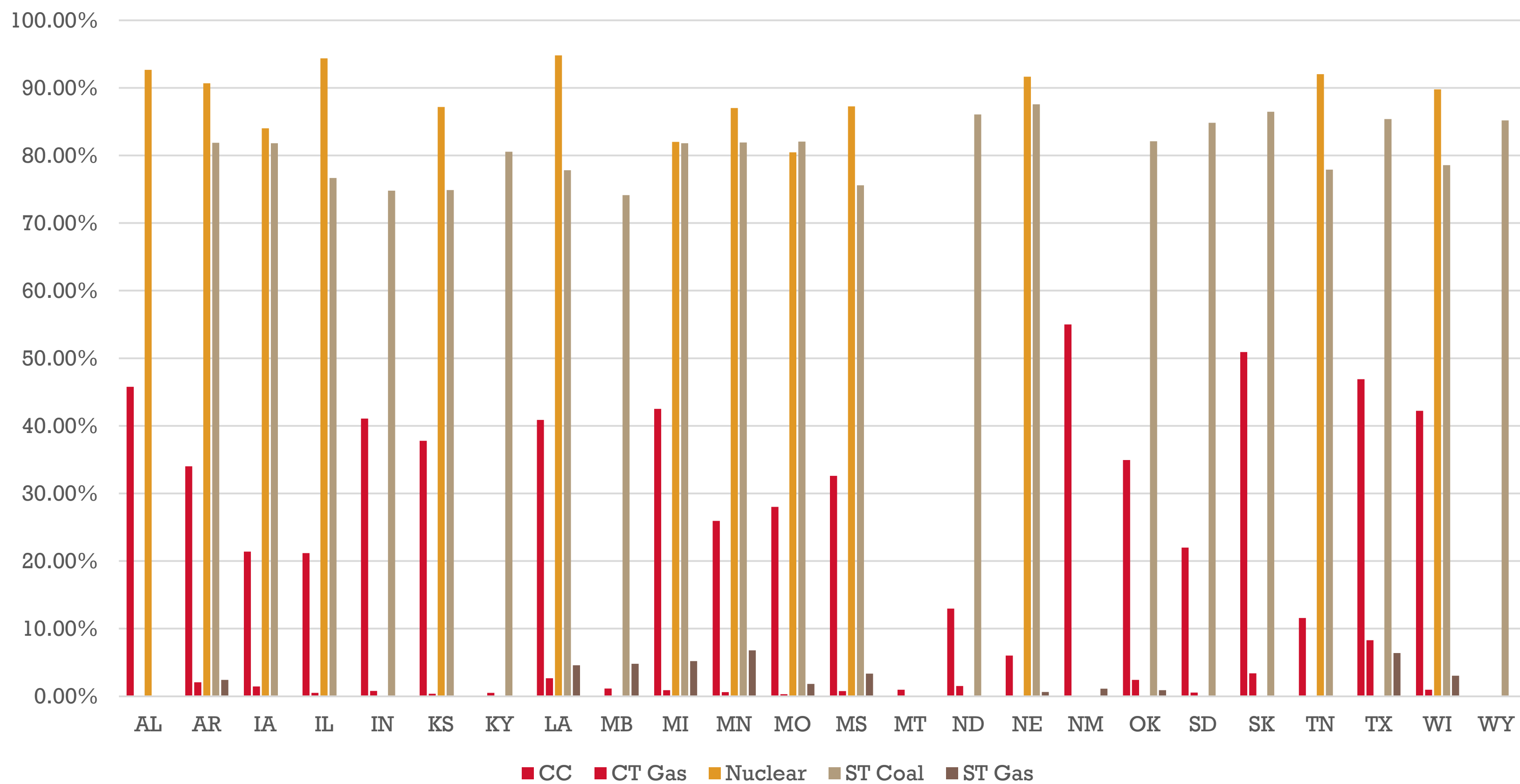
Capacity Factors by State – Future 1



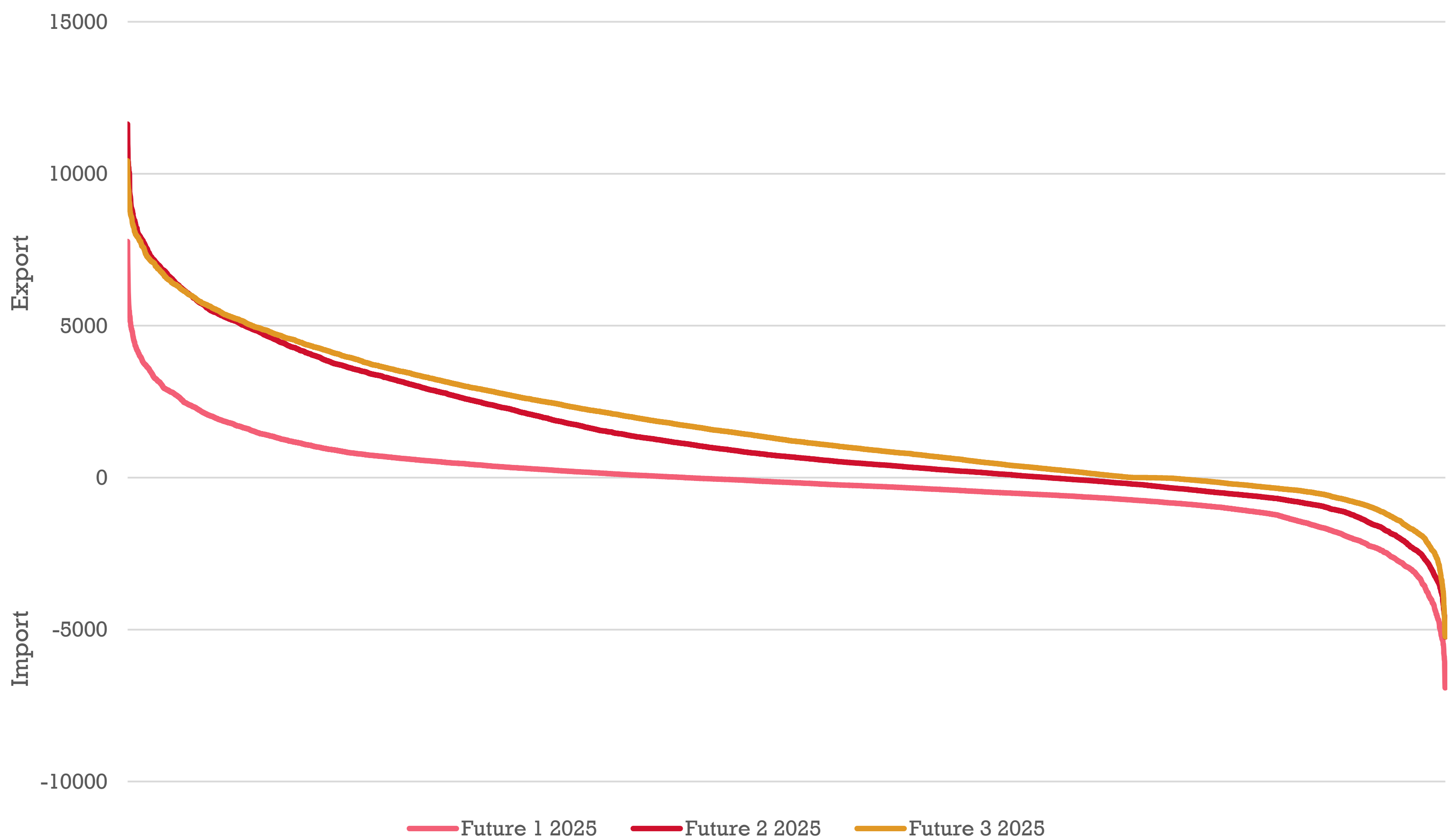
Capacity Factors by State – Future 2



Capacity Factors by State – Future 3

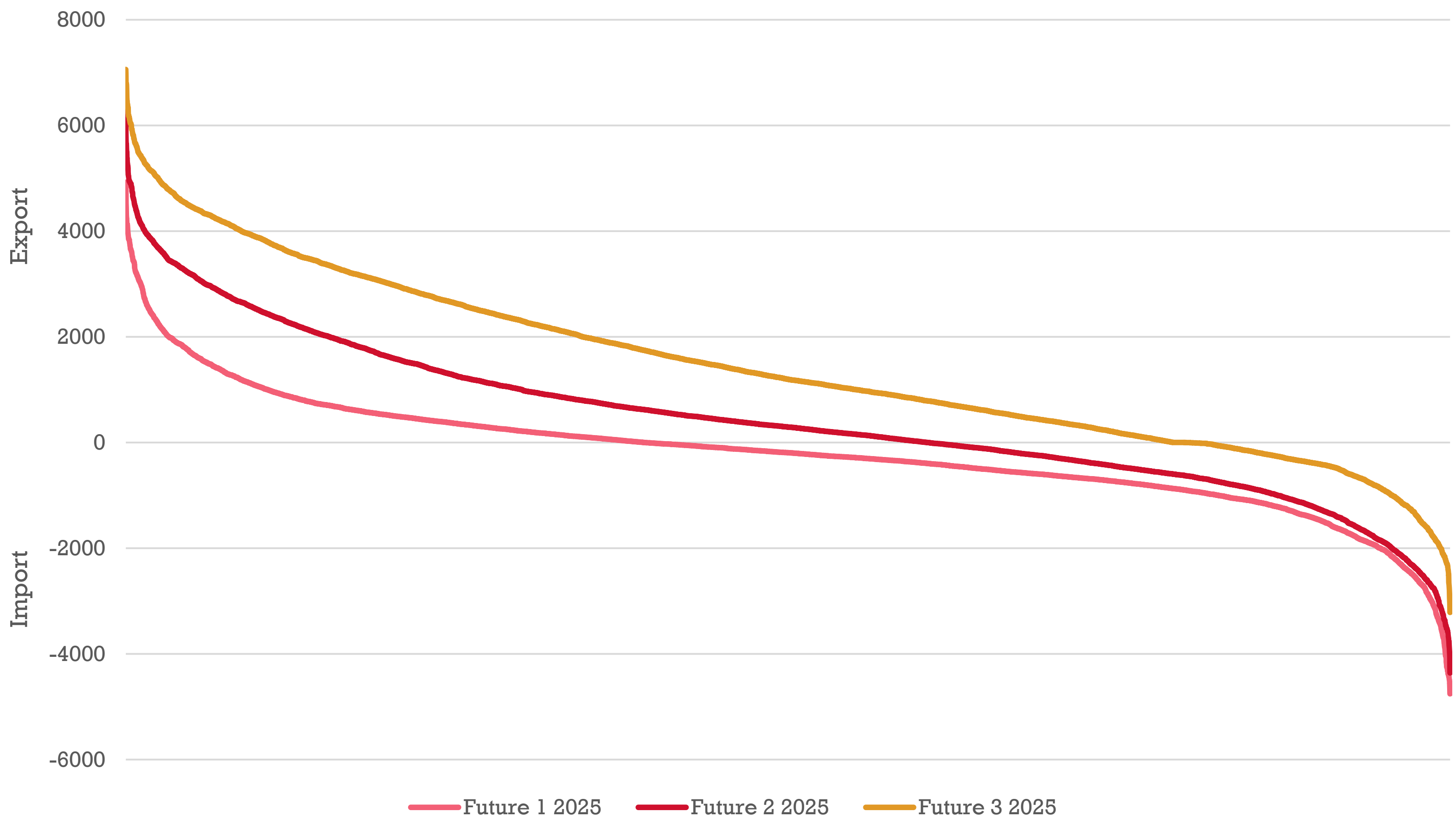


Interchange per Future



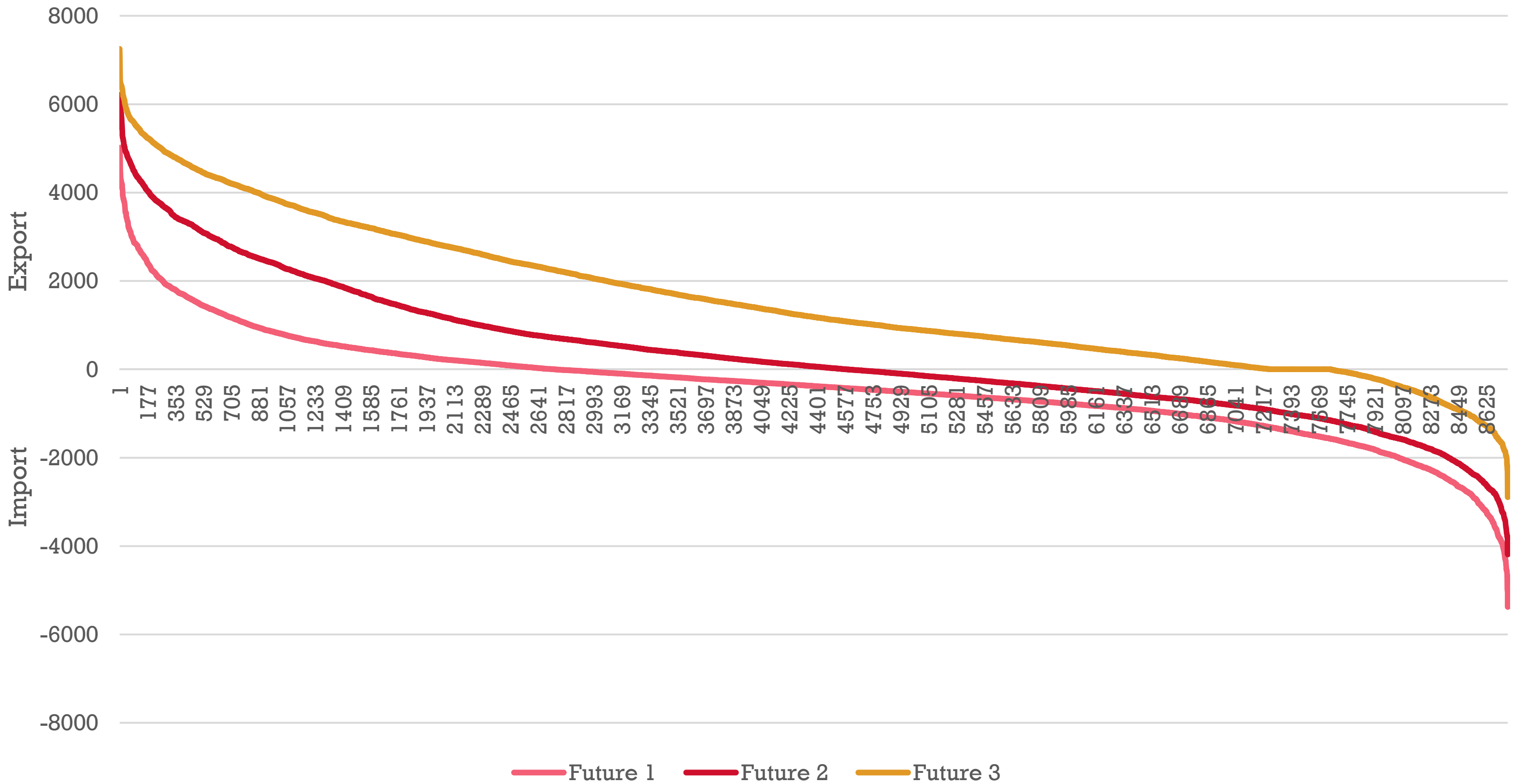
Unconstrained model

Interchange per Future



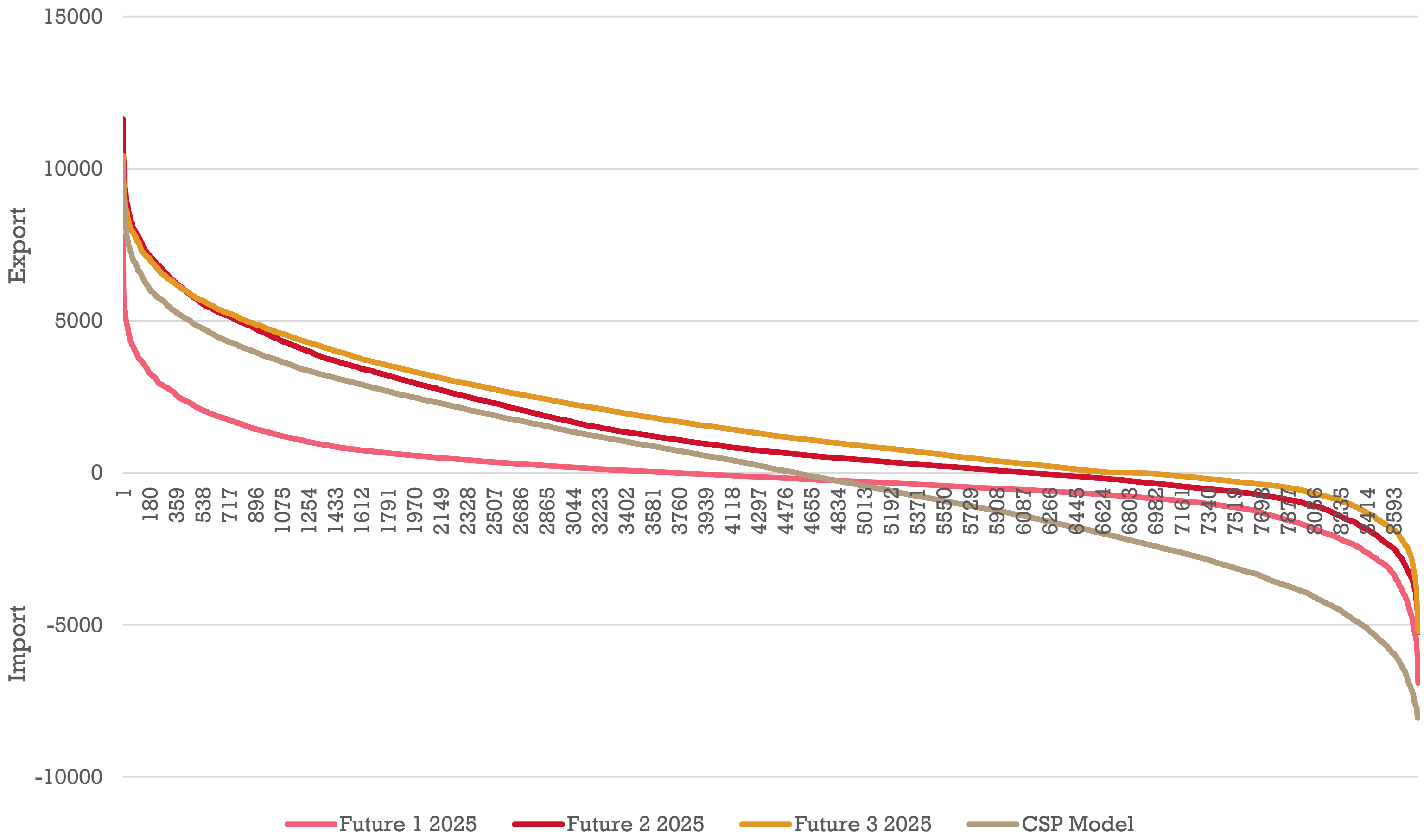
Book of Flowgates Event File model

Interchange per Future

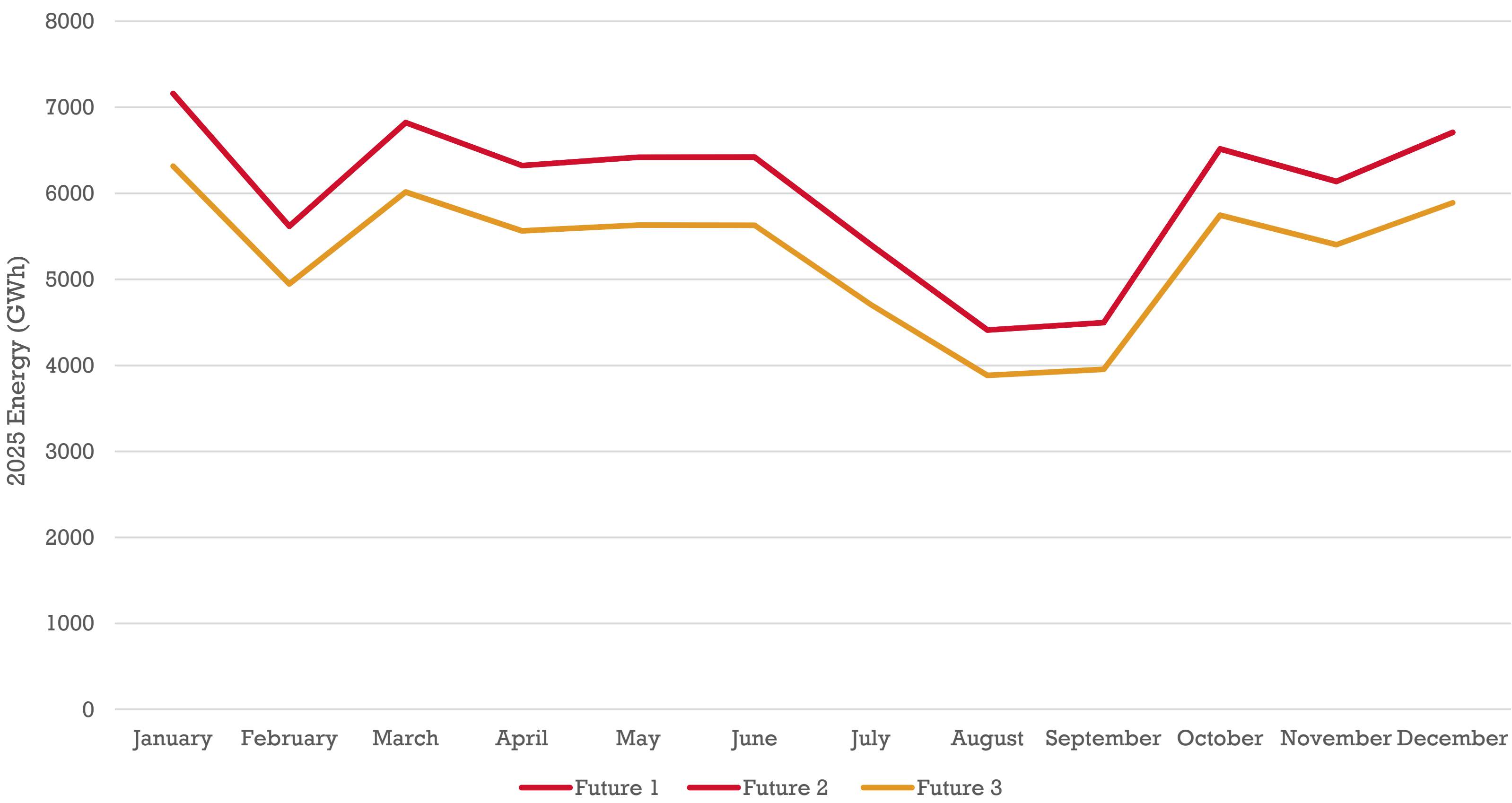


Final Event File model

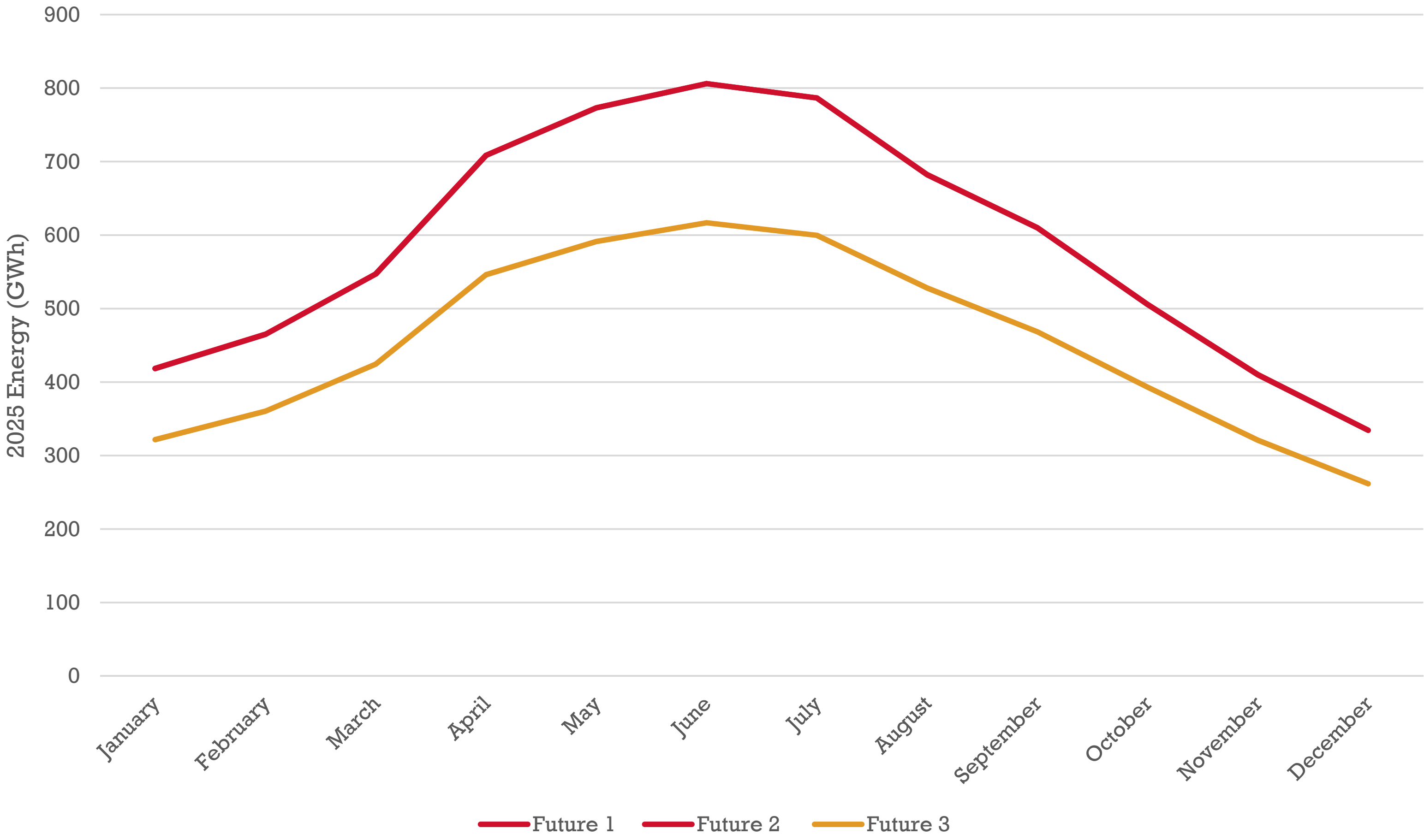
CSP Model Comparison



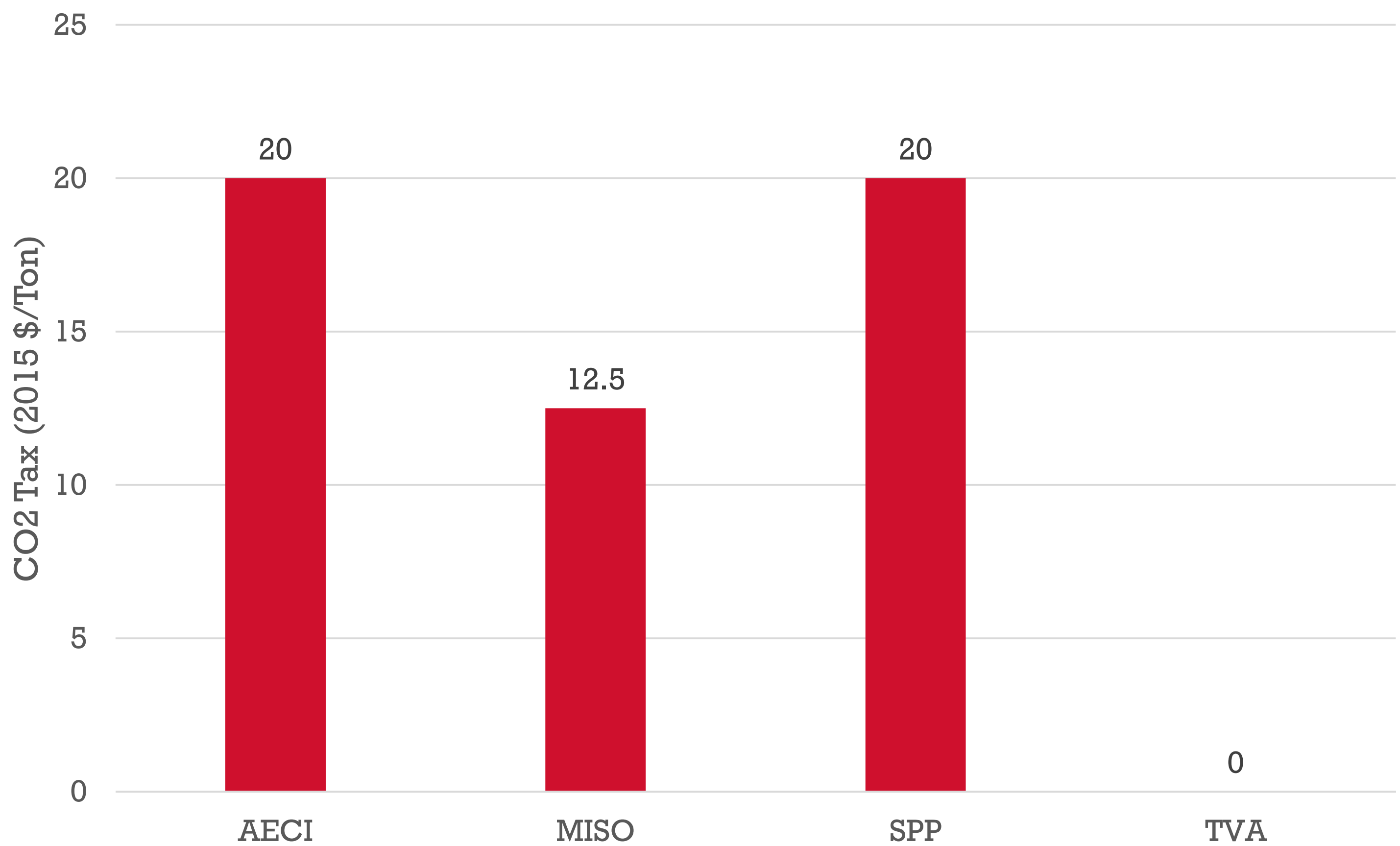
SPP Wind Output per Future



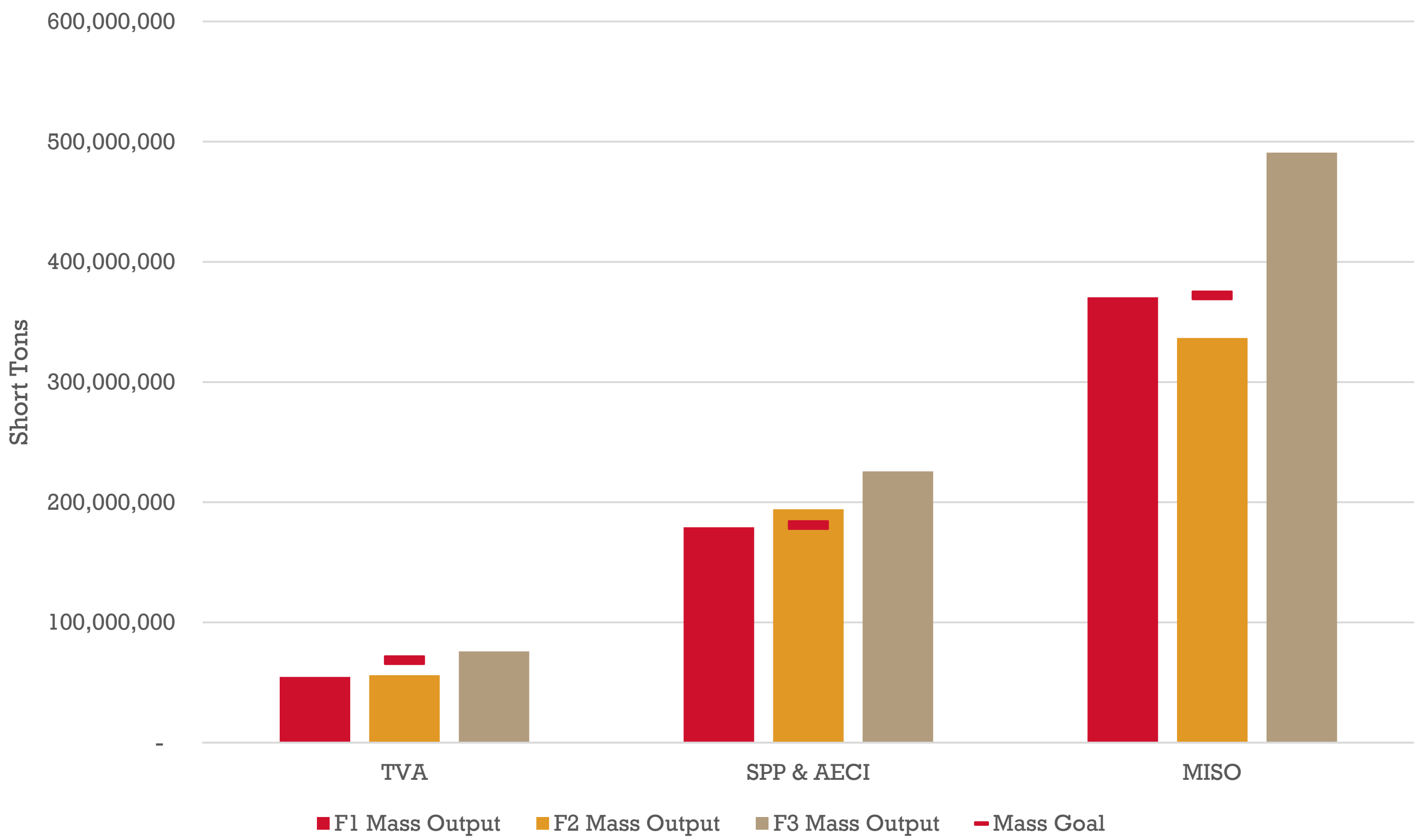
SPP Solar Output per Future



2025 Regional Carbon Prices



2025 Regional Emissions by Future



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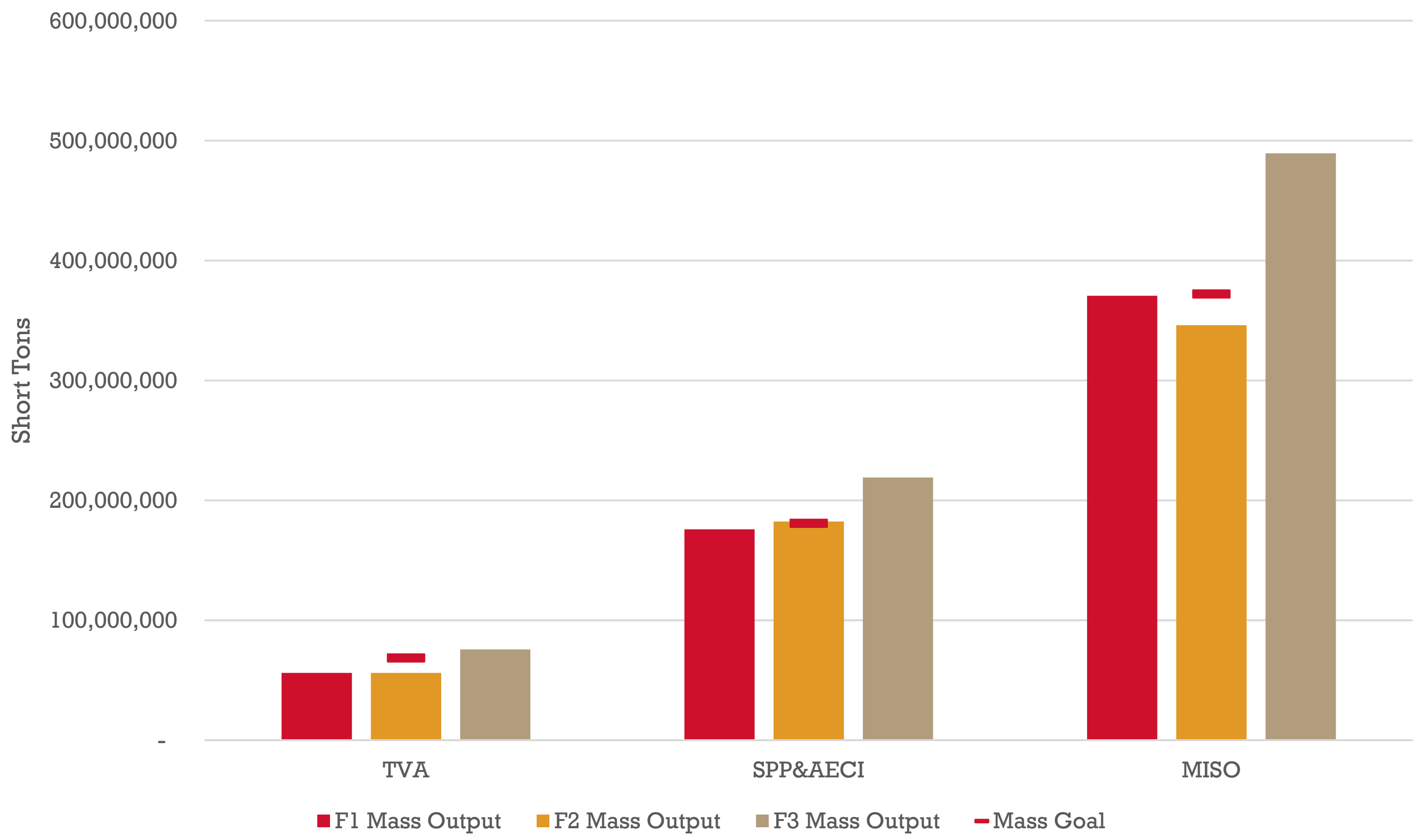
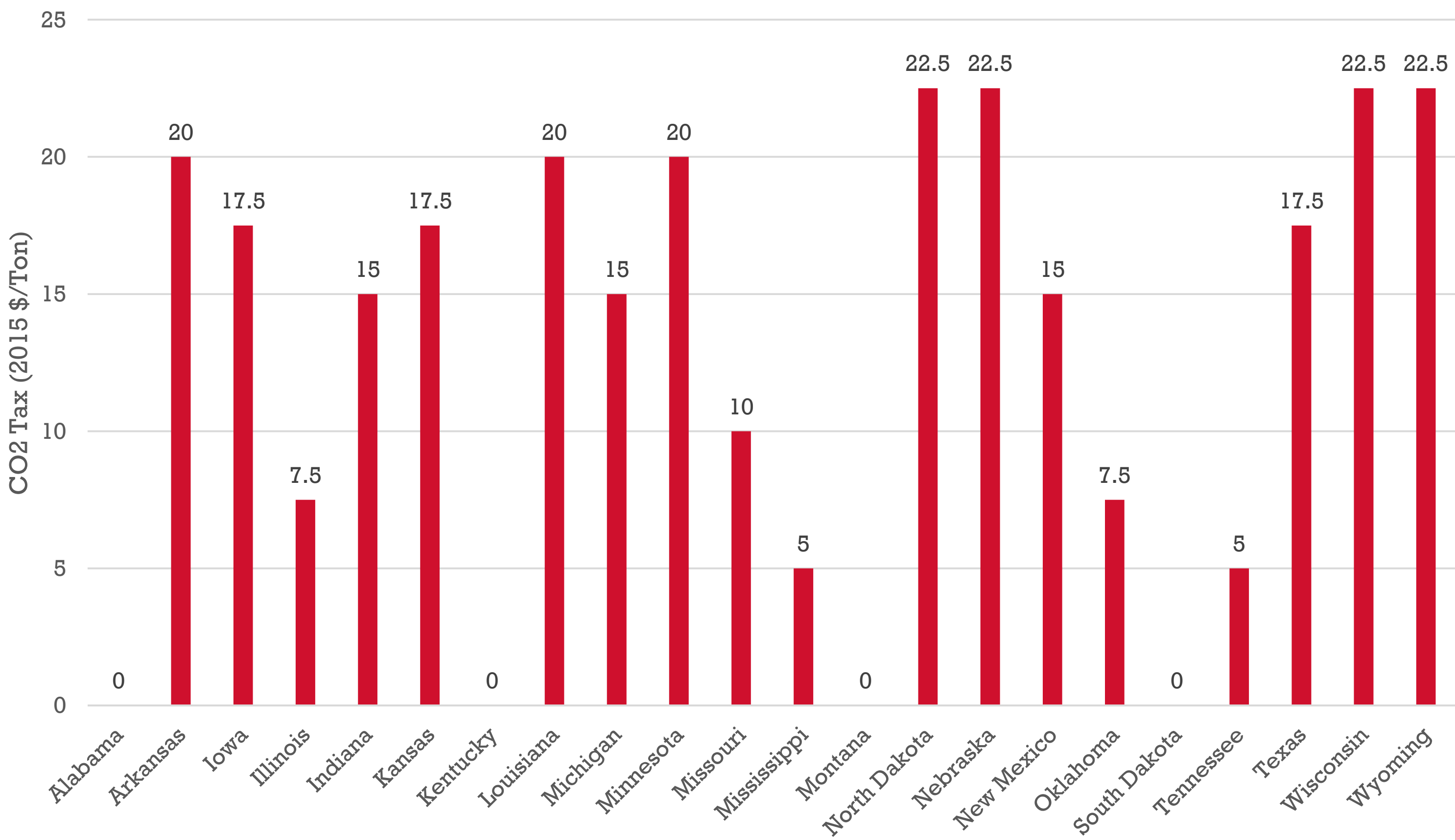
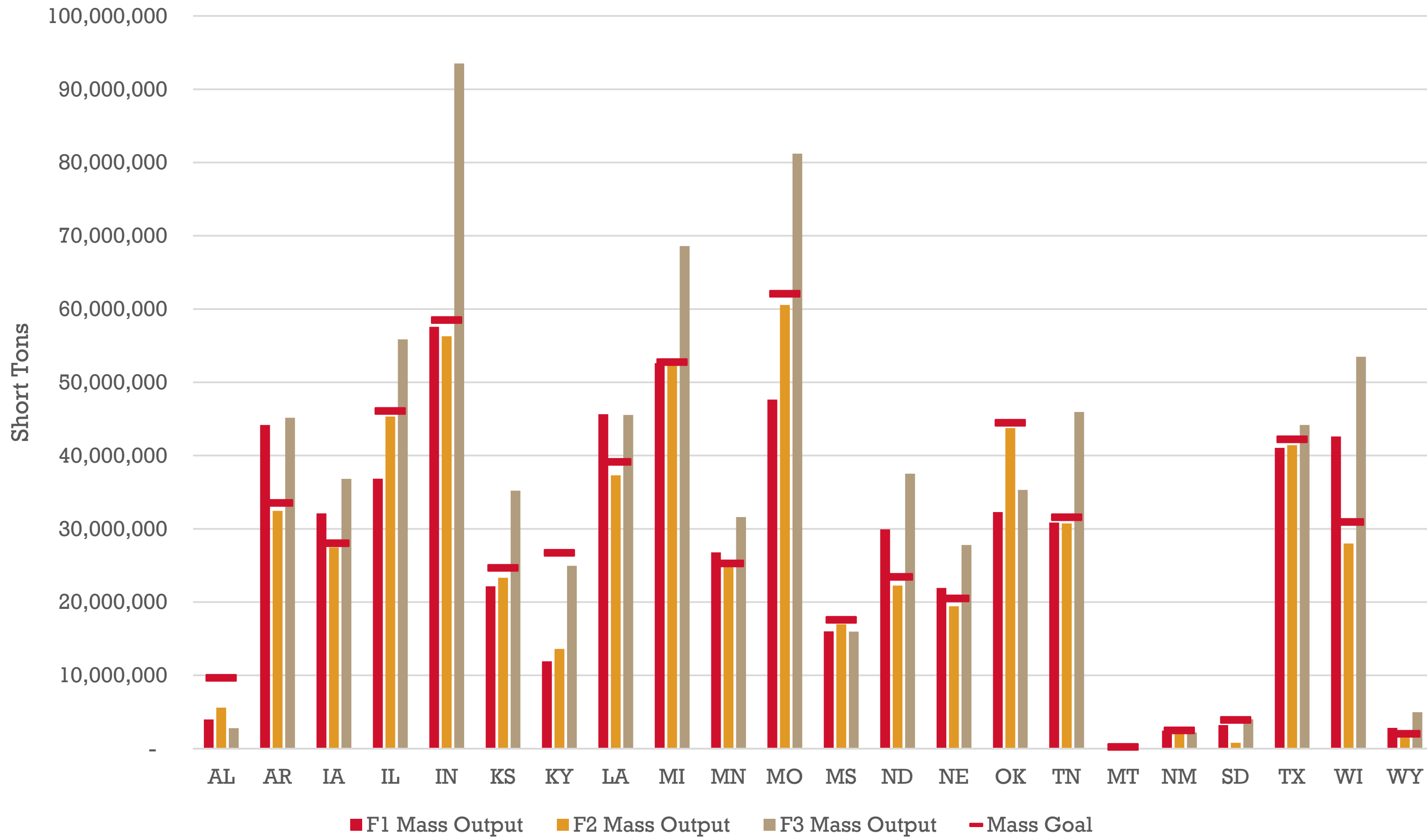


Constrained Model

2025 State by State Carbon Prices



2025 State Emissions by Future



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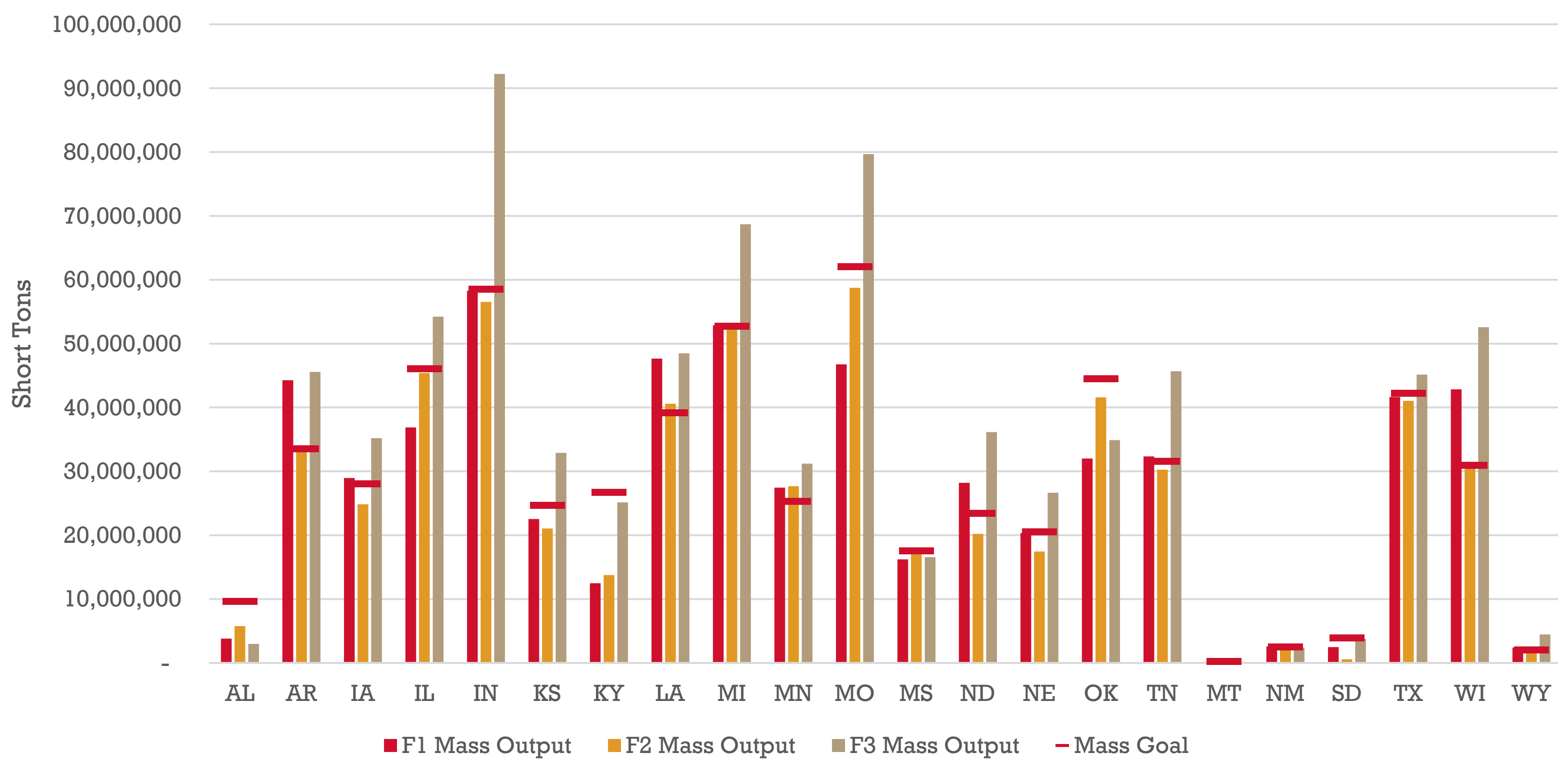
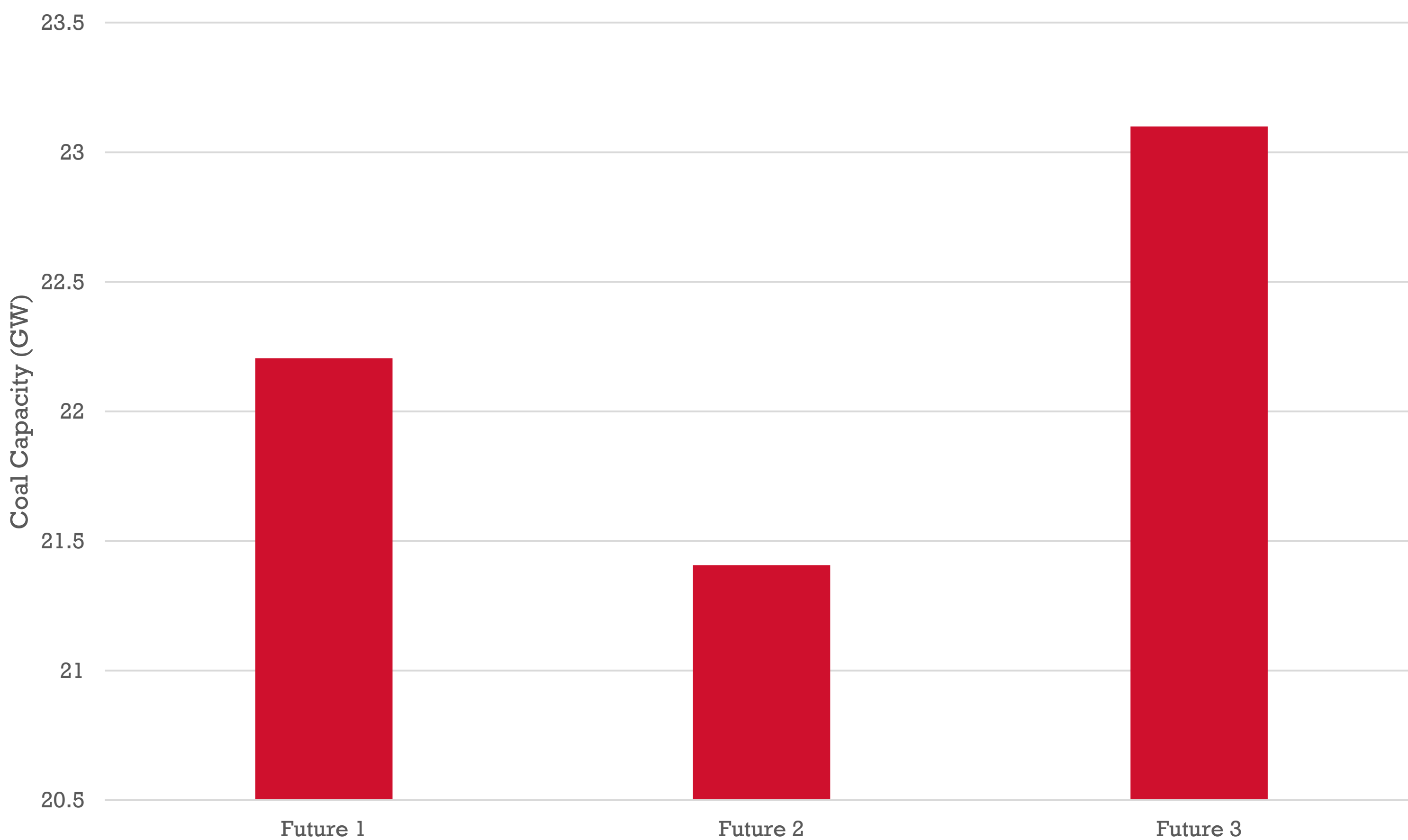
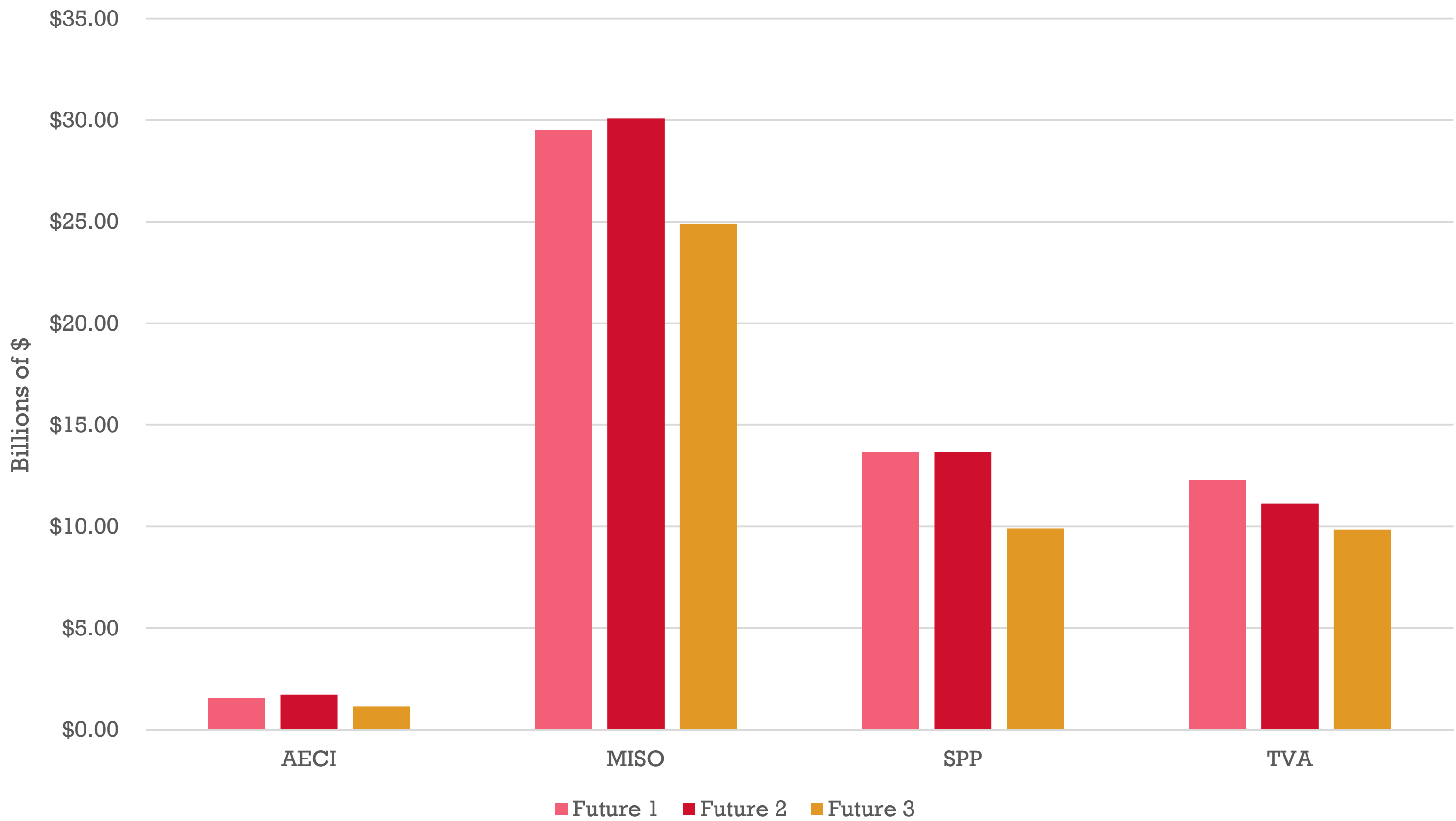


Constrained Model

SPP Coal Capacity by Future

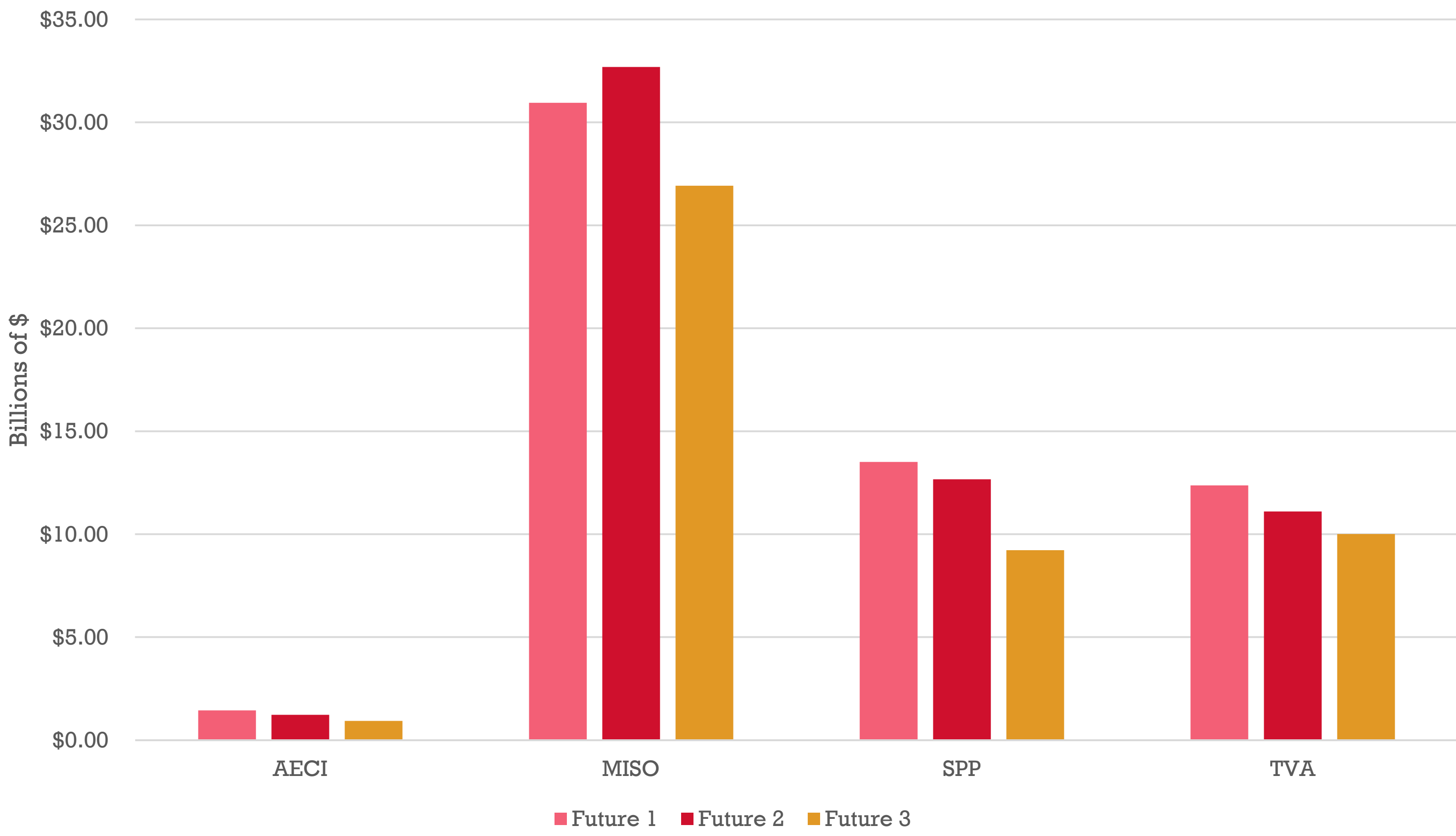


2025 Production Costs by Region

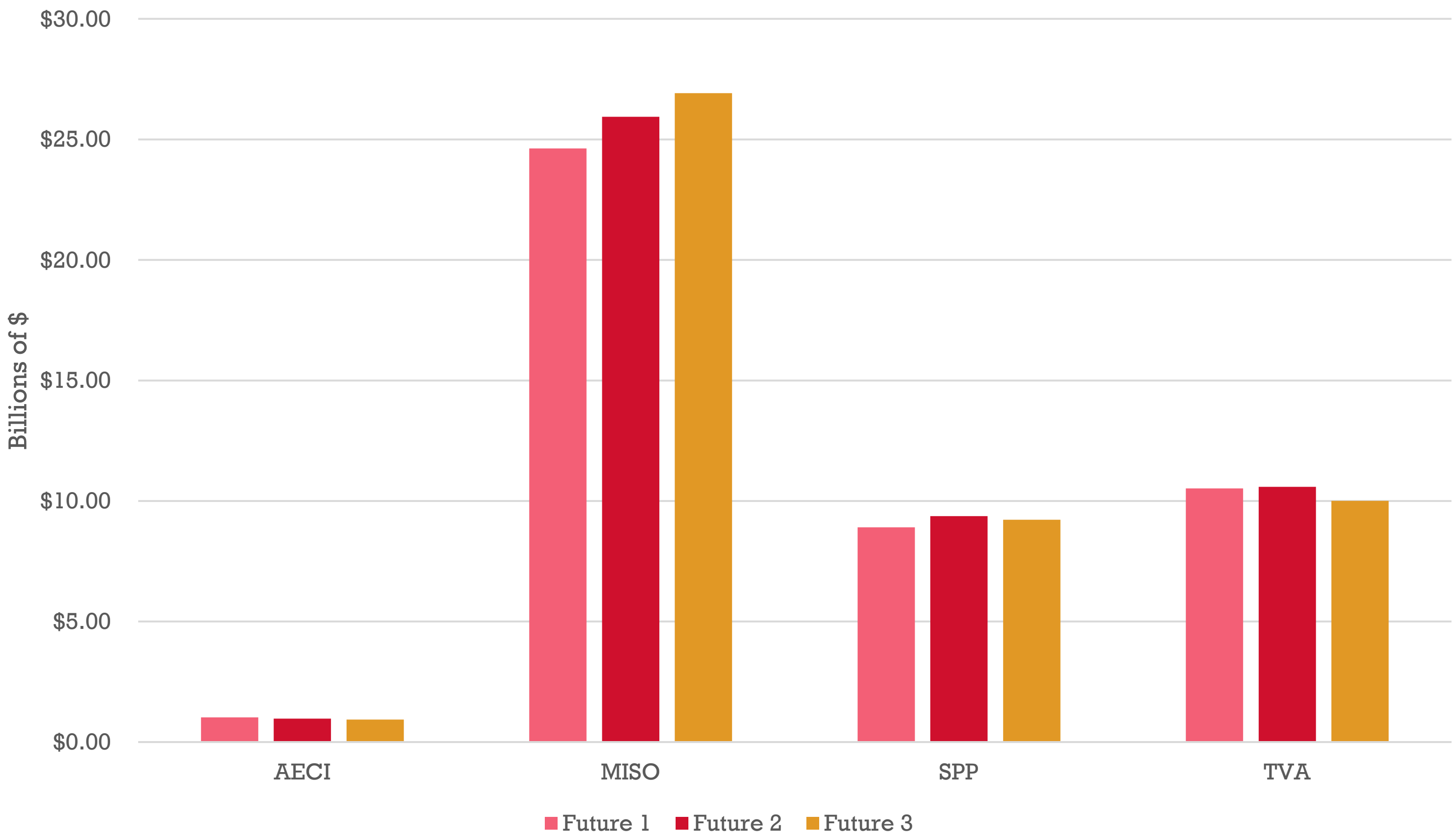


2025 Production Costs by Region – CO2 Suppressed

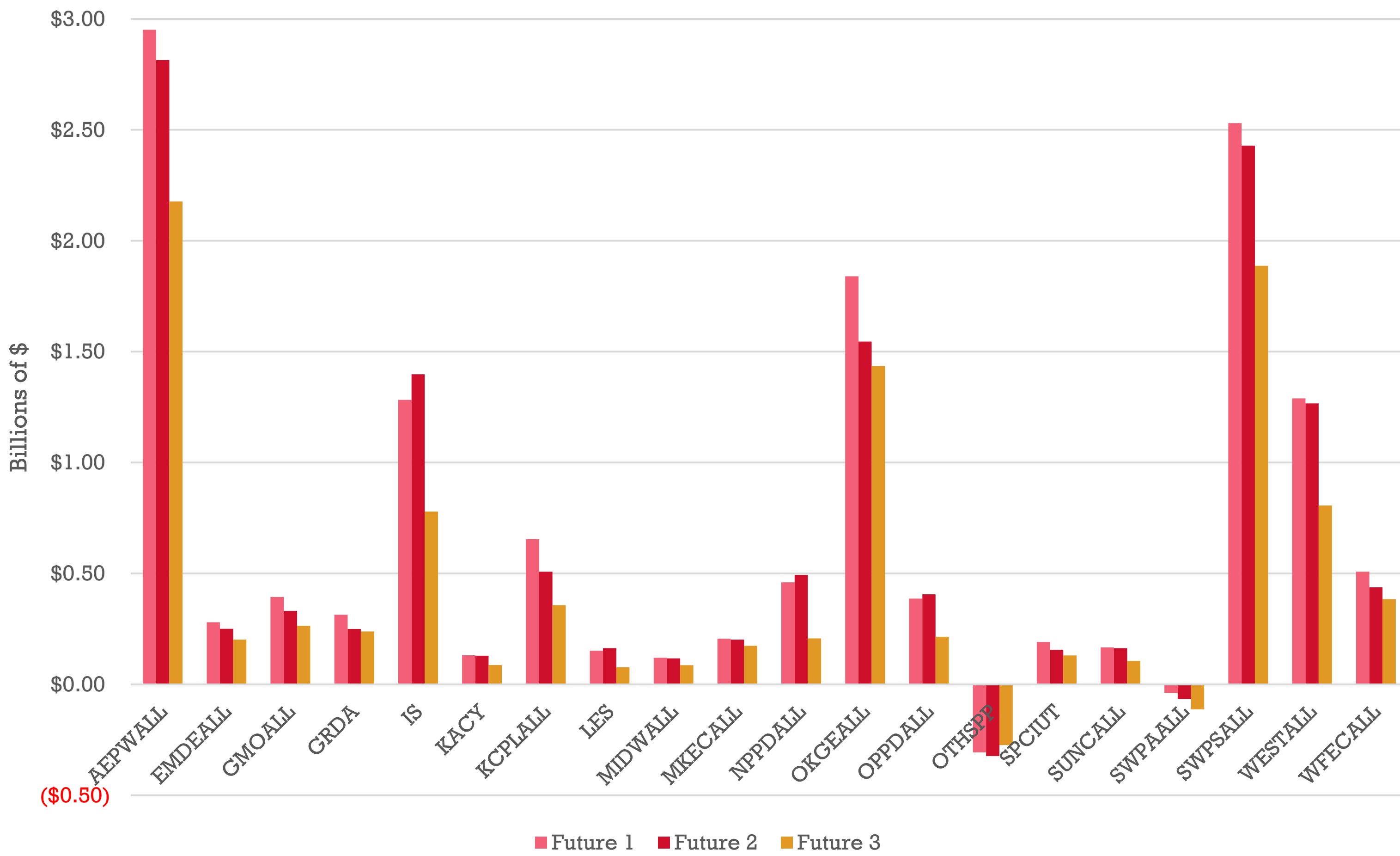
2025 APC by Region



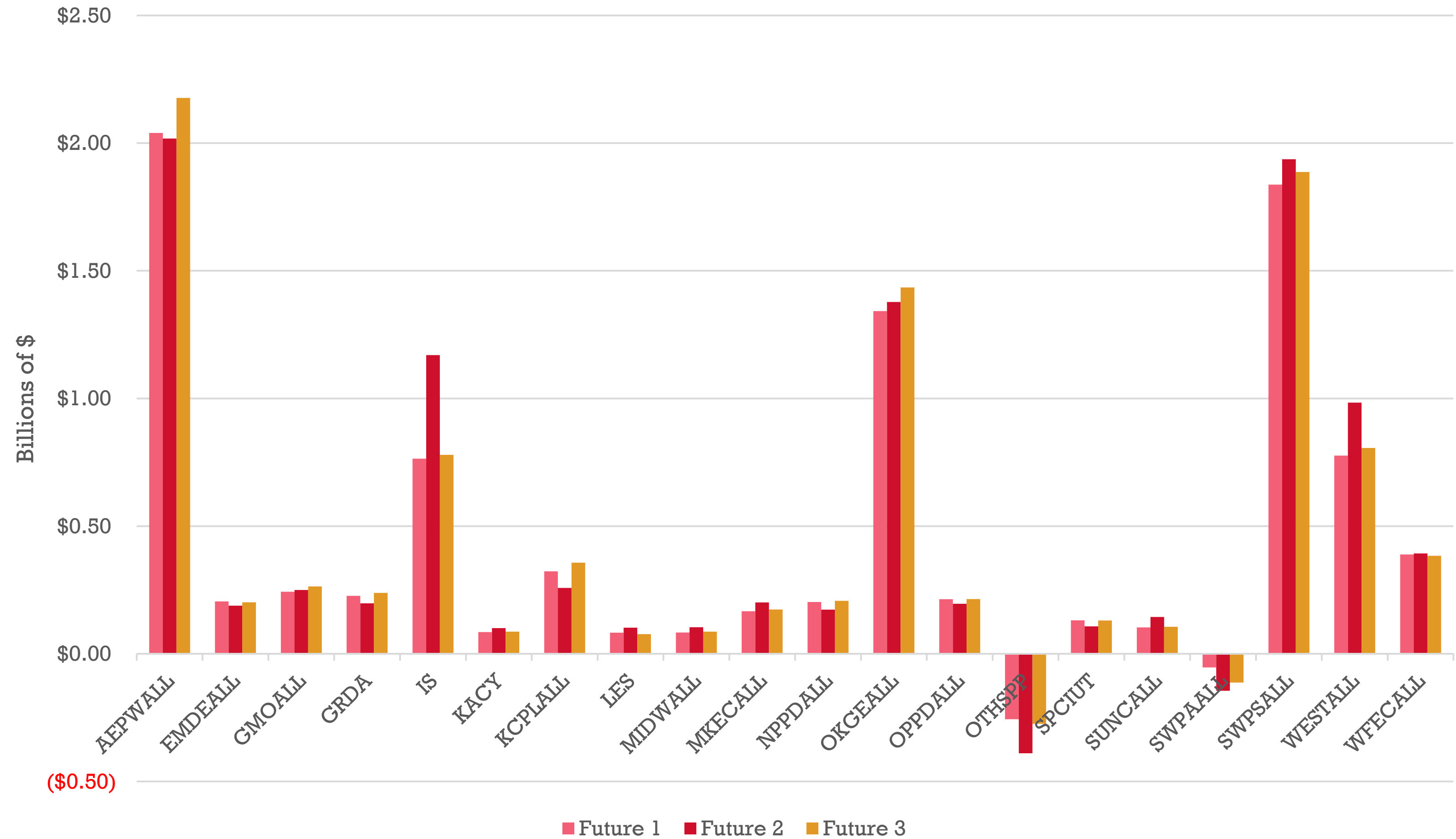
2025 APC by Region CO2 Suppressed



2025 APC by Zone



2025 APC by Zone Suppressed CO2

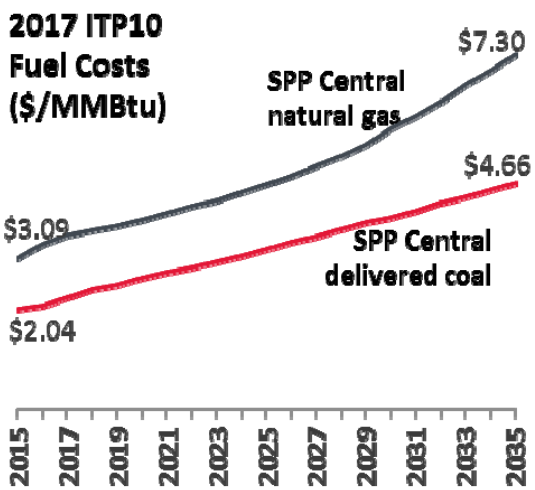


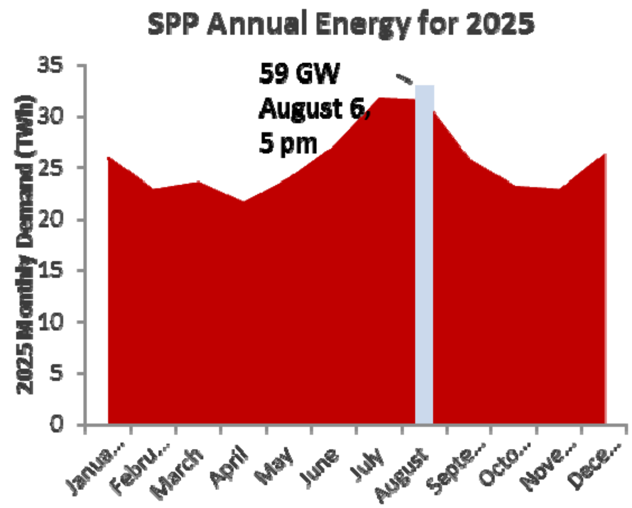
Recommendation

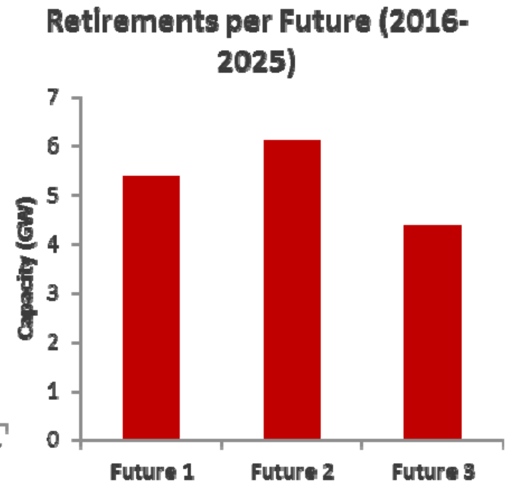
- SPP Staff recommends the ESWG approve the completion and results of the Benchmarking milestone of the 2017 ITP10

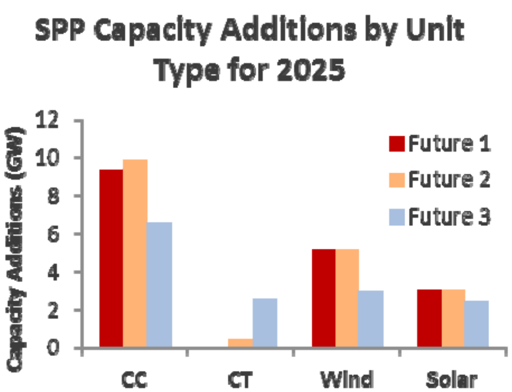
Appendix

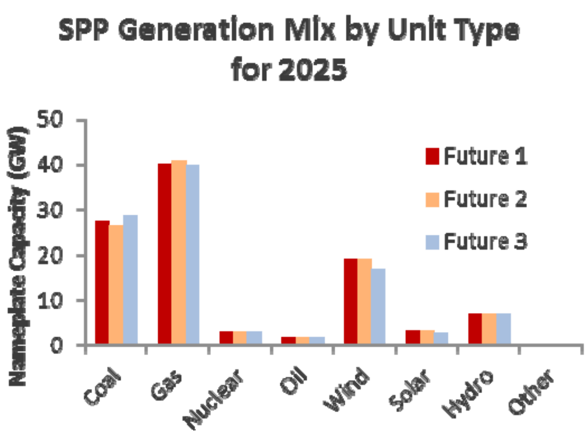
2017 ITP10 Input Assumptions

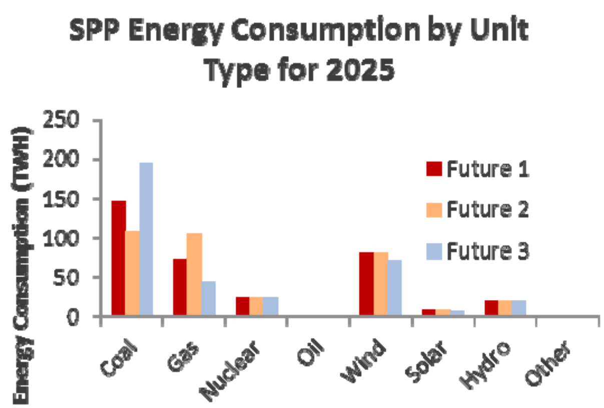




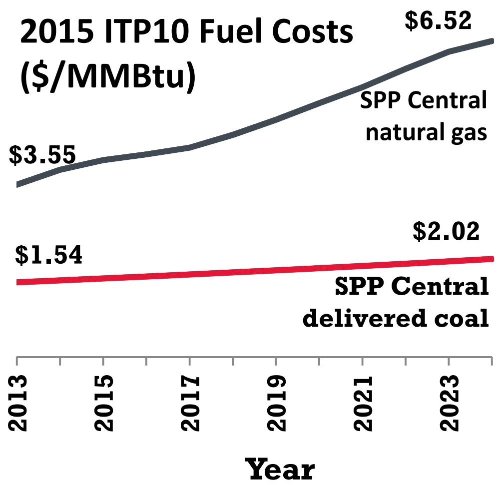


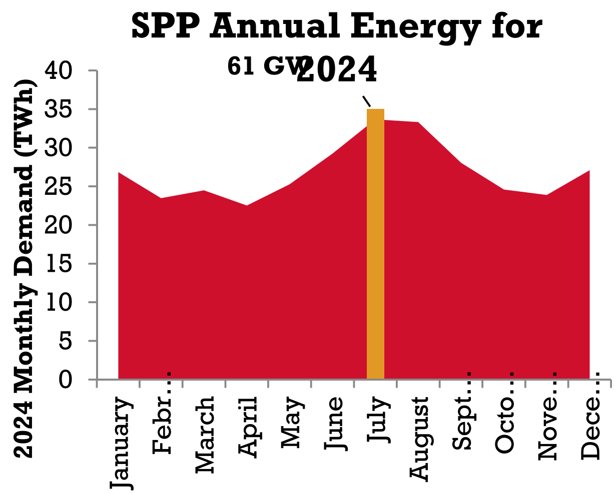


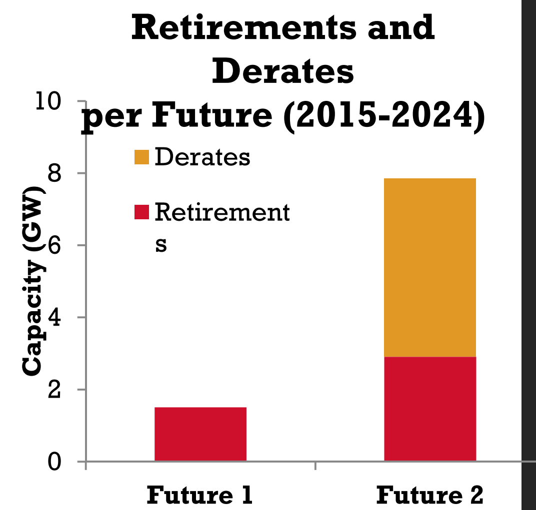


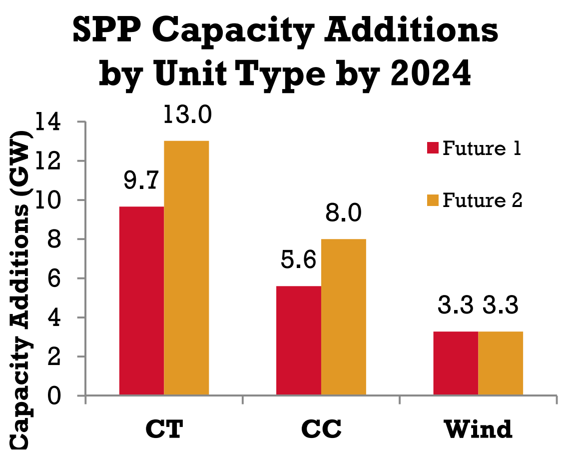


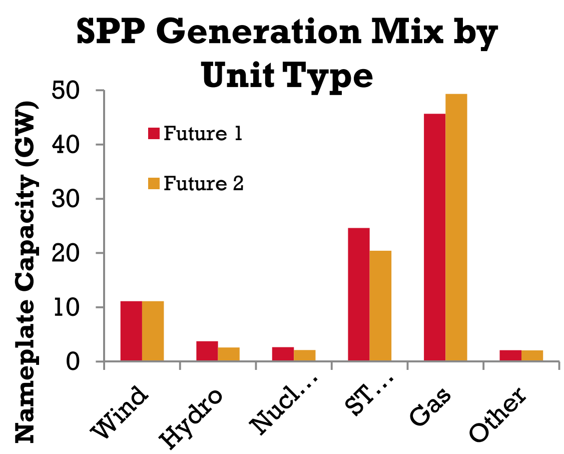
2015 ITP10 Input Assumptions

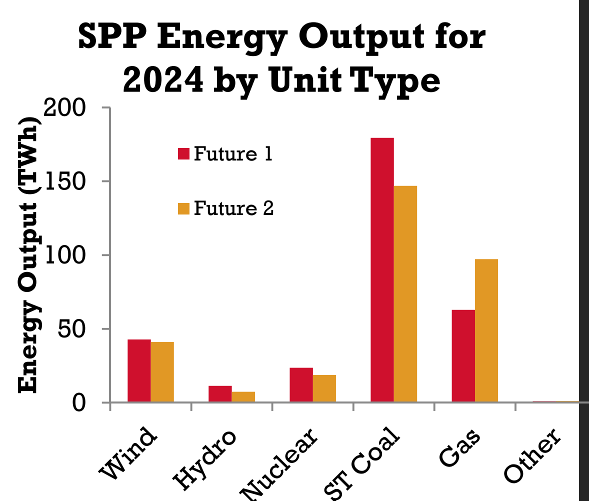












SPP Wind Integration Study Recommended Projects for Acceleration

Jason Tanner

March 17, 2016

WIS Recommended Projects for Acceleration

PID	State(s)	Upgrade Name	Project Type	New Date provided by TOP		Project Owner Indicated In-Service Date
30364	OK	Tatonga - Woodward District EHV 345 kV Ckt 2	Regional Reliability	**7/1/2018**	new date set by TO	3/1/2021
30364	OK	Mathewson - Tatonga 345 kV Ckt 2	Regional Reliability	**7/1/2018**	new date set by TO	3/1/2021
30364	OK	Cimarron - Mathewson 345 kV Ckt 2	Regional Reliability	**7/1/2016**	new date set by TO	6/1/2017
30364	OK	Mathewson 345 kV	Regional Reliability	**7/1/2016**	new date set by TO	6/1/2017
30367	KS	Elm Creek - Summit 345 kV Ckt 1 (ITCGP)	Regional Reliability	**12/31/2016**	new date set by TO	3/1/2018
30367	KS	Elm Creek 345/230 kV Transformer	Regional Reliability	**12/31/2016**	new date set by TO	12/31/2016
30367	KS	Elm Creek 345 kV Terminal Upgrades	Regional Reliability	**12/31/2016**	new date set by TO	12/31/2016
30367	KS	Elm Creek 230 kV Terminal Upgrades	Regional Reliability	**12/31/2016**	new date set by TO	12/31/2016
30367	KS	Elm Creek - Summit 345 kV Ckt 1 (WR)	Regional Reliability	**12/31/2016**	new date set by TO	12/31/2016
30509	TX	Canyon East Sub - Canyon West Sub 115 kV Ckt 1 Rebuild	Regional Reliability	**7/1/2016**	new date set by TO	5/31/2016
30817	TX	Canyon West - Dawn 115 kV Ckt 1 Rebuild	Regional Reliability	**not feasible to accelerate**	Right of way coordination needed	4/1/2018
30817	TX	Dawn - Panda 115 kV Ckt 1 Rebuild	Regional Reliability	**not feasible to accelerate**	Right of way coordination needed	4/1/2018
30817	TX	Deaf Smith - Panda 115 kV Ckt 1 Rebuild	Regional Reliability	**not feasible to accelerate**	Right of way coordination needed	4/1/2018
30842	TX	Pantex North - Pantex South 115 kV Ckt 1 Reconductor	Regional Reliability	**needs NTC**		4/1/2019
30842	TX	Highland Park - Pantex South 115 kV Ckt 1 Reconductor	Regional Reliability	**needs NTC**		4/1/2019
30842	TX	Martin - Pantex North 115 kV Ckt 1 Reconductor	Regional Reliability	**needs NTC**		4/1/2019
30843	OK	Cimarron - Draper 345 kV Terminal Upgrades	Regional Reliability	**6/1/2017**		4/1/2019
30844	TX	Amoco - Sundown 230 kV Terminal Upgrades	Economic	**10/1/2018**		4/1/2019
30916	KS	Buckner - Spearville 345 kV Ckt 1 Terminal Upgrades	Regional Reliability	**3/1/2017**	not feasible to accelerate	12/31/2016

75

Methodology

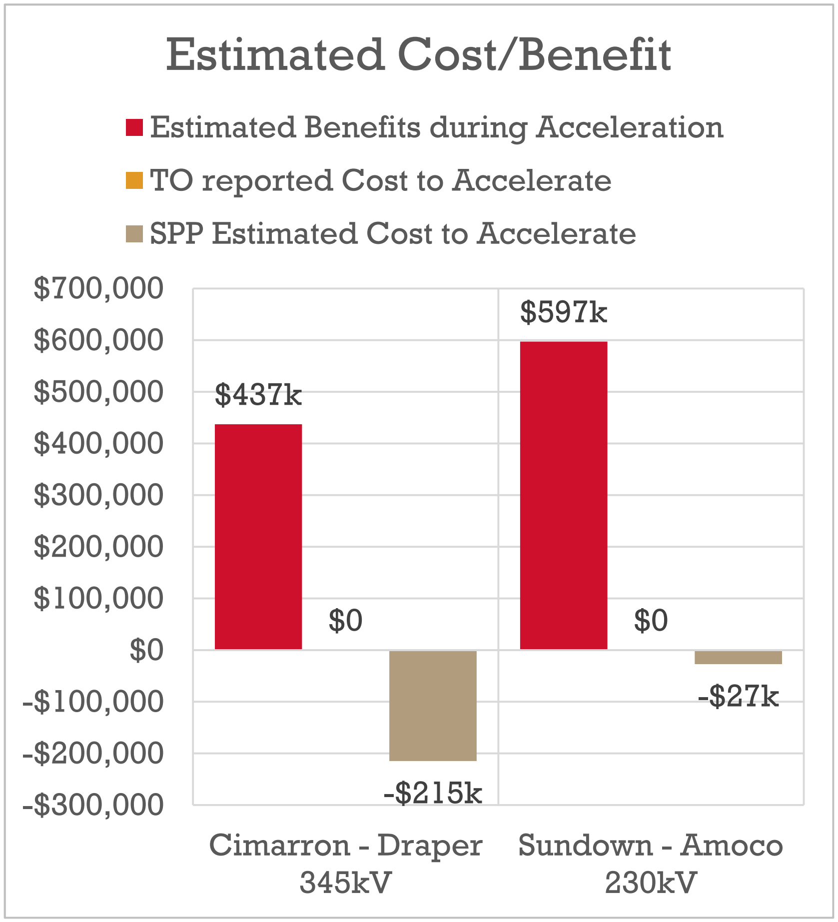
- Same as before
  - Used WIS scenarios, benefit calculated based on production cost difference between scenarios with and without selected project(s)
  - It was not feasible to re-build models based on individual project acceleration dates or rebuild 8760 models
  - Major change to models was the assessment of benefits with updated topology, specifically adding approved upgrades (including those others identified in WIS. Modeled to be in-service by 7/1/2018 and impacted binding constraints in the analysis (ex. Chisholm – Gracemont 345kV ISD 3/1/18)
- Calculate average benefit for each project based on WIS 30-60% scenarios and extrapolate to annual benefits based on expectation of congestion occurrence throughout the year (estimated ~22.6% of hours in the year)
- Multiply annual benefit values times acceleration window to get total expected benefits of acceleration
- Compare total benefits to cost of acceleration

Benefits

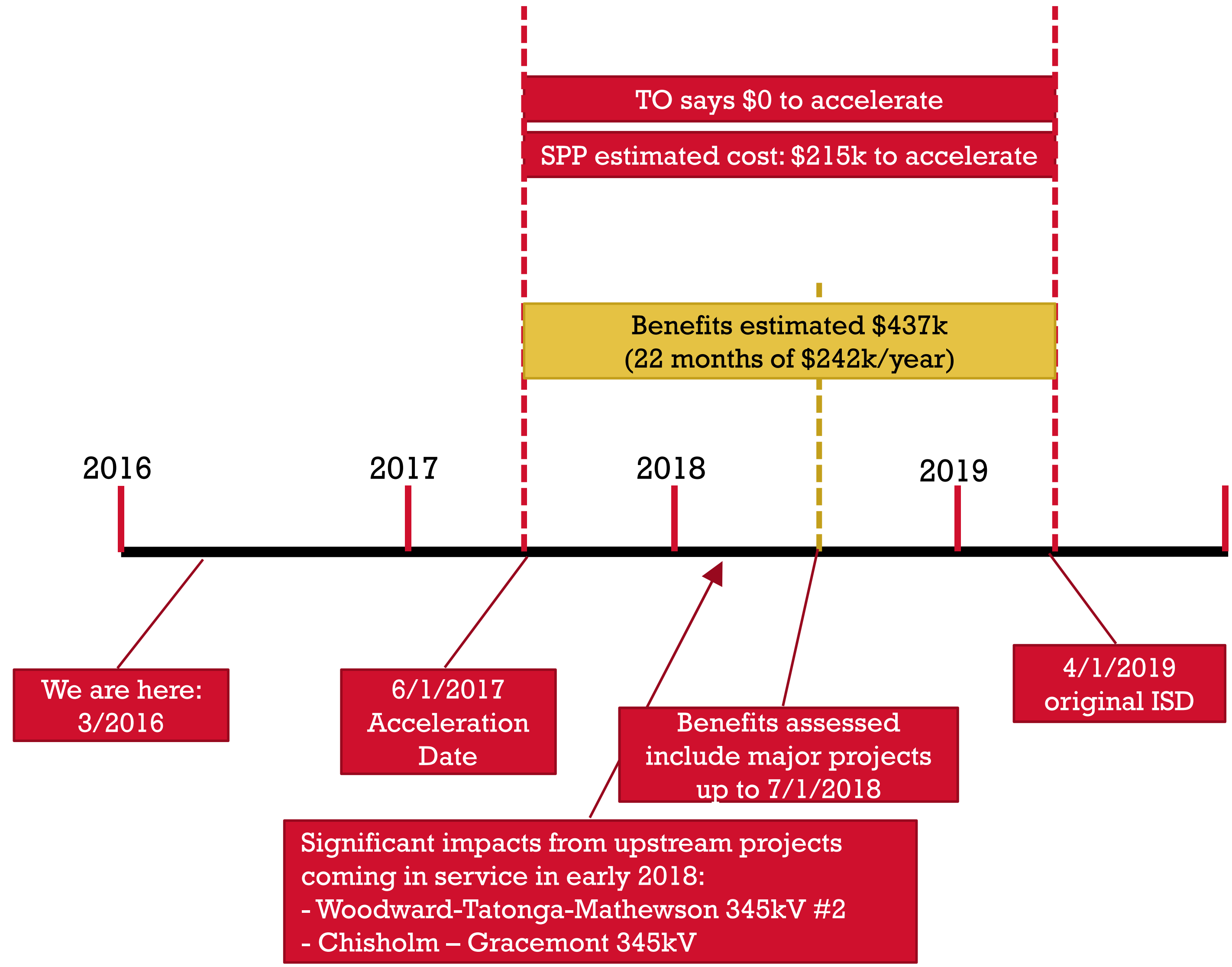
- Cimarron – Draper 345kV
  - Average benefit for scenario (~$120/hour)
  - Annual benefit = $238k/year (~$120/hour * 8760 hours/year * 0.226)
  - Benefit over acceleration window = **$437k** (~$238k/year * 1.833 years)
- Sundown – Amoco 230kV
  - Average benefit for scenario (~$603/hour)
  - Annual benefit = $1,194k/year (~$603/hour * 8760 hours/year * 0.226)
  - Benefit over acceleration window = **$597k** (~$1,194k/year * 0.5 years)
- Additional scenario was run with both projects
  - Average benefit for scenario (~$650/hour)
  - Annual benefit = $1,287k/year (~$650/hour * 8760 hours/year * 0.226)

Cost/Benefit

- TO reported $0 additional cost to project to accelerate
- SPP internally calculated cost of acceleration based on Net Plant Carrying Charge (NPCC), construction inflation, depreciation, etc. over life of equipment
  - $215k cost for 2 years of acceleration for Cimarron – Draper 345kV
  - $27k cost for 1 year of acceleration for Sundown – Amoco 230kV
- **<u>Benefits outweigh cost over acceleration window</u>**

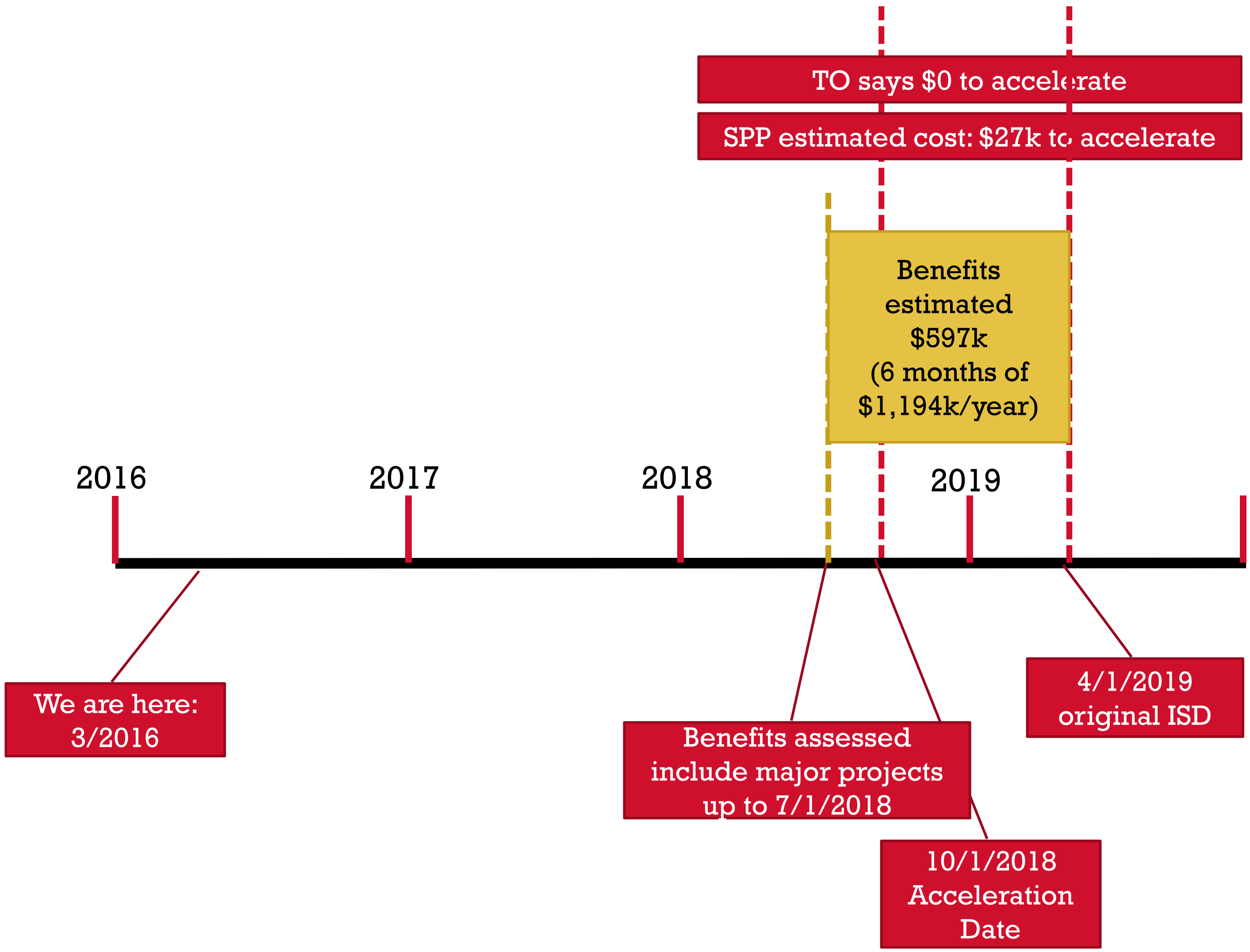


Cimarron – Draper 345kV



*We already have existing temporary flowgate TEMP63_21164 built (Cimarron – Draper 345kV ftlo Minco – Gracemont 345kV) that was built and saw congestion in summer 2015

Sundown – Amoco 230kV



*We already have existing permanent flowgate #5548 (SUNAMOTOLYOA) since 2014 (was temporary flowgate before), which saw >300 hours of congestion in RTBM in 2015

Recommendation

- SPP Staff Recommends Stakeholder Approval to endorse the Wind Integration Study recommendation #5 to begin accelerating the approved ITP projects with issued NTCs, specifically:

PID	State(s)	Upgrade Name
30843	OK	Cimarron - Draper 345 kV Terminal Upgrades
30844	TX	Amoco - Sundown 230 kV Terminal Upgrades


SPP
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SEVENTY-FIVE YEARS OF
RELIABILITY THROUGH RELATIONSHIPS

2017 ITP10 Analysis Methodology

ESWG

March 17th, 2016

Considering the Clean Power Plan

2017 ITP10

Reflecting the Price of Carbon

2017 ITP10

Reflecting the Price of Carbon

- Options on modeling carbon price
  - Affect dispatch
    - Price of carbon reflected in dispatch decisions
  - Affect dispatch and APC
    - Price of carbon reflected in the cost of energy
- Considerations
  - Should the cost of carbon be reflected in APC calculations or just as a means to affect dispatch?
  - Should the carbon price be applied to all units or just affected EGUs?

Recommendation

- Cost of carbon should be reflected in energy costs of affected EGUs
  - Generators will be bidding into the market will assume the price of carbon
    - It is a true cost that needs to be recovered
    - It is can be an incurred cost or a lost opportunity cost, therefore should apply regardless of whether the utility needs to buy allowances/credits to actually generate
  - Able to include additional economic benefit of transmission projects that reduce carbon emissions

- Dispatch of non-affected EGUs should be controlled due to constraints that we have limited way of considering: fuel supply, air permit requirements, water availability
  - Cost of carbon should be utilized as a modeling technique to affect dispatch of non-affected EGUs

Meeting CPP Compliance

2017 ITP10

Monitoring Emissions

- CPP compliance has been targeted during resource planning
- Carbon cost adders have been set to ensure compliance in an unconstrained economic model
  - Carbon pricing was determined as a function of the resource plan analysis to reflect the impact of long-term utility decisions
  - Economic model utilized to appropriately price carbon for external regions and on a state by state basis

Compliance of the Transmission Plan

- Should the final portfolio per future show compliance in the model? Two schools of thought.
  - 1: The final portfolio must demonstrate CPP compliance
    - Via the model showing compliance
    - We have developed a reasonable scenario for which to comply with emissions targets and we should develop a transmission plan that demonstrates compliance.
  - 2: The final portfolio must facilitate CPP compliance
    - Via the model showing reduced emissions
    - With the uncertainties of the CPP, development of a plan through traditional methodologies within the context of our modeling assumptions is both a sufficient and appropriate path to CPP compliance

Implementing the Schools

- School 1a
  - Follow the normal process
  - Develop a plan that potentially leaves the model out of compliance
  - Use engineering judgment to determine incremental upgrades that will achieve compliance for informational purposes only
- School 1b
  - Define emission targets for affected EGUs as needs
    - F1 by region
    - F2 by state
- School 2
  - Follow normal process
  - Develop a plan that potentially leaves the model out of compliance

Recommendation

- Develop portfolios for Future 1 and Future 2 following School 1a
  - Follow normal process
  - Identify potential additional projects needed to meet emission targets for informational purposes
- Note: the recommended plan (consolidated portfolio) will likely not demonstrate compliance in any one future model

Portfolio Consolidation

2017 ITP10

Previous Discussion

- Develop 2 final portfolios for MOPC/BOD consideration, CPP and non-CPP
- Highlight "no regrets" projects selected for all futures
- Portfolios
  - Reference case portfolio
  - Consolidate CPP futures using weighted benefit methodology
    - Equal weighted sum 1-year APC B/C, 0.9 or greater

Staff Recommendation

- Develop multiple plans to present to MOPC/BOD
- CPP Portfolio
  - Consolidate F1 and F2 plans
  - Weighted sum 1-year APC B/C methodology
  - 75% weight to F1, 25% weight to F2
    - Project strong in F1 will continue to consolidated CPP plan
    - Projects decent in F1 and F2 will continue to consolidated CPP plan
- Non-CPP Portfolio

Metrics and Sensitivities

2017 ITP10

Staff Recommendation

- Metrics
  - Calculate approved benefit metrics on 2 final plans
- Sensitivities
  - Calculate demand and gas sensitivities on 2 final plans
- Model selection
  - Calculate CPP plan metrics and sensitivities in F1 model
  - Calculate non-CPP plan metrics and sensitivities in F3 model


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SEVENTY-FIVE YEARS OF
RELIABILITY THROUGH RELATIONSHIPS

2017 ITP10 Economic Model

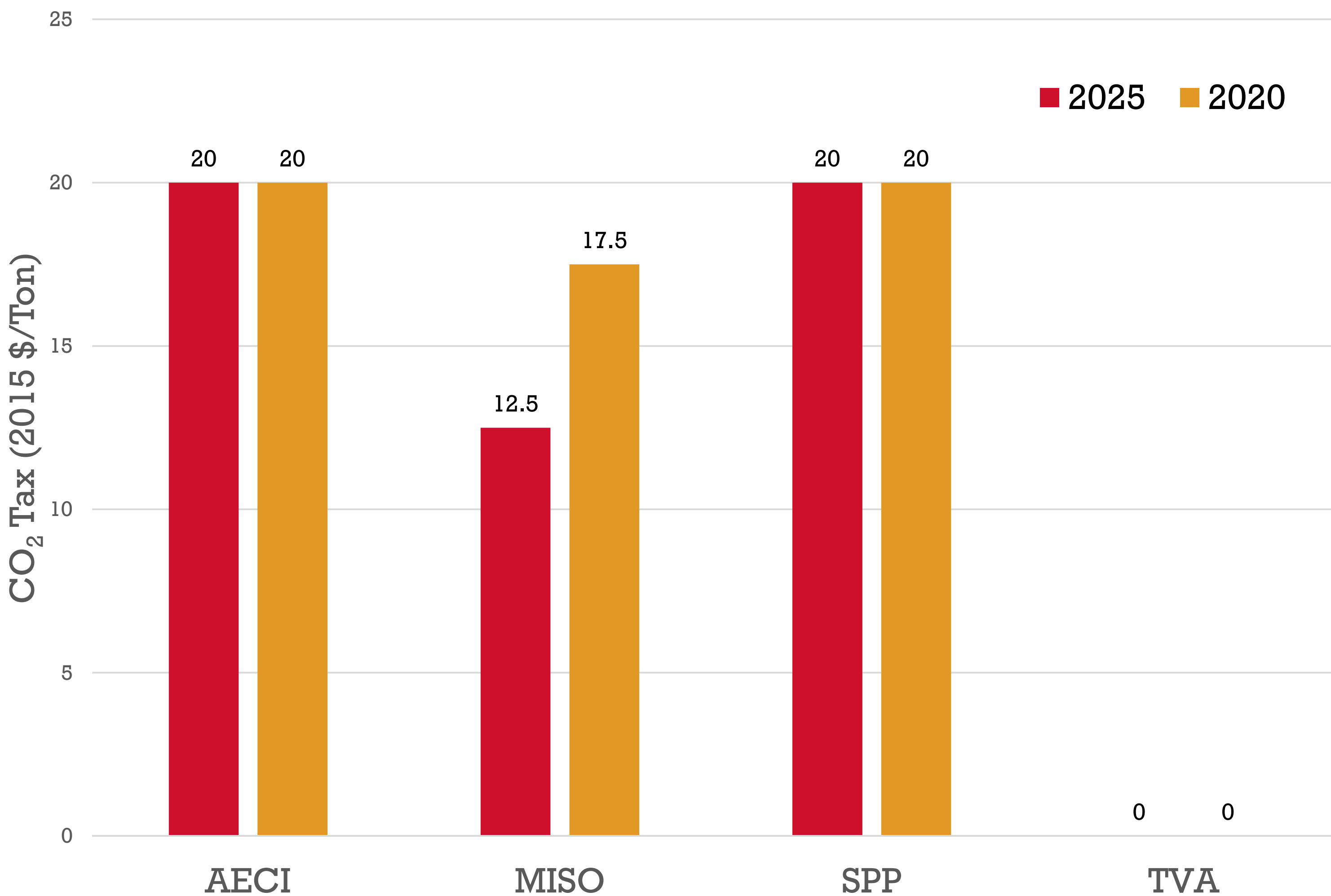
ESWG

March 17th, 2016

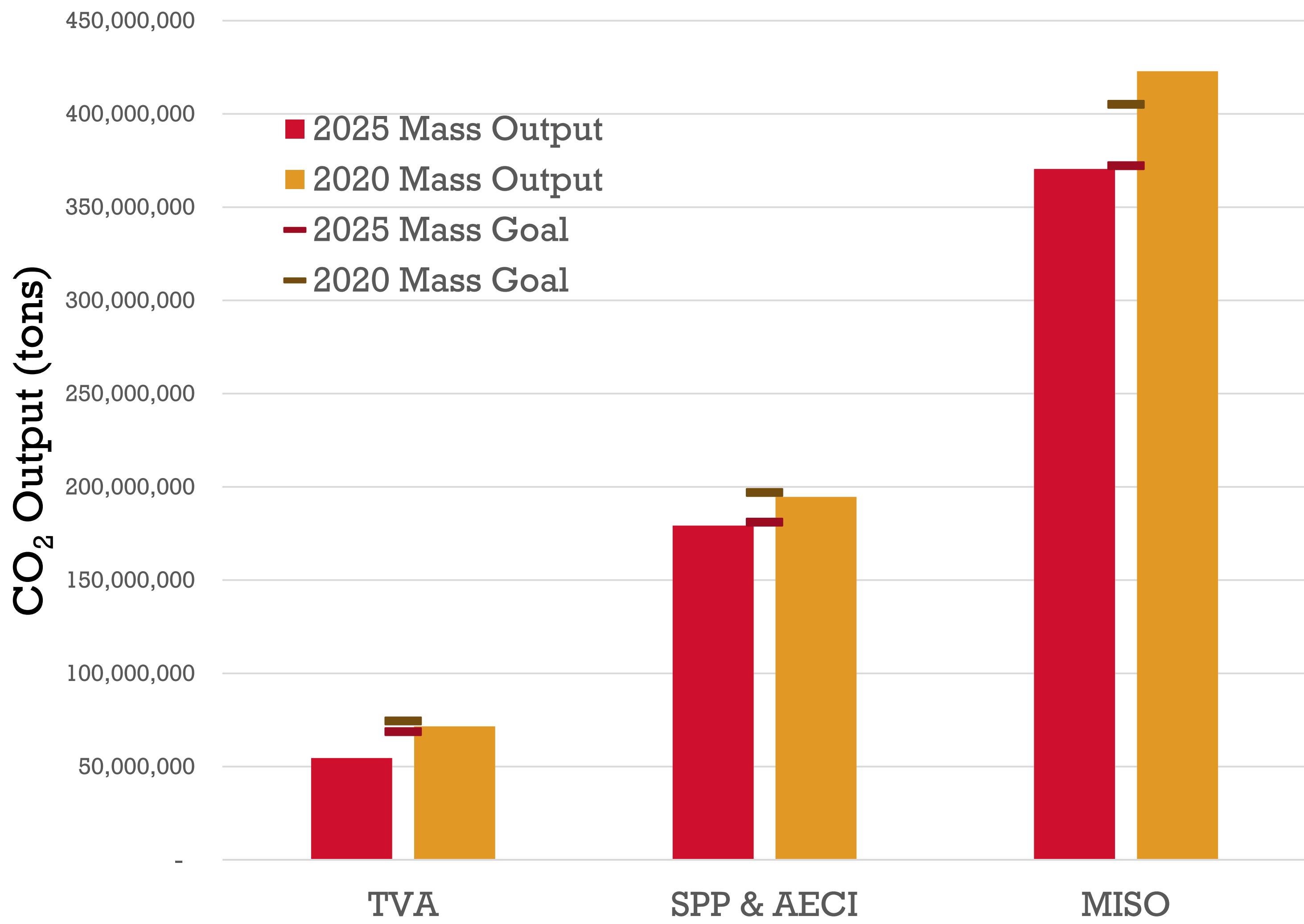
2017 ITP10 Economic Model

- Final Version (5th Pass) Posted to TrueShare on March 10th
  - For ABB Licensees:
    - Trueshare >> Integrated Transmission Planning--Confidential and Protected Material and or Critical Energy Infrastructure Information-Do Not Release >> 2017 ITP10 >> Joint NDA – 2017 ITP10 Models
  - For ABB NDA Signees:
    - Trueshare >> Integrated Transmission Planning--Confidential and Protected Material and or Critical Energy Infrastructure Information-Do Not Release >> 2017 ITP10 >> Joint NDA – 2017 ITP10 Modeling Data

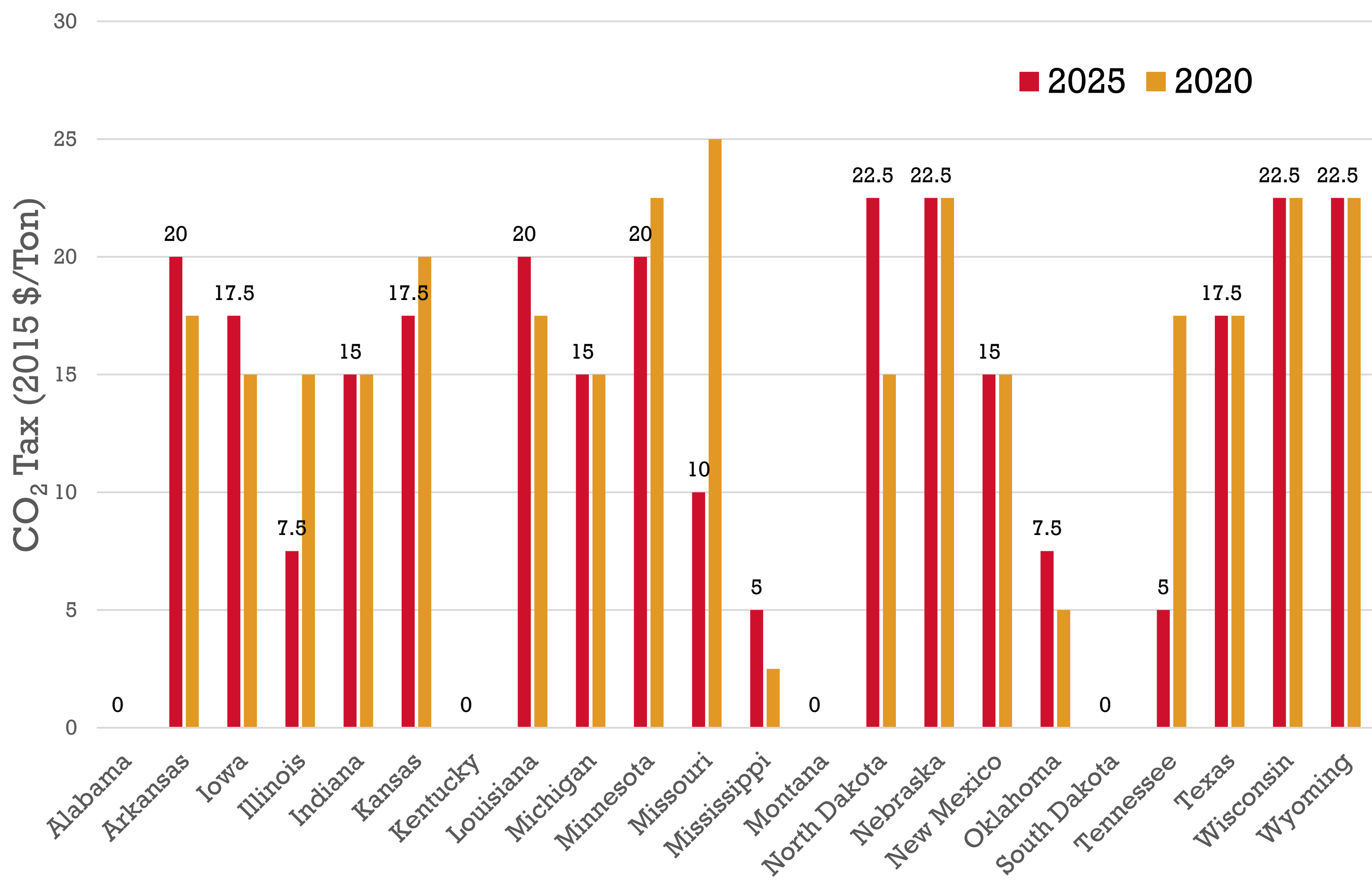
F1 Regional Carbon Prices



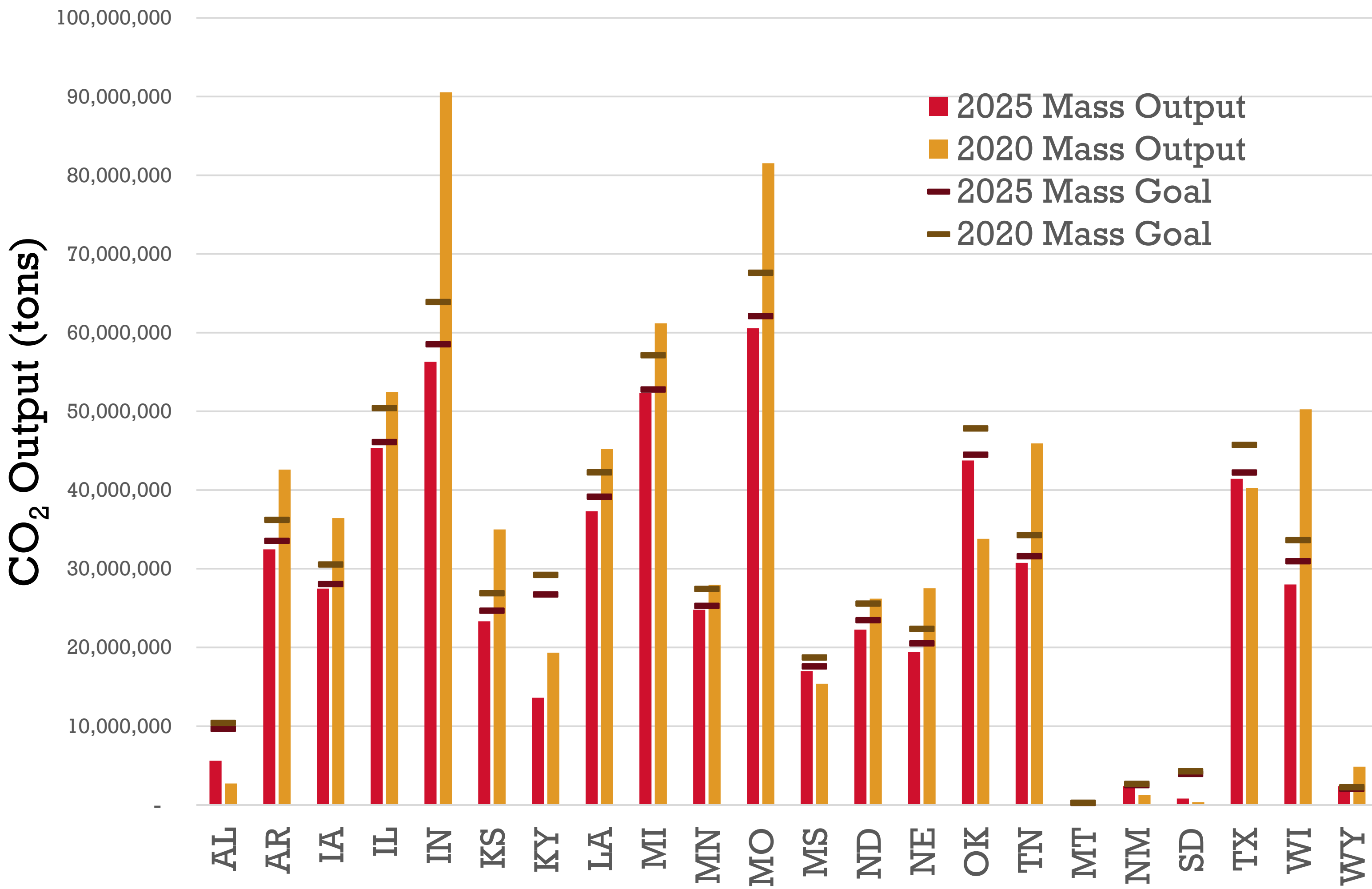
F1 Regional Emissions



F2 State Carbon Prices



F2 State Emissions



Recommendation

SPP Staff recommends that the ESWG approve the 2017 ITP10 economic models as posted on TrueShare with adjustments to 2020 carbon prices for Future 1 and Future 2 detailed in the Economic Model presentation at the 3/17 ESWG meeting, including direction to be given by the ESWG on modeling of carbon costs for APC calculation.

2017 ITP10 Scope Changes

ESWG

March 17th, 2016

Scope Changes

- Analysis – Needs Assessment – Economic Assessment
  - Removed language stating that the ESWG will approve the constraint list
- Analysis - Solution Development
  - Updated consolidation language to allow for a CPP portfolio and a reference case portfolio
- Analysis - Solution Development – Economic Project Solutions
  - Included language for the 0.5 B/C ratio threshold
- Analysis - Final Recommended Portfolio
  - Updated consolidation language to allow for a CPP portfolio and a reference case portfolio
- Analysis – Benefit Metric Development and Usage
  - Updated language to allow metric calculation one more than one portfolio
  - Removed legacy language allowing changes to Benefit Metrics
- Analysis – Sensitivities
  - Updated language stating sensitivities to perform

2017 ITP10 Scope

Approved by ESWG: 09/23/2015
Approved by TWG: 09/29/2015
Approved by MOPC: 10/13/2015

ESWG / TWG / SPP Staff

SPP Southwest Power Pool

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Overview

This document presents the scope and schedule of work for the Integrated Transmission Planning (ITP) 10-Year Assessment. This document will be reviewed by the Transmission Working Group (TWG) and the Economic Studies Working Group (ESWG) beginning June 2015, with the expectation of approvals from the Market Operations and Policy Committee (MOPC) and the Board of Directors (BOD) in October 2015. The assessment begins in July 2015 and is an 18-month study scheduled to be finalized in January 2017.

Objective

The 2017 ITP 10-Year Assessment (ITP10) is a value-based planning approach that will analyze the 10-year out Transmission System and identify 100 kV and above solutions to needs stemming from multiple sources: (a) needs identified in the reliability analysis of the 100 kV and above system, (b) needs identified to meet projected renewable policy mandates and goals, and (c) needs arising from transmission system congestion.

The SPP ITP process is open and transparent and allows for stakeholder input through the FERC Order 1000 and Order 890 processes. The Economic Studies Working Group (ESWG) and Transmission Working Group (TWG) will have opportunities to review and vet components of the 2017 ITP10 process, which includes but is not limited to the following items: model development, economic, policy, and reliability analysis, transmission plan development, seams impacts, and the 2017 ITP10 Report. In addition, SPP will present the ITP10 Transmission Plan at the SPP transmission planning summits as an opportunity for SPP stakeholders to provide feedback. SPP will also coordinate the study results with first-tier neighbors.

The focus of the Study is to develop a comprehensive, flexible, and cost-effective transmission expansion plan to meet the requirements of the SPP footprint under various futures.

Stakeholder Process

Working Group Involvement

The 2017 ITP10 will be vetted through the SPP working groups. The ESWG will oversee the economic portions of the 2017 ITP10 and all related data and assumptions. The TWG will oversee the reliability portions of the 2017 ITP10 and all related data and assumptions. The following items will be discussed at the respective working groups:

Transmission Working Group (TWG), Model Development Working Group (MDWG)

The TWG and/or the MDWG will be responsible for reviewing the data and results for the following items:

1) Scope
2) Futures
3) Load Forecast
4) Generator Review
5) Generator Outlet Facilities
6) Steady State Models
7) Constraint Review
8) Reliability Assessment
9) Stability Assessment
10) Transmission Plan Development
11) Benefit Metrics
12) Report

Economic Studies Working Group (ESWG)

The ESWG will be responsible for reviewing the data and results for the following items:

1) Scope
2) Futures – Development and Approval
3) Renewable Policy Survey
4) Load Forecast - Energy
5) Generator Review
6) Resource Plan and Siting

7) Economic Modeling Assumptions
8) Policy Assessment
9) Economic Assessment
10) Transmission Plan Development
11) Benefit Metrics
12) Sensitivities
13) Report

Markets and Operations Policy Committee (MOPC)

The MOPC will be sought for endorsement of the following items:

1) Scope
2) Futures
3) Policy-Driven Decisions
4) Report

Strategic Planning Committee (SPC)

The SPC will be sought for endorsement of the following items:

1) Futures

Seams Steering Committee (SSC)

The SSC will be responsible for the review of the following item:

1) Seams Impacts

Regional State Committee (RSC)

The RSC will be presented with the following items:

1) Transmission Plan
2) Cost and Benefit Allocation
3) Report

Board of Directors (BOD)

The BOD will approve the following items:

1) Transmission Plan
2) Cost and Benefit Allocation

3) Report

The final 2017 ITP10 Report will be endorsed by the TWG, ESWG, MOPC, and approved by the BOD.

Stakeholder Reviews

The following is a list of reviews to be provided by stakeholders during the 2017 ITP10 study:

Load Forecast Review

Projected peak load per area for the year 2020 and 2025 will be submitted by the modeling contacts for the development of a peak 2020 and 2025 model. Stakeholders will review projected peak load, as well as annual load and loss factors. Peak load and energy will also be identified for load serving entities within SPP RTO areas (for example, Hastings Utilities and City of Grand Island load within NPPD).

Renewable Policy Survey

Stakeholders will provide feedback through a survey, conducted by the ESWG, on anticipated renewable mandates and goals based on current regulations. Stakeholders will provide energy or capacity requirements for years 2020 and 2025.

Generation Review

ESWG and MDWG will review the data for all generators added to the model as part of the 2017 ITP10 study. This will include conventional and renewable generation.

Proposed resources and facilities will be included and designated to a utility if it meets the resource inclusion criteria approved by the ESWG. Non-designated resources will be included based on commercial operation statuses and results of a transmission owner and generation interconnection customer survey of interconnection agreements with an on schedule status.

Economic Model Review

ESWG will be provided with model data indicating generators and the parameters used in the economic model. Parameters such as maximum capacity, run status, O&M costs, etc. will be provided for review.

Constraint Assessment Review

A list of constraints will be developed to be used in the economic dispatch, as detailed in the Constraint Review Section below. The constraints will be provided to the TWG for review; they will approve the final list of constraints to use, as well as the associated constraint ratings.

Power Flow Model Review

TWG and MDWG will review the economically-dispatched power flow models and provide feedback. The review will consider reactive imbalance on the system.

Generator Outlet Facilities

The Generator Outlet Facilities (GOF) methodology will be developed by staff and approved by the TWG and ESWG to ensure that facilities needed for Generation Interconnection to dispatch the resource plans are not considered regional needs. Generator Outlet Facilities (GOF) will be developed where existing transmission facilities near a point of interconnection are unable to withstand 100% dispatch of the resource plan additions and existing resources. These upgrades will be applied to the base model.

The TWG will review all facilities added as Generator Outlet Facilities (GOF) to the models as part of the Generation Resource Plan to mimic transmission upgrades that would be expected as a result of the Generation Interconnection process for resource additions.

Solution Development

SPP staff will analyze a pool of possible solutions in order to develop the 2017 ITP10 portfolio. This pool of solutions will be comprised of Detailed Project Proposals (DPPs), SPP-identified solutions, and any other solutions proposed by SPP stakeholders identified in the 2017 ITP10 needs assessment. These solutions will be analyzed to assess the project's potential to meet needs. This includes reliability, economic, and policy needs, as detailed in the Analysis Section of this document.

Study Process

1. The futures will be selected and assumptions refined through the various stakeholder groups (ESWG, TWG, MOPC, and RSC).
2. The ESWG will oversee the development of the economic models that incorporate the assumptions developed in step #1 above, including review of data and results. Similarly, the TWG will oversee the development of the power flow and stability models used in this analysis, including a summer peak case and a light load case. These will be developed through the existing SPP Planning Model Process via the MDWG.
3. Generator Outlet Facilities will be developed by Staff and approved by stakeholders where existing transmission facilities are unable to dispatch 100% of the new resource plan. They are included in the base model to ensure that facilities needed to dispatch the resource plans are not considered as solutions to regional needs.
4. Constraints will be developed through the identification of congested facilities. All constraints will be for 100 kV and above facility outages within SPP and first tier neighbor systems.
5. Staff will perform an initial AC analysis using applicable NERC Reliability Standards and SPP Criteria on power flow models that represent the applicable load profiles and generation dispatch associated with each future. The assessments will be limited to the planning horizon year. All facilities 69 kV and above in the models will be monitored within SPP and the first-tier for this analysis as a means to determine 100 kV and above solutions for SPP to the problems identified. The TWG will review the results.
6. Concurrently, an economic assessment will be performed to analyze congested facilities on the SPP Transmission System. This will be done using a security constrained unit commitment (SCUC) and security constrained economic dispatch (SCED) model over 8,760 consecutive hours.
7. 100 kV and above solutions to criteria violations, policy requirements, and/or congested facilities will be identified with input from stakeholders and coordinated as applicable with SPP neighbors. Staff will request suggestions for solutions from stakeholders and perform a preliminary assessment of benefits for these projects. During this phase, Staff will coordinate solutions with the Aggregate Studies and Generation Interconnection Study processes to best accommodate the high-demand areas for the SPP transmission system footprint.
8. A sensitivity analysis will be performed on the recommended portfolio to assess how versatile the plan is in handling a range of uncertainties.
9. Benefit metrics will be calculated for the recommended portfolio in the appropriate future(s).
10. A 40-year financial analysis will be conducted on the recommended portfolio.

11. Stability analyses will be conducted on the recommended portfolio to determine if voltage stability requirements for the region are met. A transfer voltage stability analysis will be performed on the appropriate future(s).

Data inputs

Economic

The analysis for the 2017 ITP10 will utilize stakeholder approved powerflow and economic models to facilitate the development of long range transmission plans. These models require certain assumptions regarding generation resources, parameters, and locations (detailed in the following sections). The output of these models will allow SPP Staff to identify the appropriate transmission solutions needed from an economic perspective. This output can also be used to determine deliverability of the resources to market used in the analysis.

The major assumptions needed to construct the economic models are detailed below and contain, but are not limited to: market structure, load forecasts, resource forecasts and parameters, transmission topology, renewable assumptions, fuel pricing and availability, etc. Once these assumptions are input into the model, a security constrained unit commitment (SCUC) and security constrained economic dispatch (SCED) will be simulated.

The following sections detail the parameters to be used in the economic portion of modeling.

Market Structure

SPP implemented its Integrated Marketplace and Consolidated Balancing Authority (CBA) in March 2014. The Integrated Marketplace and CBA will be baseline assumptions for the analysis.

Futures

Futures 1 and 2 of this study were developed based on how a solution to the EPA Clean Power Plan would be implemented, Future 3 is a reference case with no solution implemented.

Future 1: Regional Clean Power Plan Solution

This Future assumes that the EPA Clean Power Plan will be implemented at a Regional level by meeting emissions targets within the SPP footprint. Future 1 includes all assumptions from Future 3 with an increase in large scale solar development, as shown below, and minimal distributed solar development.

	Utlility-Scale Solar
Year	% of Peak Demand
2020	3%
2025	5%

Future 2: State Level Clean Power Plan Solution

This Future assumes that the EPA Clean Power Plan will be implemented at a State level by meeting emissions targets within each state. It will include all assumptions from Future 3 with an increase in large scale solar development, as shown in Future 1 above, and minimal distributed solar development.

Future 3: Reference Case

This Future assumes that the EPA Clean Power Plan will not be implemented. Future 3 will include all statutory/regulatory renewable mandates and goals as well as other energy or capacity as identified in the Renewable Policy Survey, load growth projected by load serving entities through the MDWG model development process, and the impacts of existing regulations. Additional significant features of this future include competitive wind and high availability of natural gas. This Future assumes no major changes to policies that are currently in place. Utility-scale and distributed solar will be included at the following nameplate capacity amounts:

	Utlility-Scale Solar	Distributed Solar
Year	% of Peak Demand	
2020	1%	0.50%
2025	3%	1%
2035	6%	2.00%

Clean Power Plan (CPP)

The impact of the Clean Power Plan (CPP)[1] will be accounted for in the resource planning, production cost modeling and benefit metric calculations where applicable. The following primary techniques will be employed to capture these impacts:

- unit retirements,
- energy efficiency,
- renewable additions,
- unit fuel switching, and
- emission price forecasts for CO_2

These decisions will be guided by the ESWG.

Load Forecasts

The study will require load forecasts for SPP members and non-members within the SPP footprint, as well as areas outside of the SPP footprint, for the years 2020 and 2025. SPP Staff queries its members through the MDWG for applicable load forecasts to use in each of the zones for the modeling footprint. Energy forecasts will be provided by the ESWG and other contacts. Load shapes will be obtained from publicly available data for the typical load projections.

For load forecasts outside of the SPP footprint, SPP will request load forecasts from SPP tier 1 neighbors. If data is not provided, publicly available data will be utilized as the source of the load forecasts, where available. If unavailable, publicly available information on projected load growth will be extrapolated to develop a representation for load expected in the study timeframe.

[1] Clean Power Plan Ruling

Resource Plan

A generation resource plan for 2020 and 2025 will be developed for use in the study for each future. This resource plan will include both renewable and conventional generation. Additionally, new renewable and conventional generation resources will be sited as detailed below.

Additional renewables will be included in the plans, as needed, to meet the renewable Mandate and Goal projections, as supplied by the Renewable Policy Survey. In addition to meeting renewable Mandates and Goals, each SPP RTO load serving member must meet the current reserve margin requirement outlined in SPP Criteria. The siting of new generation in the resource plan will target the current reserve margin requirement for each zone. Capacity needs will be identified for each future for 2020 and 2025.

Renewable generation, for the purposes of this study, includes hydro, wind, solar, and bio-fuel. Designated renewable resources will be identified through the Generation Review and will feed into the Resource Plan. Additional renewables identified by the resource planning software may also be included. The renewable ownership designations will be reviewed by stakeholders and posted on SPP.org.

SPP tier 1 neighbors will be provided the opportunity to provide feedback and input into the generation resource plan for their area.

System Topology

Power flow models will be required for the Study for both the economic and reliability assessments. The starting point of these power flow models will be the latest MDWG information from Model on Demand™, which includes the current projects from the latest SPP planning studies. These power flow models will serve as an input into the economic (production) modeling program to develop a market based economic dispatch for the system.

The topology used to account for the transmission system, excluding generation, will be the current transmission system and the following transmission upgrades: SPP upgrades that have been approved for construction, SPP Transmission Owner's planned (zonal sponsored) upgrades, Sponsored Upgrades endorsed by the SPP BOD, and first-tier entities' planned upgrades (first-tier entities listed below).

First-tier entities include the following:

- Associated Electric Cooperative, Inc. (AECI)
- Alliant Energy West (ALTW)
- Ameren Missouri (AMMO)
- CLECO Corporation (CLEC)
- Dairyland Power Cooperative (DPC)
- Entergy Arkansas (EAI)
- Entergy Electric System (EES)
- Great River Energy (GRE)

- Lafayette Utilities (LAFA)
- Louisiana Energy and Power Authority (LEPA)
- MidAmerican Energy (MEC)
- Montana-Dakota Utilities Co. (MDU)
- Otter Tail Power Company (OTP)
- Saskatchewan Power Co. (SPC)
- Xcel Energy North (XEL)

Economic Model Generation Parameters

The generation parameters (Startup cost, operating costs, Min/Max Operating Levels, etc.) will be updated by the ESWG as part of the Generation Review and economic model review.

Renewables

Renewable generation, primarily wind and solar, operate as energy resources that will require the development of hourly generation profiles for individual plants based on historical data or modeled time-series wind speed datasets. The economic dispatch model will attempt to realistically model renewable generation curtailment, based on expected market conditions and reliability requirements. A curtailment price consistent with the variable O&M cost will be used to simulate the behavior of the wind and solar generation within the Security Constrained Economic Dispatch (SCED).

Siting

The expected location of future generation will be considered in areas with appropriate potential. These sites will be developed utilizing those selected in the 2013 ITP20 and the 2015 ITP10 studies, the SPP Generation Interconnection queue, in addition to other analysis as appropriate for the futures of this study. SPP will request that tier 1 neighbors provide siting based on SPP's identification of capacity needs from the esource plan. If siting is not provided, SPP will site new generation.

DC Ties and Lines

DC ties and lines connect SPP to the WECC and ERCOT and Eastern Interconnect systems. Confirmed long-term firm transmission service will be used as a basis for modeling the flow levels of DC ties and lines. Hourly profiles will be developed based on 3-year historical flows on the DC facilities, limited to boundaries of existing long-term firm service commitments. No curtailment price will be assumed for the long-term firm service profile. For those DC ties or lines with no confirmed long-term firm transmission service, Staff will model no flow across the DC ties and lines.

Fuel Prices

Fuel forecasts will be utilized in the resource planning and production cost modeling. Fuel prices for coal, oil, and uranium, including transportation costs, will be forecasted for the study years based upon the latest NERC Nodal Reference Case available at the onset of the study. NYMEX futures will be utilized for natural gas prices, out to the latest year for which the futures are available. For natural gas prices beyond this year, growth rates from the DOE Annual Energy Outlook will be utilized. The specific NYMEX and DOE numbers will be developed during the resource planning phase of the study and then locked down for the remainder of the study.

Emission Prices

Emission price forecasts for SO_2 and NO_X for the study years will be based upon the latest NERC Nodal Reference Case data available at the onset of the study.

Renewable Policy Survey

A Renewable Policy Survey will be administered by the ESWG and will be used by stakeholders to provide assumptions regarding specific renewables information. The previous renewables surveys will be used as a reference for development of the current survey. The survey will contain, at a minimum, renewable capacity and/or energy totals for 2020 and 2025 based on state and utility mandates and goals.

For all renewable sites in the models, the renewable energy output for each hour of the year will be based on the maximum capacity or energy provided in the survey. Capacity factors and hourly profiles will be based on expected or historical behavior. Calculations for policy requirements will incorporate stakeholder specific inputs, and capacity factors and hourly profiles for wind used in the Study will be based on NREL wind profiles that correspond to a similar location as the wind site and are based on historical weather patterns.

Hurdle Rates

Hurdle rates will be utilized in the economic model between SPP and neighboring systems to help keep imports and exports at reasonable exchange levels. Hurdle rates for imports and exports between SPP and other entities will be developed and reviewed by the ESWG.

Benchmarking

After all assumptions and data are included in the economic model, it will be benchmarked against operational system behavior. This benchmarking will be used to assess the reasonability of the simulations.

Simulation results from the economic model will be compared with operational statistics and measurements from the SPP real time data, NERC data, and the Energy Information Administration data.

The ESWG will review the benchmarking data as part of the model review process. Specific benchmarks will include some or all of the following: capacity factor by unit type, generation by unit category, maintenance outages, renewable generation profiles, operating and spinning reserve levels, coal transportation costs, system Locational Marginal Prices (LMPs), flowgate loading, production costs, generation dispatch order, and zonal purchases and sales.

Steady State

Power flow models with a market dispatch under coincident peak load and off peak load will be developed.

Steady state analysis will be conducted using load and generation dispatch output from the economic simulations. These models will be utilized in additional engineering tools in order to conduct an assessment to determine the SPP system's voltage and thermal impacts. This steady state assessment is detailed in sections below.

Load

The load density and distribution for the steady state analysis will be reviewed by the MDWG. The load forecasts supplied by Stakeholders through the MDWG model development process take into consideration what load is industrial, non-scalable type loads and which load grows over time. The load used in the steady state analysis will be the same as that used in the economic model as described in Section: System Topology.

Generation Resources

The generating resources determined through the Resource Plan will be added to the power flow. Each future will contain a different subset of generation resources and correspond to a unique power flow case. These generating resources will be reviewed by the ESWG and will correspond to the economic analysis conducted for the Study.

Steady-State System Topology

The topology used in the steady state analysis will be the same as that used in the economic model as described in Section: System Topology.

Exports/Imports to First Tier

The exports/imports used in the steady state analysis between SPP and neighboring AC systems will be determined by the economic dispatch model. Exports and imports between DC interconnections will be based on historical hourly scheduling of long-term firm transmission service. This economic exchange of energy between neighboring systems will be modeled for the steady state analysis.

Market Dispatch

The economic models will be used to determine hourly load and generation dispatch at two snapshots in time for the steady state analysis. The generation dispatch and corresponding hourly load will be mapped from the economic model to the reliability power flow model as part of a DC – AC conversion.

Analysis

Define Constraints

To identify which constraints are applicable in 2025, Staff will begin by reviewing the existing flowgates to determine additions or deletions from the list of constraints (event file) for the economic model. Staff will perform additional analysis using Power Analytics and Trading Tool (PAT) to identify the top constraints by flowgate congestion costs on the system for 8,760 hours. These additional constraints will be reviewed and approved by TWG. The following items will be considered in the analysis:

- The initial constraint list will be the then-current SPP section of the Book of Flowgates
- Constraints studies will be run over 8,760 hours (1 year)
- This analysis will use the 2025 economic model(s) for each future
- Contingencies 100 kV and above in SPP and first-tier
- Monitored elements 100 kV and above in SPP and first-tier
- Unless other information is available, each constraint's rating will be selected based upon the applicable Rating A (normal rating) or Rating B (emergency rating) in the power flow model.

Needs Assessments

The policy, economic, and reliability needs of the system will be identified in each future in order to develop a transmission portfolio for each future. Each analysis will be performed in parallel to determine all needs across the system in 2025. All needs identified in the assessments below will be evaluated by Staff for potential consideration in the interregional planning process pursuant to the requirements of Order 1000.

Economic Assessment

The economic needs of the system will be identified in each future in order to develop a portfolio for each future. All of the system needs will be identified through the use of a SCUC & SCED simulation that accounts for 8,760 hours representing each hour of the year 2025.

The SCED will determine nodal Locational Marginal Prices (LMPs) while dispatching the generation economically. The LMPs, among other cost components, reflect the congestion occurring on the power grid's binding constraints. System congestion will be identified in each of the 8,760 hours. A list of binding constraints will be developed for each future and ranked based upon the congestion costs associated with each constraint. Up to twenty-five constraints, with greater than $50,000 in annual congestion cost, based upon this ranking will be identified as economic needs. ~~This list may be modified, subject to ESWG review and approval.~~

Policy Assessment

The policy needs of the system will also be identified for each future in order to develop a portfolio for each future. All of the system needs will be identified through the use of a SCUC & SCED simulation that accounts for 8,760 hours representing each hour of the year 2025. Renewable generation may experience the effects of congestion and be curtailed by the SCED. Shortfall in the achievement of the renewable requirements of each future due to this curtailment will be identified. Renewable resources that experience an annual energy output of less than the statutory/regulatory mandate or goal will be identified as policy needs. The required energy is based on maximum capacity, capacity factor, and generation profile.

Reliability Assessment

The steady state assessment will use 2025 summer peak and high wind with low load (off peak) models based on a market dispatch. Each future will be evaluated for the same peak and off peak hours. A contingency analysis will be conducted on each future for the peak and off peak cases. All SPP and first tier facilities 69 kV and above will be monitored for N-1 contingencies in development of 100 kV and above solutions. Also, all SPP BES facilities will be monitored for the NERC TPL-001-4 standard Table 1 planning events that do not allow for non-consequential load loss or curtailment of firm transmission service in development of 100 kV and above solutions.

Any non-converged contingencies will be reviewed.

DPP Window

In order to comply with FERC's Order 1000, SPP developed the Transmission Owner Selection Process, as outlined in Attachment Y of the SPP Tariff. In accordance with Attachment O, Section III.8.b, SPP 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 DPP. SPP shall track each DPP and retain the information submitted pursuant to Attachment O, Section III.8.b(i). For more information see SPP.org.

Solution Development

A pool of possible solutions will be used to mitigate the economic, reliability, and policy needs in creating the 2017 ITP10 transmission plan. This pool of solutions will come from DPPs, transmission service studies, generation interconnection studies, previous ITP studies, and any other solutions proposed by SPP stakeholders. Solutions developed could meet more than one need (*i.e.*, economic, policy, and/or reliability needs) and will be classified as project types based on the criteria outlined below.

~~Based on the criteria below, Staff will develop a plan for each future. Staff will then consolidate the projects from each future into a recommended plan.~~ Based on the criteria below, Staff will develop a plan for each future. Staff will then consolidate the projects from each CPP future (Futures 1 and 2) into a single portfolio. This CPP portfolio and the reference case (Future 3) portfolio will move on for additional benefit calculations.

Commented [AG1]: Consolidation decision point

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Economic Project Solutions

Economic projects will be developed and evaluated based upon how well they mitigate congestion. Any economic project with a one-year B/C ratio greater than the approved ESWG threshold of 0.5 will be included for further evaluation.

Policy Project Solutions

Policy projects will be developed and evaluated based upon how well they mitigate curtailment of renewable energy required by the regulatory/statutory mandates and goals as defined by the 2017 ITP10 Policy Survey. Any policy project that helps to mitigate curtailment of renewable requirements will be included for further evaluation.

Reliability Project Solutions

Reliability projects will be developed and evaluated based upon how well they mitigate NERC and/or SPP criteria violations for the peak and off peak hours.

Transmission Operating Guides (TOGs)

TOGs are tools used to mitigate violations in the daily management of the transmission grid, TOGs may be evaluated as alternatives to proposed ITP10 projects and tested to determine effectiveness in mitigating violations.

Interregional Considerations

Seams projects will be considered as part of the 2017 ITP10 study and expansion plan as potential solutions, and SPP will collaborate with neighboring entities regarding the identified needs, benefits, potential solutions, and costs. For the neighbors that SPP has an agreement with, joint coordination will be done in accordance with that agreement.

Seams projects will be initially evaluated and considered under the assumption that the project would be cost shared with an SPP neighbor. As the evaluation progresses and the SPP neighbor identifies the level with which they would be willing to share in the project's cost, the cost will be updated to reflect a more accurate cost distribution.

Final Recommended Portfolio

Reliability, policy, and economic solutions will be grouped together and refined to create a portfolio for each future. The grouping of projects will be evaluated for redundancies. If, for example, a reliability project is similar to a policy project, the two projects will be evaluated to see which project meets both the reliability need and the policy need in the most cost effective way, while the other project is then discarded. The final portfolio for each future will be consolidated into a single CPP portfolio and a reference case portfolio. The consolidation of reliability, policy and economic projects will be based upon criteria approved by the ESWG, TWG, and the MOPC.

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Forty-Year Financial Analysis

The 2017 ITP10 shall assess the cost effectiveness of the recommended portfolio over a forty-year time horizon in accordance with Section III.3.c of Attachment O of the SPP OATT. To estimate the benefits over 40 years, APC savings will be calculated for multiple model years, including 2020 and

2025. The slope between the selected points will be used to extrapolate the benefits beyond 2025. A terminal value will be used for the last 20 years of the benefit calculation. The project costs will be calculated using the formulas for Annual Transmission Revenue Requirement (ATRR). The total benefits and costs will be reported in net present value (NPV) dollars.

Benefit and impact calculations will be made on a Regional, Zonal, and State basis. Many zones are only in one state. For those zones that are only in one state, their full portion of both costs and benefits will be allocated to the state. For zones crossing state borders, their portion of both costs and benefits will be allocated to each state based on their percentage of load that is in each state.

Net benefits and B/C ratios will be calculated based on NPV benefit and NPV cost and will be reported based on present dollars (2017).

Benefit Metric Development and Usage

The metrics used to measure the value of the final portfolio(s) in the 2017 ITP10 are identified here and will be vetted with the ESWG. These metrics will be used to measure the value of the final consolidated portfolio(s) in the appropriate Future(s).

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Metric Description
APC Savings
Savings Due to Lower Ancillary Service Needs and Production Costs
Avoided or Delayed Reliability Projects
Marginal Energy Losses
Capacity Cost Savings Due to Reduced On-Peak Transmission Losses
Reduction of Emissions Rates and Values
Public Policy Benefits
Assumed Benefit of Mandated Reliability Projects
Mitigation of Transmission Outage Costs
Increased Wheeling Through and Out Revenues

Table 1: Monetized Cost Benefit Metrics for 2017 ITP10

~~To the extent that any adjustments or changes to Benefit Metrics are recommended by the Regional Allocation Review Task Force (RARTF), these changes will be considered by the ESWG and TWG.~~

Sensitivities

Sensitivities will be conducted on the final recommended portfolio for the appropriate Future(s) to assess how versatile the plan is in handling a range of uncertainties. Economic analysis will be performed for the sensitivities. ~~Some or all of t~~The following sensitivities will be performed:

- Natural Gas Price

- Demand levels
- ~~Others as determined~~

The sensitivities will be used to measure the viability of the proposed transmission plan that is produced through the 2017 ITP10. These sensitivities will not be used to develop the transmission projects or filter out projects.

Staging

A project implementation plan will be developed for the final recommended portfolio. The final portfolio will be structured such that each element can be implemented in a staged manner as actual system developments approach the assumptions resulting in the need for that element. To help stage the projects SPP will utilize years 2020 and 2025. This section is broken into two parts: one for projects classified to meet one set of needs (i.e. economic, policy, or reliability needs); one for projects meeting multiple needs.

Single Project Classification

For economic projects, Staff will stage projects based on linear interpolation of B/C ratios from 2020 to 2025 with consideration of lead times.

For policy projects, Staff will stage projects in order to meet the renewable requirements.

For reliability projects, Staff will stage projects based on linear interpolation of thermal loadings and voltage violations from 2020 to 2025.

Multiple Project Classification

If a project is classified as more than solely economic, policy, or reliability project, the project will be staged to meet the earliest need date established through the Single Project Classification Section.

Reactive Needs

If any 300 kV and above upgrades are identified as solutions in the portfolio, line-end reactive requirements analysis will be performed for the new transmission lines greater than 300 kV system to provide an indicative amount of reactor needs before design level studies are completed.

Final Reliability Assessment

A steady state contingency analysis, like that described in the Reliability Assessment~~Reliability Assessment~~ section will be conducted to identify any remaining outstanding issues on the final recommended portfolio(s).

Cost Estimates

The cost estimates used for projects that are tested in the initial project development phase will be Conceptual Estimates as defined by the SPP Business Practice 7060. The Conceptual Estimates will be developed by Staff and utilize standardized estimates and multipliers that are based on historical data. Projects that pass the initial screening phase will be designated for Study Estimates as defined by Business Practice 7060.

A Study Estimate will be prepared by the designated TO(s) for non-competitive upgrades and by Staff for competitive upgrades by completing a Standardized Cost Estimate Reporting Template (SCERT) for all upgrades that are required to complete that project. The Study Estimate will provide a more refined cost estimate for potential project approval.

Final Stability Assessment

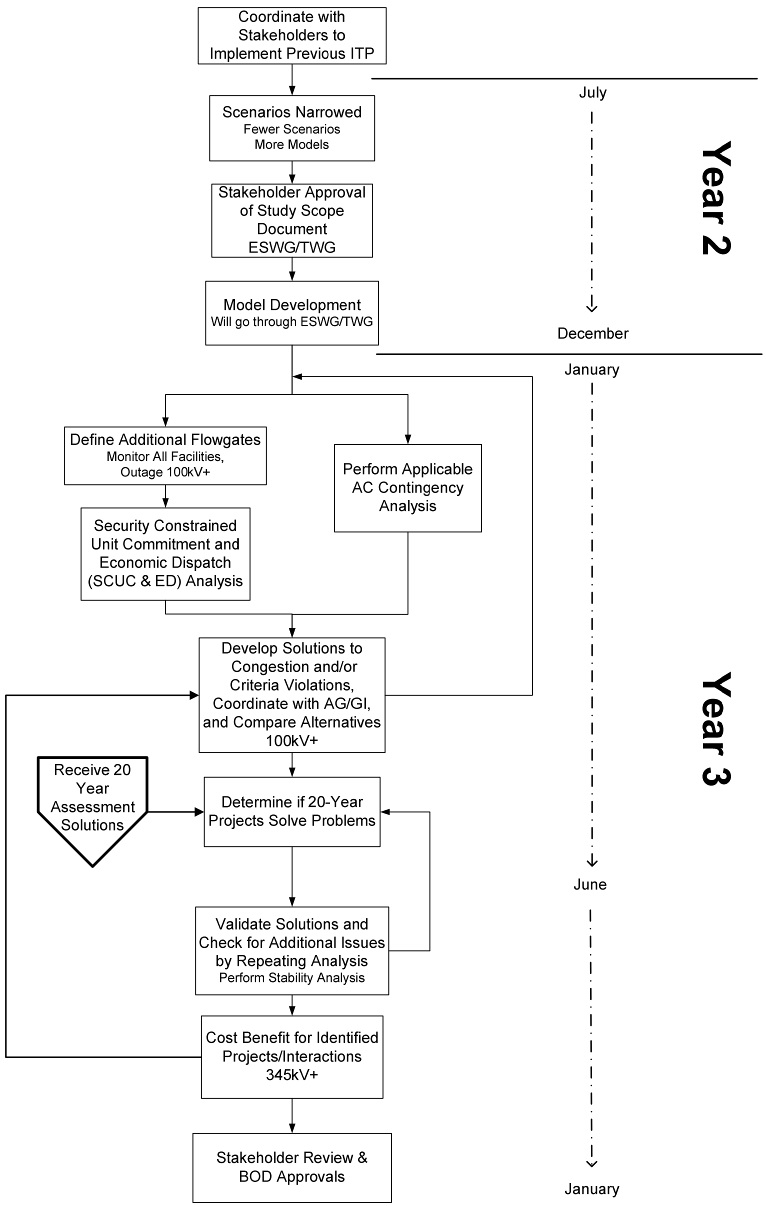
A voltage stability assessment will be conducted on the appropriate future(s) using the recommended final portfolio to assess the transfer limit (MW) due to transfers from north to south, south to north, and west to east across the SPP footprint. These must be determined by examining voltage performance during power transfer into a load area or across an interface. The stability assessment consists of a dispatch analysis to determine if the dispatched generation in the 2017 ITP10 2025 summer and light load models can be dispatched without the occurrence of voltage collapse or thermal violations.

Timeline

The 2017 ITP10 will generally follow the process flow below beginning in July 2015 with final results in January 2017. The estimated timeline is as follows:

2017 ITP10	Group(s) to review/endorse	Start Date	Completion Date
Futures & Scope	ESWG, TWG, MOPC, SPC	January 2015	October 2015
Policy Survey	ESWG	May 2015	July 2015
Load Forecast and Generation Review	ESWG, TWG	February 2015	July 2015
Renewable Resource Plans	ESWG	June 2015	August 2015
Conventional Resource Plans	ESWG	June 2015	October 2015
Siting Plan	ESWG	September 2015	December 2015
Powerflow Model Development	TWG	June 2015	January 2016
Economic Model Development	ESWG	June 2015	January 2016
Model Benchmarking	ESWG	December 2016	
Constraint Review	TWG	August 2015	March 2016
Needs Assessment	ESWG, TWG	March 2016	April 2016
Detailed Project Proposal Request	ESWG, TWG	April 2016	May 2016
Solution Development	ESWG, TWG	April 2016	July 2016
Project Grouping	ESWG, TWG	August 2016	September 2016
Portfolio Consolidation	ESWG, TWG	September 2016	October 2016
Project Staging	ESWG, TWG	October 2016	November 2016
Sensitivities Conducted	ESWG	October 2016	December 2016
Final Benefit Metrics Calculations	ESWG	October 2016	December 2016
Stability Analyses	TWG	October 2016	November 2016
Review draft report with recommended solutions	ESWG, TWG	August 2016	October 2016
	MOPC	October 2016	
Final report with recommended solutions	ESWG, TWG	November 2016	December 2016
	RSC	January 2017	
	MOPC, BOD		

10-Year Assessment Process (Initiated Every 3 Years)



Deliverables

Final Report and Recommended Portfolio

The results from the 2017 ITP10 will be compiled into a report detailing the findings and recommendations of SPP Staff. The report will include a project list identifying each upgrade. This report will also be incorporated into the 2017 STEP Report.

Staging and Timing of Project Implementation

A project implementation plan will be developed for the recommended transmission plan. The final plan will be structured such that each element can be implemented in a staged manner as actual system developments approach the assumptions resulting in the need for that element. Each element will have at least one of the following justifications: policy, economic or reliability justification. NTCs/NTC-Cs and RFPs will be issued for the 2017 ITP10 plan elements in accordance with the Tariff, Attachment O, Section VI and SPP written procedures (see Business Practice 7060[2]).

[2] SPP.org > Org Groups > Access SPP's Governing Documents > OATT Business Practices

Changes in Process and Assumptions

In order to protect against changes in process and assumptions that could present a significant risk to the completion of the 2017 ITP10, any such changes must be vetted. If a stakeholder group votes on any process steps or assumptions to be used in the study, those assumptions will be used for the 2017 ITP10. Changes to process or assumptions recommended by stakeholders must be approved by the appropriate stakeholder group(s) and the MOPC. This process will allow for changes if they are deemed necessary and critical to the ITP, while also ensuring that changes, and the risks and benefits of those changes, will be fully vetted and discussed.

Economic Studies Working Group (ESWG)

MOPC Action Item 255

Strawman Proposal

Background

SPP Staff was directed by the Markets and Operations Policy Committee (MOPC) in January, 2015 to review the method to determine the cost of congestion as it relates to outages for rebuilds approved. Staff enlisted the expertise of the Economic Studies Working Group (ESWG) to develop a proposal to address this item.

Purpose

This strawman proposal considers costs related to increases in system congestion that could be relevant during the project screening and selection phase of the ITP. These costs could be relevant when comparing two projects relatively close in economic value if one of the projects would incur significant congestion costs during construction..

Current Method

The current methodology to evaluate projects submitted to address transmission needs defined by any ITP study relies on SPP and NERC reliability criteria and economic and policy criteria developed by the ESWG.

Reliability: Mitigation of thermal and voltage violations defined by SPP and NERC criteria assuming the proposed project in-service

Economic: Projected adjusted production cost savings assuming the proposed project in-service

Policy: Mitigation of curtailment of renewable resources required to satisfy a public policy objective assuming the proposed project in-service

Proposed Method

The proposed methodology builds on the current method to select transmission solutions by including economic impacts experienced during construction of proposed rebuild projects. The proposed analysis to include these potential costs is as follows:

- Perform analysis in study model
    - Outage line proposed to be rebuilt
    - Determine outage duration leveraging historical data
        - Develop typical durations by kV and mileage
        - Alternatively, request potential outage durations from incumbent TO
- Add congestion cost to project engineering and construction costs during project selection phase
    - For reliability project analysis, this cost is assumed in full
    - For economic project analysis, this cost is assumed to be an annuity payment to be paid down concurrent with transmission investment in order to calculate a more accurate 1-year B/C

Example Results

The following example results include the additional economic impacts in evaluation of potential economic rebuild solutions.

Project	E&C Cost*	Benefit**	Old B/C	Congestion Cost***	New B/C
Project A	$14,387,085	$13,469,000	0.94	($147,686)	0.95
Project B	$3,064,773	$24,979,000	8.15	$908,966	6.29
Project C	$5,557,498	$6,784,000	1.22	($105,440)	1.24
Project D	$522,527	$999,000	1.91	$49,241	1.75

*1-year conceptual cost

**All results from test runs on 2015 ITP10 base model

***1-year annuity payment, 2.5% rate

Discussion

Staff conclusions are as follows:

- The impact of the congestion cost during rebuild of a facility is very situational
- Example analysis contains assumptions and limitations that contribute to both overstating and understating congestion costs
    - Potentially overstates congestion impacts due to assumed 1-year outage duration
    - Potentially overstates cost due to lack of project staging considerations
    - Likely understates cost due to constraint assessment limitations
        - Constraints are developed to redispatch around congestion seen in the base study models
        - No adjustments are made to account for the impact of changing system topology on system congestion after needs assessments
- Historically constrained areas will likely show higher and more accurate costs than future constrained areas due to inclusion of all current permanent flowgates regardless of system congestion in the future

Implementing this methodology is selective in nature. Other approved benefit metrics are not being incorporated in the project selection process that likely have a much greater impact on project selection results. At the same time, it is not feasible to include all benefit analysis at the project screening/selection phase.

This methodology should be considered selectively. Options:

- This methodology should generally not be implemented, but allow Staff the discretion to consider these impacts as appropriate, or

- Due to the wide variability and applicability, more time should be spent to determine a methodology to selectively apply the analysis in order to avoid performing it for every rebuild solution proposed.

~~Recommendation~~Conclusion

The impact of congestion costs ~~on~~ due to rebuild upgrades ~~should~~ could be considered in project selection for the ITP assessment. Preliminary analysis demonstrates an infrequent and situational impact on transmission congestion that could change transmission expansion decisions. It is the ESWG's belief that there are currently approved benefit metrics that could have a broader and greater impact on transmission expansion decisions.

Recommendation

If the impact of congestion due to outages for rebuild upgrades should be considered to affect transmission expansion decisions in ITP assessments, ESWG recommends the analysis to be evaluated against the other approved benefit metrics to determine the set of analyses that would both be feasible to implement and have the greatest collective impact on the selection transmission upgrades. ~~In order to effectively assess these impacts, an assessment of system constraints should be performed following the development of a portfolio of projects, taking into account any prolonged outages for proposed upgrades. Any upgrades significantly impacted by this assessment should be re-evaluated with alternatives. More time is needed to perform an assessment to determine the feasibility of implementation and potential schedule impacts.~~


SPP
75th Anniversary
75
SEVENTY-FIVE YEARS OF
RELIABILITY THROUGH RELATIONSHIPS

2016 ESWG Meeting Schedule

ESWG

March 17th, 2016

Approved Schedule – 1st Semester

January						
S	M	T	W	T	F	S
					1	2
3	4	5	6	7	8	9
10	11	12	13	14	15	16
17	18	19	20	21	22	23
24	25	26	27	28	29	30
31						

April						
S	M	T	W	T	F	S
					1	2
3	4	5	6	7	8	9
10	11	12	13	14	15	16
17	18	19	20	21	22	23
24	25	26	27	28	29	30

February						
S	M	T	W	T	F	S
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7	8	9	10	11	12	13
14	15	16	17	18	19	20
21	22	23	24	25	26	27
28	29					

May						
S	M	T	W	T	F	S
1	2	3	4	5	6	7
8	9	10	11	12	13	14
15	16	17	18	19	20	21
22	23	24	25	26	27	28
29	30	31				

March						
S	M	T	W	T	F	S
		1	2	3	4	5
6	7	8	9	10	11	12
13	14	15	16	17	18	19
20	21	22	23	24	25	26
27	28	29	30	31		

June						
S	M	T	W	T	F	S
			1	2	3	4
5	6	7	8	9	10	11
12	13	14	15	16	17	18
19	20	21	22	23	24	25
26	27	28	29	30		

Month	Day	Location
January	21	Lubbock
February	17-18	Kansas City
March	17	Dallas
April	21	Oklahoma City
May	18-19	Omaha
June	16	Dallas

- BOD
- RSC
- MOPC
- PCWG
- SPCWG
- CAWG
- TWG
- ESWG
- MDWG
- SSC
- SPC
- GWG
- SPP Holiday

Combination Dates
- ESWG/TWG
- ESWG/SSC
- ESWG/PCWG
- SSC/CAWG

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Proposed Schedule – 2nd Semester

July

S	M	T	W	T	F	S
					1	2
3	4	5	6	7	8	9
10	11	12	13	14	15	16
17	18	19	20	21	22	23
24	25	26	27	28	29	30
31						

October

S	M	T	W	T	F	S
						1
2	3	4	5	6	7	8
9	10	11	12	13	14	15
16	17	18	19	20	21	22
23	24	25	26	27	28	29
30	31					

August

S	M	T	W	T	F	S
	1	2	3	4	5	6
7	8	9	10	11	12	13
14	15	16	17	18	19	20
21	22	23	24	25	26	27
28	29	30	31			

November

S	M	T	W	T	F	S
		1	2	3	4	5
6	7	8	9	10	11	12
13	14	15	16	17	18	19
20	21	22	23	24	25	26
27	28	29	30			

September

S	M	T	W	T	F	S
				1	2	3
4	5	6	7	8	9	10
11	12	13	14	15	16	17
18	19	20	21	22	23	24
25	26	27	28	29	30	

December

S	M	T	W	T	F	S
				1	2	3
4	5	6	7	8	9	10
11	12	13	14	15	16	17
18	19	20	21	22	23	24
25	26	27	28	29	30	31

Month	Day	Location
July	21	?
August	17-18	Billings
September	15	Dallas
October	20	?
November	16-17	Little Rock
December	8	Dallas

- BOD
- RSC
- MOPC
- PCWG
- SPCWG
- CAWG
- TWG
- ESWG
- MDWG
- SSC
- SPC
- GWG
- SPP Holiday

Combination Dates
- ESWG/TWG
- ESWG/SSC
- ESWG/PCWG
- SSC/CAWG